Energy Tidbits

India to Expand Natural Gas Distribution to Cover 96% of Population Sets Up Huge LNG Demand Growth in 2020s

Produced by: Dan Tsubouchi

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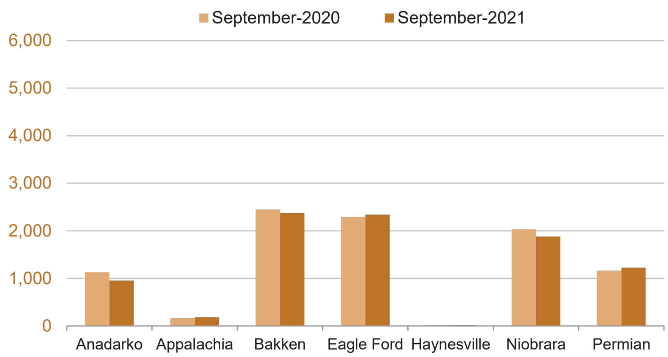
Year-over-year summary

Drilling Productivity Report

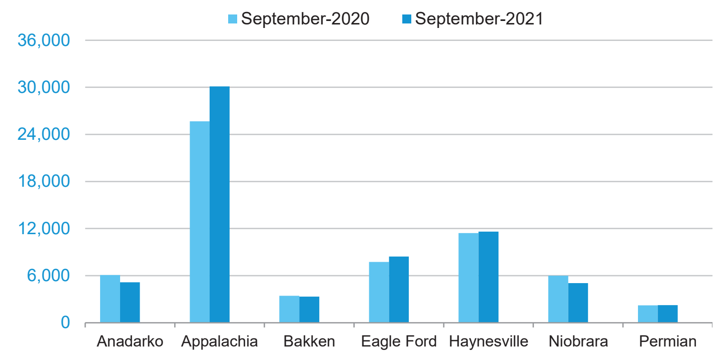
August 2021

drilling data through July
projected production through September

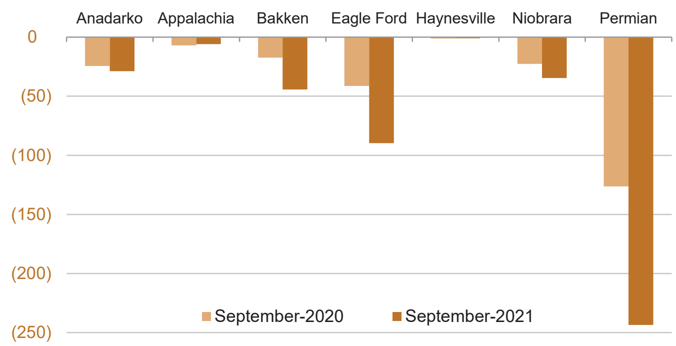
New-well oil production per rig
barrels/day



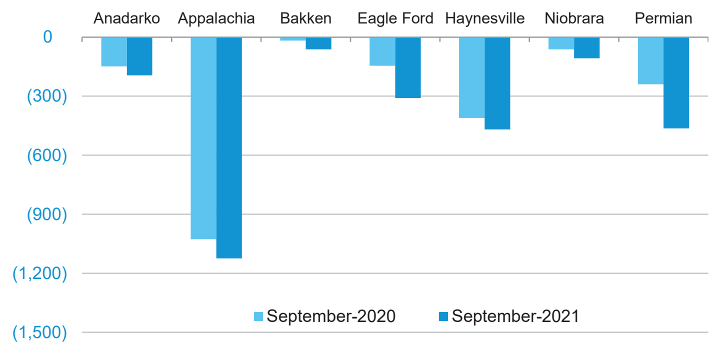
New-well gas production per rig
thousand cubic feet/day



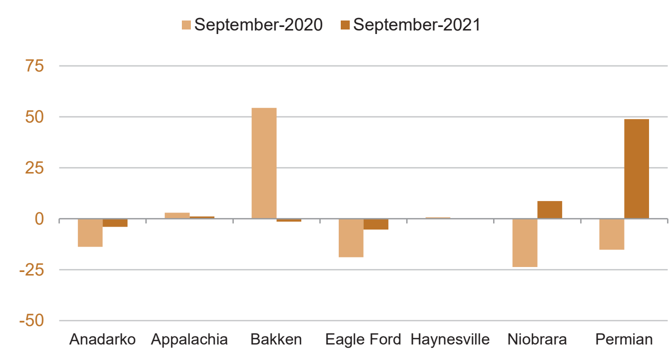
Legacy oil production change
thousand barrels/day



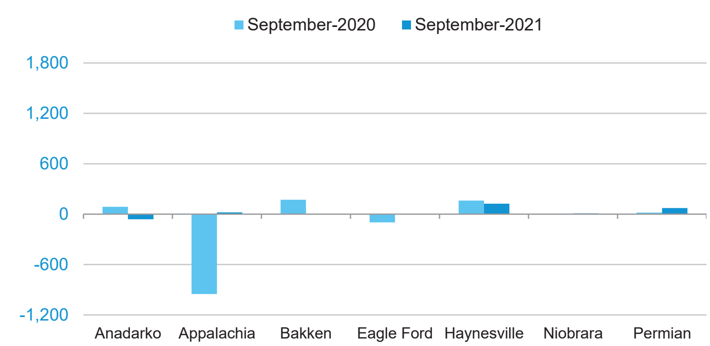
Legacy gas production change
million cubic feet/day



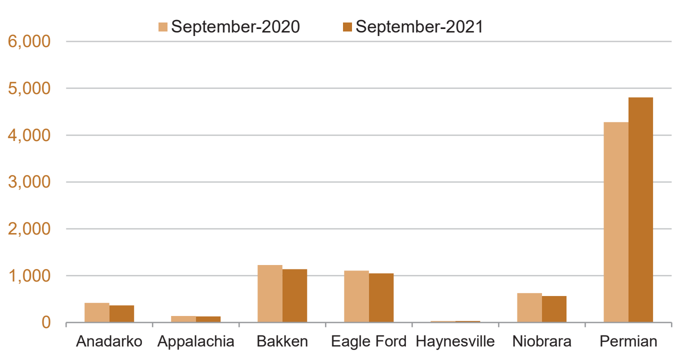
Indicated monthly change in oil production (Sep vs. Aug)
thousand barrels/day



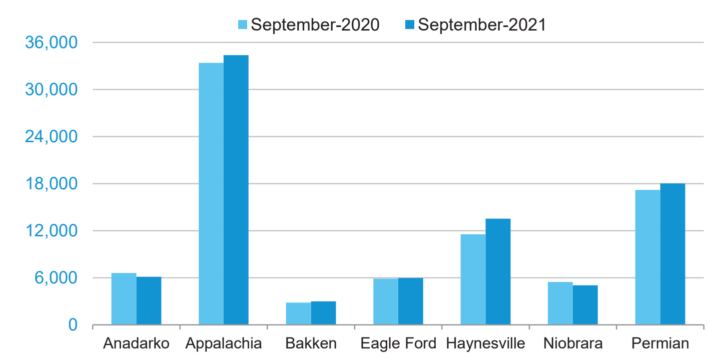
Indicated monthly change in gas production (Sep vs. Aug)
million cubic feet/day



Oil production
thousand barrels/day



Natural gas production
million cubic feet/day



Anadarko Region

Drilling Productivity Report

August 2021

drilling data through July
projected production through September

Oil -19 barrels/day month over month

955 *September* **974** *August* barrels/day

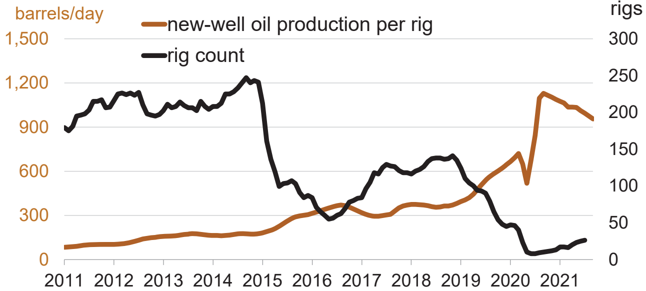
Monthly additions from one average rig

September **5,145** *August* **5,250** thousand cubic feet/day

Gas -105 thousand cubic feet/day month over month

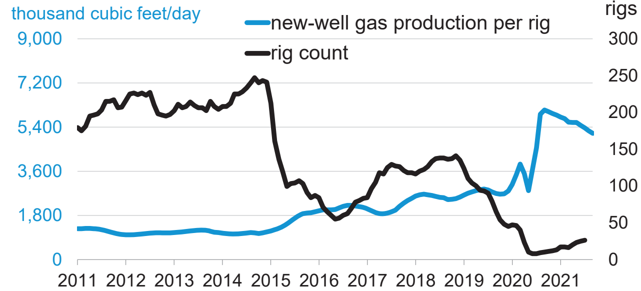
Anadarko Region
New-well oil production per rig — **Rig count**

barrels/day — rigs



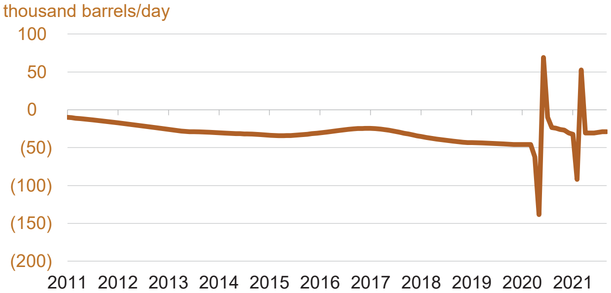
Anadarko Region
New-well gas production per rig — **Rig count**

thousand cubic feet/day — rigs



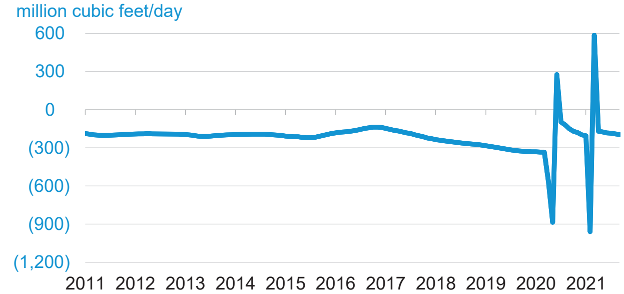
Anadarko Region
Legacy oil production change

thousand barrels/day



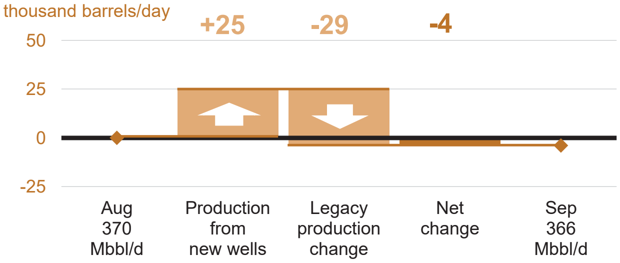
Anadarko Region
Legacy gas production change

million cubic feet/day



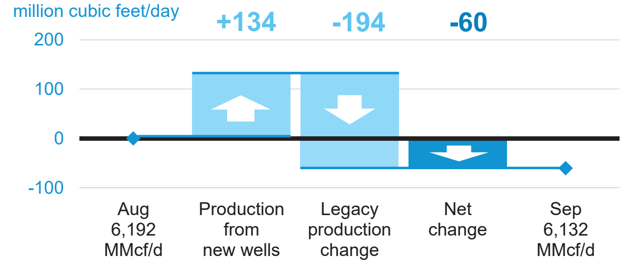
Anadarko Region
Indicated change in oil production (Sep vs. Aug)

thousand barrels/day



Anadarko Region
Indicated change in natural gas production (Sep vs. Aug)

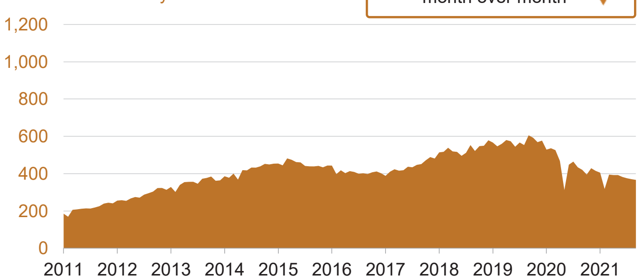
million cubic feet/day



Anadarko Region
Oil production

thousand barrels/day

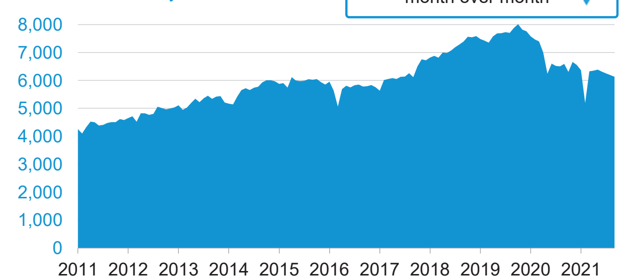
Oil -4 thousand barrels/day month over month



Anadarko Region
Natural gas production

million cubic feet/day

Gas -60 million cubic feet/day month over month



Appalachia Region

Drilling Productivity Report

August 2021

drilling data through July
projected production through September

Oil
0
barrels/day
month over month

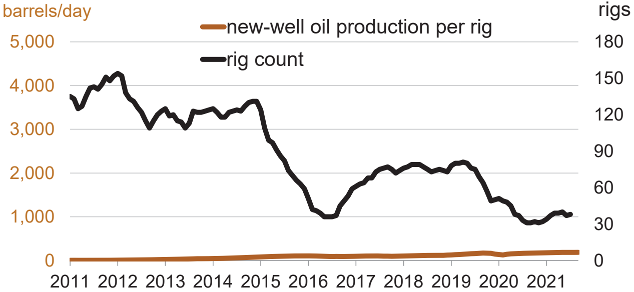
186 *September*
186 *August*
barrels/day

Monthly additions from one average rig

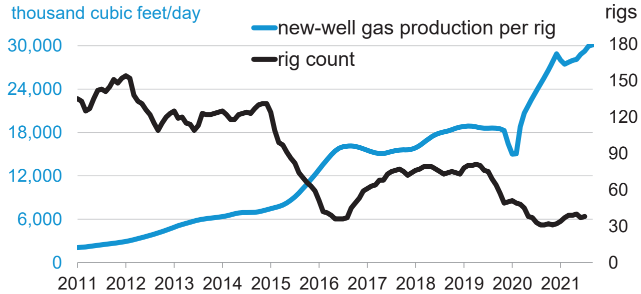
September **30,121**
August **29,971**
thousand cubic feet/day

Gas
+150
thousand cubic feet/day
month over month

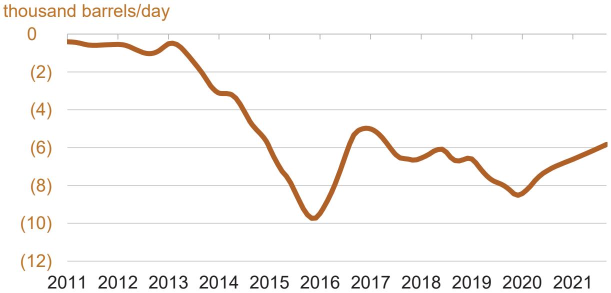
Appalachia Region
New-well oil production per rig



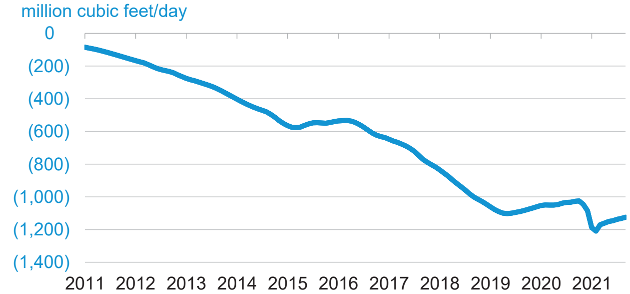
Appalachia Region
New-well gas production per rig



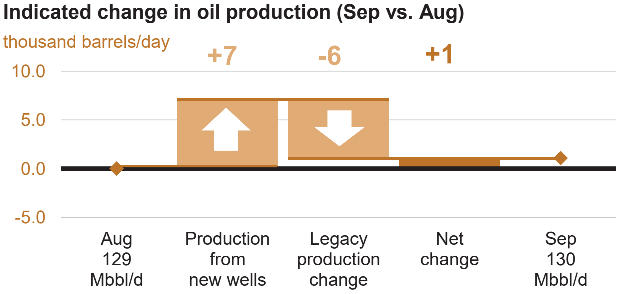
Appalachia Region
Legacy oil production change



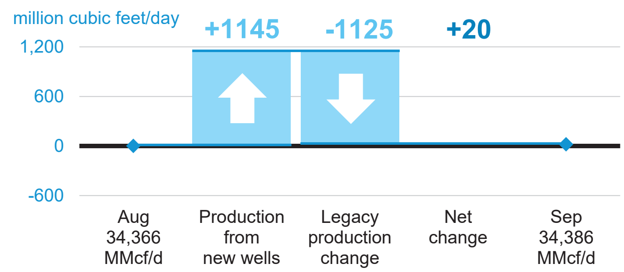
Appalachia Region
Legacy gas production change



Appalachia Region
Indicated change in oil production (Sep vs. Aug)

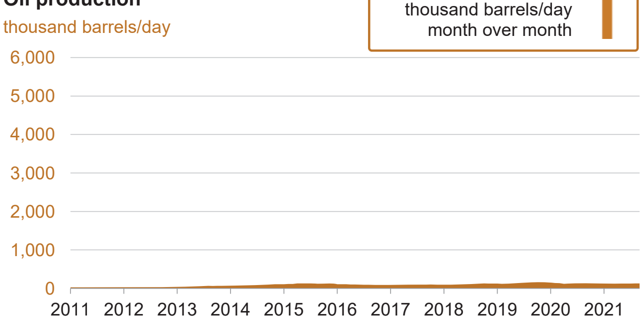


Appalachia Region
Indicated change in natural gas production (Sep vs. Aug)



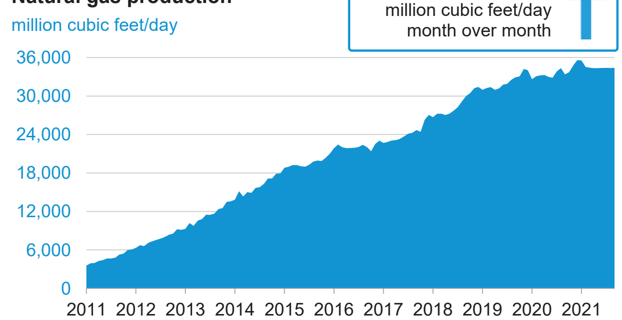
Appalachia Region
Oil production

Oil +1
thousand barrels/day
month over month



Appalachia Region
Natural gas production

Gas +20
million cubic feet/day
month over month



Bakken Region

Drilling Productivity Report

August 2021

drilling data through July
projected production through September

Oil
-10
barrels/day
month over month

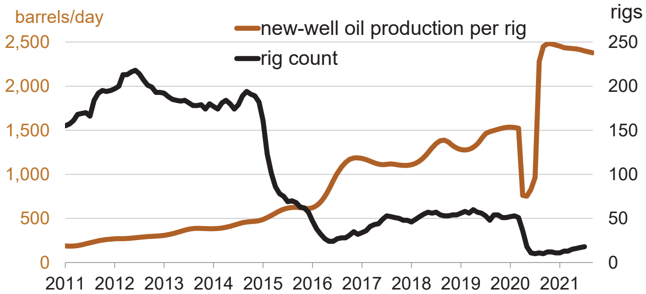
2,378 *September*
2,388 *August*
barrels/day

Monthly additions from one average rig

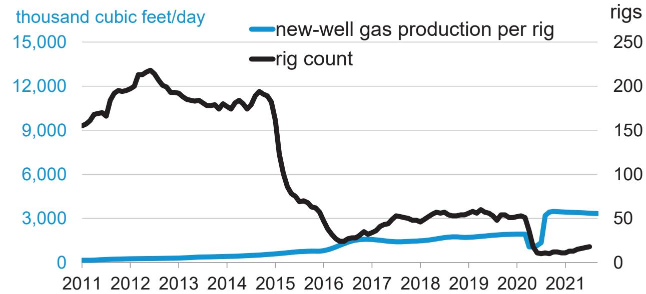
September **3,329**
August **3,344**
thousand cubic feet/day

Gas
-15
thousand cubic feet/day
month over month

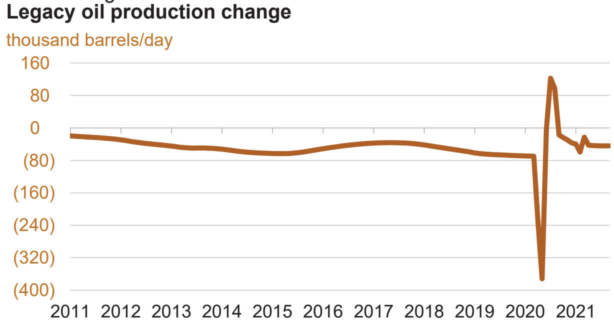
Bakken Region
New-well oil production per rig **Rig count**



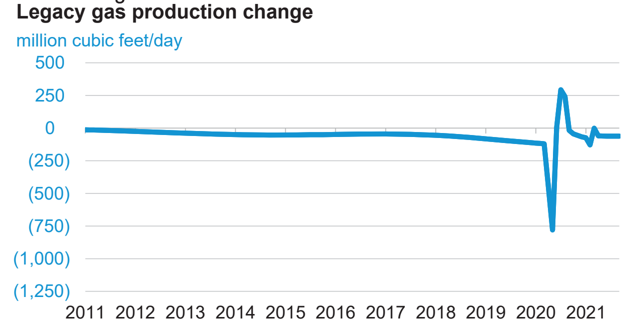
Bakken Region
New-well gas production per rig **Rig count**



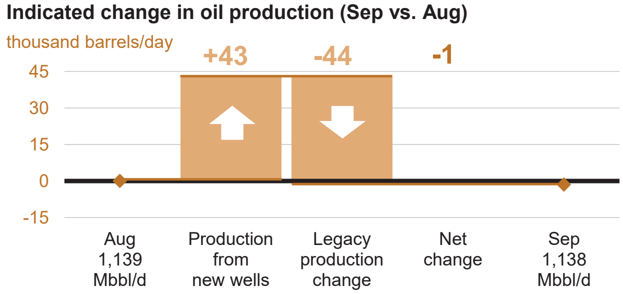
Bakken Region
Legacy oil production change



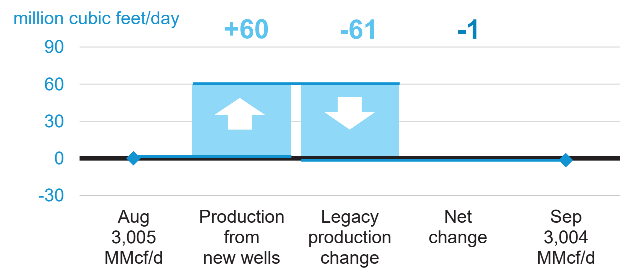
Bakken Region
Legacy gas production change



Bakken Region
Indicated change in oil production (Sep vs. Aug)

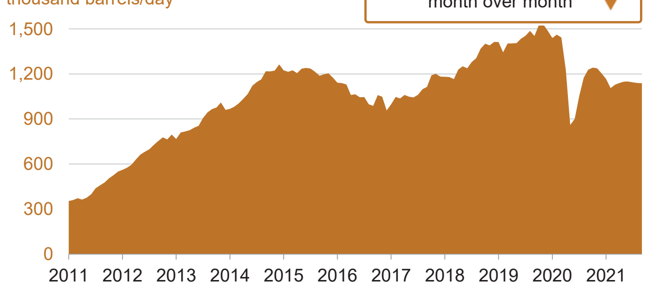


Bakken Region
Indicated change in natural gas production (Sep vs. Aug)



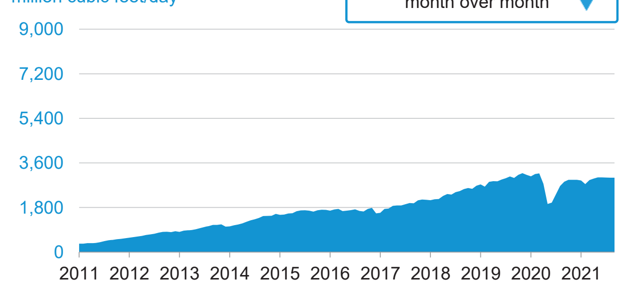
Bakken Region
Oil production

Oil -1
thousand barrels/day
month over month



Bakken Region
Natural gas production

Gas -1
million cubic feet/day
month over month



Eagle Ford Region

Drilling Productivity Report

August 2021

drilling data through July
projected production through September

Oil +1 barrels/day month over month

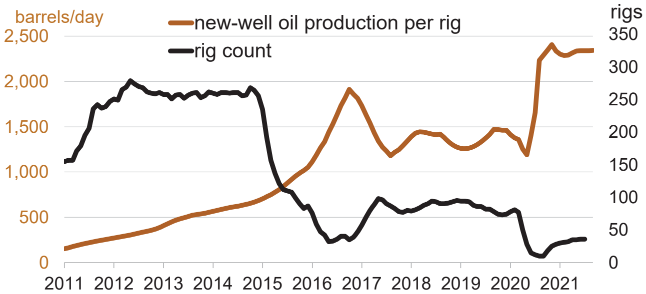
2,343 *September*
2,342 *August*
barrels/day

Monthly additions from one average rig

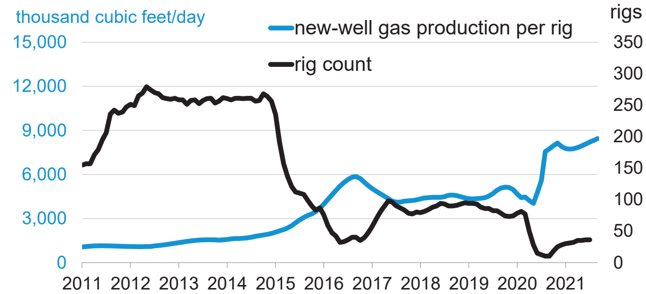
September **8,426**
August **8,302**
thousand cubic feet/day

Gas +124 thousand cubic feet/day month over month

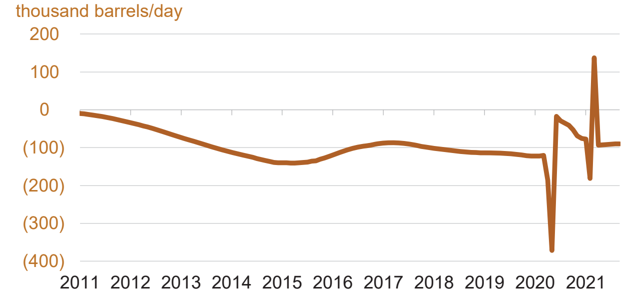
Eagle Ford Region
New-well oil production per rig



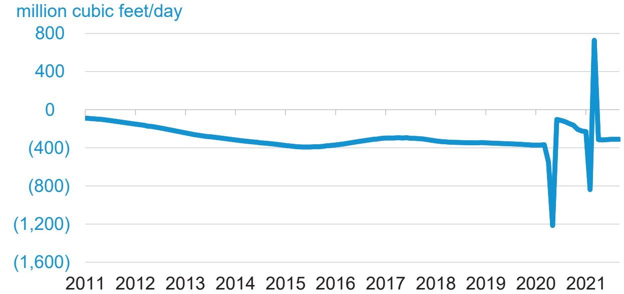
Eagle Ford Region
New-well gas production per rig



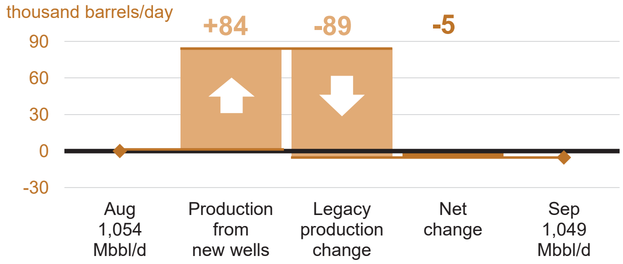
Eagle Ford Region
Legacy oil production change



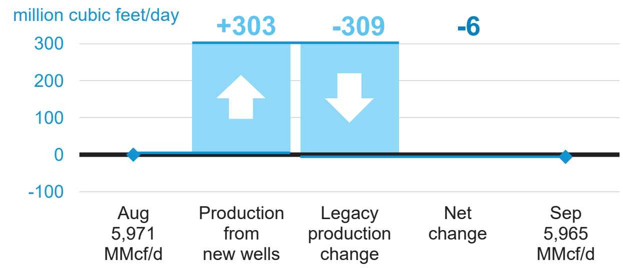
Eagle Ford Region
Legacy gas production change



Eagle Ford Region
Indicated change in oil production (Sep vs. Aug)

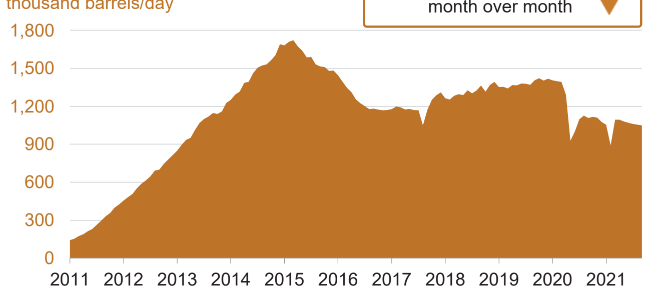


Eagle Ford Region
Indicated change in natural gas production (Sep vs. Aug)



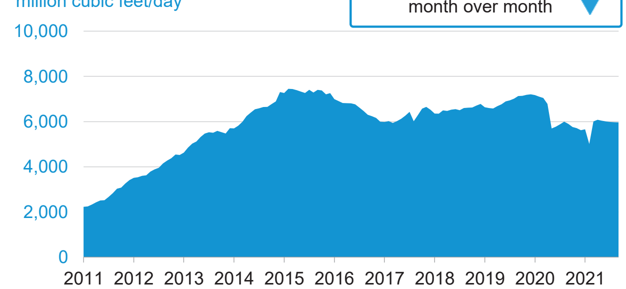
Eagle Ford Region
Oil production

Oil -5 thousand barrels/day month over month



Eagle Ford Region
Natural gas production

Gas -6 million cubic feet/day month over month



Haynesville Region

Drilling Productivity Report

August 2021

drilling data through July
projected production through September

Oil
0
barrels/day
month over month

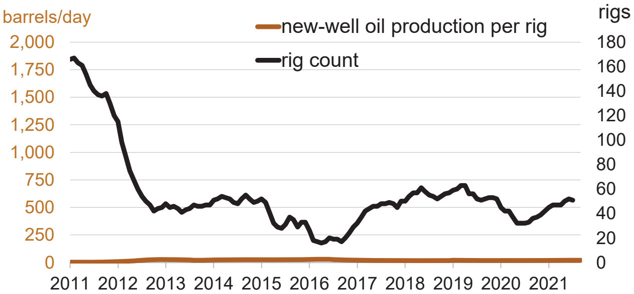
19 *September*
19 *August*
barrels/day

Monthly additions from one average rig

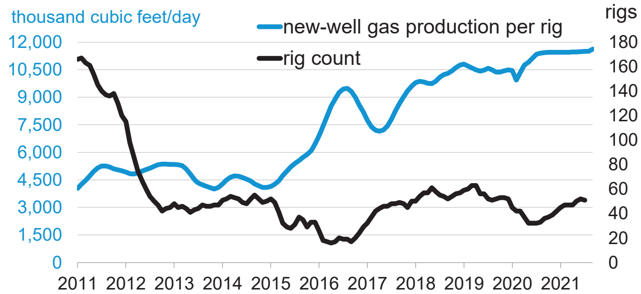
September **11,615**
August **11,500**
thousand cubic feet/day

Gas
+115
thousand cubic feet/day
month over month

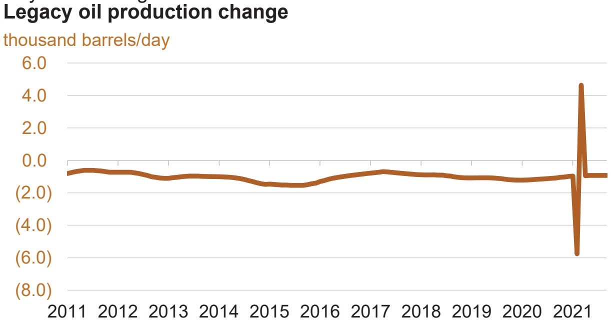
Haynesville Region
New-well oil production per rig **Rig count**



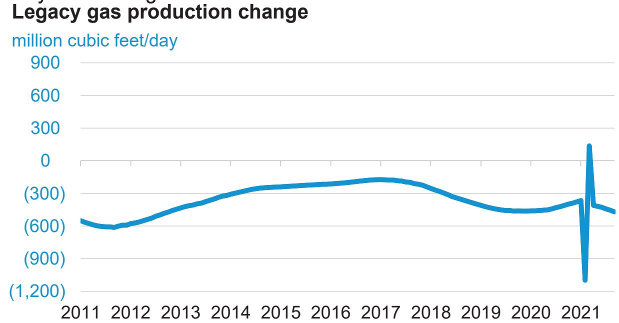
Haynesville Region
New-well gas production per rig **Rig count**



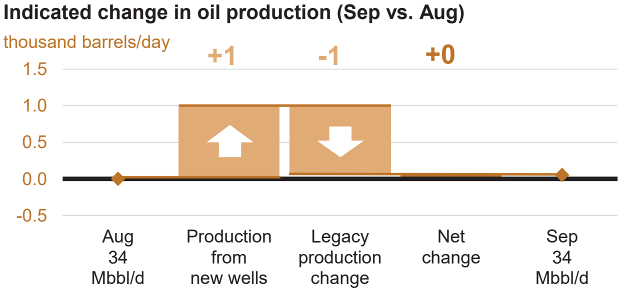
Haynesville Region
Legacy oil production change



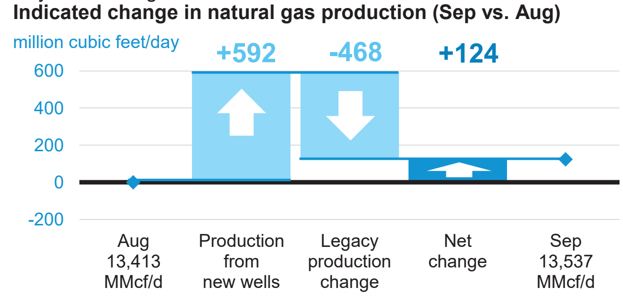
Haynesville Region
Legacy gas production change



Haynesville Region
Indicated change in oil production (Sep vs. Aug)

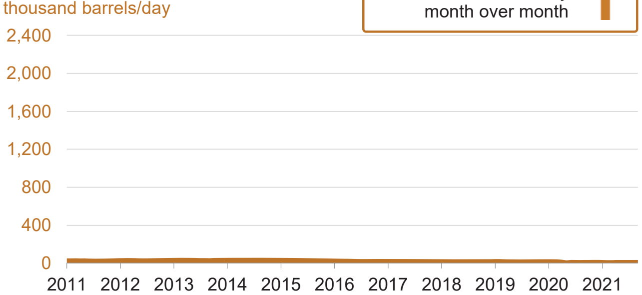


Haynesville Region
Indicated change in natural gas production (Sep vs. Aug)



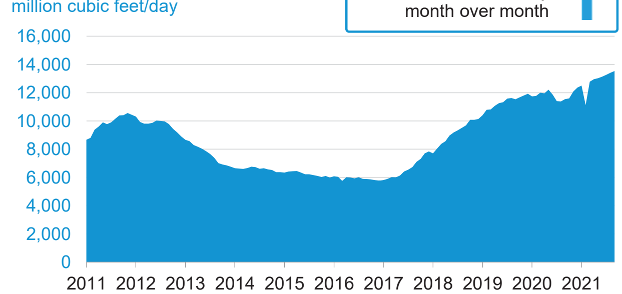
Haynesville Region
Oil production

Oil +0
thousand barrels/day
month over month



Haynesville Region
Natural gas production

Gas +124
million cubic feet/day
month over month



Niobrara Region

Drilling Productivity Report

August 2021

drilling data through July
projected production through September

Oil
-17
barrels/day
month over month

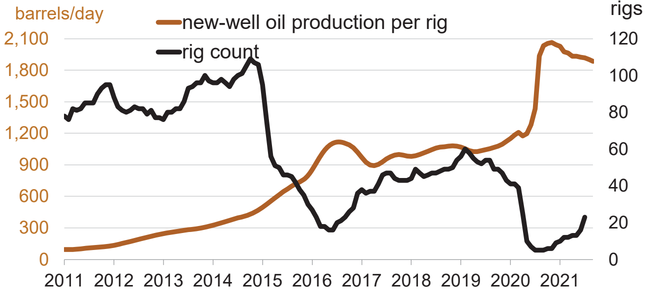
1,884 *September*
1,901 *August*
barrels/day

Monthly additions from one average rig

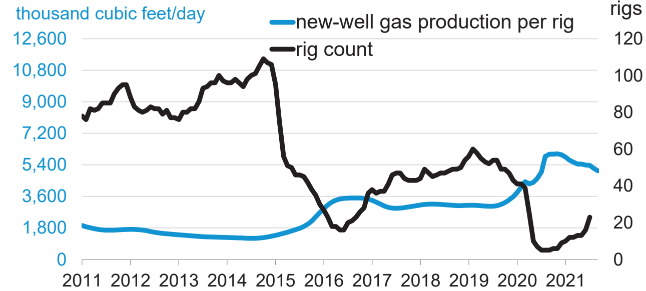
September **5,053**
August **5,209**
thousand cubic feet/day

Gas
-156
thousand cubic feet/day
month over month

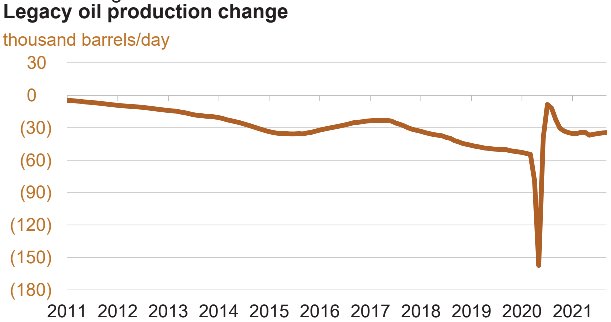
Niobrara Region
New-well oil production per rig



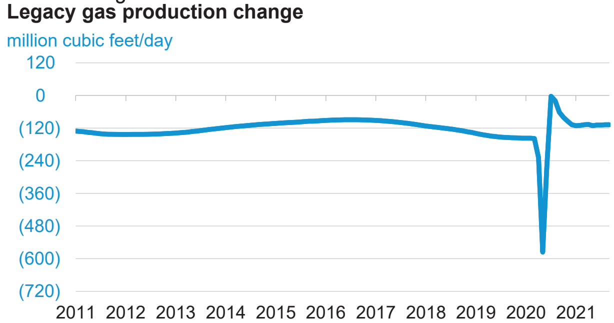
Niobrara Region
New-well gas production per rig



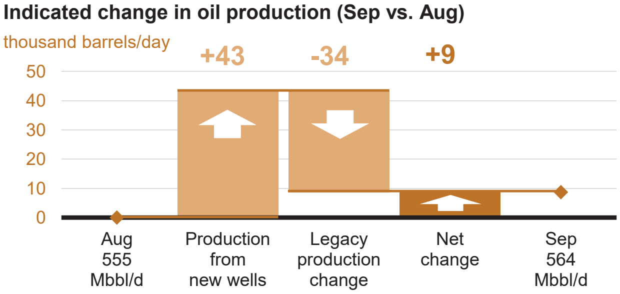
Niobrara Region
Legacy oil production change



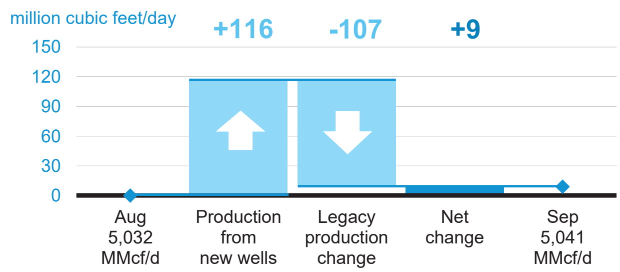
Niobrara Region
Legacy gas production change



Niobrara Region
Indicated change in oil production (Sep vs. Aug)

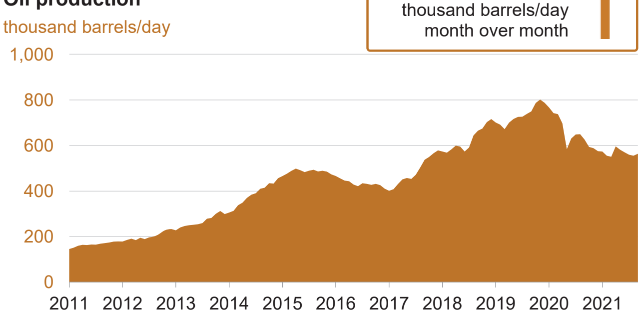


Niobrara Region
Indicated change in natural gas production (Sep vs. Aug)



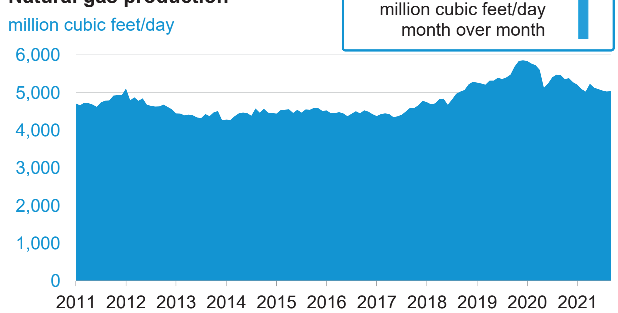
Niobrara Region
Oil production

Oil +9
thousand barrels/day
month over month



Niobrara Region
Natural gas production

Gas +9
million cubic feet/day
month over month



Permian Region

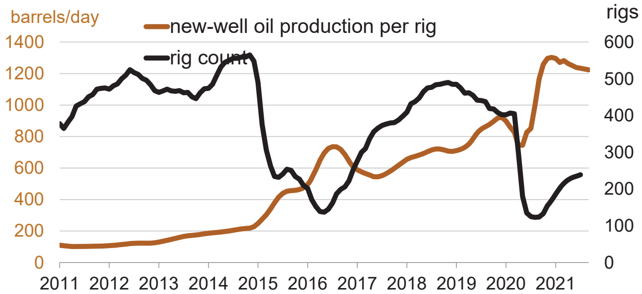
Drilling Productivity Report

August 2021

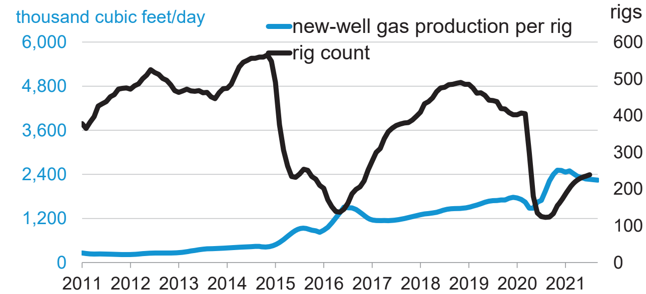
drilling data through July
projected production through September

Oil			Monthly additions from one average rig			Gas
Oil -5 barrels/day month over month	**1,224** *September* **1,229** *August* barrels/day			*September* **2,243** *August* **2,254** thousand cubic feet/day		**Gas -11** thousand cubic feet/day month over month

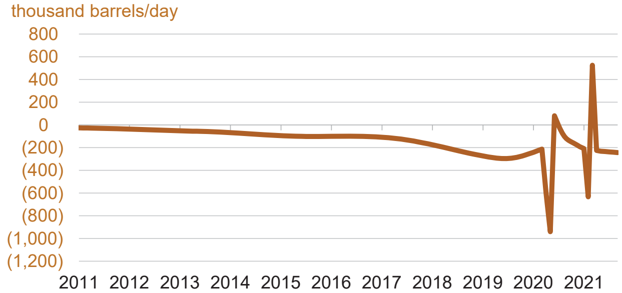
Permian Region
New-well oil production per rig
Rig count



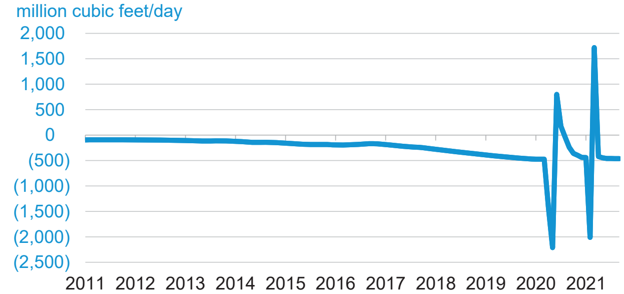
Permian Region
New-well gas production per rig
Rig count



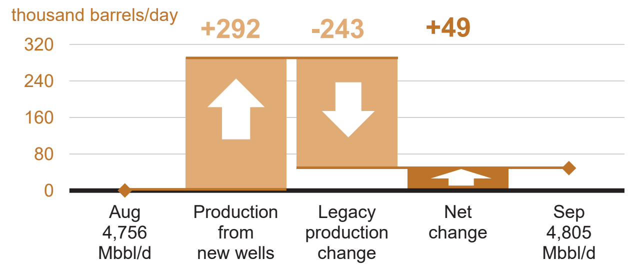
Permian Region
Legacy oil production change



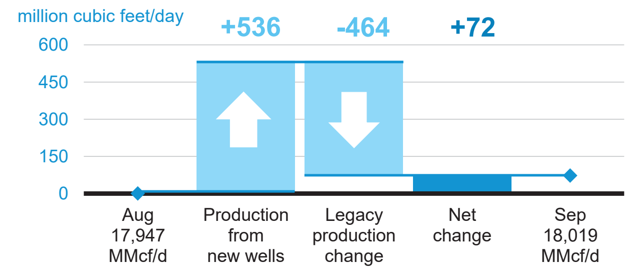
Permian Region
Legacy gas production change



Permian Region
Indicated change in oil production (Sep vs. Aug)

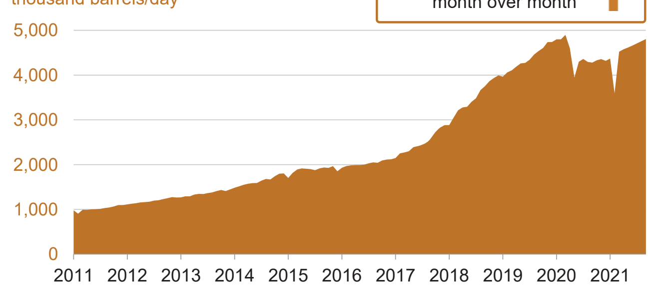


Permian Region
Indicated change in natural gas production (Sep vs. Aug)



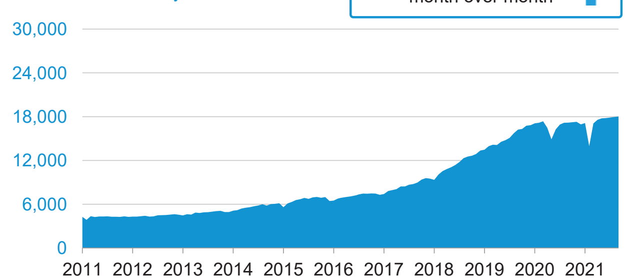
Permian Region
Oil production

Oil +49 thousand barrels/day month over month



Permian Region
Natural gas production

Gas +72 million cubic feet/day month over month



The Drilling Productivity Report uses recent data on the total number of drilling rigs in operation along with estimates of drilling productivity and estimated changes in production from existing oil and natural gas wells to provide estimated changes in oil[1] and natural gas[2] production for seven key regions. EIA's approach does not distinguish between oil-directed rigs and gas-directed rigs because once a well is completed it may produce both oil and gas; more than half of the wells do that.

Monthly additions from one average rig
Monthly additions from one average rig represent EIA's estimate of an average rig's[3] contribution to production of oil and natural gas from new wells.[4] The estimation of new-well production per rig uses several months of recent historical data on total production from new wells for each field divided by the region's monthly rig count, lagged by two months.[5] Current- and next-month values are listed on the top header. The month-over-month change is listed alongside, with +/- signs and color-coded arrows to highlight the growth or decline in oil (brown) or natural gas (blue).

New-well oil/gas production per rig
Charts present historical estimated monthly additions from one average rig coupled with the number of total drilling rigs as reported by Baker Hughes.

Legacy oil and natural gas production change
Charts present EIA's estimates of total oil and gas production changes from all the wells other than the new wells. The trend is dominated by the well depletion rates, but other circumstances can influence the direction of the change. For example, well freeze-offs or hurricanes can cause production to significantly decline in any given month, resulting in a production increase the next month when production simply returns to normal levels.

Projected change in monthly oil/gas production
Charts present the combined effects of new-well production and changes to legacy production. Total new-well production is offset by the anticipated change in legacy production to derive the net change in production. The estimated change in production does not reflect external circumstances that can affect the actual rates, such as infrastructure constraints, bad weather, or shut-ins based on environmental or economic issues.

Oil/gas production
Charts present all oil and natural gas production from both new and legacy wells since 2007. This production is based on all wells reported to the state oil and gas agencies. Where state data are not immediately available, EIA estimates the production based on estimated changes in new-well oil/gas production and the corresponding legacy change.

Footnotes:
1. Oil production represents both crude and condensate production from all formations in the region. Production is not limited to tight formations. The regions are defined by all selected counties, which include areas outside of tight oil formations.
2. Gas production represents gross (before processing) gas production from all formations in the region. Production is not limited to shale formations. The regions are defined by all selected counties, which include areas outside of shale formations.
3. The monthly average rig count used in this report is calculated from weekly data on total oil and gas rigs reported by Baker Hughes.
4. A new well is defined as one that began producing for the first time in the previous month. Each well belongs to the new-well category for only one month. Reworked and recompleted wells are excluded from the calculation.
5. Rig count data lag production data because EIA has observed that the best predictor of the number of new wells beginning production in a given month is the count of rigs in operation two months earlier.

The data used in the preparation of this report come from the following sources. EIA is solely responsible for the analysis, calculations, and conclusions.

Drilling Info (http://www.drillinginfo.com) Source of production, permit, and spud data for counties associated with this report. Source of real-time rig location to estimate new wells spudded and completed throughout the United States.

Baker Hughes (http://www.bakerhughes.com) Source of rig and well counts by county, state, and basin.

North Dakota Oil and Gas Division (https://www.dmr.nd.gov/oilgas) Source of well production, permit, and completion data in the counties associated with this report in North Dakota

Railroad Commission of Texas (http://www.rrc.state.tx.us) Source of well production, permit, and completion data in the counties associated with this report in Texas

Pennsylvania Department of Environmental Protection (https://www.paoilandgasreporting.state.pa.us/publicreports/Modules/Welcome/Welcome.aspx) Source of well production, permit, and completion data in the counties associated with this report in Pennsylvania

West Virginia Department of Environmental Protection (http://www.dep.wv.gov/oil-and-gas/Pages/default.aspx) Source of well production, permit, and completion data in the counties associated with this report in West Virginia

Colorado Oil and Gas Conservation Commission (http://cogcc.state.co.us) Source of well production, permit, and completion data in the counties associated with this report in Colorado

Wyoming Oil and Conservation Commission (http://wogcc.state.wy.us) Source of well production, permit, and completion data in the counties associated with this report in Wyoming

Louisiana Department of Natural Resources (http://dnr.louisiana.gov) Source of well production, permit, and completion data in the counties associated with this report in Louisiana

Ohio Department of Natural Resources (http://oilandgas.ohiodnr.gov) Source of well production, permit, and completion data in the counties associated with this report in Ohio

Oklahoma Corporation Commission (http://www.occeweb.com/og/oghome.htm) Source of well production, permit, and completion data in the counties associated with this report in Oklahoma

Soaring Gas Saddles U.S. Drillers With $14 Billion in Bad Bets
2021-09-16 18:58:11.992 GMT

By Gerson Freitas Jr.

(Bloomberg) -- U.S. natural gas producers should be celebrating over the biggest rally for the fuel in two decades. Instead, wrong-way bets on prices are muting gains and turning away investors.

Top natural gas explorers seeking to protect against price declines hedged about 80% of combined output for 2021 and 50% for next year, according to BloombergNEF. As a result, drillers are facing more than $14 billion in hedging losses through 2022 that will eat away at any profits they make from selling their gas at current prices, BNEF said.

U.S. natural gas prices have more than doubled over the past year -- the best performance among widely traded commodities -- to the highest since 2014 as tightening inventories spur fears of a supply crunch in winter. While that should be a boon to producers, companies including EQT Corp. are missing out on much of the surge, and the hedging has made them less attractive for equity investors looking to make money from the gas rally.

"It takes away the bull case on the stock," analyst Paul Sankey of Sankey Research LLC said this week in a note to clients, adding that the strategy is "costly and damaging" and "makes no sense."

Drillers often enter into forward contracts to sell their output at fixed prices, a practice known as hedging. Gas suppliers have for years used tools such as swaps to protect their debt-heavy balance sheets and capital spending programs against any downward spirals in natural gas.

Drillers were possibly "comfortable hedging so drastically" after years in which the strategy paid off, BNEF analyst Danny Adkins said. BNEF surveyed 39 drillers to arrive at the cost estimates. "Robust hedge positions have worked out incredibly well for them over the past years."

EQT, the U.S. largest natural gas producer, is poised to lose $4.5 billion with their hedges if gas prices remain at current levels, according to BNEF. The company has hedged over three quarters of its output through next year at an average $2.89 per million British thermal units, while gas for 2022 has been priced at an average $4.12 per mmbtu on the New York Mercantile Exchange.

The company was slammed by investors after it disclosed in July a major increase in the volume of swaps aimed at protect its balance sheet against a potential drop in gas prices. The driller's shares have since slid, while gas futures gained more than 30%. EQT declined to comment.

Scaling Back

Southwestern Energy Co., which has locked in prices for about two thirds of its production through next year, is facing almost $2 billion in potential losses, while Antero Resources Corp.'s protections would cost the company about $1.5 billion if prices remain at current levels, according to BNEF. Southwestern didn't respond to a request for comment.

Antero, which has for several years fully hedged its production, said in July it's now scaling back as part of efforts to take bigger advantage of rising prices. Antero didn't respond to a request for comment. Other heavily hedged producers include CNX Corp., which is not among companies surveyed by BNEF.

"The lion's share" of Appalachia-focused producers added hedges that are "significantly underwater" and limiting free cash flow growth, JPMorgan Chase & Co. analysts led by Arun Jayaram said Wednesday in a note to clients. "We believe investors are struggling with the best way to play the natural gas trade."

The qualms come as shale drillers have been answering investors' calls for financial discipline, with explorers wary of increasing output after a decade of wild spending brought on excess supplies and plunging prices that pushed many producers into bankruptcy.

To be sure, shale producers still have room to "drastically improve" the prices they are guaranteed to receive through next year by hedging the remainder of their output at much higher prices, BNEF's Adkins said. Locking in $4 to $5 gas "would certainly guarantee solid free cash flows."

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https://rbnenergy.com/crossroads-record-global-gas-prices-signal-more-room-for-north-american-lng

Crossroads - Record Global Gas Prices Signal More Room For North American LNG

Tuesday, 09/14/2021
Published by: Lindsay Schneider

It has been a chaotic 18 months for North American LNG and the global gas market. In a short time, international gas markets went from oppressively oversupplied balances, high storage inventories, and historically low prices for much of 2020, to reckoning with panic-inducing supply shortage, low inventories, multi-year or all-time high prices in the biggest LNG-consuming regions. The resulting whiplash has transformed key aspects of the LNG market, including making a profound impact on the way existing LNG terminals operate, how projects secure funding and capacity commitments, and what offtakers expect for the next generation of LNG capacity buildout. The tight market appears to have settled the question of whether more export capacity is needed, at least for now, but the market's sharp U-turn has also put potential offtakers on edge and underscored the need for contractual flexibility. Additionally, pressure to reduce greenhouse gas (GHG) emissions is higher than ever, and LNG offtakers are increasingly demanding greener solutions to address government regulations and public concerns. This convergence of factors has put the LNG market at a crossroads. Taking all of the lessons learned from the past 18 months and before, the industry must now forge a new path forward. Today, we discuss highlights from our new Drill Down report, looking at the major trends that will define the North American LNG market in the coming years.

The domestic and international LNG markets today are almost unrecognizable from a year ago. At this time last year (yellow-shaded area in Figure 1), U.S. Gulf Coast LNG producers were just emerging from the peak of the cargo cancellations that had been occurring all summer long, precipitated by COVID-related shutdowns and demand destruction around the globe. International gas prices had partially recovered from the all-time lows seen over the summer but were still near multi-year lows, while Henry Hub was languishing in the low to mid-$2/MMBtu range. The economics for delivering to Europe and Asia still left U.S. LNG mostly out of the money (see Sultan of Swing for a detailed breakdown of export economics). For example, the Japan-Korea Marker (JKM; gray line on the right axis), the oldest and most liquid LNG price index and a good representation of the global LNG market, fell to historical lows near $2/MMBtu in the spring and carried $2 handles through much of summer. As COVID conditions in Asia began to ease (earlier in Asia than in Europe or the U.S.), JKM prices staged a modest recovery but stayed below $3/MMBtu until the September contract expired in mid-August and prices began climbing from there. This time last year, prices were just shy of $5/MMBtu.

As for domestic feedgas deliveries to the terminals (blue line on the left axis), they had gone from flowing at rates of nearly 100% utilization of operating liquefaction capacity pre-COVID, down to more like a third of the estimated total feedgas requirement (orange line on the left axis) in July 2020. By September 2020, as cargo cancellations were starting to ease, feedgas flows had begun to recover but were still running at little more than 50% of the total requirement. Overall, there was still a great deal of uncertainty about when, how, and by how much global gas demand would recover. With much of the existing capacity sitting idle, the idea of building or expanding LNG terminals, which was already losing favor before COVID, became downright unpalatable. Export projects were losing offtaker or developer interest and being canceled or paused (see Holding On for Life).

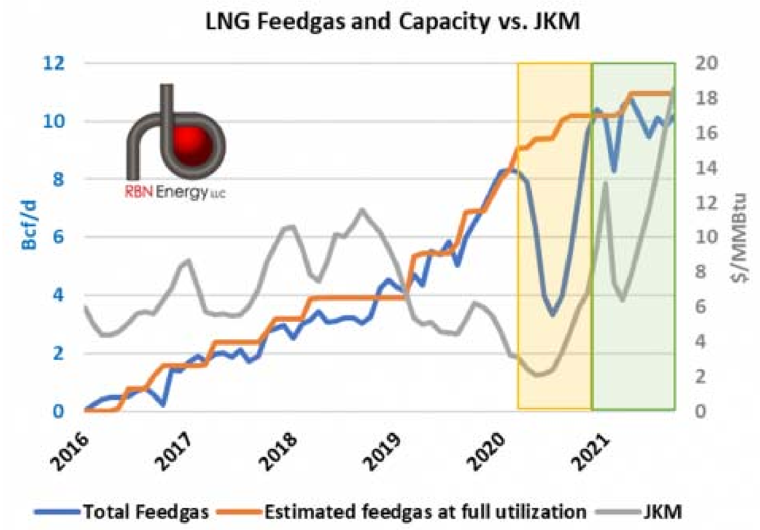

Figure 1. Monthly U.S. LNG Feedgas and Capacity vs. JKM Prices. Source: RBN LNG Voyager

Fast forward to a year later, and the market is facing just the opposite: an extreme undersupply situation that has driven prices to the longest and strongest bull run in the Shale Era, if not ever. JKM has catapulted to all-time seasonal highs this summer and is averaging above $18/MMBtu in September to date (gray line in the shaded green area), which is less than $2/MMBtu shy of the all-time high seen in January 2021, when constraints for transiting the Panama Canal were causing severe delays and vessel shortages. At the same time, European gas price indices (not shown in the graph) have posted all-time highs recently. You can read more about the reasons why — low storage inventories, low imports, steep competition for cargoes, and robust demand, among them — in It's Too Late. But suffice it to say, U.S. feedgas demand has more than recovered this year.

After Corpus Christi Train 3 came online in late March, total feedgas reached a record of 11.24 Bcf/d and averaged an astounding 10.77 Bcf/d this past April (see Such Great Heights). Feedgas flows subsequently retreated from those record levels in the spring and summer, primarily due to pipeline maintenance and the related constraints in moving gas to the terminals, particularly in Louisiana. That record from late March still stands. Nevertheless, deliveries to the terminals have been at record highs each month, averaging just shy of 10 Bcf/d from May through August, up an average 5.5 Bcf/d from the same period last year. Moreover, feedgas demand is headed even higher soon. Sabine Pass Train 6 and Calcasieu Pass are both currently commissioning and due online early next year. Both projects are expected to take feedgas this fall as they prepare to produce first LNG by the end of the year. The addition of these projects will add more than 2.25 Bcf/d of new feedgas demand to the U.S. Gulf Coast, ensuring that we've not yet seen the highest feedgas levels yet this year.

Beyond 2022, a handful of projects that reached a final investment decision (FID) prior to COVID are still under construction, including Golden Pass in the U.S. Gulf Coast, and two new terminals outside of the U.S. — Energía Costa Azul (ECA) LNG in Mexico and LNG Canada in Canada. The latter two will export from the Pacific Coast, which is becoming a hot-bed of LNG development because it bypasses the Panama Canal constraints and provides more than $1/MMBtu transport cost advantage over the Gulf Coast thanks to its proximity to the all-important Asian markets. Of course, the ease of sourcing gas in the U.S. Gulf Coast counterbalances some of that advantage, and at this point, more LNG development in both areas seems likely, albeit with a different scope and pace than was expected in the previous decade (the 2010s) when North America was first entering the global gas market.

Any new LNG development is a welcome change from where the market was last summer, when we were witnessing a slow-motion meltdown among the second wave of North American LNG export projects that saw many of them delayed, put on the backburner or canceled. The rapid swing to undersupply and prolonged high global gas prices have renewed interest in offtake agreements and new LNG buildout. Support is coalescing around a handful of North American LNG projects that may take FID in the next year or so (see Only the Strong Survive and You Can Make It If You Try). However, offtakers and developers have learned a number of lessons from recent events, and the contracts underpinning these projects look very different from those that supported the first wave of North American LNG. For one thing, new deals signed in recent months share the market risks and rewards between LNG buyers and sellers, and offer LNG indexed to a variety of different global price indices, as opposed to just Henry Hub, as was the standard for the first-wave projects. The latest deals often also offer shorter terms in order to appeal to offtakers who are working to balance the need for reliability with long-term uncertainty, particularly as environmental regulations tighten worldwide.

Another consideration that wasn't on the radar during the first wave of projects but is now practically a requirement: going green. As the pressure to become greener has intensified, LNG producers and developers are looking at ways to reduce or offset emissions. This effort is not only an essential strategy for the next generation of LNG terminals but one that is being explored by the existing terminals as well. LNG offtakers are increasingly looking for "green" LNG cargoes and contracts and to minimize or offset their carbon footprint. Carbon-neutral LNG cargoes have already been produced and sold from U.S. terminals, using carbon credits (see Matter of Trust). A number of existing and planned LNG terminals are exploring carbon sequestration options. And, finally, many of the new terminals that go forward are likely to opt for an all-electric liquefaction process to reduce emissions.

Overall, the North American LNG industry has demonstrated a resilience over the past 18 months that has cemented its position as an important marginal producer for global markets. LNG developers have had to shift strategies to attract offtakers, focusing on green initiatives, shorter contracts, and diverse pricing structures and that, coupled with growing global demand, has ensured that North America has not seen its last LNG project take FID. With gas demand growth led by Asia, as well as increasing Russian exports to Europe decreasing that market's reliance on LNG, the next wave of North American LNG development is exploring new Asia-centric strategies — specifically with new projects announced in Mexico and Canada on the Pacific Coast. Some of these projects could move quickly and bypass a number of previously announced Gulf Coast projects on their way to FID. But don't count the Gulf Coast projects out either, as the market weighs the relative ease of supply access along the Gulf Coast versus easy access to the increasingly important Asian markets from the Pacific Coast. All in all, 2022 could realistically see multiple projects from both the Gulf and West coasts take FID.

In our latest Drill Down Report, we take a look at North American LNG and its place in the global gas market, which is at a crossroads as near-term supply shortages intersect with long-term demand uncertainty. We examine how we got here, what it means for LNG now and most importantly, what the future of North American LNG looks like. For more information on the Drill Down report, click here.

"Crossroads" was first written and recorded as "Cross Road Blues" by Robert Johnson in 1936, with his recording released the following year. This song has a lot of mythology surrounding it, with the main story being that Johnson was a guitarist with limited skills until he sold his soul to the devil at the crossroads described in his song. There is a roadside landmark at the intersection of Highway 61 and Highway 49 in Clarksdale, MS, where this event is said to have transpired. American blues artist, Elmore James, also released two versions of the song, one in 1954, and the other in 1965. Cream recorded its version of the song — retitled "Crossroads" and including a verse from Robert Johnson's "Traveling Riverside Blues" — in November 1966 for broadcast on the BBC *Guitar Club* radio show. The band recorded a longer live version of the song at the Winterland Ballroom in San Francisco in March 1968. It is this version that leads side three of Cream's two-disc 1968 album, *Wheels of Fire*. Personnel on the record were: Eric Clapton (vocals, guitar), Jack Bruce (bass), and Ginger Baker (drums).

Wheels of Fire is the third album released by Cream. Disc one of the double-LP was recorded in the studio at IBC Studios in London, and Atlantic Studios in New York City. Disc two features live material recorded by the band at the Winterland and Fillmore ballrooms in San Francisco. Produced by Felix Pappalardi, the record was released in the U.S. in July 1968 and went to #1 on the Billboard Top 200 Albums chart. It has been certified Platinum by the Recording Industry Association of America. Two singles were released from the album.

Cream was a British rock power trio formed in London in July 1966 with Eric Clapton, Jack Bruce, and Ginger Baker. They released four studio albums, four live albums, 10 compilation albums, and 10 singles. They are members of the Rock and Roll Hall of Fame and have a Grammy Lifetime Achievement Award. The band announced its breakup in May 1968 and performed its final live show in November of that year. Cream reunited to perform three songs live during its induction into the Rock and Roll Hall of Fame in 1993. The band reunited again for four shows at the Royal Albert Hall in London in May 2005 and three shows at Madison Square Garden in New York City in October 2005. All three members of Cream went on to successful careers as solo artists and members of other ensembles. Jack Bruce died in October 2014, and Ginger Baker in October 2019. Eric Clapton continues to record and perform live.

https://rbnenergy.com/reaching-out-the-gathering-pipes-that-will-supply-the-coastal-gaslink-pipeline

Reaching Out - The Gathering Pipes That Will Supply The Coastal GasLink Pipeline

Monday, 09/13/2021

Published by: Martin King

It will still be a few years until Canada joins the ranks of nations exporting natural gas in the form of LNG. Until then, a great deal of work has to be completed on both the LNG Canada liquefaction and export facility in Kitimat, BC, and the primary gas pipeline linked to it: the Coastal GasLink. Unlike most LNG export sites in the U.S., which can receive feedgas from multiple production basins via an array of major trunklines, the LNG Canada plant will be relying on gas supplies from primarily one basin: the Montney in Western Canada. And all that feedgas will be transported across British Columbia through one mammoth pipeline. In today's blog, we take a closer look at the small number of pipelines that will supply gas from the Montney to Coastal GasLink for eventual delivery to LNG Canada.

It was in October 2018 that Canada's natural gas industry happily received the news that a new export outlet for its primary product was going to be constructed in Kitimat, a small town on British Columbia's North Coast. A Shell Canada-led consortium had announced at that time plans to construct a 1.8-Bcf/d LNG export plant (LNG Canada) and an affiliated trunkline (Coastal GasLink, or CGL) to provide the 2.1 Bcf/d (14 MMtpa) of total feedgas (exports plus fuel) required for the plant from the prolific unconventional Montney Basin in Western Canada. With production and reserves rapidly growing in the Montney, the new LNG plant was seen as a means to not only create immense value by exporting the gas in the form of LNG to higher-priced Asian markets, but also a way to break Canada's long-standing reliance on a single export customer: the U.S.

Since that announcement, an immense amount of construction work has taken place, but a lot more is still to be done before LNG exports from Kitimat become a reality. We discussed much of this work — and some of the COVID-related complications and delays — in our two-part blog, Stir It Up. In Part 1, we described the work that had been completed to date on the $30 billion LNG Canada plant, which the Shell-led consortium hopes to have fully operational by 2025. In Part 2, we examined the $4.5 billion CGL pipeline that will be supplying natural gas to the export site, and that is being constructed by Calgary, AB-based TC Energy. Running 416 miles (670 kilometers) from the heart of the prolific gas-producing Montney unconventional gas play near Dawson Creek, BC (Figure 1), the pipeline will provide up to 2.1 Bcf/d of natural gas to the LNG Canada plant (yellow tank icons). At the time we wrote that previous blog, TC Energy was still publicly committing to a late-2023 start-up for the pipeline, apparently well in advance of the planned 2025 date for the LNG Canada plant to come online.

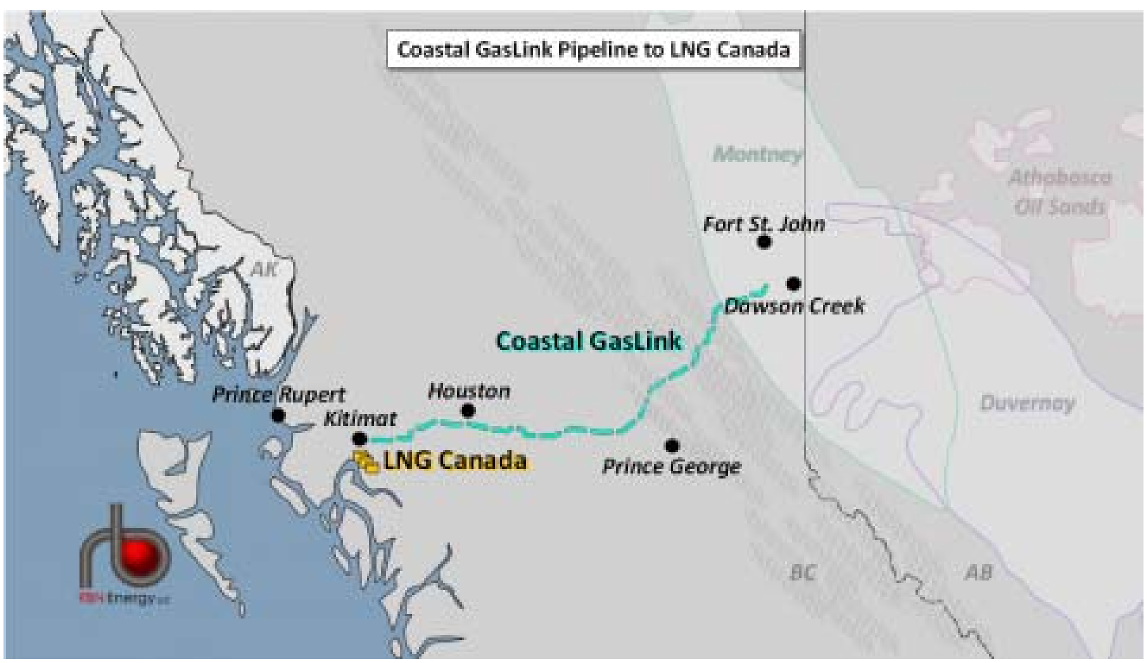

Figure 1. Coastal GasLink Pipeline Route. Source: RBN

More recently, TC Energy mentioned on its July 29, 2021, earnings call that construction costs for the pipeline had increased beyond the originally budgeted amount due to various regulatory and COVID-related delays, and that the completion date would be later than the original 2023 start date, possibly much later, in 2024. TC Energy also said that it was in negotiations with Shell and its LNG Canada cohorts about recovering the increased costs through higher tolls that would be charged from the consortium members for their gas flowing in the pipeline. Any conclusions on what the higher costs and toll structure will look like have not yet been announced. It is also worth pointing out that in May 2020 TC Energy sold a combined 65% equity interest in Coastal GasLink to Alberta and South Korea pension funds managed by Alberta Investment Management Corp. (AIMCo) and New York City-based KKR & Co. Inc. As of late August 2021, TC Energy reported that about one-third of the pipeline construction had been completed.

In addition to its dependence on a single production basin and long-haul pipeline for its feedgas, LNG Canada is also somewhat more unique in that the members of the consortium building the plant are entitled to shares of the liquefaction capacity equal to their equity ownership. Under the current equity arrangements, Shell Canada, as operator, owns 40%; 25% is held by North Montney LNG Partnership, a wholly owned subsidiary of Malaysia's Petroliam Nasional Berhad (Petronas); PetroChina Canada Ltd. holds 15%; another 15% is owned by Diamond LNG Canada Ltd., a wholly owned subsidiary of Mitsubishi Corp.; and KOGAS Canada LNG Ltd., a wholly owned subsidiary of Korea Gas Corp. (KOGAS), owns the remaining 5%. That means, for example, that Shell Canada will have access to 5.6 MMtpa of LNG (40% x 14 MMtpa). Importantly, for our later discussion, each company's share of liquefaction capacity also translates into it being responsible for the equivalent amount of upstream gas supply that will feed the Coastal GasLink pipeline. Again, using Shell Canada as an example, this would translate into an upstream supply commitment of 0.84 Bcf/d (40% x 2.1 Bcf/d).

However, the pipeline cannot do its job unless there are other feeder pipelines that will collect gas from the Montney Basin. By taking a closer look at these feeder pipelines through regulatory filings, we can get a better sense of the scale of the pipelines involved, who will be constructing and operating them, and when they might be completed to eventually send gas into CGL. It is also the case that some of these plans remain unrealized as supply arrangements and pipeline connections have yet to be fully finalized.

Coastal GasLink (CGL; dashed red line in Figure 2) originates approximately 25 miles (40 kilometers) west of the town of Dawson Creek, where gas will enter the pipeline through the Wilde Lake compressor station (red dot). Thanks to long-standing gas production in the area, plus the rapid expansion of Montney unconventional gas supplies over the past decade, a number of major pipelines already in the area will be able to connect to Coastal GasLink, and two major connections have been approved within the past year.

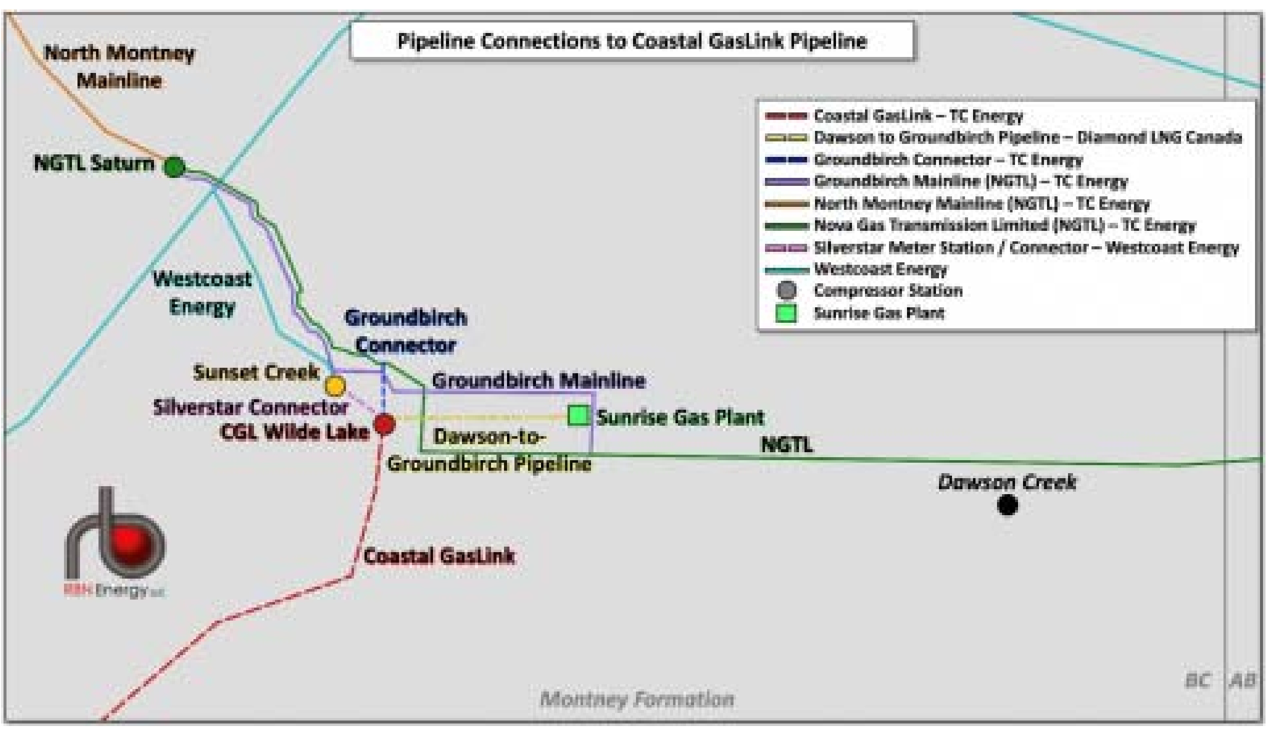

Figure 2. Pipeline Connections to Coastal GasLink Pipeline. Source: RBN

The first, approved by the Canada Energy Regulator (CER) in November 2020, is the Silverstar Connector (dashed pink line) connecting Enbridge's Westcoast Energy pipeline (aqua lines) through the Sunset Creek compressor station (gold dot) to the start of Coastal GasLink at Wilde Lake. Sized to handle up to 1.2 Bcf/d, the station and short connector are expected to be finished by December of this year, according to Westcoast. TC Energy has reported that work on the initial section of Coastal GasLink near the Wilde Lake station is about 88% complete. This should allow Westcoast to tie in the station and connector to CGL, although the facilities will not be flowing any gas until much later.

The second major connection, which received regulatory approval in May 2021 from the BC Environmental Assessment Office, is the Groundbirch Connector (dashed navy-blue line). Sized to handle up to 2 Bcf/d, this 1.9-mile (3 kilometers), 48-inch-diameter connector will allow the sourcing of gas from both TC Energy's Nova Gas Transmission Limited pipeline (NGTL; green line), which crosses the provincial boundary from Alberta, and NGTL's Groundbirch Mainline (purple line), both of which tie into the NGTL Saturn compressor station (green dot), which connects to even more Montney supplies on NGTL's North Montney Mainline (orange line) further to the north.

The sum of both connections (Silverstar + Groundbirch) is 3.2 Bcf/d, or well in excess of the 2.1 Bcf/d needed for the Coastal GasLink pipeline. However, with each partner in LNG Canada also responsible for procuring gas supply in the same percentage as its equity interest, it is unclear which pipeline connections may be utilized by each partner. Moreover, during times of maintenance and unforeseen outages, having ample upstream supply capacity and sourcing flexibility in excess of CGL's capacity is going to be an advantage if the pipeline and the LNG Canada plant are to run as consistently as possible. The size of the pipeline connections may be in consideration of the possibility that the capacities of both LNG Canada and Coastal GasLink could be doubled should the consortium partners sanction an expansion consisting of two additional trains at the Kitimat site. There has been speculation that such a decision could be made next year.

Each member of the LNG Canada consortium has also laid out tentative plans as to how they intend to connect their respective share of gas supplies to the CGL pipeline, although some of these plans may now be moot given the Silverstar and Groundbirch connections. Considering each partner's proposed connection based on the descending order of equity interest, we will start with Shell Canada's plans.

As mentioned earlier, Shell's supply commitment to Coastal GasLink is estimated at 840 MMcf/d. It proposed to provide most of this supply commitment via its Groundbirch producing asset in BC's Montney. Based on July 2021 production data from the BC Oil & Gas Commission, Shell was producing 271 MMcf/d from the BC Montney as a whole while its Groundbirch asset was pegged at 147 MMcf/d, both well short of its supply commitments. These production volumes may have reflected downtime in July, as the prior six-month production averages were 372 MMcf/d and 181 MMcf/d, respectively, or 553 MMcf/d in total. Despite the apparent difference between current production and its supply commitment, Shell has stated that it intends to fulfill its supply obligations to CGL and LNG Canada through a combination of its own production, including supplies in Alberta, and supply purchases from third parties.

As part of a regulatory submission with other partners to the CER in early 2019, Shell stated that it was contemplating construction of a short, 0.8-mile (1.3-kilometer) direct pipeline connection from its Groundbirch gas plants to Coastal GasLink, but would also consider sourcing third-party supplies via other pipeline connections, such as NGTL. In this case, the recent approval of the Groundbirch Connector may be what Shell has in mind in terms of being able to ship its supply commitments to CGL.

We look next at the North Montney LNG Partnership's (Petronas) supply share commitment to Coastal GasLink of 25% (530 MMcf/d). Petronas, as the operator in the partnership, was producing 587 MMcf/d from its BC Montney assets in July 2021, in which it has a 62% share (363 MMcf/d). Petronas has also been one of the more active drillers in the BC Montney in the past few years, and the partnership's gross supplies have risen by around 100 MMcf/d in the past year.

In a regulatory filing, Petronas stated that it was committed to fulfilling all its supply commitment to CGL via its share of production from the partnership. To this end, its has secured a pipeline transportation agreement with Westcoast for 500 MMcf/d for 40 years starting in September 2023, with additional agreements possible with Westcoast or NGTL. In its filing, Petronas also stated that the Sunset Creek compressor station would be the final endpoint for its share of production into Coastal GasLink, suggesting that the gas could flow through the Westcoast Silverstar Connector. Initially, Petronas stated that it might connect its supplies through a 1.5-mile (2.4-kilometer) connection from Westcoast to CGL, which the Silverstar pipe now appears to fulfill.

Next is PetroChina's 15% share, which translates into a 315 MMcf/d supply commitment. Currently, the company has a 20% non-operated share in Shell Canada's Montney gas production and its wholly owned gas production from the Duvernay play in Alberta, through which it has access to the NGTL system. PetroChina was thought to be contemplating its own direct connection to Coastal GasLink, but approval of the Groundbirch Connector may provide the needed connection solution, as it appears to do for Shell Canada.

Like PetroChina, Diamond LNG Canada (DLC) is committed to 315 MMcf/d of gas supply into CGL. Mitsubishi, the owner of DLC, is also the owner of Cutbank Dawson Gas Resources Ltd., which further owns 40% of the gas-producing Cutbank Ridge Partnership (CRP), in conjunction with Ovintiv, which is the operator with a 60% share. Ovintiv’s gross BC Montney gas production in July 2021 was reported as 1.27 Bcf/d, giving DLC a production share of 509 MMcf/d, in excess of its supply commitment to Coastal GasLink. Of course, this could allow DLC to up its supply into CGL should LNG Canada be expanded in the future, and also allow it to sell any excess share of gas supplies over and above its CGL commitments into the North American gas market.

Unlike the three prior equity partners, which appear to be tying into either Westcoast and/or NGTL to connect their gas supplies to Coastal GasLink, DCL has proposed its own direct pipeline connection: the Dawson Groundbirch Pipeline (D-G Pipeline; dashed yellow line in Figure 2). Running approximately 16 miles (25 kilometers) from the Ovintiv-operated Sunrise gas plant (lime green square), this 1.14-Bcf/d pipeline would connect DCL’s share of CRP Montney gas into CGL and be in service prior to the start-up of the pipeline. It is still possible that DCL may abandon this proposal and instead connect via NGTL.

Finally, KOGAS Canada Ltd.’s (KCL) 5% share translates into a 105-MMcf/d gas supply commitment to Coastal GasLink. Up-to-date information on KCL’s activities is hard to get, but in late 2018 when it filed responses to information requests from the CER, it stated that it was producing 20 MMcf/d of gas from its Horn River assets that was transported on the Westcoast system. No other information is available for any other of its producing assets, transportation agreements, or proposals.

In all, there are three major pipeline connections either under construction (the Silverstar and Groundbirch connectors) or proposed (the D-G Pipeline) that could provide in excess of 4 Bcf/d of gas supplies into the currently planned 2.1-Bcf/d Coastal GasLink pipeline. As such, plans for full gas supply into CGL and onto the LNG Canada site looks promising. However, with several years to go until LNG production and exports get under way, this will remain an evolving story both in terms of supply and pipeline connections.

"Reaching Out" was written by Don Black and Andy Hill NS appears as the opening song on the live double album by Queen and Paul Rodgers entitled *Return of the Champions*. It was released as a single, backed with "Tie Your Mother Down," in August 2005. The song first appeared on a three-song charity CD called *Rock Therapy,* released in 1996, and benefiting the Nordoff-Robbins Music Therapy Center, which helps special needs children to communicate through music. The project included Brian May, Paul Rodgers, Charlie Watts, Lulu, and others. When the Rock Therapy single was released in England, it went to #126 on the UK charts. "Reaching Out" was also sampled on Eminem's single, "Beautiful," which was released in August 2009, and went to #17 on the Billboard Hot 100 Singles chart. Personnel on the Queen/Rodgers version are: Paul Rodgers (lead vocals), Jamie Moses (rhythm guitar), Brian May (lead guitar, backing vocals), Roger Taylor (drums, backing vocals), Danny Miranda (bass), and Spike Edney (piano, keyboards).

Return of the Champions is a double live album featuring Queen and Pail Rodgers. It was mostly recorded at a live concert at the Hallam FM Arena in Sheffield, England, in May 2005. Produced by Joshua J. Macrae, Justin Shirley-Smith, and Peter Brandt, the album was released in September 2005. It went to #84 on the Billboard 200 Albums chart. "Reaching Out" was the only single released from the LP.

Queen is a British rock band formed in London in 1970 by Freddie Mercury, Brian May, Roger Taylor, and John Deacon. The band has released 15 studio albums, 10 live albums, two soundtrack albums, 16 compilation albums, two EPs, and 72 singles and has sold more than 170 million records worldwide. Queen has won four Brit Awards and four Ivor Novello Awards and was inducted into the Rock and Roll Hall of Fame and Songwriters Hall of Fame. It has three songs in the Grammy Hall of Fame and has been awarded a Grammy Lifetime Achievement Award. Freddie Mercury died in 1991, and John Deacon retired from the band in 1997. Since 2004, Brian May and Roger Taylor have toured under the Queen banner with vocalists Paul Rodgers, and Adam Lambert. The band still occasionally tours with Adam Lambert on vocals. At this time, shows are booked beginning in May 2022.

https://twitter.com/PetroleumMin/status/1439125597653909517?s=20

Thread

Ministry of Petroleum and Natural Gas
@PetroleumMin

In line with Hon'ble Prime Minister's vision for a gas based economy, Petroleum and Natural Gas Regulatory Board has started inviting bids for the development of city gas distribution network in 65 Geographical Areas covering 208 districts across the Country.

1:14 AM · Sep 18, 2021 · Twitter for Android

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This 11th round of bidding is the largest in terms of coverage of area, population and the number of districts in the country.
Once completed, the CGD network in India shall cover 86% of the Country's area and 96% of the population.

2 12

https://www.thehindubusinessline.com/companies/lngs-share-of-indian-gas-demand-to-rise-to-70-by-2030-petronet-ceo/article34845886.ece

LNG’s share of Indian gas demand to rise to 70% by 2030: Petronet CEO

Reuters NEW DELHI | Updated on June 18, 2021

Replacing about 30% of the country’s crude oil imports with LNG would save $10 billion at current global oil price of $74/barrel, he said

The share of liquefied natural gas (LNG) in India’s gas consumption could rise to 70% from the current 50% in 10 years, and new import terminals are needed, the chief executive of the country’s top gas importer said.

Prime Minister Narendra Modi has set a target to raise the share of natural gas in the country's energy mix to 15% by 2030 from the current 6.3% to cut its carbon footprint.

To meet that target India's gas consumption needs to rise to 640 million standard cubic metres a day (mmscmd) from the current 155 mmscmd, AK Singh, chief executive of Petronet LNG, said at ET Energy Leadership summit.

Huge invesments by Indian cos

Indian companies are investing billions of dollars to strengthen gas infrastructure, including laying 15,000-kilometer pipelines to supply cleaner fuel to households and industries. India currently has 17,000 kms of gas pipeline network.

Also, LNG projects of 19 million tonnes per annum (mtpa) capacity are under construction and plans are afoot to increase use of LNG in trucks and buses.

“With limited increase in domestic gas supply LNG will play a major role in catering to this incremental demand and share of LNG in natural gas consumption is likely to increase from the present 55% to 70% in coming 9-10 years,” Singh said.

Petronet operates two LNG terminals in India accounting for about 53% of the nation’s existing 42.5 mtpa import capacity.

Singh said India needed to increase its LNG import capacity to 155 mtpa “considering 80% utilisation” to boost use of the cleaner fuel.

India imports about 85% of its oil needs. He said replacing about 30% of the country’s crude oil imports with LNG would save $10 billion at current global oil price of $74/barrel.

Published on June 18, 2021

Finally, Some Visibility That India Is Moving Towards Its Target For Natural Gas To Be 15% Of Its Energy Mix By 2030

Posted: Wednesday October 23, 2019. 3:45pm MT

It's taking longer than expected, but we are finally getting visibility that India is investing significantly towards its goal to have natural gas be 15% of its energy mix by 2030. Earlier in Oct, India Oil Minister Dharmendra Pradhan said that there are $60 billion of natural gas infrastructure and LNG import terminals that are "under execution". He said "*I am not talking about potential investment. This number relates to the project that are under execution".* Natural gas consumption in India is only now back to 2011 levels at 5.6 bcf/d and represents only 6.2% of its energy mix. If India hits its 15% target of its energy mix by 2030, it would add natural gas demand, on average, of >1.5 bcf/d per year. At the same time India's domestic natural gas production peaked in 2010 at 4.6 bcf/d, but has been flat from 2014 thru 2018 at ~2.7 bcf/d, which means the big winner will be LNG. The most important factor driving this expectation for natural gas consumption growth is likely price. Asian LNG landed prices are down about 50% YoY and, more significantly, the expectation is for future Asian LNG prices to be at lower levels than prior cycles. India, by itself, may not be a LNG global game changer, but it is another positive support for why we believe LNG markets will rebalance sooner than expected ie. in 2022/2023. We see mid term Asian LNG landed prices lower than prior cycles in a rebalanced market (ie. +/- $8), which means that low capital costs will be critical for future LNG projects. We believe that BC's LNG key potential projects (LNG Canada Phase 2 and Chevron Kitimat LNG) can compete in this price environment as they have the potential for brownfield capital costs if they move to a continuous construction cycle following in lockstep to LNG Canada Phase 1, much like Cheniere does for its LNG projects in the Gulf Coast.

<u>India has a pollution crisis.</u> We don't think it is unfair to say India has a pollution crisis. In every pollution ranking, India has several cities among the most polluted cities. The 2018 World Air Quality Report (AirVisual) list of the World's Most Polluted Cities 2018 has 20 of the world's 25 most polluted cities being in India. India has all of the top 25 most polluted cities other than #3 Faisalabad (Pakistan), #7 Hotan (China), #10 Lahore (Pakistan), #17 Dhaka (Bangladesh), and #19 Kashgar (China). Like us, many people have been to Beijing on business and believe Beijing's reputation as a very polluted city is deserved. But to put in perspective, Beijing's ranking isn't even close to the 15 most polluted cities in China, let alone the world. Beijing's score on their scale is 50.9 vs the other Chinese cities #7in the world, Hotan at 116.0, and #19 Kashgar at 95.7, and the world's most polluted city #1 Gurugram (India) at 135.8 .

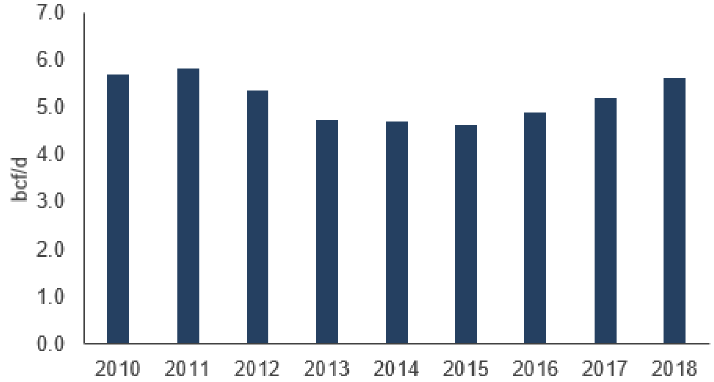
World's Most Polluted Cities 2018

Rank	City	Country	Rank	City	Country
1	Gurugram	India	14	Varanasi	India
2	Ghaziabad	India	15	Moradabad	India
3	Faisalabad	Pakistan	16	Agra	India
4	Faridabad	India	17	Dhaka	Bangladesh
5	Bhiwadi	India	18	Gaya	India
6	Noida	India	19	Kashgar	China
7	Patna	India	20	Jind	India
8	Hotan	China	21	Kanpur	India
9	Lucknow	India	22	Singrauli	India
10	Lahore	Pakistan	23	Kolkata	India
11	Delhi	India	24	Pali	India
12	Jodhpur	India	25	Rohtak	India
13	Muzaffarpur	India	26	Mandi Gobindgarh	India

Source: Airvisual

<u>India natural gas consumption is only now back to 2011 levels.</u> For the past couple years, we have been highlighting that the growth in India's natural gas consumption (and linked LNG imports) has been very low due to the slow buildout of domestic natural gas infrastructure and LNG import facilities. BP data shows India's natural gas consumption was 5.6 bcf/d in 2018, and this compares to its peak of 5.8 bcf/d in 2011. To put in perspective, China's natural gas consumption in 2011 was 13.1 bcf/d and reached 27.4 bcf/d in 2018.

India's Natural Gas Consumption (bcf/d)



Source: BP

Perhaps the best reason why there is better visibility – LNG prices are expected lower than prior cycles. A key reason for this lack of growth has been the price of LNG relative to coal. Our June 17, 2018 Energy Tidbits [LINK] highlighted comments from the Q&A from BP's Chief Economist speech "*Energy in 2017: two steps forward, one step back*" on this relative cost concept. We then wrote on the BP Chief Economist comments from an India company on why there isn't more natural gas and why coal is still going up. He said that the Indian executive said it was because the cost of natural gas was significantly more expensive than domestic coal and that the push in India is to get more power to more poorer people, but if natural gas is significantly higher, it can't be done, they have to rely on coal. What has happened since the BP Chief Economist June 2018 comment is that Asian LNG prices are down 50% and the expectation going forward is that future LNG prices are not expected to be at prior cycle highs. But the other question is what does it mean for LNG prices. There is an increasing supply of reasonable priced LNG around the world, whether it from Qatar, Papua New Guinea, the Gulf of Mexico and even Canada. And each of these areas has anchor projects to support future brownfield development. Couple that with increasing linkage of LNG prices away from oil indexed contracts, we believe this means that a balanced LNG market going forward is going is not going to see sustained high Asian LNG prices from prior cycles, but around more costs related more to lower LNG supply basins ie. LNG prices around mid to long term +/- $8 landed Asian LNG prices, and not the prior $10 - $12 range. As the BP Chief Economist highlights, price is a huge issue for India and it is likely that the expectation for lower LNG prices than prior cycles is the most important reason to push India to increased natural gas consumption.

Japan/Korea Marker (JKM) LNG Price

Source: Bloomberg

India is now getting serious about increasing natural gas consumption, has $60b of projects under execution. We follow the key India news as part of our weekly news scan for our Energy Tidbits memos and there is no question that the India government and its people realize they have to deal with this increasing pollution problem. And perhaps most of all, India is now taking specific, significant action to set the stage for increasing natural gas consumption and LNG imports. Earlier in Oct, Japan Times picked up a Reuters story "*India investing $60 billion on gas grid to link up nation by 2024*" [LINK]. The story notes "*India, one of the world's largest consumers of oil and coal, is investing $60 billion to build a national gas grid and import terminals by 2024 in a bid to cut its carbon emissions, the oil minister said on Sunday. India has struggled to boost its use of gas, which produces less greenhouse gas emissions than coal and oil, because many industries and towns are not linked to the gas pipeline network. Gas consumption growth was running at 11 percent in 2010 but growth slid to just 2.5 percent in the financial year 2018/19*." The most significant part of this story is that this is $60 billion of projects under execution, not planned or potential projects. The story quotes Oil Minister Dharmendra Pradhan "*I am not talking about potential investment. This number relates to the project that are under execution*". The critical natural gas infrastructure requirement is a domestic natural gas pipeline network to deliver gas throughout India. The India Ministry of Petroleum & Natural Gas Oct 3, 2019 release [LINK] said "*On the issue of moving towards the gas economy, Shri Pradhan said that over 16,000 km of gas pipeline has been built and an additional 11,000 km is under construction. With the tenth bid round for City Gas Distribution completed, it will cover over 400 districts and will extend coverage to 70 percent of our population".* Progress is being made. Plus LNG regasification projects continue to be completed. Below is our updated table of India LNG projects that are estimated to come on stream in 2019 and 2020. We haven't included the projects beyond 2020, but there are several planned projects already on the books.

India Current/Planned LNG Regasification Projects Est. In Service In 2019/2020

	State	Coast	Operator	Capacity (mtpa)	Capacity (bcf/d)	Expected Timelines
Existing Terminals						
Dahej	Gujarat	West	Petronet LNG	10.00	1.32	Operating
Dahej Phase 2	Gujarat	West	Petronet LNG	5.00	0.66	Operating
Hazira	Gujarat	West	Shell	5.00	0.66	Operating
Dabhol RGPPL	Maharashtra	West	GAIL & NTPC JV	5.00	0.66	Operating
Kochi	Kerela	West	Petronet LNG	5.00	0.66	Operating
Ennore Phase 1	Tamil Nadu	East	IOCL	5.00	0.66	Operating
Total Existing				**35.00**	**4.61**	
Upcoming Terminals						
Mundra	Gujarat	West	Adani & GSPC	5.00	0.66	2019
Jaigarh	Maharashtra	West	H-Energy Gateway Pvt. Limited	4.00	0.53	2019
Dahej Phase 3	Gujarat	West	PLL	2.50	0.33	2019
Mundra	Gujarat	West	Adani	5.00	0.66	2020
Digha FSRU	Odisha	East	H-Energy	4.00	0.53	2020
Ennore Phase 2	Tamil Nadu	East	IOCL	1.75	0.23	2020
Jafrabad	Gujarat	West	Swan Energy	5.00	0.66	2020
Total Upcoming				**27.25**	**3.59**	

Source: Bloomberg, Company Reports, Street Reports

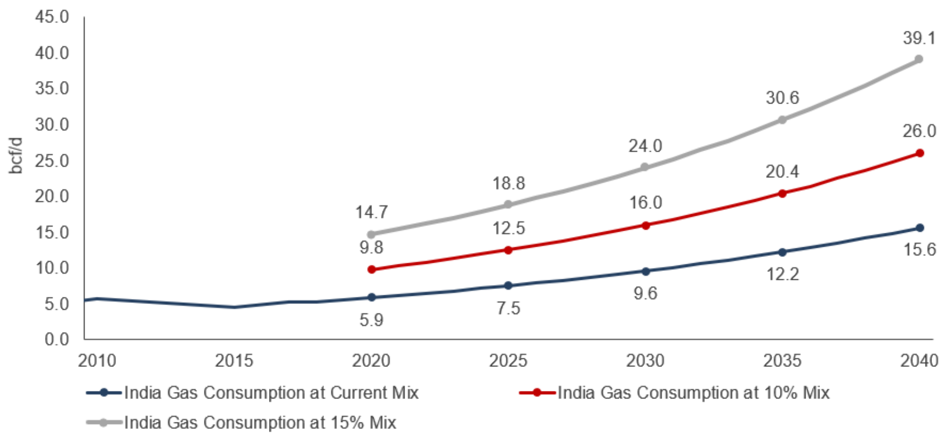
It reminds us of when China got really serious about natural gas in 2018. We should be clear that we do not consider India anywhere near as significant to global LNG markets as China. But conceptually, India getting serious about increasing natural gas consumption reminds us of what we were seeing in China in 2016/2017. India is probably more like China in 2016 as opposed to the summer of 2017, when it seemed clear that China was on the cusp of a major push in natural gas consumption and LNG would be the winner in 2018. India's impact should start to play out by year end 2020 as opposed to this winter. We first outlined the China LNG thesis in our Sept 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]. Our Sept 20, 2017 blog wrote "*The news flow from China this summer on its increasing fight and urgency to fight pollution supports China's plan to increase natural gas to 10% of its energy mix in 2020 and 15% of its energy mix in 2030. This is a game changer to global natural gas markets and, by itself, can bring LNG to undersupply 2 to 3 years earlier than expected. China's natural gas consumption increased by ~15% per year from 2005 thru 2016 and ~1.5 bcf/d per year vs China's 8.5%*

growth rate in energy in total. Yet natural gas only got to 5.9% of China's energy mix. If China is to hit 10% by 2020, it will need to increase natural gas consumption by 4 to 5 bcf/d per year. Assuming China continues to grow its domestic natural gas production by 0.6 bcf/d per year (its growth rate for last five years), China will need to import an additional ~3.5 to ~4.5 bcf/d per year. This is "per year"! And if so, we believe BC LNG will be back and there is a higher probability than ever before for a Shell FID on its BC LNG project in 2018." As it turned out, Shell did FID its LNG Canada project on Oct 1, 2018.

Natural gas is only 6.2% of India's energy mix vs its target of 15% in 2030. India, similar to China, has a target to have natural gas to be 15% of its total energy mix by 2030. This is not a new target, rather it has been in place and we first highlighted India's 15% target of its energy mix in our Nov 23, 2018 blog "*"India's Natural Gas Consumption Would Be Up ~1.3 Bcf/D Per Year If Its To Reach Its Target Of 15% Of Its Energy Mix By 2030*" [LINK] At that time, we noted some specific steps that were happening in 2019 and 2020 to put them on that long term plan. The impact to get to 15% of energy mix is significant to world LNG markets. This is a big increase from natural gas being 6.2% of India's energy mix in 2018. To put in perspective, in 2018, natural gas was 30.5% of US energy mix, 21.9% of Japan's energy mix, 16.0% of South Korea's energy mix, and 7.4% of China's energy. Note, China is up from 6.6% in 2017.

Hitting 15% of its energy mix would increase India's natural gas consumption by >1.5 bcf/d per year. We projected how much India's natural gas consumption would increase if it can hit its target of 15% of total energy mix in 2030. BP data shows India's natural gas consumption in 2018 was 5.6 bcf/d and natural gas was only 6.2% of total energy mix. BP also estimates India's total energy consumption grew at a rate of 5.2% per year for the 2007 – 2017 period, but energy consumption growth increased to +7.9% in 2018 YoY vs 2017 But if we only assume a 5% growth in total energy mix to 2030, then if natural gas is 15% of India's energy mix, it would be 18.8 bcf/d in 2025 and 24.0 bcf/d in 2030 ie. growth of +13.2 bcf/d to 2025 and +18.4 bcf/d to 2030. India's domestic natural gas production peaked in 2010 at 4.6 bcf/d, but has been flat from 2014 thru 2018 at +/- 2.7 bcf/d. We expect there to be some increased focus to at least return India to modest domestic natural gas production. But, until then, any growth in natural gas consumption will be met with LNG. Our model forecasts of >1.5 bcf/d per year, on average, in consumption is the equivalent of 2.5 Cheniere LNG trains per year.

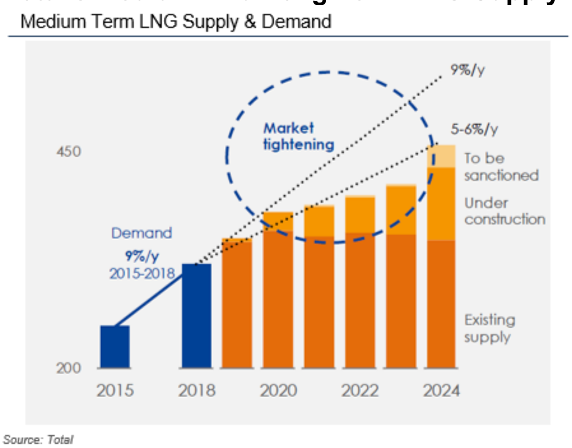
India's Projected Natural Gas Consumption @15% Of Energy Mix (bcf/d)

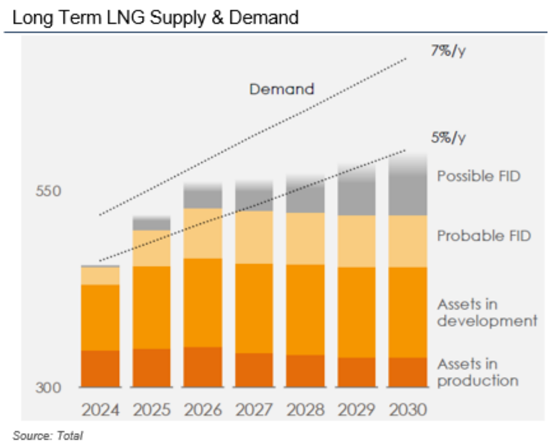


Source: BP, SAF

India may not be a LNG global game changer by itself like China, but does support the call that LNG markets rebalance sooner than expected. We had our SAF Group 2020 Energy Market Outlook on Monday Oct 7. A replay of the call and the supporting slide presentation are available on our website at [LINK]. Two of our key off consensus calls were on LNG including our view LNG market would balance earlier than expected ie. 2022/2023. We noted that we agree with markets that LNG will be oversupplied thru 2021, but where we disagree is that we see LNG markets balancing in 2022 or 2023. Our presentation reminded that LNG supply capacity needs to be in excess of demand to provide for turnarounds and allowance such that suppliers can deliver contract volumes. We also expect the required over capacity of supply is increasing as contract mix shifts away from historical oil indexed take or pay contracts with destination clauses to an increase share of portfolio contracts. There is no firm number, but we believe the required excess supply capacity relative to demand has increased from approx. 5% to 10% to +/-15% ie. LNG markets are effectively balanced when LNG supply capacity is >10% of demand. As a result, we believe that LNG markets rebalance in 2022/2023, a view which is similar to Total's Sept 25, 2019 Investor Day [LINK] (see below graphs). We should note that our view of balanced LNG markets doesn't mean a return to $12 or more Asian landed LNG prices, rather, we see the emergence of anchor LNG projects in areas with brownfield expansion potential means that a planning case for mid term Asian LNG price is in the $8 range. Our outlook presentation also includes our view that BC's LNG key potential projects (LNG Canada Phase 2 and Chevron Kitimat LNG) can compete in this price environment as they have the potential for brownfield capital costs if they move to a continuous construction cycle following in lockstep to LNG Canada Phase 1, much like Cheniere does for its LNG projects in the Gulf Coast. Our outlook call did not specifically work in the India Energy Minister's comment on in execution projects, but, if anything, it provides us with more confidence for the call for LNG markets to rebalance in 2022/2023.

Total's Medium And Long Term LNG Supply & Demand





Source: Total Sept 25, 2019 Investor Day https://www.spglobal.com/platts/en/market-insights/latest-news/oil/091521-some-oil-fired-units-in-japan-might-be-restarted-amid-rising-lng-coal-prices-paj-chief

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- 15 Sep 2021 | 12:41 UTC

Some oil-fired units in Japan might be restarted amid rising LNG, coal prices: PAJ chief

HIGHLIGHTS

Oil-fired power increasingly cost competitive: PAJ chief

Refiners cautious about fuel oil supply capacity in event of demand boost

Spot LNG above $20/MMBtu, Northeast Asia spot thermal coal at all-time high

Japan may see some restarts of oil-fired power generation units this winter, amid soaring LNG and coal prices, Petroleum Association of Japan President Tsutomu Sugimori said Sept. 15, as refiners carry out contingency planning in response to the tightened power supply and demand

"If this steep rise continues, it would be a matter of comparing costs between oil, coal and LNG thermal power and looking at which sources are cheap and expensive," Sugimori told an online press conference. "By a simple cost comparison, competitiveness of oil-fired power will likely increase amid soaring coal and LNG [prices]."

"In case of oil-fired power being competitive, there is a possibility of seeing a part of oil-fired power plants being restarted," Sugimori said.

"In such occasion, we are uncertain how much we can meet supply requests," he added, citing the reduced oil share in the thermal power generation mix.

Refiners, however, will "maximize efforts" to ensure their fuel oil supply for power generation, he said.

Japanese refiners boosted their fuel oil supply for power generation in January, following an emergency fuel supply request from the Federation of Electric Power Companies of Japan to PAJ in the wake of LNG shortages after a surge in power demand following severe cold spells.

Fuel oil sales surged 43% on the year to 179,585 b/d in January, when there were domestic shipments of 751,109 barrels of crude oil for power generation, nearly double the 429,323 barrels in December 2020, while there were no crude shipments for power in January 2020, according to the Ministry of Economy, Trade and Industry data.

Soaring prices

Power utilities -- which typically require a two-month lead time to adjust their LNG receiving volumes to balance their requirements -- are moving to secure fuels early for winter, with some having already secured enough LNG, coal and oil, according to industry sources.

Amid the rising spot LNG price, some Japanese power utilities have moved to secure fuel oil domestically, with some having filled their tanks in the summer, according to a source with one Japanese refiner.

The price of generation fuels has surged across the board, making life difficult for those Asian utilities that have yet to ramp up procurement.

Asia LNG spot prices have surged past $20/MMBtu, with the S&P Global Platts JKM for October assessed at $23.185/ MMBtu on Sept. 14. This is the second-largest JKM price spike on record since the assessment was launched in 2009, and a record high for this time of year.

In comparable terms, the price of 180 CST 2% sulfur fuel oil FOB Singapore was priced at $11.848/MMBtu on Sept. 14, after hitting a two-year high of $11.979/MMBtu last week. The price of Minas crude FOB Indonesia was around $11.924/MMBtu and naphtha CFR Japan was at $14.607/MMBtu on Sept 14, according to Platts data.

The benchmark prices of competing fuels are still much lower than LNG despite hitting record highs.

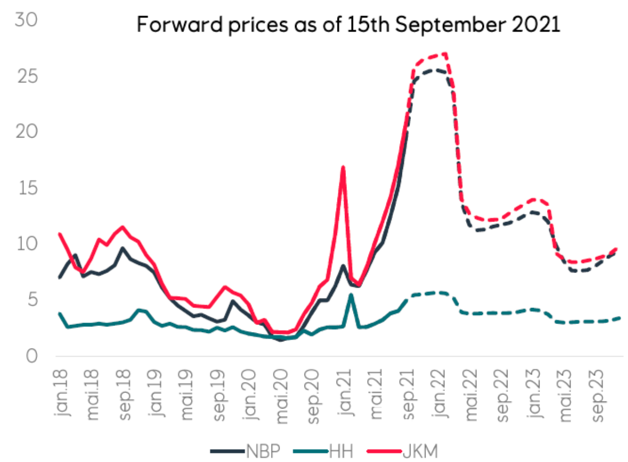
The Platts Northeast Asia Thermal (NEAT) Coal Index is at an all-time record high of $143.99/mt on Sept. 14, after trading at less than half this level for most of 2020. In thermal units, Platts Northeast Asian coal prices crossed $6/MMBtu for the first time on Sept .14.

Global gas price forecast: changes since Gas Seminar in February 2021

Prolonged winter spell April-May in Europe and unseasonably strong Asian LNG demand in spring

Global Gas Prices ($/MMBtu)

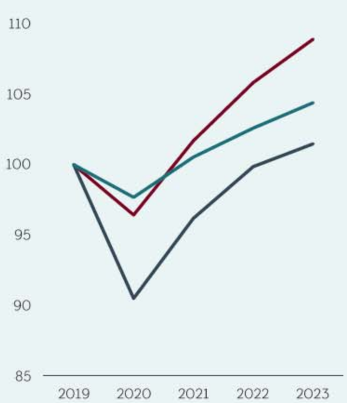
Global Gas Prices ($/MMBtu)



COVID-19: A shock with profound impact

On human beings, societies, economies, and markets – and we are not out of it yet

Global GDP, oil and gas demand
Indexed, 2019 = 100



Source: Equinor

Countries in recession in 2020
Real GDP growth, annual percent change

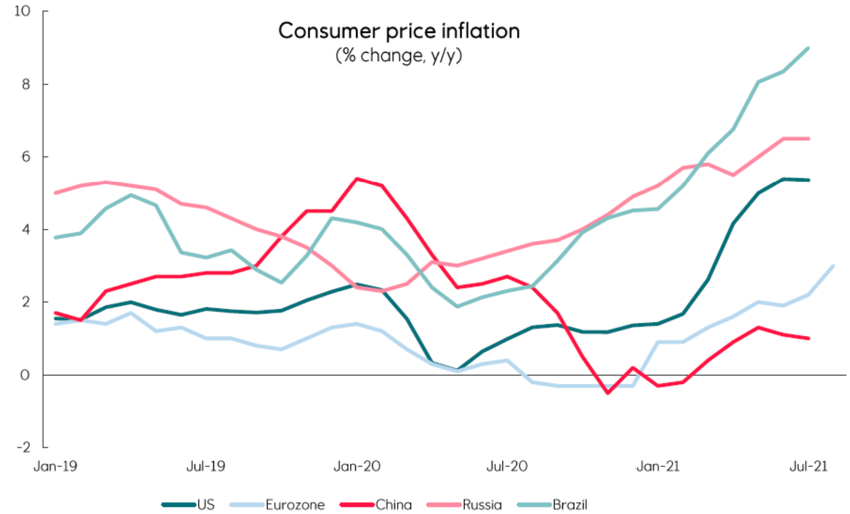
Source: International Monetary Fund

Key uncertainties:

- Vaccine rollout and impact
- Delta and other variants
- Supply chain bottlenecks
- Inflation
- Tightening fiscal policies

Elevated inflation mainly reflects pandemic-related developments

When will inflationary pressures abate? What if they don´t?



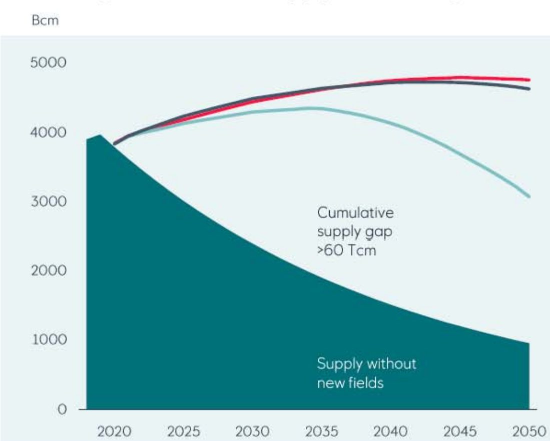
- Inflation has surprised to the upside across economies
- The recent acceleration in inflation largely reflects pandemic-related disruptions on supply and demand
- Bottlenecks are present both in trade and labor markets
- Inflation is mostly expected to decline as the transitory disturbances abate
- If inflation lasts, tightening policies are expected
- Potential impact on the energy transition:
  - Higher costs of renewables a drag
  - Higher fossil fuel prices an accelerator

Source: Refinitiv Datastream

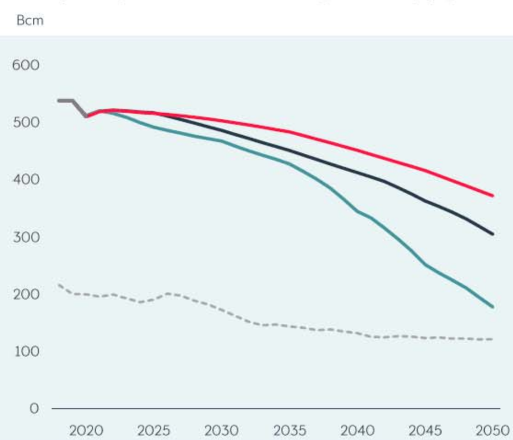
Wide outcome space for long-term gas demand – global growth until ~2035

Large investments in all scenarios – Europe still needs imports in Rebalance – matching supply and demand globally a challenge

Global gas demand and supply from existing fields



European gas demand and indigenous supply



Factors driving gas demand:

- Economic growth
- Energy transition in Asia
- Energy and climate policies
- Geopolitics
- Market design
- Technology
- Impact of blue (and green) H_2

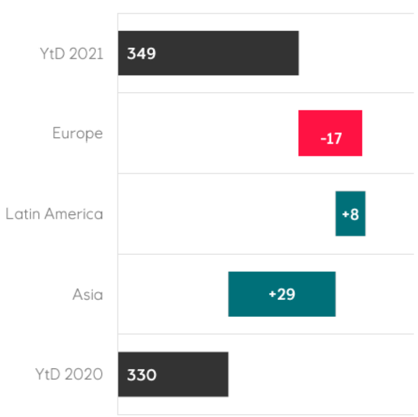
Source: IEA, Equinor

Reform Rebalance Rivalry Indigenous European supply in Reform (incl NCS) equinor

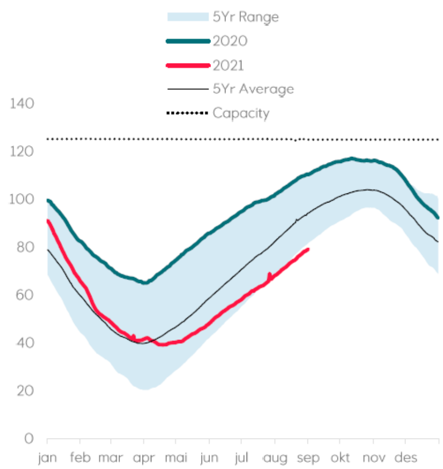
Gas price rally: caused by strong Asian LNG demand, low European stocks and surging carbon prices

Prolonged winter spell April-May in Europe and unseasonably strong Asian LNG demand in spring

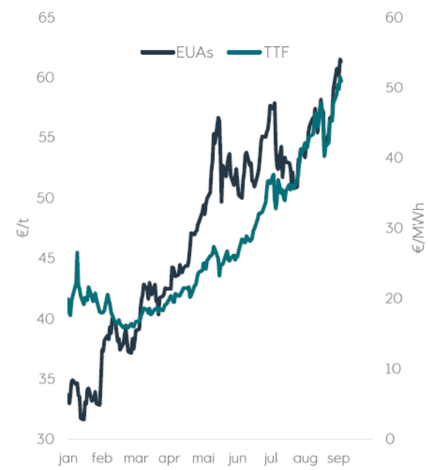
LNG Imports (Bcm)



European stocks (Bcm)



EU ETS (€/t)

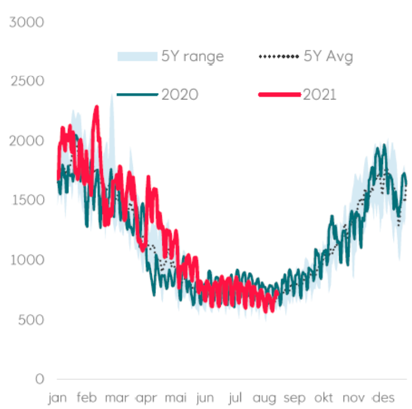


equinor

1H 2021 Gas demand growth: driven by weather and economic recovery

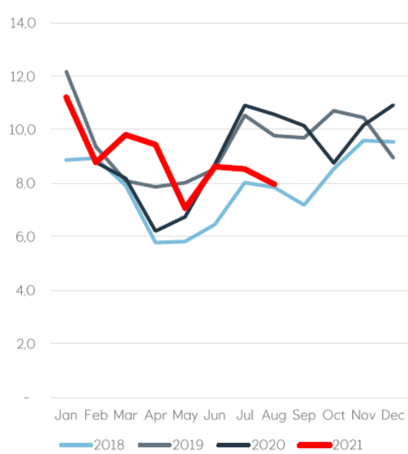
GtP 2H 2021 expected to remain at a lower level than the previous two years

European* gas consumption (mcm/d)

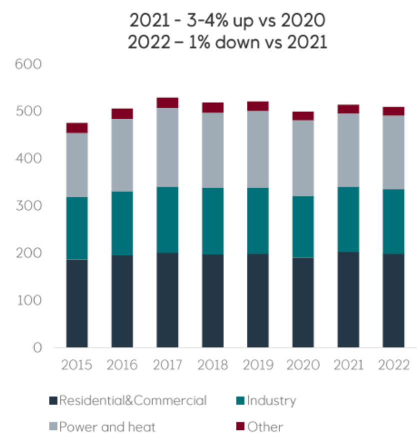


* Excl Turkey.

Gas to Power (Bcm)



European gas demand by sector (Bcm)



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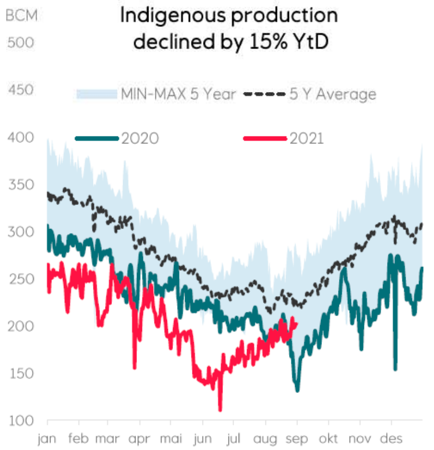
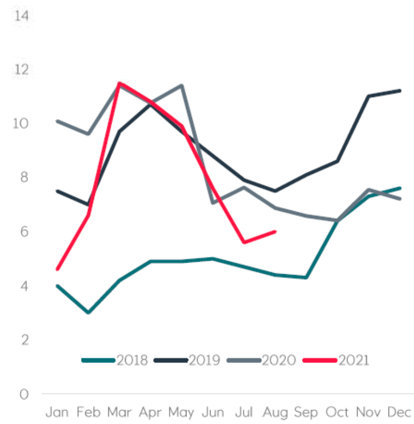
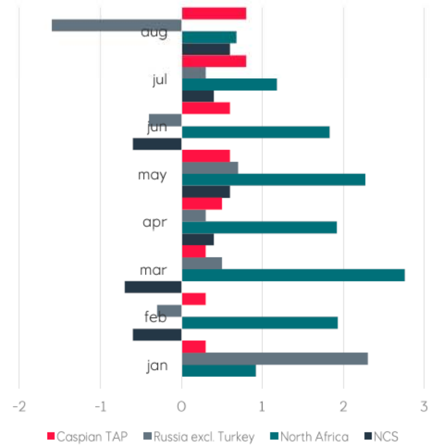
European supply:
Overall strong pipeline import mainly driven by import from Algeria

European gas production (Bcm)	European LNG Import* (Bcm)	European Pipeline Import2021 vs 2020 (Bcm)





*Excl Turkey

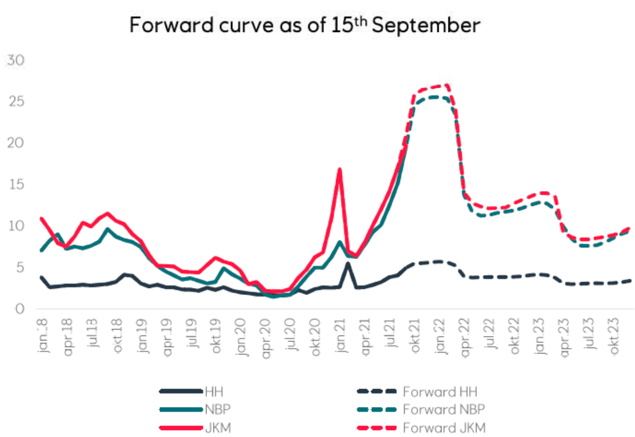


equinor

European gas prices will remain high this winter on low gas stocks

HH strengthens well above $4/MMBtu due to mismatch between flat supply and growing demand.
JKM grows relative to TTF – spread supported by Asian demand and higher shipping costs

Global Gas Prices ($/MMBtu)



Key drivers NBP	Impact on Price
Low storage fill	
Weather related risk	
Continued Asian demand	
Pipeline supply uncertainties	
LNG supply	

Summary

- High gas prices are expected to continue during winter 21-22, driven by strong global LNG demand and low European stock levels
- Europe will enter the winter months with storage ranging around 70-75% full, which is below the 5-year average, This leaves the market exposed to high prices when demand rises.
- Key supply outages remain a risk in the market
- Uncertainties surrounding Russian supply – Nord Stream 2 start of supply and/or additional capacity booking via Ukraine route – are bullish drivers for the prices.
- Asian LNG fundamentals suggest tight winter 21-22
- Forward market indicates a bullish sentiment for summer 22 based on low storages ahead of the summer and a consequential need for strong storage injections. This might happen if Asian demand remains strong also in 2022, absorbing the incremental LNG supply.
- Global LNG supply is recovering from a prolonged period of maintenance and outages. New LNG supply for the 2H 2021 +2022 is expected to be approximately 30 bcm, US capacity additions represent 67%.

https://tass.ru/ekonomika/12431777
SEP 17, 03:45Updated Sep 17, 04:31

Miller said that gas reserves in Russia will last more than 100 years

The chairman of the board of Gazprom also said that the study of the Power of Siberia-2 gas pipeline project allows for export deliveries of gas from Western Siberia both to the west and to the east.

Alexey Miller, head of Gazprom

MOSCOW, September 17. / TASS /. Gas reserves in Russia are the largest in the world, they will last more than 100 years. This was stated by the chairman of the board of "Gazprom" Alexey Miller, speaking at the 24th annual general meeting of the International Business Congress, which took place on September 14-17 in a mixed format.

"Gas reserves in Russia, Gazprom's gas reserves are the largest in the world. And we will not experience problems with our reserves for the next hundred years," he said.

At the same time, Miller added that some of the fields that Gazprom is currently developing in Yamal will work until 2132. "Therefore, the prospects for pipeline gas supplies are very great," he said.

Miller said that the study of the Power of Siberia-2 gas pipeline project allows for export deliveries of gas from Western Siberia both to the west and to the east.

"The development of such a project as Power of Siberia - 2, in fact, allows gas to be supplied from Western Siberia not only to the east of Russia, not only to large industrial centers of Eastern Siberia, but also allows gas to be exported both to the west and east, "he said.

Miller said Gazprom could sharply increase gas supplies despite the growing seasonal unevenness in demand.

He noted that the demand for gas is growing, including due to seasonal unevenness caused by climate change. “We have the so-called“ saw ”of Gazprom, and, without a doubt, this is our competitive advantage, that we can work, not just bringing our annual volumes to the market in terms of a certain average monthly volume of gas supplies to the market, but we can to sharply increase the volume of supplies, despite the fact that the production capacity for such a peak daily production for a long period is not in demand at all, "he said.

At the same time, Miller added that the volume of surplus production capacities, which Gazprom provides for the peak volumes, is almost 150 billion cubic meters. m of gas

https://tass.ru/ekonomika/12432031
SEP 17, 03:59Updated Sep 17, 04:48

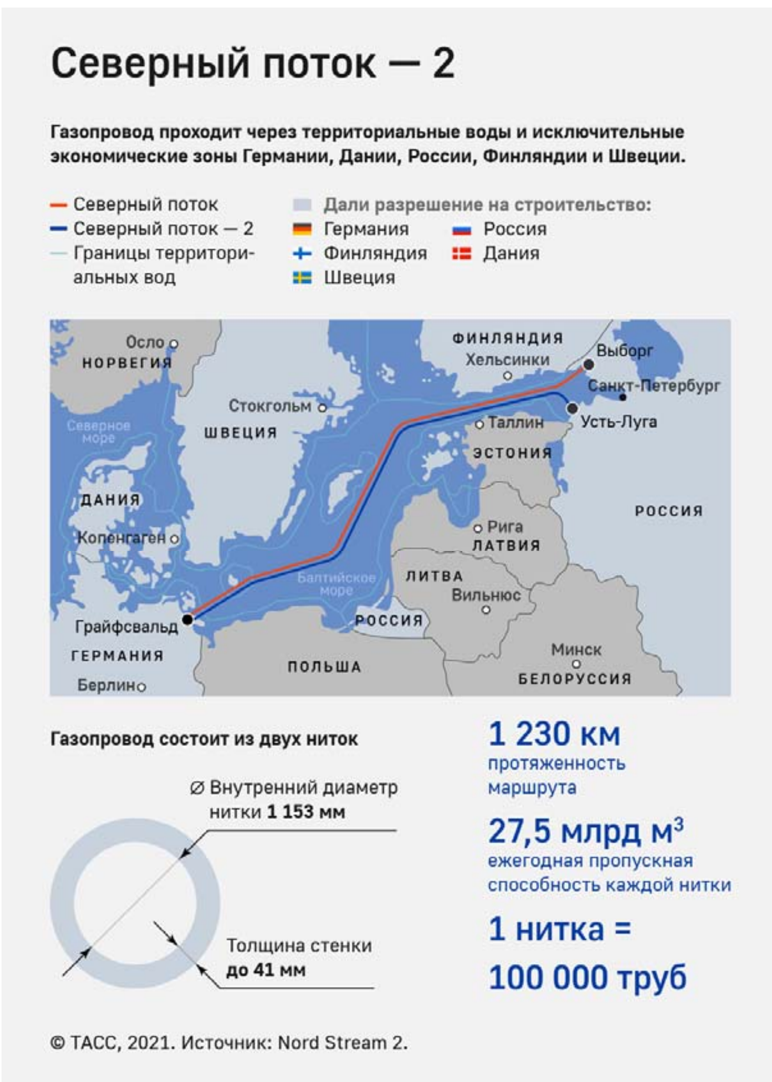
Uniper CEO: timing for completion of Nord Stream 2 is "just perfect"

Klaus-Dieter Maubach noted that this gas pipeline is the most important source of gas supplies to Europe

MOSCOW, September 17. / TASS /. The Nord Stream 2 gas pipeline is the most important source of gas supplies to Europe, and the timing of its completion was chosen "just perfect," said the head of the Uniper concern (one of Gazprom's European partners in the project) Klaus-Dieter Maubach, speaking at the annual meeting of the International Business Congress.

“I would like to congratulate Gazprom and Nord Stream 2 AG on the completion of Nord Stream 2. This is certainly great news, and I sincerely congratulate all the participants. Technically, the project has been completed, and, if I may, I would like to add that the timing of the completion is just perfect, "he said.

Nord Stream 2 is the most important source of gas supplies to Europe, the head of Uniper added.



https://twitter.com/KwasiKwarteng/status/1439265378878828545

Kwasi Kwarteng @KwasiKwarteng

Today, I've held a series of individual meetings with senior executives from the energy industry to discuss the impact of high global gas prices.

I was reassured that security of supply was not a cause for immediate concern within the industry. (1/7)

10:29 AM · Sep 18, 2021 · Twitter Web App

37 Retweets **37** Quote Tweets **150** Likes

Kwasi Kwarteng @KwasiKwarteng · 19h

Replying to @KwasiKwarteng

The UK benefits from having a diverse range of gas supply sources, with sufficient capacity to more than meet demand.

The UK's gas system continues to operate reliably and we do not expect supply emergencies this winter. (2/7)

10 7 15

Kwasi Kwarteng @KwasiKwarteng · 19h

Protecting customers during a time of heightened global gas prices is an absolute priority.

The Energy Price Cap exists to protect millions of customers.

Initiatives such as the Warm Home Discount, Winter Fuel Payments and Cold Weather Payments will help further. (3/7)

8 4 11

Kwasi Kwarteng @KwasiKwarteng · 19h

Some energy companies are facing pressure. Ofgem has robust measures in place to ensure that customers do not need to worry, their needs are met, and their gas and electricity supply will continue uninterrupted if a supplier fails. (4/7)

6 5 12

Kwasi Kwarteng @KwasiKwarteng · 19h

Energy security is an absolute priority. We are confident supply can be maintained.

Our largest single source of gas is from domestic production, and the vast majority of imports come from reliable suppliers such as Norway.

We are not dependent on Russian oil and gas (5/7)

15 13 20

Kwasi Kwarteng @KwasiKwarteng · 19h

However, our exposure to volatile global gas prices underscores the importance of our plan to build a strong, home-grown renewable energy sector to further reduce our reliance on fossil fuels.

Renewable energy has quadrupled since 2010, but there is more to do (6/7)

67 48 83

Kwasi Kwarteng @KwasiKwarteng · 19h

Tomorrow morning, I will meet Ofgem again to discuss this in more detail.

On Monday, I will convene a roundtable with industry to plan a way forward.

I will remain in constant contact with colleagues across Govt to manage the wider implications of the global gas price increase.

26 10 37

https://www.gov.uk/government/news/uk-gas-supply-explainer

UK gas supply explainer

This explainer sets out the background to the issue of wholesale gas prices and the action the government is taking to protect the UK's energy supply, industry, and consumers.

From: Department for Business, Energy & Industrial Strategy
Published 18 September 2021

There has recently been widespread media coverage of wholesale gas prices, and the effect this could have on household energy bills. The impact on certain areas of industry, and its ability to continue production, has also attracted attention.

This explainer sets out the background to the issue and the action the government is taking to protect the UK's energy supply, industry, and consumers.

Natural gas prices have been steadily rising across the globe this year for a number of reasons. This has affected Europe, including the UK, as well as other countries around the world.

We have a diverse range of gas supply sources, with sufficient capacity to more than meet demand. The UK's gas system continues to operate reliably and we do not anticipate any increased risk of supply emergencies this winter.

Why are there high global gas prices?

The prices that are currently visible reflect the high value being placed on gas at the present time, with prices being determined by global supply and demand. They are not necessarily representative of pre-existing contracts and therefore do not apply to all of the gas being consumed in the UK this winter.

Current prices reflect a number of factors including:

- as the world comes out of COVID-19 lockdowns and economies reopen, we are seeing an uptick in global gas demand this year. *combined with a cold winter (which has an impact on gas demand as gas is often used for heating homes) this has led to a much tighter gas market with less spare capacity
- in particular, high demand in Asia for Liquified Natural Gas (LNG), natural gas transported globally by ship, means less LNG than expected has reached Europe *some essential maintenance projects rescheduled from 2020 due to coronavirus coincided with necessary scheduled projects in 2021, while weather events in the US have adversely affected their LNG exports to Europe

How are high global gas prices impacting the UK?

The gas market is crucial to the UK's energy supply because of its significance in heating, industry and power generation.

Over 22 million households are connected to the gas grid and in 2020, 38% of the UK's gas demand was used for domestic heating, 29% for electricity generation and 11% for industrial and commercial use.

High gas wholesale prices have subsequently driven an increase in wholesale power prices this year.

In recent weeks, this trend has been exacerbated by the weather and planned maintenance at some power stations. This has resulted in unusually low margins for this time of year. These factors have combined to cause spikes in wholesale electricity prices, with a number of short-term markets trading at, or near, record levels.

While we are not complacent, we do not expect supply emergencies this winter.

Is our gas supply at risk?

The Great Britain (GB) gas system has delivered securely to date and is expected to continue to function effectively, with a diverse range of supply sources and sufficient delivery capacity to more than meet demand.

While our largest single source of gas supply continues to be the UK Continental Shelf (approximately 48% of total supply in 2020), the maturity of that source means we have to supplement supply from international markets.

Whilst the diversity of those international sources promotes our energy security, by reducing reliance on a particular source, the UK – as with other nations – is exposed to global trends in supply and demand which affect the price of gas traded at UK's market hub (the National Balancing Point).

We have a wide range of supply sources including direct pipelines across the North Sea from Norway to the UK, our single biggest source of imports. We are also investing millions into scaling up strong renewable energy capacity and driving down demand for fossil fuels.

GB also has a number of gas storage facilities that act as a source of system flexibility when responding to short-run changes in supply and demand.

What is the government doing on this?
Energy security is an absolute priority for this government. The government works closely with the regulator and gas supply operators to monitor supply and demand.
While wholesale gas prices have increased internationally this year, the market continues to balance supply and demand through adjusting the prices at which energy trades take place. We have no reason to suggest this will not continue but will monitor the market.
National Grid Gas has a number of tools at its disposal to mitigate the risk of a gas supply emergency, including requesting additional gas supplies be delivered to the National Transmission System. Together with the Department for Business, Energy and Industrial Strategy (BEIS), National Grid Gas has robust response plans in place in the unlikely event that risk should materialise. Read plans for network gas supply emergencies.
Will this affect energy bills?
The high wholesale gas prices that are currently visible may not be the actual prices being paid by all consumers.
This is because major energy suppliers purchase much of their wholesale supplies many months in advance, giving protection to them and their customers from short-term price spikes.
The Energy Price Cap is also in place to protect millions of customers from the sudden increases in global gas prices this winter. Despite the rising costs of wholesale energy, the cap still saves 15 million households up to £100 a year.
The current global wholesale gas price situation as set out above could have an effect on companies. Companies without longer-term contracts may face higher costs, but we expect that companies with longer-term contracts in place may have little exposure to the current high wholesale prices. If there were an event where a supplier fails, Ofgem would work to ensure that customers are moved to a new supplier, so they are not without energy.
How is the government helping poorer households?
Our Energy Price Cap will protect millions of customers from the sudden increases in global gas prices this winter.
We are also supporting low income and fuel poor households with their energy bills in a number of ways which demonstrates the government's commitment.
This includes through:
- the Warm Home Discount which provides eligible households with a £140 discount
- in addition, Winter Fuel Payments and Cold Weather Payments will help ensure those most vulnerable are better able to heat their homes over the colder months

Vulnerable people and anyone in financial distress during this time should talk to their energy supplier, who will be able to discuss personal circumstances and consider options to help, including reassessing, reducing or pausing payments. Emergency measures have been agreed between government and energy suppliers to support those most in need during the disruption caused by COVID-19, and this agreement remains in place this winter. Read details of the agreement.
As set out in the Energy white paper, we plan to extend the Warm Home Discount until 2026, increase it to £150, and help an extra 780,000 pensioners and low-income families with their energy bills. With a total of 2.7 million to get support, with the vast majority to receive the money back automatically, without having to apply as at present.
Cold Weather Payments provide vulnerable households on qualifying benefits with financial support when the weather has been, or is forecasted to be, unusually cold. £25 is available for eligible households for each 7 day period of very cold weather between 1 November and 31 March.
Published 18 September 2021

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

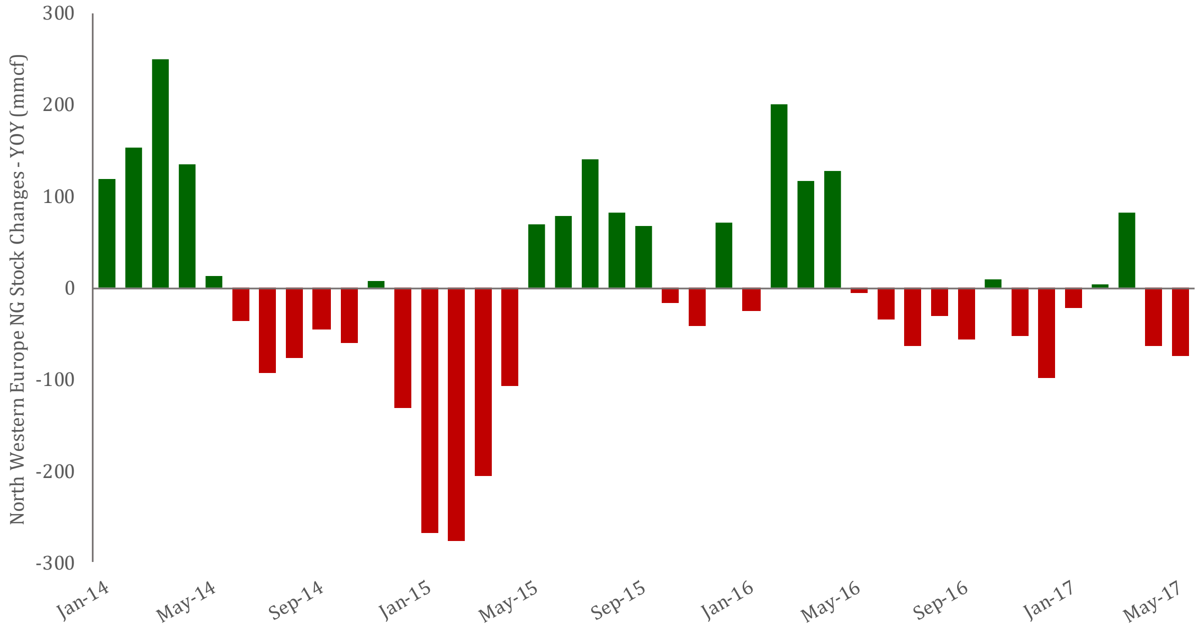
We will be presenting a very bullish outlook for natural gas later today in our webcast for Stream’s 2018 Energy Outlook. The key to our call is that a massive natural gas demand surge has started and will lead to world LNG markets being corrected closer to 2020 than the current conventional wisdom of 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.

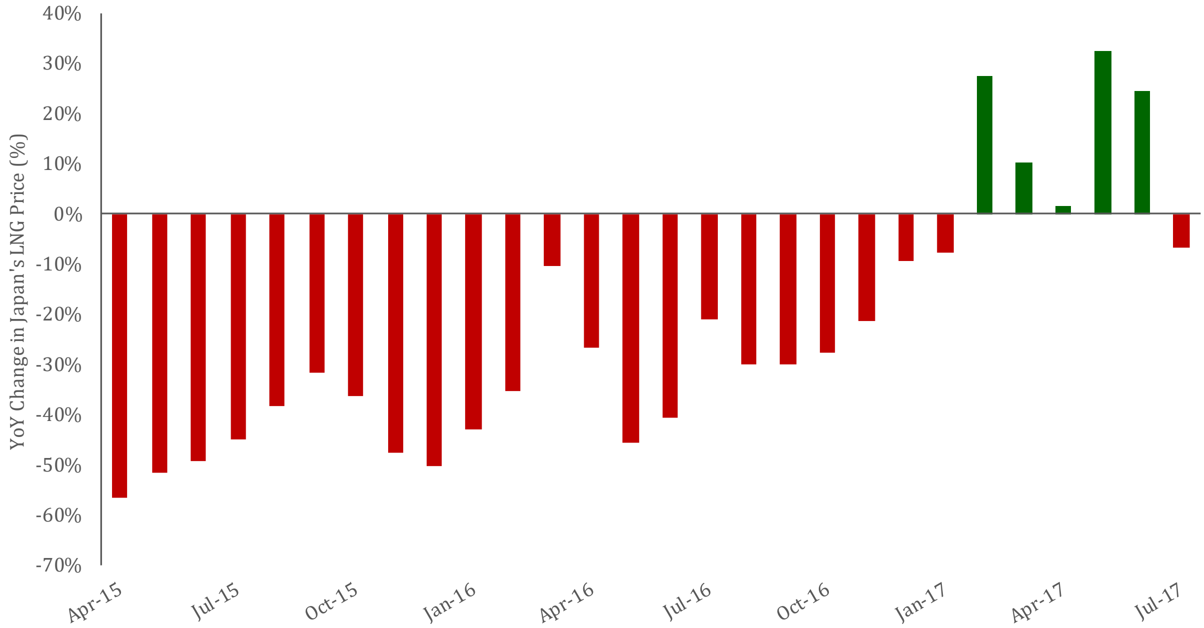
NW Europe YoY Changes In Monthly Storage Net Injections/Withdraw



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?

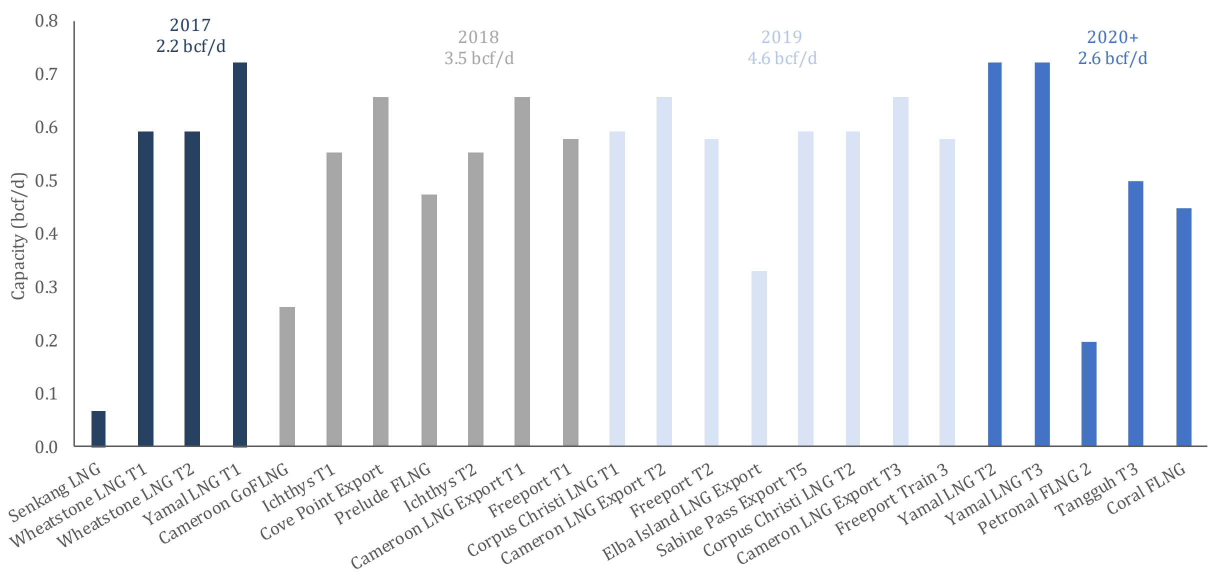
Japan Spot LNG Prices – YoY Monthly Change



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

A better starting point moves LNG to undersupply quicker, especially if combined with a massive surge in natural gas demand. 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.

North Dakota | Mineral Resources
Be Legendary.™

Release Date: 9/17/2021
Director Lynn Helms

Director's Cut
July 2021 Production

Oil Production

June	34,004,943 barrels = 1,133,498 barrels/day (final)
July	33,411,470 barrels = 1,077,789 barrels/day (all-time high 1,519,037 BOPD Nov 2019)
	1,036,839 barrels/day or 96% from Bakken and Three Forks
	40,951 barrels/day or 4% from legacy pools

Revised Revenue Forecast **= 1,200,000→1,100,000→1,000,000 barrels/day**

Crude Price[1] ($/barrel)

	North Dakota Light Sweet	WTI	ND Market estimate
June	63.62	71.35	65.47
July	64.80	72.43	66.93
Today	65.50	72.61	69.06
All-time high (6/2008)	$125.62	$134.02	$126.75

Revised Revenue Forecast **= $50.00**

Gas Production & Capture

June Production	89,634,861 MCF = 2,987,829 MCF/day
Gas Captured: 92%	82,383,284 MCF = 2,746,109 MCF/day
July Production	89,122,575 MCF = 2,874,922 MCF/day (all-time high 3,145,172 MCFD Nov 2019)
Gas Captured: 90%	79,902,861 MCF = 2,577,512 MCF/day (all-time high 2,899,998 MCFD Mar 2020)

Rig Count

June	20
July	23
August	28
Today	27
Federal Surface	0
All-time high	*218 (5/29/2012)*

[1] Pricing References: WTI: EIA and CME Group; ND Light Sweet: Flint Hills Resources

Wells

	June	July	August	Revised Revenue Forecast
Permitted	75 drilling 0 seismic	40 drilling 0 seismic	79 drilling 0 seismic (All-time high was 370 – Oct. 2012)	-
Completed	41 (Final)	47 (Revised)	53 (Preliminary)	**30→40→50→60**
Inactive[2]	1,839	2,082	-	-
Waiting on Completion[3]	680	521	-	-
Producing	16,844	16,881 (Preliminary) (All-time high 16,844 in June 2021) *14,590 (86%) from unconventional Bakken – Three Forks* *2,291 (14%) from legacy conventional pools*	-	-

Fort Berthold Reservation Activity

	Total	Fee Land	Trust Land
Oil Production (barrels/day)	236,638	94,720	141,918
Drilling Rigs	3	1	2
Active Wells	2,590	646	1,944
Waiting on completion	TBD		
Approved Drilling Permits	TBD	TBD	TBD
Potential Future Wells	3,962	1,118	2,844

Drilling and Completions Activity & Crude Oil Markets

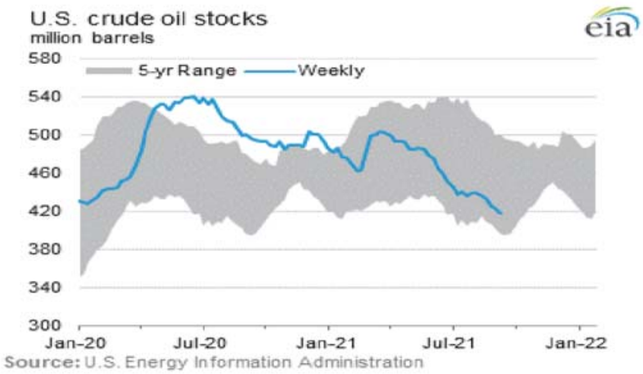
The drilling rig count was stable in the mid 50's second half of 2019 through May 2020. Drilling rig count fell 59% from January 2020 to July 2021 and is slowly increasing.

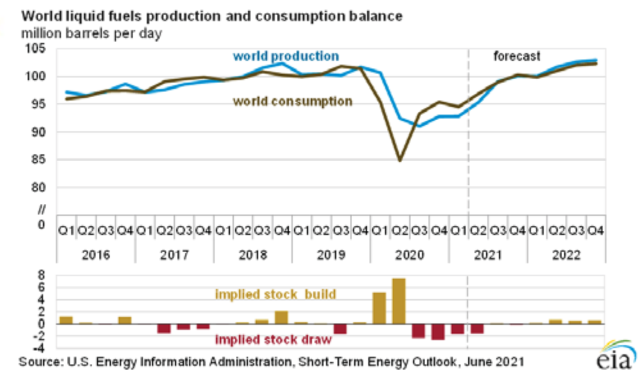
The number of well completions has been low and volatile since April 2020 as the number of active completion crews dropped from 25 to 1 then increased to 6 in July 2021 and to 12 this week.

OPEC+ reached a deal Sunday to phase out 5.8 million barrels per day of oil production cuts by September 2022 as prices of the commodity hit their highest levels in more than two years. Coordinated increases in oil supply from the group known as OPEC+ began in August. Overall production will increase by 400,000 barrels per day on a monthly basis from that point onward.

The International Energy Agency estimates a 1.5 million barrel per day shortfall for the second half of this year, indicating a tight market despite the gradual OPEC supply boost. EIA now estimates that supply and demand are balanced with demand returning to 2019 levels in the second quarter 2022.

[2] Includes all well types on IA and AB statuses: **IA** = Inactive shut in >3 months and <12 months;
AB = Abandoned (Shut in >12 months)
[3] The number of wells waiting on completions is an estimate on the part of the director based on idle well count and a typical five-year average. Neither the State of North Dakota, nor any agency officer, or employee of the State of North Dakota warrants the accuracy or reliability of this product and shall not be held responsible for any losses caused by this product. Portions of the information may be incorrect or out of date. Any person or entity that relies on any information obtained from this product does so at his or her own risk.





Crude oil transportation capacity including rail deliveries to coastal refineries is adequate, but could be disrupted due to:

- US Appeals Court for the ninth circuit upholding of a lower court ruling protecting the Swinomish Indian Tribal Community's right to sue to enforce an agreement that restricts the number of trains that can cross its reservation in northwest Washington state.
- DAPL Civil Action No. 16-1534 continues, but the courts have now ruled that DAPL can continue normal operations through March 2022.

Drilling activity is slowly increasing and operators continue to maintain a permit inventory of approximately 12 months.

Gas Capture

US natural gas storage is now 7% below the five-year average. Crude oil inventories are below normal in the US, but world storage is above the five-year average.

The price of natural gas delivered to Northern Border at Watford City increased to $23.42/MCF February 17, 2021 and has returned to a significantly higher than normal level of $4.77/MCF today. This results in a current oil to gas price ratio of 14 to 1. The state wide gas flared volume from June to July increased 55,689 MCFD to 297,410 MCF per day, and the percent flared increased to 10.2% while Bakken capture percentage decreased to 90% due to maintenance and outages at Bear Creek, Lonesome Creek, Robinson Lake, Tioga, and Watford City.

The historical high flared percent was 36% in 09/2011.

Gas capture details are as follows:

Statewide	90%	79,903,000 MCF
Statewide Bakken	90%	77,934,000 MCF
Non-FBIR Bakken	90%	67,752,000 MCF
FBIR Bakken	91%	15,447,000 MCF
Trust FBIR Bakken	93%	13,406,000 MCF
Fee FBIR	78%	2,600,000 MCF

The Commission established the following gas capture goals:

74%	October 1, 2014 - December 31, 2014
77%	January 1, 2015 - March 31, 2016
80%	April 1, 2016 - October 31, 2016
85%	November 1, 2016 - October 31, 2018
88%	November 1, 2018 - October 31, 2020
91%	November 1, 2020

Seismic

Seismic activity for oil and gas has stopped.

Active Surveys	Recording	NDIC Reclamation Projects	Remediating	Suspended	Permitted (Oil and Gas)	Permitted (CCS)
0	0	0	0	4	0	1

Agency Updates

BIA has published a new final rule to update the process for obtaining rights of way on Indian land. The rule was published 11/19/15 and became effective 12/21/15. The final rule can be found at https://www.federalregister.gov/articles/2015/11/19/2015-28548/rights-of-way-on-indian-land. On 3/11/16, the Western Energy Alliance filed a complaint and motion for a temporary restraining order and/or a preliminary injunction. On 04/19/16, the US District court for the District of North Dakota issued an order denying the motion for a preliminary injunction. The new valuation requirements were resulting in increased delays so BIA provided a waiver that expires 04/05/2020. On 03/09/2020 the NDIC submitted comments supporting an extension of that waiver through 04/05/2021 to allow infrastructure development to continue while BIA develops and implements the new process. NDIC comments can be found at http://www.nd.gov/ndic/ic-press/Sweeney%20letter%20200309.pdf

BLM on 1/20/21 DOI issued order 3395 implementing a 60 day suspension of Federal Register publications; issuing, revising, or amending Resource Management Plans; granting rights of way and easements; approving or amending plans of operation; appointing, hiring or promoting personnel; leasing; and permits to drill. On 1/27/21 President Biden issued an executive order that mandates a “pause” on new oil and gas leasing on federal lands, onshore and offshore, “to the extent consistent with applicable law,” while a comprehensive review of oil and gas permitting and leasing is conducted by the Interior Department. There is no time limit on the review, which means the president’s moratorium on new leasing is indefinite. The order does not restrict energy activities on lands the government holds in trust for Native American tribes.

What is the percentage of federal lands in ND?

Mineral ownership in ND is 85% private, 9% federal (4% Indian lands and 5% federal public lands), and 6% state. 66% of ND spacing units contain no federal public or Indian minerals, 24% contain federal public minerals, 9% contain Indian minerals,1% contain both.

How many potential wells could be delayed or not drilled by a Biden administration ban on drilling permits and hydraulic fracturing on federal lands?

A spatial query found 3,443 undrilled wells in spacing units that would penetrate federal minerals, 2,902 undrilled wells in spacing units would penetrate BIA Trust minerals (700 tribal minerals and 2,202 allotted minerals), and the total number of wells potentially impacted is 6,345. The minimum number of future Bakken wells is 24,000 so the 3,443 wells on federal public lands = 14%, and the 2,902 wells on trust lands = 12%.

What is the potential federal royalty loss from a Biden administration ban on drilling permits and hydraulic fracturing on federal lands?

A recent study from University of Wyoming estimated the ND loss as follows: 2021-2025 $76 million, 2026-2030 $113 million, 2031-2035 $160 million, and 2036-2040 $221 million for a total of $570 million over 15 years. Please note that 50% of the royalties on federal public lands go to the state and 50% of the state share goes to the county where the oil was produced.

The U.S. Interior Department launched its review of the federal oil and gas leasing program on 3/25/21, a key step that will determine whether the Biden administration will permanently halt new leases on federal land and water. The review kicked off with a public forum on oil and gas leasing on federal land and water, with participants representing industry, environmental conservation and justice groups, labor and others, and commence an online comment period. This input will inform an interim report to be released in early summer outlining next steps and recommendations on the future of the program and what can be done to reform how leases are managed and how much revenue should go to taxpayers and other issues.

On 7/7/21 North Dakota sued the Department of Interior (DOI), Secretary of Interior Debra Haaland, Bureau of Land Management (BLM), Director of the BLM Nada Culver, and Director of the Montana-Dakotas BLM John Mehlhoff in US District Court for the District of North Dakota. The lawsuit requests the court:
Compel the Federal Defendants to hold quarterly lease sales.

https://bismarcktribune.com/news/state-and-regional/17-carbon-storage-projects-eye-north-dakota-state-loses-status-as-2nd-biggest-oil-producer/article_d3ad1ff7-893e-50ef-8da6-71c047f7caa0.html#tracking-source=home-top-story

17 carbon storage projects eye North Dakota; state loses status as 2nd-biggest oil producer

AMY R. SISK
North Dakota has officially lost its status as the nation's second-biggest oil producer, but a new industry rapidly gaining momentum in the state has offset officials' disappointment.

In the last three weeks, State Mineral Resources Director Lynn Helms has heard from companies interested in pursuing as many as 17 projects in North Dakota to store carbon emissions underground.

North Dakota for years has worked to create regulations and assume authority from the federal government surrounding the capture and storage of carbon dioxide from coal and ethanol plants and other industrial facilities. Researchers have also spent considerable time studying the geology of rocks deep underground in various parts of the state to see if they hold the right characteristics to store carbon dioxide, a greenhouse gas that contributes to climate change.

"Man, it's cool to see all that bear fruit," Helms said.

He spoke Friday in Bismarck at his monthly press conference, which typically focuses on oil and natural gas production. But his department is also tasked with permitting carbon storage projects, which are finally starting to come before regulators. Last month, the Oil and Gas Division **held a first-of-its-kind hearing** regarding a permit for the underground storage area that will make up part of Red Trail Energy's carbon capture project at its Richardton ethanol plant.

That project could be operational early next year, Helms said.

"If I sound a little excited, I am," he said. "I'm just not too bummed out about going from No. 2 to No. 3 (in oil production)."

North Dakota ranked second, behind Texas, in oil production for nine years. It lost that status to New Mexico in July. The two states **had been neck and neck** for several months.

Drilling in the Bakken oil patch of western North Dakota took off in the mid to late 2000s. The region faces competition from the Permian Basin of Texas and New Mexico, where drilling is a more recent phenomenon.

"It's a long-term trend," Helms said. "It's not something that's just a quick flash and we're back to No. 2."

New Mexico has 82 rigs drilling for oil today, far more than the 27 operating in North Dakota. Helms said oil companies are drilling there so as to maintain government leases for the right to develop federal minerals. There is a lot of federal land in New Mexico, and efforts by the Biden administration to revamp its policies surrounding drilling could also play a role in the uptick in activity in that state, he said.

North Dakota produced 1.078 barrels of oil per day in July, the most recent month for which data is available. That marks a 56,000-barrel-per-day or 5% drop from June.

Helms anticipates production will grow again in the future, but he attributed the drop to five outages at natural gas processing plants this summer.

Those plants were undergoing upgrades or maintenance, as is common in the summer, said Justin Kringstad, director of the North Dakota Pipeline Authority. And although they process gas, not oil, their temporary closures had an impact on the production of both.

“When gas capture is limited, we’re seeing wells now choked back or shut in or curtailed in a way that we haven’t seen historically,” Kringstad said.

The outages at processing plants also caused an uptick in the wasteful flaring of gas, though officials don’t anticipate that will last. Producers flared 10% of all gas produced in the state in July, falling out of compliance with the state’s 9% target.

North Dakota produced 2.875 billion cubic feet of gas per day in July, a 4% drop from June.

The oil and gas industry took steps to alleviate the effects of the plant outages, Kringstad said. Outrigger Energy II’s Bill Sanderson Gas Processing Plant west of Williston had sat idle since it became operational earlier this year, but it fired up this summer to take in some of the gas displaced by outages elsewhere, he said.

MONTHLY UPDATE

JULY 2021 PRODUCTION & TRANSPORTATION

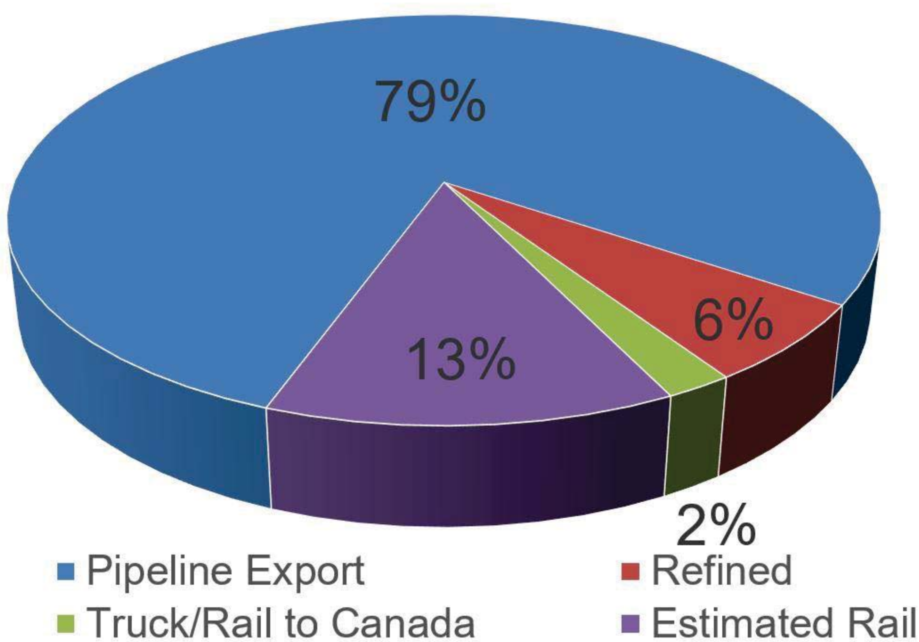
North Dakota Oil Production

Month	Monthly Total, BBL	Average, BOPD
June 2021 - Final	34,004,943	1,133,498
July 2021 - Prelim.	33,411,470	1,077,789

North Dakota Natural Gas Production

Month	Monthly Total, MCF	Average, MCFD
June 2021 - Final	89,634,861	2,987,829
July 2021 - Prelim.	89,122,575	2,874,922

Estimated Williston Basin Oil Transportation, July 2021



CURRENT DRILLING ACTIVITY:

NORTH DAKOTA[1]

27 Rigs

EASTERN MONTANA[2]

1 Rigs

SOUTH DAKOTA[2]

0 Rigs

SOURCE (SEP. 17, 2021):

1. ND Oil & Gas Division
2. Baker Hughes

PRICES:

Crude (WTI): $71.60

Crude (Brent): $74.89

NYMEX Gas: $5.22

SOURCE: BLOOMBERG (SEP 17, 2021 – 9:59AM)

GAS STATS*

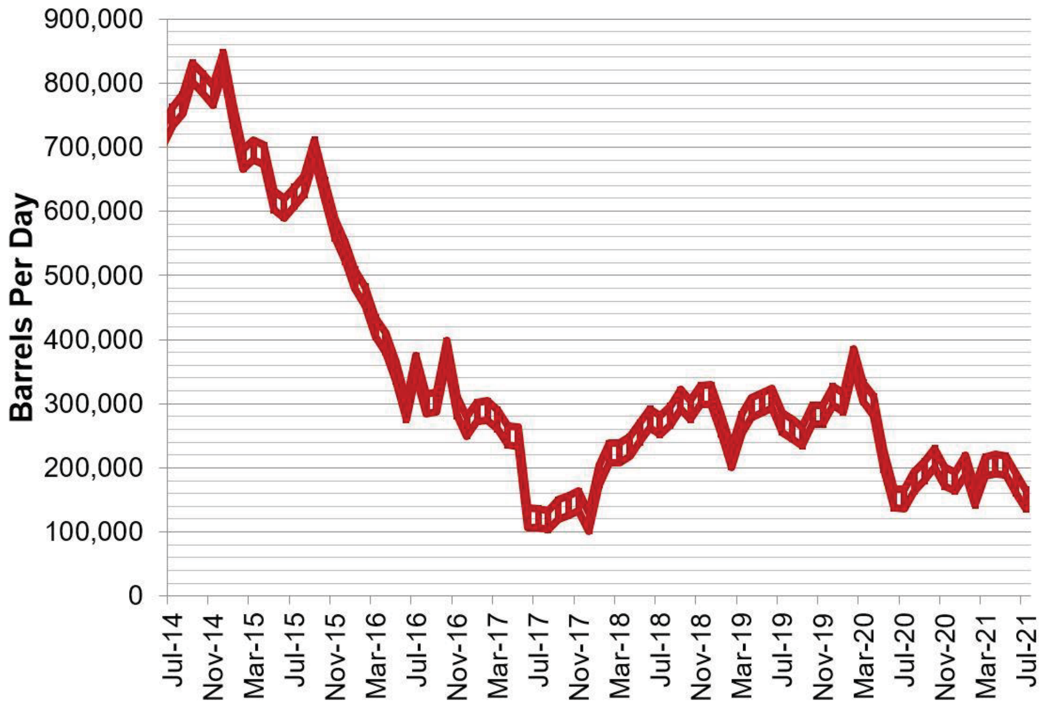
90% CAPTURED & SOLD

8% FLARED DUE TO CHALLENGES OR CONSTRAINTS ON EXISTING GATHERING SYSTEMS

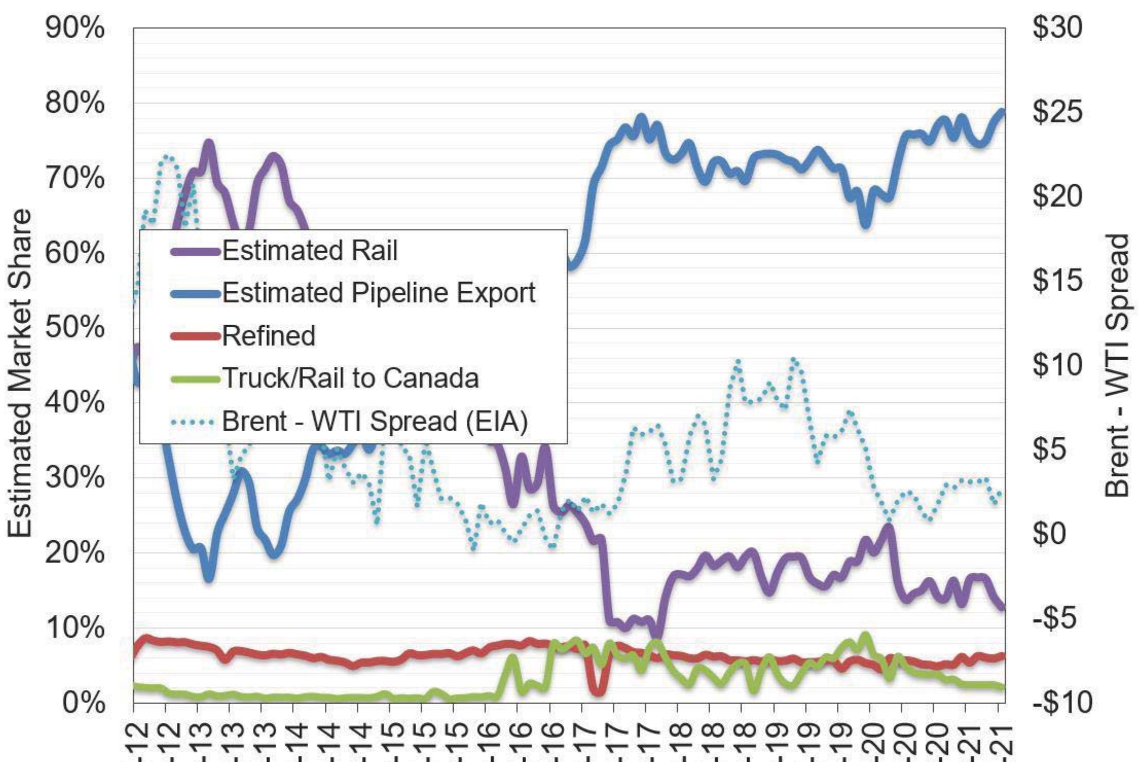
2% FLARED FROM WELL WITH ZERO SALES

JULY 2021 NON-CONF DATA

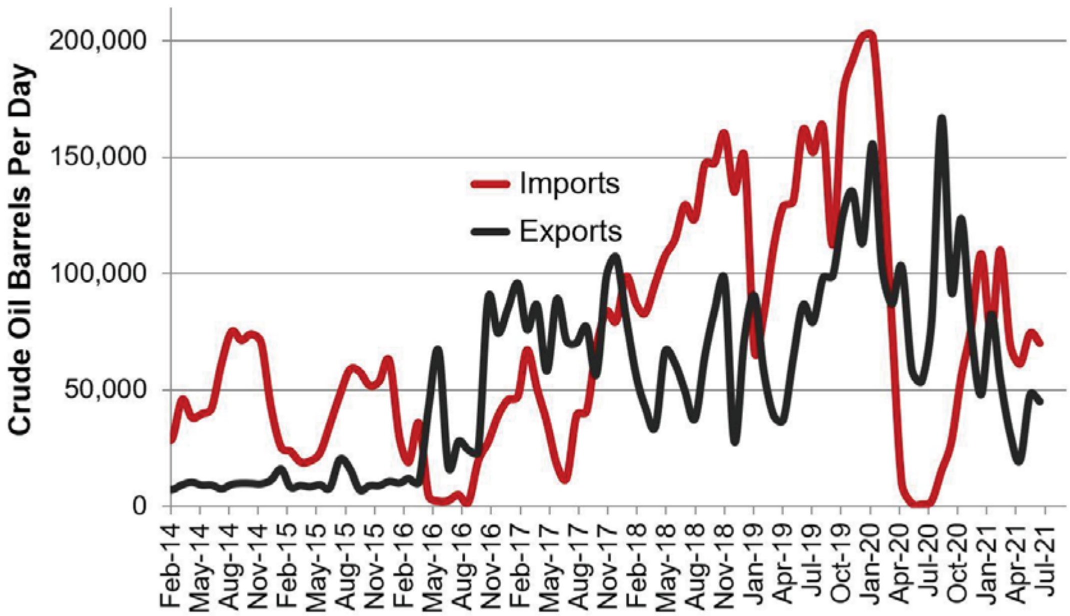
Estimated North Dakota Rail Export Volumes



Estimated Williston Basin Oil Transportation

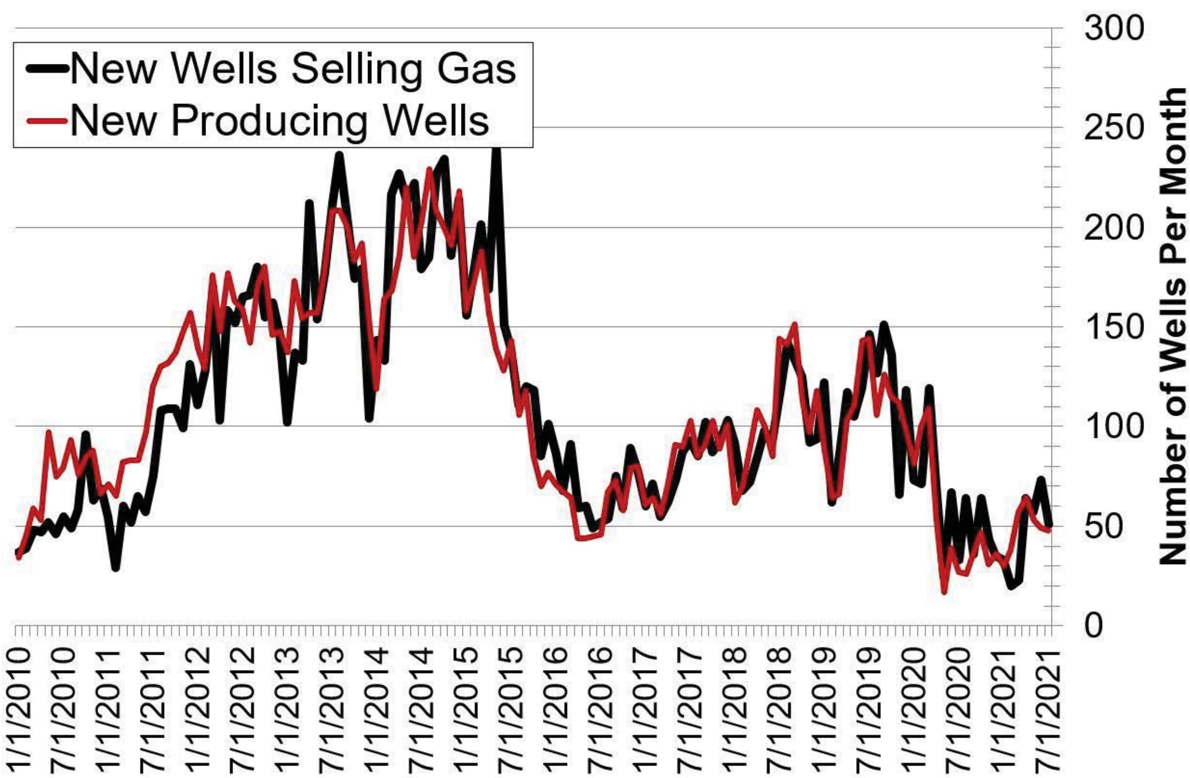


Williston Basin Truck/Rail Imports and Exports with Canada



Data for imports/exports chart is provided by the US International Trade Commission and represents traffic across US/Canada border in the Williston Basin area.

New Gas Sales Wells per Month



US Williston Basin Oil Production, BOPD

2020

MONTH	ND	EASTERN MT*	SD	TOTAL
January	1,431,679	57,460	3,091	1,492,230
February	1,507,069	55,425	3,070	1,565,563
March	1,435,200	57,718	2,946	1,495,864
April	1,225,476	49,054	2,610	1,277,140
May	862,254	37,066	2,466	901,786
June	895,208	42,853	2,680	940,742
July	1,043,089	48,415	3,435	1,094,939
August	1,166,242	46,925	2,807	1,215,973
September	1,224,008	47,128	2,837	1,273,973
October	1,244,056	46,505	2,749	1,293,310
November	1,226,409	45,121	2,798	1,274,327
December	1,191,429	44,500	2,827	1,238,756

2021

MONTH	ND	EASTERN MT*	SD	TOTAL
January	1,147,464	50,140	2,874	1,200,477
February	1,083,716	47,956	2,828	1,134,500
March	1,108,918	49,262	2,744	1,160,924
April	1,123,166	48,182	2,644	1,173,993
May	1,128,042	46,597	2,640	1,177,280
June	1,133,498	43,408	3,103	1,180,009
July	1,077,789			
August				
September				
October				
November				
December				

** Eastern Montana production composed of the following Counties: Carter, Daniels, Dawson, Fallon, McCone, Powder River, Prairie, Richland, Roosevelt, Sheridan, Valley, Wibaux* https://www.mlive.com/public-interest/2021/09/michigan-seeks-end-to-unproductive-enbridge-line-5-mediation.html

Michigan seeks end to 'unproductive' Enbridge Line 5 mediation

Updated: Sep. 16, 2021, 11:00 a.m. | Published: Sep. 15, 2021, 3:05 p.m.

People gather to protest Enbridge on Thursday May 13, 2021 in Lansing. Nicole Hester/ MLive.com

By Garret Ellison | gellison@mlive.com

GRAND RAPIDS, MI — The state of Michigan called talks with Enbridge Inc. over the future of its controversial Line 5 pipeline under the Straits of Mackinac "unproductive" in new filings, which ask a federal judge to bar the court-appointed mediator from disclosing session details.

On Wednesday, Sept. 15, Michigan Attorney General Dana Nessel asked U.S. District Judge Janet Neff to consider the sessions "completed without a settlement" following a Tuesday motion asking Neff to prohibit mediator Gerald Rosen from including anything in his pending report beyond the participants and whether they reached an agreement.

After the latest mediation session on Sept. 9, the state "unambiguously communicated to the mediator that any further continuation of the mediation process would be unproductive for them, and they have no 'desire to continue with the mediation process,'" the filing states.

Disclosing details of the talks and, potentially, seeking their continuance over the state's objection violates terms outlined by the court in March, the state argued.

Nessel's office declined to elaborate beyond the filings on Wednesday. A message seeking comment from Michigan Gov. Gretchen Whitmer's office was not immediately returned.

In a statement, Enbridge indicated it wants to continue, saying it has "participated in this mediation in good faith."

"We are committed to continuing to seek resolution, whether through mediation or pursuing diplomatic solutions consistent with the US-Canada Transit Pipelines Treaty and by asserting our rights in the courts," said Enbridge spokesman Ryan Duffy. "We understand the stakes in this matter are important not only for Enbridge and the state, but for many others throughout the region who have strong interest in its outcome. Meanwhile, we will continue to safely and responsibly deliver the energy the region relies upon from the Line 5 system."

In March, Neff appointed Rosen, a former U.S. District Court judge, to mediate between Enbridge and the state over Whitmer's 2020 order to shutter Line 5, a segment of which runs beneath Lake Michigan next to the Mackinac Bridge.
The two sides met four times, on April 26, May 18, June 29, and Sept. 9. An August session was cancelled. No further sessions have been scheduled.

On Sept. 12, the state says Rosen told its attorneys he "intends to file with the court in the next few days a report or other submission containing his recommendations regarding continuation of the mediation," filings state. "The State Parties have not consented to such a filing or submission by the mediator or to the continuation of the mediation."

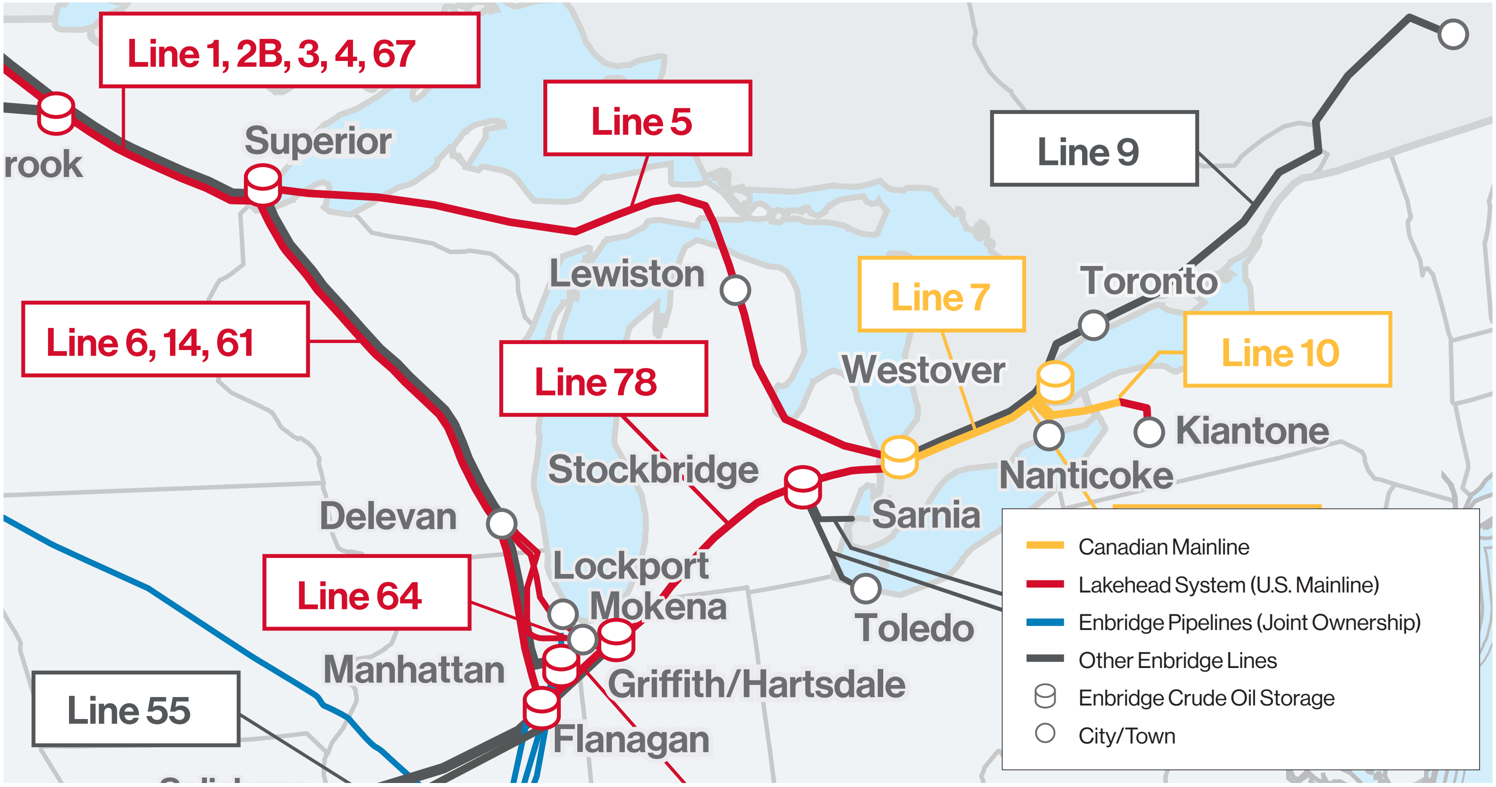
The state considers Line 5 to be operating illegally after Enbridge defied a May 12 deadline to close the submerged pipeline. Enbridge has refused to comply with Whitmer's directive absent a court order. The company sued Whitmer and the state and wants Neff to rule that only the federal Pipeline and Hazardous Materials Safety Administration (PHMSA), an agency within the U.S. Department of Transportation, can order the pipeline's closure.

The matter has threatened to escalate into an international dispute between the U.S. and Canada, which has intervened in the court and is threatening to invoke a 1977 treaty between the two countries. Canada claims the line, which moves fossil fuels between Wisconsin and Ontario by way of Michigan, is a critical piece of energy infrastructure.

Whitmer ordered the Line 5 closure after a lengthy easement compliance review by the Michigan Department of Natural Resources. Whitmer, Nessel and a coalition of environmental groups and tribes supporting their actions say the 68-year-old line poses too great an oil spill risk to continue operating where Lake Michigan and Lake Huron connect.

Meanwhile, Enbridge is attempting to replace the pipeline by constructing a utility tunnel under the straits. The project is being opposed by tribes and environmental groups. In June, the Biden administration promised to put the project through a strict environmental review that's expected to delay the start of any potential construction.

Tunnel opponents also filed expert testimony before the Michigan Public Service Commission this week arguing that greenhouse gas emissions from natural gas liquids, propane and other fossil fuels that would be moved through a new tunnel and rebuilt Line 5 would worsen the escalating impact of global climate change in Michigan and beyond.



The impact of a Line 5 shutdown

Enbridge's Line 5 has been a vital piece of energy infrastructure since 1953—not just for Michigan, but for the entire U.S. Midwest and points beyond.

For more than 65 years, Line 5 has delivered the light oil and natural gas liquids (NGL) that heat homes and businesses, fuel vehicles and power industry.

Shutting down Line 5, even temporarily, would have immediate and severe consequences on the economies of Michigan, Ohio, Ontario, and elsewhere.

Enbridge's Line 5 is a 645-mile, 30-inch-diameter pipeline that travels through Michigan's Upper and Lower Peninsulas—originating in Superior, Wisconsin, and terminating in Sarnia, Ontario, Canada.

Line 5 transports up to 540,000 barrels per day (bpd), or 22.68 million US gallons per day, of light crude oil, light synthetic crude and natural gas liquids (NGLs), which are refined into propane.

Line 5 supplies 65% of propane demand in Michigan's Upper Peninsula, and 55% of Michigan's statewide propane needs. The light crude transported by Line 5 feeds refineries in the Upper Midwest and Eastern Canada.

If Line 5 were shut down*:

- Refineries served by Enbridge in Michigan, Ohio, Pennsylvania, Ontario and Quebec **would receive approximately 45% less crude from Enbridge** than their current demand.
- Michigan would face a **756,000-US-gallons-a-day propane supply shortage**, since there are no short-term alternatives for transporting NGL to market.
- The region (Michigan, Ohio, Pennsylvania, Ontario and Quebec) would see a **14.7-million-US-gallons-a-day supply shortage of gas, diesel and jet fuel** (about 45% of current supply).
- Michigan would need to f**ind an alternative supply for anywhere from 4.2 million to 7.77 million US gallons of refined products** (gas, diesel, jet fuel and propane).

Alternatives for the above shortages are limited—and that would mean massive investment in pipeline infrastructure, or significantly increasing rail or trucking capacity, to make up for the shortfall caused by a Line 5 shutdown.

*Estimates are based on current market conditions, and contingent on similar energy demands in the future (crude oil demand is not expected to see an appreciable change)

ENBRIDGE
Life Takes Energy

Toll-free: **1-855-869-8209**
E-mail: **line5info@enbridge.com**

The effects of a Line 5 shutdown

Shutting down Line 5, even temporarily, would have a major and immediate impact on crude oil supply for refineries—and, as a result, refined product supply for consumers, motorists and industry.

Crude oil impacts

Regional **crude oil and NGL demand** on Enbridge's Line 5 and Line 78 totals about **40.74 million US gallons a day.**

Demand for crude is not expected to change any time soon—and with Enbridge's pipeline system already essentially full, a Line 5 shutdown would cause federally regulated apportionment, or reduction in deliveries, on our Line 78 by approximately 45%.

In other words, refineries in Michigan, Ohio, Pennsylvania, Ontario and Quebec **will receive approximately 45% less crude from Enbridge** than their current demand.

Refined products impacts

Michigan uses about **15.75 million US gallons of transportation fuel (gas, diesel and jet fuel) every day**—and with Detroit's refining capacity meeting only about 25% of that demand, Michigan relies heavily on surrounding states like Ohio, Illinois and Indiana for its refined products.

A Line 5 shutdown would cause a **shortfall of 14.7 million US gallons of transportation fuel a day** (that's 45% of the current Enbridge supply in Michigan, Ohio, Pennsylvania, Ontario and Quebec) and a **Michigan propane shortage of 756,000 US gallons a day** (or 55% of the current supply).

That means Michigan would **need to find more than 4.2 million US gallons a day of gas, diesel, jet fuel and propane** to make up for the shortfall—assuming Ohio and other regional refineries are receiving crude oil from Line 78 at an apportioned rate of approximately 55%. If those refineries are unable to meet local needs, and stop supplying Michigan, then **that number would rise to 7.77 million US gallons a day.**

The effect on regional refineries

According to PBF Energy, which operates one of two refineries in Toledo:

- A Line 5 shutdown would put Ohio refineries at risk. The closure of one of those refineries could result in the loss **of $5.4 billion in annual economic output** to Ohio and southeast Michigan, and the **loss of thousands of direct and contracted skilled trades jobs.**
- A Line 5 shutdown would compromise crude supply to 10 refineries in the region to varying degrees, **directly affecting fuel prices.**
- Closing Line 5 would **hurt Ohio and Michigan economies**, and **threaten union jobs.**
- There are **no viable options for replacing** the volume of light crude delivered by Line 5, with **rail able to provide less than 10%** of that volume.
- A Line 5 shutdown puts **at least 15% of northwest Ohio's fuel supply at risk**, as well as more than **half of the jet fuel supplies** for the Detroit Metro Airport.

Demand on Enbridge pipelines (approximate)

Line	Kbpd	US gallons per day
Line 5 (including NGL)	500	21,000,000
Line 78	470	19,740,000
Total	**970**	**40,740,000**

Capacity of Enbridge pipelines

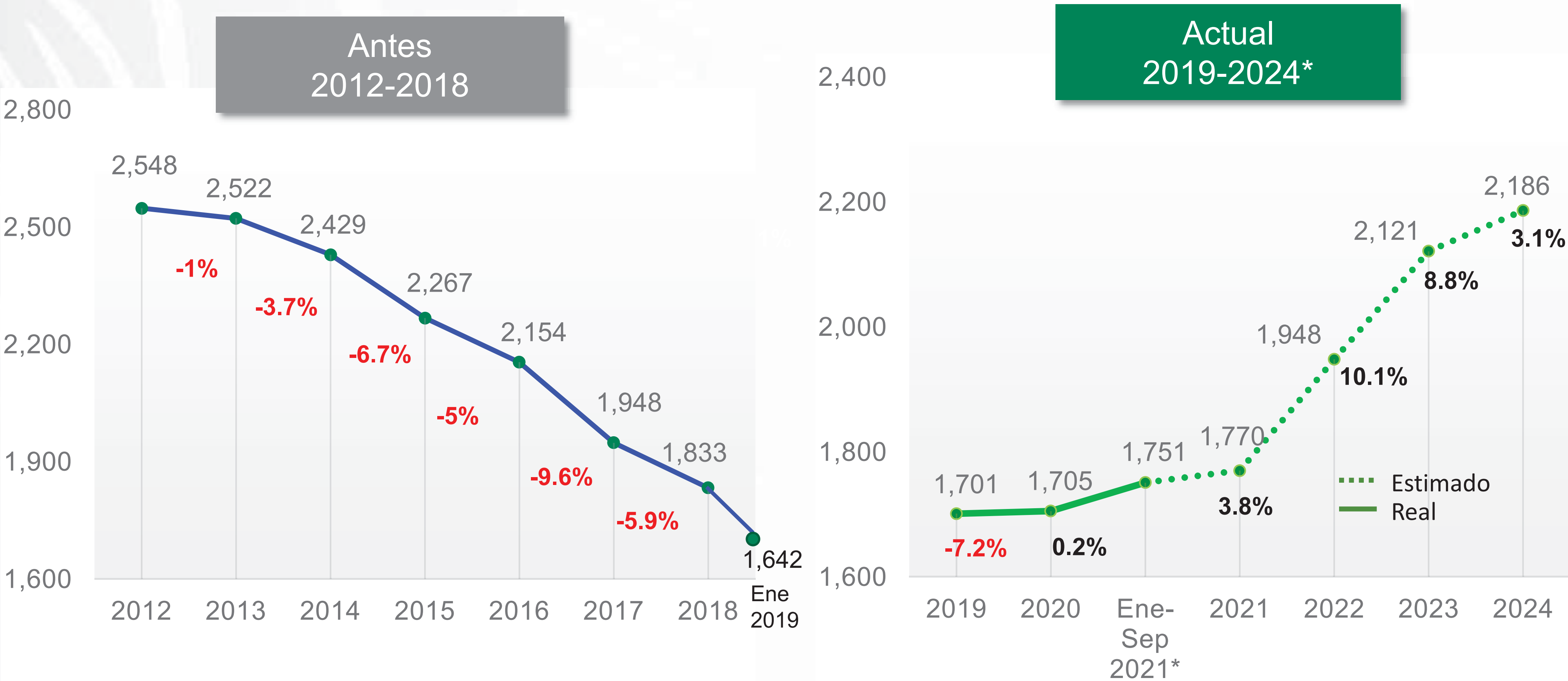
Line	Kbpd	US gallons per day
Line 5	540	22,680,000
Line 78	570	23,940,000
Line 78 (ex-Stockbridge)	502	21,084,000

ENBRIDGE
Life Takes Energy

Toll-free: **1-855-869-8209**
E-mail: **line5info@enbridge.com**

Producción de crudo total[1]

Miles de barriles diarios (Mbd)



1. Considera producción de crudo y condensados. Incluye producción de socios.

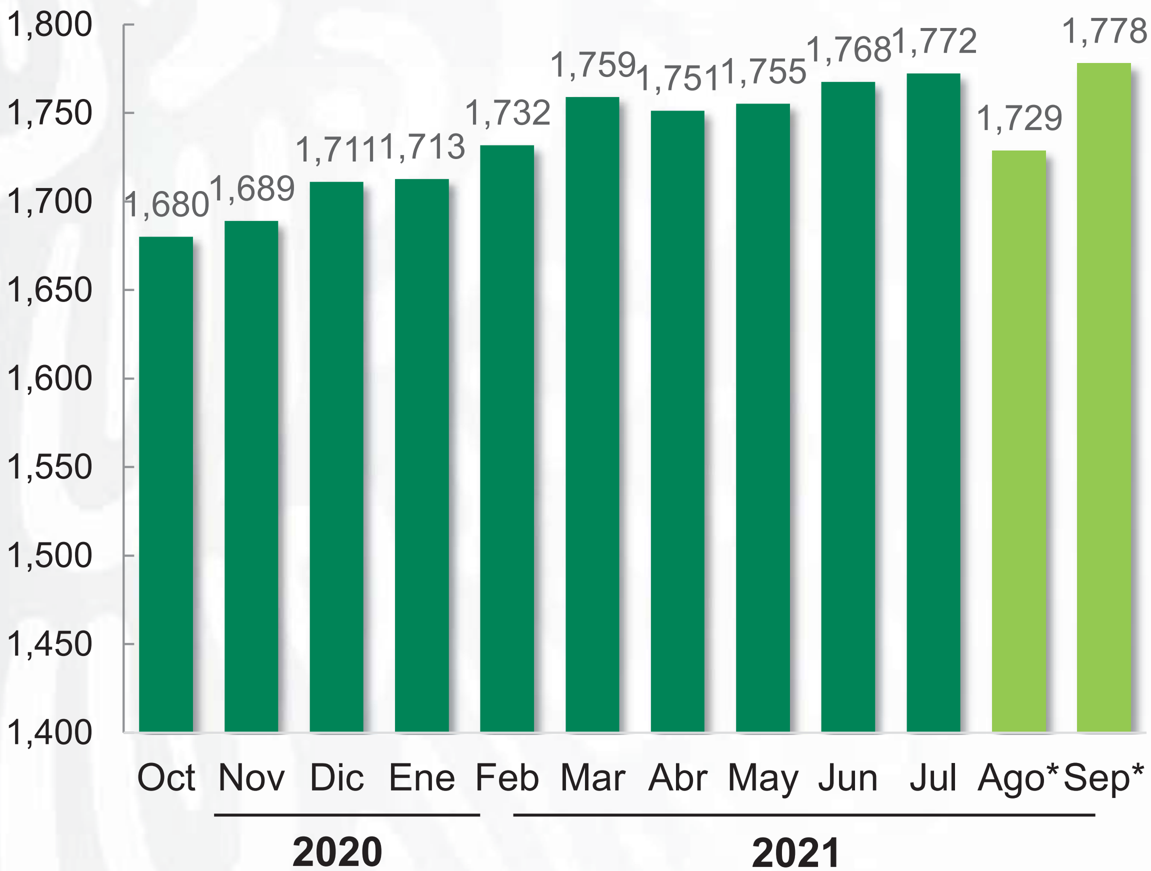
* Ene-sep 2021 con cifras preliminares al 9 de septiembre de 2021. 2021 en adelante estimaciones.

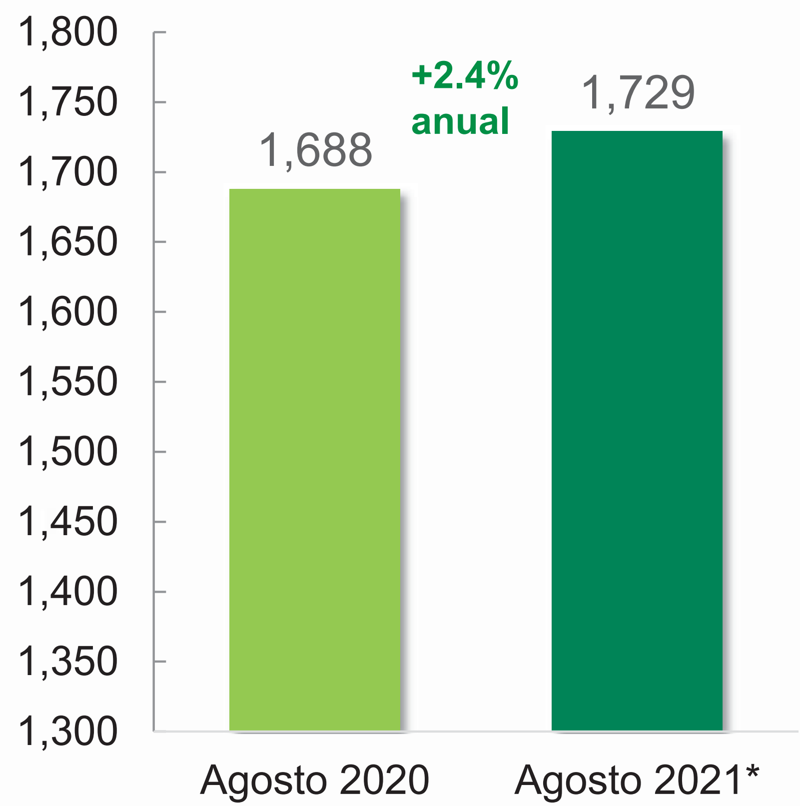
- Por 15 años se registró una caída constante de la producción de petróleo y no se elaboró una estrategia correcta para detener la caída de la producción, mucho menos para incrementarla.
- Esta administración realizó un cambio en la política de inversión de exploración y producción que detalló en su Plan de Negocios, con resultados positivos y llegando a un segundo año consecutivo de crecimiento de la producción.

Producción de crudo total[1]

Miles de barriles diarios (Mbd)

En el mes de agosto de 2021, no obstante las incidencias que se enfrentaron por el accidente en la plataforma E-Ku-A2, la producción de petróleo creció **2.4%** respecto al mismo mes de 2020, es decir, un incremento de **41 mil barriles diarios promedio.**





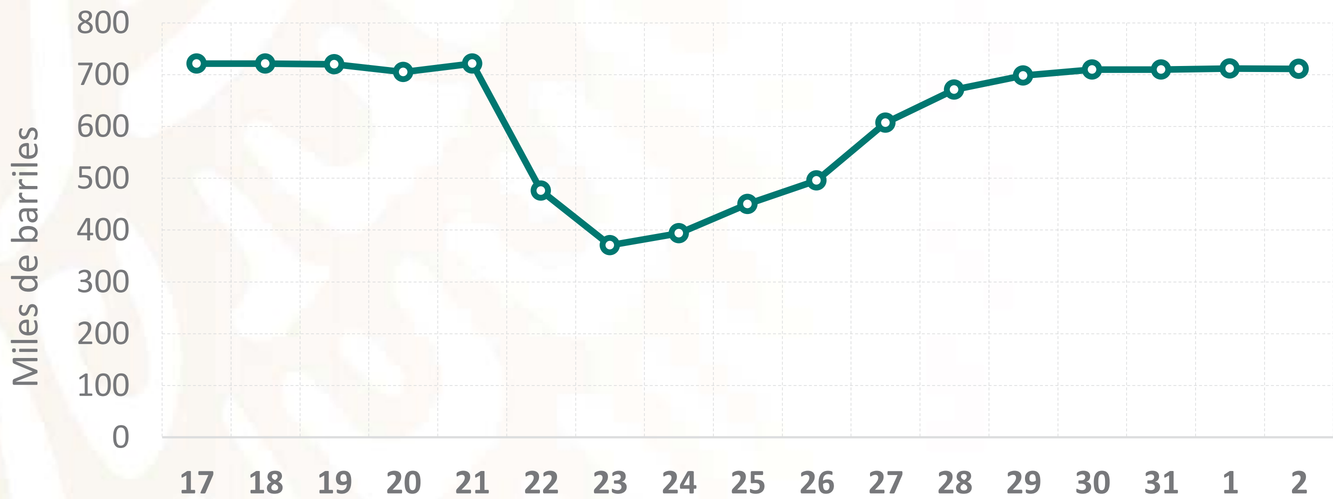
1. Considera producción de crudo y condensados producidos en campos petroleros, incluye producción de socios.

* Con cifras preliminares estimadas al 13 de septiembre de 2021.

Recuperación del Accidente en la Plataforma Ku-A

Consecuencias personales y volumétricas

Personales	Volumétricas	Estado actual
6 lesionados 7 fallecidos	▪ 125 pozos cerrados ▪ 421 mil barriles cerrados puntualmente ▪ **Recuperación de la producción de hidrocarburos** mediante el manejo operativo por rutas alternas	▪ En una semana se recuperó en su totalidad la producción. ▪ El análisis causa raíz (ACR) **se realiza con la empresa noruega DNV**.



Producción acumulada diferida
1,623.8 Mbls

Dia	17	18	19	20	21	22	23	24	25	26	27	28	29	30	31	1	2
Prod.	721	721	720	705	721	476	371	394	450	496	607	671	698	710	710	712	711

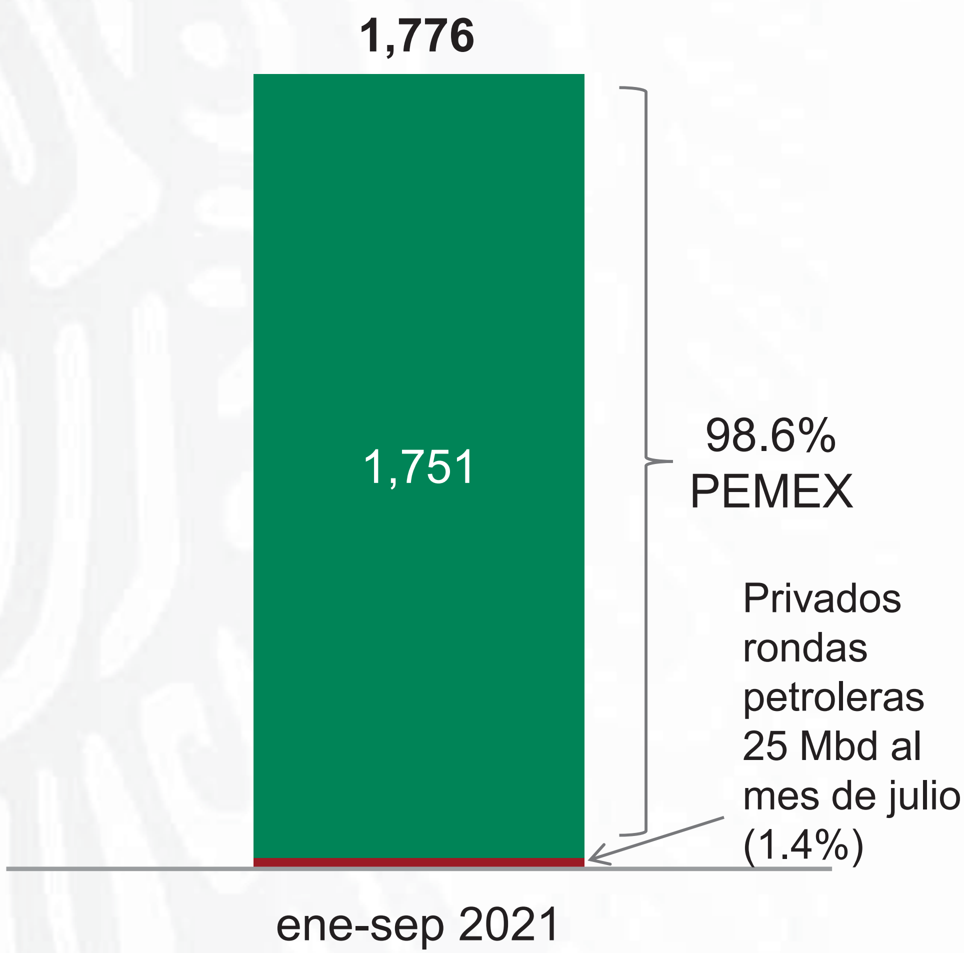
Contribución de los campos nuevos de PEMEX

Miles de barriles diarios (Mbd)

Fuente: datos de producción de PEMEX son aportados por Pemex Exploración y Producción. Cifra de privados corresponde a datos publicados por la Comisión Nacional de Hidrocarburos, producción de contratos www.cnh.gob.mx al mes de julio.

Producción de petróleo en México

Miles de barriles diarios (Mbd)

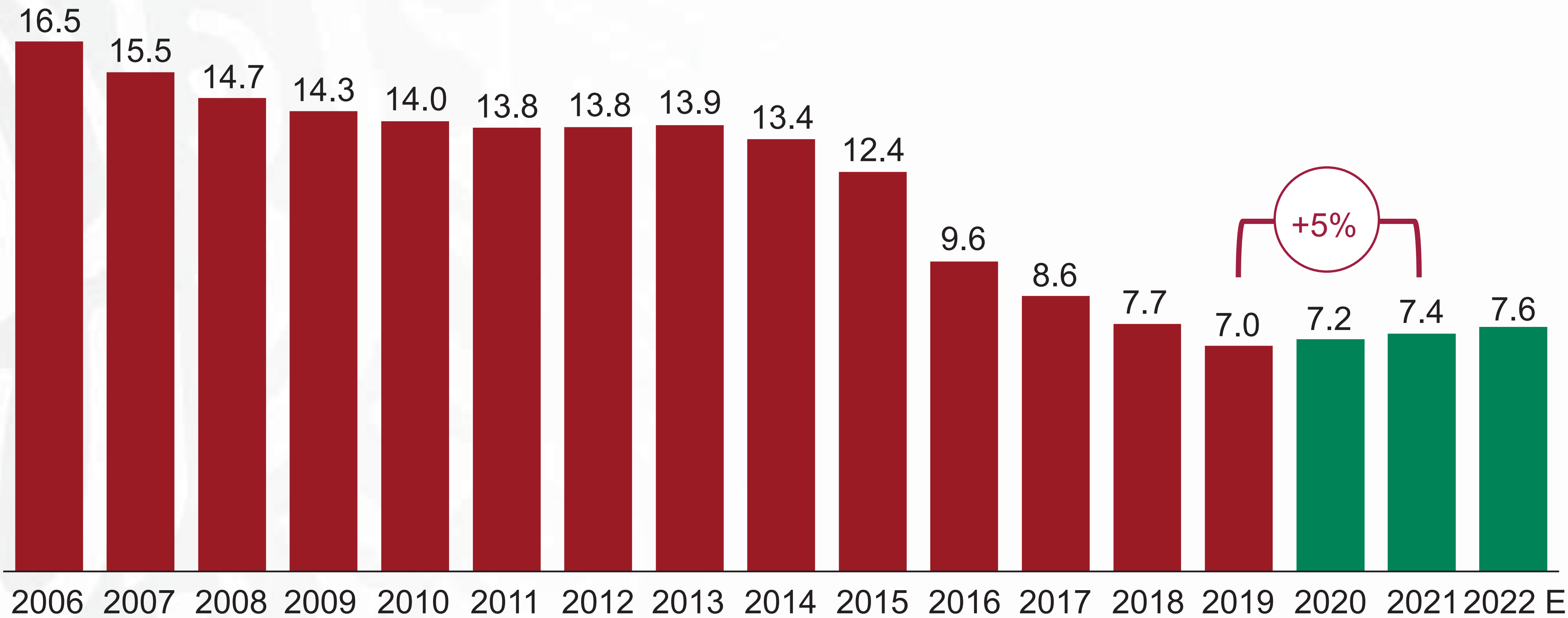


- A más de 7 años de la reforma energética, Petróleos Mexicanos soporta casi la totalidad de la producción petrolera del país.
- El mes de julio pasado, la producción de los terceros en las rondas sumaba 28 Mbd, siendo el promedio del semestre 25 Mbd.
- En lo que va del año, casi el 99% de la producción de petróleo en México continúa siendo extraída por PEMEX.

Nota: Para Pemex corresponde a cifras del periodo enero-septiembre: PEMEX 1,730 Mbd + Socios 21 Mbd. Con cifras preliminares al 9 de septiembre de 2021. Para las compañías privadas son cifras publicadas al mes de julio de 2021 por parte de la Comisión Nacional de Hidrocarburos para la producción de rondas contractuales.

Evolución de las Reservas Probadas 1P

Miles de millones de barriles de petróleo crudo equivalente

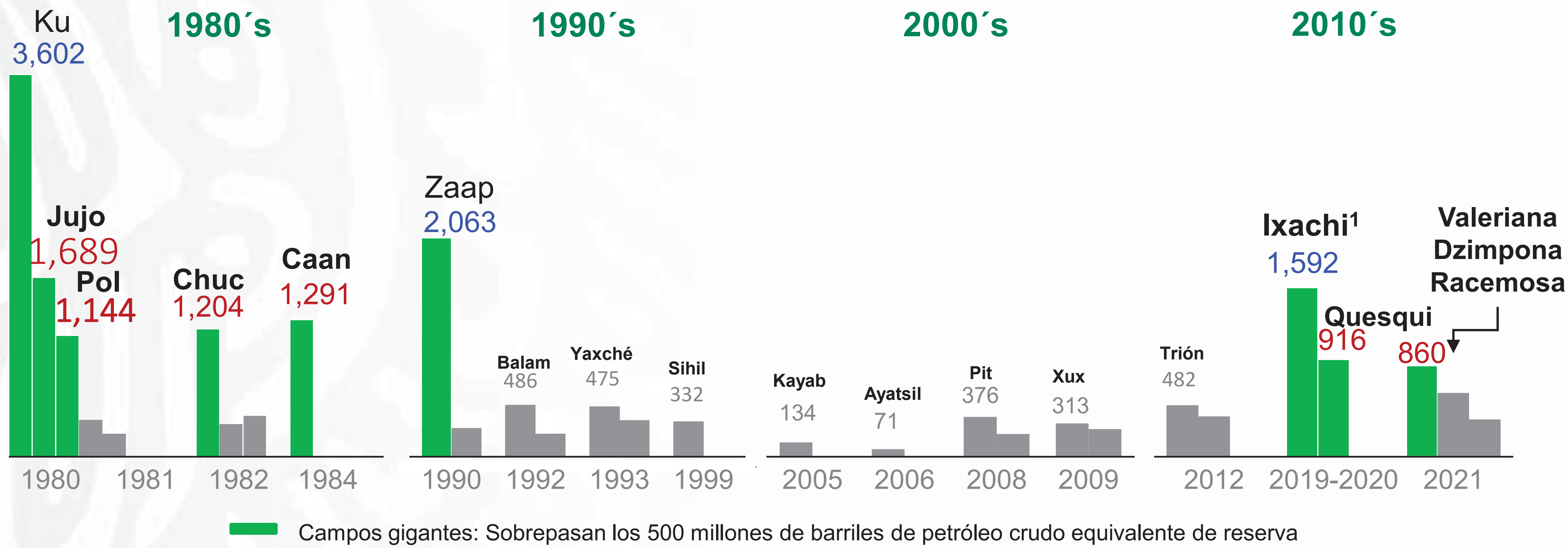


- Esta administración logra por segundo año consecutivo incorporar más barriles de reservas de petróleo que los que extrae de sus reservas 1P.
- Fueron catorce años en los que Pemex extraía más barriles que los que logró incorporar a sus reservas 1P.
- Vamos en la ruta correcta.

Nota: Valores al 1° de enero de cada año
E = Valor estimado.

Principales campos descubiertos en los últimos 40 años

Millones de barriles de petróleo crudo equivalente



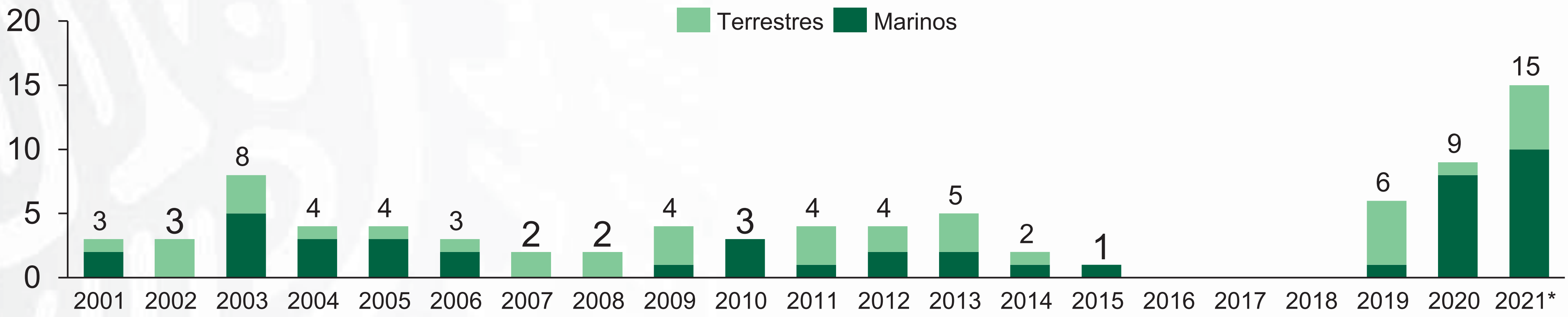
- El cambio de estrategia de explorar en aguas someras y en tierra ha sido uno de los mayores exitos, la administración actual de Petróleos Mexicanos abandonó la fallida estrategia de exploración de aguas profundas de la que en 18 años no se obtuvo un solo barril de petróleo.
- Por el contrario, focalizar los recursos de inversión en exploración en aguas someras y en tierra ha sido todo un éxito para PEMEX.
- En esta lámina se muestran los resultados de los descrubrimientos de los últimos años.

1. Aunque Ixachi fue descubierto en 2018 fue en 2019 cuando por los trabajos exploratorios Ixachi casi triplicó sus reservas

Evolución de los desarrollos de nuevos campos

PEMEX®
POR EL RESCATE DE LA SOBERANÍA

Campos que iniciaron su desarrollo en cada año

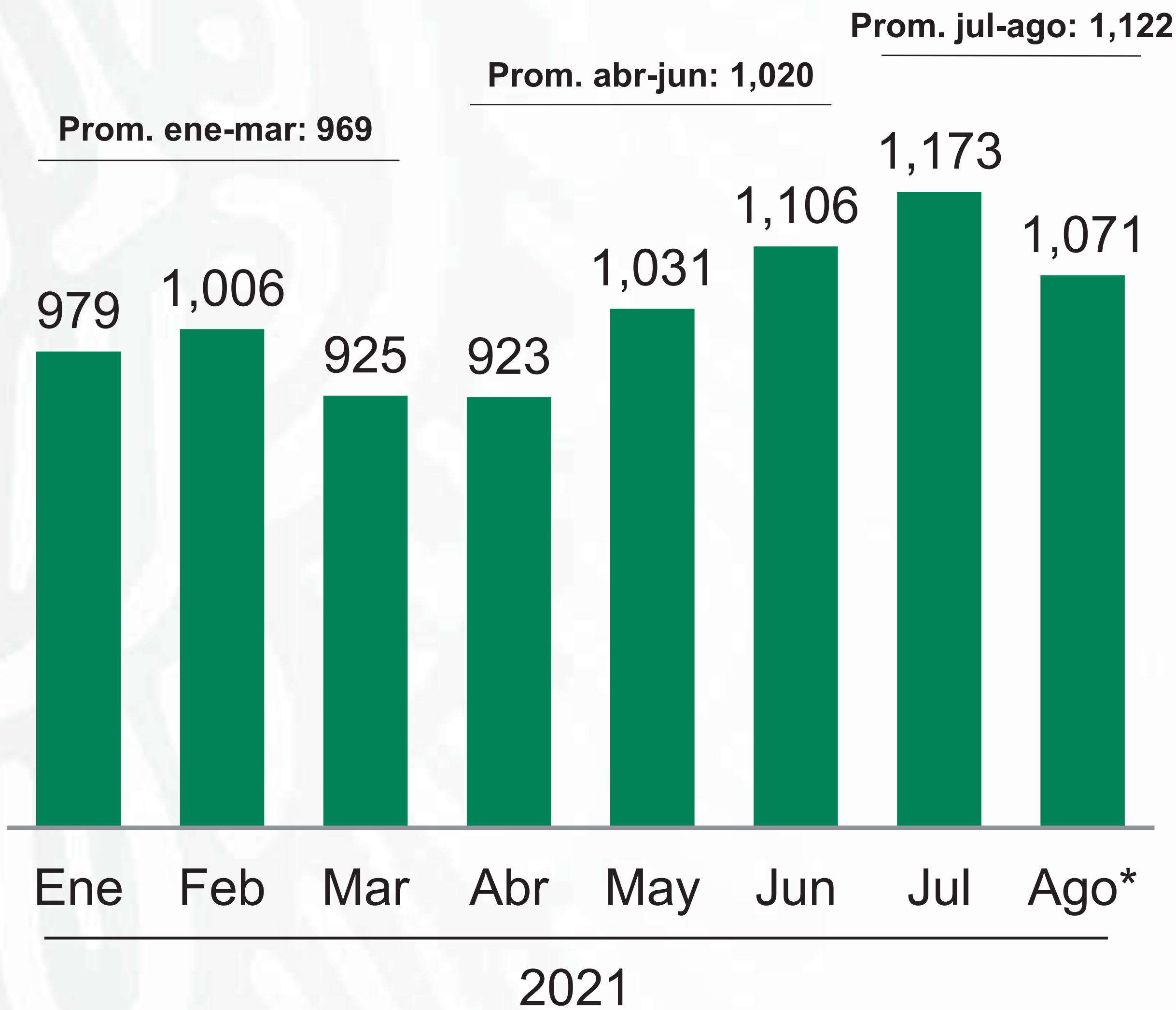


	2001	2002	2003	2004	2005	2006	2007	2008	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021*
Marinos	Kutz Sihil		Chuhuk Ektal Homol Lobina Carpa	Citam May Sinan	Ixtal Manik Bolontiku	Kab Yaxche			Xanab	Ché Ajux Yum	Tumut	Kuil Tsimin	Kambesah Onel	Xux	Ayatsil				Xikin	Cahua Cheek Hok Manik NW Mulach Octli Pokché Tlacame	Camatl Itta Koban Tetl Tlamatini Uchbal Xolotl Chamak Saap Copali
Terrestres	Perdíz	Acahual Cafeto Saramako	Guaricho Shihito Malva	Costero	Tiumut	Nelash	Rabasa Teotleco	Tajón Crater	Cupache Madrefil Terra		Brillante Pareto Tokal	Gasífero Bedel	Anhélido Eltreinta Siní	Ayocote					Cibix Quesqui Valeriana Ixachi Chocol	Pachil	Racemosa Tupilco Tum Kuun Terra (BA)

*Real al 13 de septiembre

Exportación de crudo, 2021

Miles de barriles diarios (Mbd)

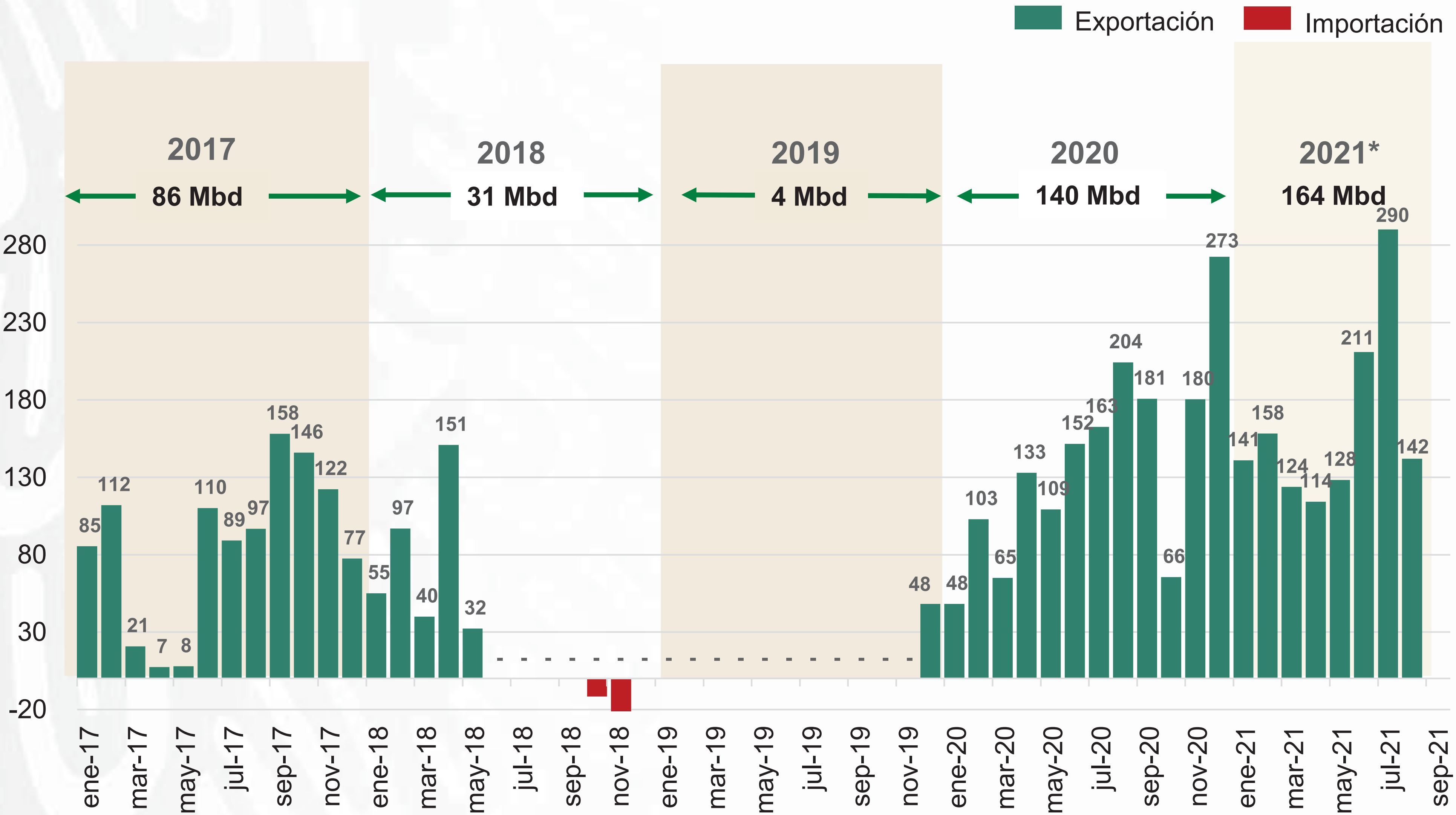


La disponibilidad de crudo a exportación se vio limitada en agosto por el incidente en Ku-Maloob-Zaap. El 30 de agosto se restableció la producción y se espera que en septiembre se recupere la tendencia positiva.

* Con cifras preliminares del mes de agosto de 2021.

Comercialización de crudo ligero
Miles de barriles diarios (Mbd)

En la administración anterior PEMEX importó petróleo crudo ligero, ahora **estamos exportando 164 mil barriles diarios en promedio de crudo ligero en el año.**



* Con cifras preliminares del mes de agosto de 2021.

Mexico to raise Pemex's budget to $32bn
2021-09-17 13:36:17.313 GMT

Sophie Davies for NewsBase

(NewsBase)

Mexican President Andres Manuel Lopez Obrador has offered to raise national oil company (NOC) Pemex's budget for next year to about $32bn in the hope of boosting crude production.

The company's proposed budget for 2022 would be 17% above the 2021 figure and would include operational spending, according to a Bloomberg report. It earmarks more than half of the total $32bn, or around $18bn, for investment in exploration and production, a 26% year-on-year increase, the news agency noted.

Meanwhile, the Mexican government is taking other measures to improve the NOC's financial standing. Specifically, Bloomberg reported, it has said that Pemex's profit-sharing duty will fall to 40% next year, down from 54% this year, and has also kicked off the process of refinancing the company's debt.

Lopez Obrador has said that reviving Pemex, which is Mexico's largest company and also its largest taxpayer, is a major priority. Past governments have argued that the company faces an excessive tax burden, and the current administration is now considering whether to lighten its load by bringing its tax rates closer to those paid by ordinary corporations.

The government has already taken a step in this direction. Last year, it cut the shared utility tax, which constitutes Pemex's largest single payment to the government, from 65% to 58%.

The NOC is currently the world's most indebted oil company, with a debt portfolio of more than $115bn. It is also trying to reverse a long-term decline in production but is likely to have difficulty doing so, especially since several prominent international ratings agencies have stripped it of its investment-grade credit ratings over the last two years.

Mexico's Finance Ministry expects Pemex's oil production to hit 1.826mn barrels per day (bpd) this year, up 4.2% from last year. The company still accounts for the vast majority of the country's crude output, even after the passage of landmark energy reforms in 2013-2014 that put an end to its long-standing monopoly on the hydrocarbon industry.

]]> -0- Sep/17/2021 13:36 GMT

To view this story in Bloomberg click here:
https://blinks.bloomberg.com/news/stories/QZKZ4HAA7G8Z

Oil Market Highlights

Crude Oil Price Movements

The OPEC Reference Basket (ORB) averaged $70.33/b in August, representing a decline of $3.20 m-o-m, or 4.4%. Year-to-date (y-t-d), ORB was $25.42, or 62.8%, higher, averaging $65.93/b. Crude oil futures prices on both sides of the Atlantic moved sharply lower in August, reaching their lowest levels since last May, as concerns about short-term Asian oil demand, mixed economic data, and the prospect of higher global oil supply triggered a sell-off. In August, the ICE Brent front-month declined $3.78 m-o-m, or 5.1%, to average $70.51/b, and NYMEX WTI fell $4.72 m-o-m, or 6.5%, to average $67.71/b. Consequently, the Brent/WTI front-month futures spread widened in August by 94¢ to average $2.80/b, its strongest since May. The market structure of all three major crude benchmarks – ICE Brent, NYMEX WTI, and DME Oman – remained in backwardation, however, their respective forward curves flattened on uncertainty about the oil demand outlook, lower seasonal crude demand in Asia, and the prospect of rising global oil supply. In August, hedge funds and other money managers extended the previous month's sell-off, reducing their net long positions to the lowest since November 2020.

World Economy

Global economic growth forecasts for both 2021 and 2022 remain unchanged from the last month’s assessment at 5.6% and 4.2% respectively. However, this robust growth continues to be challenged by uncertainties such as the spread of COVID-19 variants and pace of vaccine rollouts worldwide, as well as ongoing global supply-chain disruptions. Additionally, sovereign debt levels in many regions, together with inflationary pressures and central bank responses, remain key factors requiring close monitoring. In the current recovery, the US economy forecasts are unchanged at 6.1% for 2021 and 4.1% for 2022. Euro-zone economic growth remains at 4.7% for 2021 and 3.8% for 2022. The forecast for Japan is also unchanged at 2.8% for 2021 and 2.0% in 2022. China’s economy is seen to grow at 8.5% in 2021 and 6% in 2022, in line with the previous month’s assessment. Meanwhile, India’s 2021 growth forecast is revised slightly down to 9%, following a weaker-than-expected recovery in 2Q21, although growth for 2022 remains unchanged at 6.8%. Given strong growth in 2Q21, Brazil’s growth forecast for this year is revised up to 4.7%, while grow in 2022 is unchanged at 2.5%. Russia’s forecast for 2021 is revised up to 3.5%, benefitting from the stabilised oil market, while the forecast for 2022 remains unchanged at 2.5%.

World Oil Demand

World oil demand growth in 2021 remains unchanged from last month’s assessment, showing growth of 6.0 mb/d despite some offsetting revisions. Oil demand in 3Q21 has proved to be resilient, supported by rising mobility and travelling activities, particularly in the OECD. At the same time, the increased risk of COVID-19 cases primarily fuelled by the Delta variant is clouding oil demand prospects going into the final quarter of the year, resulting in downward adjustments to 4Q21 estimates. As a result, 2H21 oil demand has been adjusted slightly lower, partially delaying the oil demand recovery into 1H22. Global oil demand in 2021 is now estimated to average 96.7 mb/d. In 2022, oil demand is expected to robustly grow by around 4.2 mb/d, some 0.9 mb/d higher compared to last month’s assessment. Revisions were driven by both the OECD and non-OECD, as the recovery in various fuels is expected to be stronger than anticipated and further supported by a steady economic outlook in all regions. Oil demand in 2022 is now projected to reach 100.8 mb/d, exceeding pre-pandemic levels.

World Oil Supply

Non-OPEC liquids supply growth in 2021 is revised down by 0.17 mb/d from the previous month’s assessment, due to a downward adjustment of 0.5 mb/d in 3Q21. The revisions are mainly due to outages in North America from a fire on a Mexico’s offshore platform and the disruptions caused by Hurricane Ida. The estimate for North Sea production has also been revised down due to lower-than-expected output in 3Q21, resulting in an annual growth forecast of 0.9 mb/d to average 63.8 mb/d. The main drivers for 2021 supply growth remain to be Canada, Russia, China, the US, Brazil and Norway, with the US expected to see y-o-y growth of only 0.08 mb/d. The non-OPEC supply growth forecast for 2022 is unchanged at 2.9 mb/d, amid offsetting revisions, to average 66.8 mb/d. The main drivers of liquids supply growth are Russia and the US, followed by Brazil, Norway, Canada, Kazakhstan, Guyana and other countries in the DoC. OPEC NGLs are forecast to grow by

0.1 mb/d in both 2021 and 2022 to average 5.2 mb/d and 5.3 mb/d, respectively. OPEC crude oil production in August increased by 0.15 mb/d m-o-m, to average 26.76 mb/d, according to available secondary sources.

Product Markets and Refining Operations

Global refinery margins continued to trend upwards, supported by the seasonal strength in transportation fuels, amid easing mobility restrictions. In the US, product markets were supported by a reduction in total product inventory levels, while seasonal support pushed gasoline margins to new record highs. In Europe, refining margins benefitted from a positive performance across the barrel, while a contraction in fuel outputs from key traditional fuel suppliers within the region helped strengthen European product markets. Meanwhile, in Asia, weakness from rising regional fuel output levels were overshadowed by the robust performance in the jet fuel-kerosene and fuel oil markets, driven by an improvement in summer-related air travel and cooling requirements. Robust fuel consumption levels in India added to the upturn in regional refining economics.

Tanker Market

The VLCC tanker rates remained at depressed levels in August, weighed down by ample tonnage availability despite increased tanker demand. Suezmax and Aframax rates managed a better performance in intra-Asian routes, as well as the Atlantic basin, particularly from West Africa to the US Gulf. Clean tanker rates showed a healthy improvement East of Suez but slipped in the West. The arrival of Hurricane Ida in the Gulf of Mexico at the end of the month resulted in temporary dislocations, lending some support to dirty Aframax rates, while depressing clean rates in the early days of September as Gulf Coast refineries remain offline.

Crude and Refined Products Trade

Preliminary data shows US crude imports averaged 6.3 mb/d in August, while crude exports recovered to just under 3.0 mb/d. US product imports rose m-o-m to a robust 2.6 mb/d, while product exports averaged 5.3 mb/d in August, as lower demand from Latin America offset higher flows to Asia. Disruptions caused by Hurricane Ida at the end of August will likely impact these crude and product flows in September, as oil installations along the US Gulf Coast seek to restart. China's crude imports averaged 9.7 mb/d in July, remaining relatively flat since April, although recently released data for August shows crude inflows jumping to 10.5 mb/d now that refiners have a further round of quotas. India's crude imports continued to fall in July, averaging 3.6 mb/d, but positive expectations remain for a pick-up in August, as state-owned refiners look to increase runs to maximum capacity during 4Q21. Japan's crude imports averaged 2.1 mb/d in July, as the country's COVID-19 state of emergency continued to weigh on refinery runs amid uncertainty about product demand.

Commercial Stock Movements

Preliminary data shows total OECD commercial oil stocks up by 10.5 mb m-o-m in July. At 2,912 mb, inventories were 305.9 mb lower than the same month a year ago; 122 mb below the latest five-year average; and 57.2 mb lower than the 2015-2019 average. Within components, crude stocks fell by 5.6 mb m-o-m while product stocks rose by 16.1 mb. At 1,404 mb, crude stocks in the OECD were 106.9 mb below the latest five-year average and 80.0 mb below the 2015-2019 average. Meanwhile, OECD product stocks averaged 1,508 mb, representing a deficit of 15.1 mb compared with latest five-year average, but 22.7 mb above the 2015-2019 average. In terms of days of forward cover, OECD commercial stocks rose 0.1 day m-o-m to stand at 63.7 days in July. This is 11.6 days below the same month last year and 1.2 days below the latest five-year average, but 1.5 days above the 2015-2019 average.

Balance of Supply and Demand

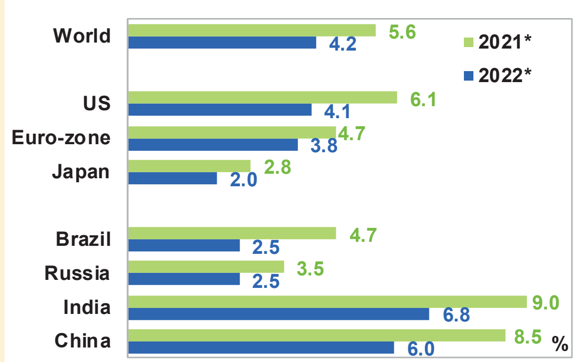
Demand for OPEC crude in 2021 is revised up by 0.3 mb/d from last month's assessment to stand at 27.7 mb/d, representing an increase of 4.9 mb/d over the previous year. Demand for OPEC crude in 2022 is revised up by 1.1 mb/d to stand at 28.7 mb/d, around 1.1 mb/d higher than in 2021.

Feature Article

Assessment of the global economy in 2021 and 2022

Although the **global economy** continues to be affected by developments related to COVID-19, 1H21 saw a healthy economic recovery. Following the strong quarterly economic growth in 3Q21, growth is forecast to slightly decelerate towards the end of the year. It should be noted that the recovery this year has been widely supported by unprecedented government-led stimulus, and global efforts done to contain COVID-19, particularly in Western economies and China. Assuming a recovery in global consumption and investment growth in 2021, global GDP growth is forecast at 5.6%. However, a further rise in COVID-19 infections, especially considering the upcoming winter season in the Northern Hemisphere, could dampen current growth projections. In addition, ongoing global supply chain disruptions, rising sovereign debt levels in many regions, together with inflationary pressures and central bank responses, remain key factors that require close monitoring. Healthy growth is also projected for 2022, with the GDP rising by 4.2%. This will be supported by ongoing fiscal and monetary stimulus and continued efforts to contain COVID-19 infections. Upside to both annual growth levels may come from further US fiscal stimulus and improvements in developments related to COVID-19.

Graph 1: GDP growth forecast for 2021-22

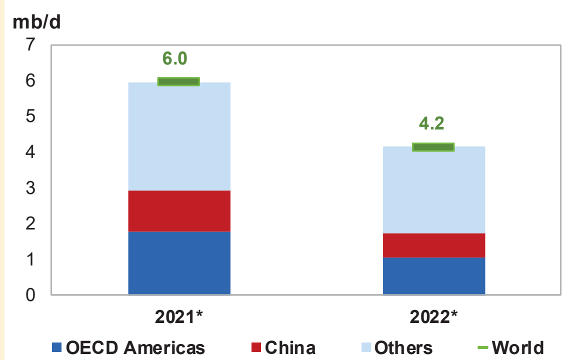


Note: * 2021-2022 = Forecast. Source: OPEC.

In terms of a geographical breakdown, the **OECD** shows a strong rebound in 2021, led by the US. US growth is forecast at 6.1% in 2021, supported by unprecedented fiscal and monetary stimulus. This is followed by projected growth of 4.1% in 2022, with further potential upside that may come from additional fiscal stimulus. Growth in the Euro-zone has also picked up strongly, especially in 2Q21, with economic growth for the entire year forecast at 4.7%, followed by 3.8% in 2022. Japan is facing ongoing COVID-19-related challenges and its economy is forecast to expand by 2.8% in 2021 and by 2% in 2022, albeit current domestic political changes and potential fiscal decisions may require revisions to these projections in the months to come.

In the **non-OECD**, the economic recovery has continued, though the pace and dynamics vary within the regions. China's 1H21 GDP figures confirmed a stable economic recovery, albeit the renewed COVID-19 variant outbreak is forecast to limit 2021 growth at 8.5%. China's anticipated softening of the 2H21 growth momentum is forecast to continue into 2022, leading to growth of 6%. India's growth is forecast at 9% for 2021 and 6.8% in 2022. Notwithstanding, there are still considerable uncertainties related to COVID-19 in India, as well as the likelihood of rising inflation. Growth forecasts for 2021 in Brazil and Russia stand at 4.7% and at 3.5%, respectively, followed by 2022 growth of 2.5% in both economies. However, rising inflationary pressures have already led Brazil and Russia to lift key interest rates in recent months, potentially dampening the recovery going forward.

Graph 2: World oil demand growth in 2021-22



Note: * 2021-2022 = Forecast. Source: OPEC.

The global economic recovery, in combination with a considerable rebound in mobility, significantly lifted oil demand growth in 1H21. While this dynamic is forecast to soften towards the end of 2021, the overall positive trend has led to projected global oil demand growth of 6.0 mb/d for 2021, followed by growth of 4.2 mb/d in 2022. Non-OPEC supply is expected to grow by 0.9 mb/d in 2021, followed by forecast growth of 2.9 mb/d in 2022. Nevertheless, numerous uncertainties, including the continued COVID-19 impact on the global economic recovery, will require continued coordinated policies, including the commendable efforts undertaken by OPEC and non-OPEC oil producers participating in the Declaration of Cooperation (DoC), to ensure stability and balance for the global oil market.

World Oil Demand

For 2021, world oil demand is expected to increase by 6.0 mb/d, unchanged from last month's projections and despite offsetting revisions within the quarters. An upward revision due to positive mobility indicators for OECD countries in 3Q21 was offset by a downward revision to 4Q21, given the risk to oil demand fundamentals stemming from the increase in COVID-19 cases, primarily related to the Delta variant. World oil demand is estimated at 96.7 mb/d in 2021.

In 2022, world oil demand is forecast to rise by 4.2 mb/d y-o-y, revised higher by around 0.9 mb/d compared to last month's report, as the pace of recovery in oil demand is now assumed to be stronger and mostly taking place in 2022. As vaccination rates rise, the COVID-19 pandemic is expected to be better managed and economic activities and mobility will firmly return to pre-COVID-19 levels. The revisions are based in both the OECD and non-OECD regions, with steady economic developments expected to support the partially delayed recovery in oil demand in various sectors. As a result, the OECD oil demand outlook was revised upward by 0.3 mb/d in 2022 compared to last month's projection and is projected to increase by 1.8 mb/d y-o-y. In the non-OECD region, oil demand in 2022 is estimated to increase by 2.3 mb/d y-o-y, revised higher by around 0.6 mb/d compared to last month's estimations, supported by steady economic activities in the main economies, particularly China, India and Other Asia. Additionally, ongoing improvements in vaccination rates and a potential increase in public confidence in managing COVID-19 is anticipated to be more widespread in 2022, further supporting the recovery of oil demand, particularly transportation fuels. World oil demand is estimated at 100.8 mb/d in 2022, exceeding pre-pandemic levels.

Table 4 - 1: World oil demand in 2021*, mb/d

							Change 2021/20	
World oil demand	**2020**	**1Q21**	**2Q21**	**3Q21**	**4Q21**	**2021**	**Growth**	**%**
Americas	22.54	22.77	24.73	25.05	24.72	24.33	1.79	7.94
of which US	*18.44*	*18.69*	*20.11*	*20.44*	*20.45*	*19.93*	*1.49*	*8.07*
Europe	12.44	11.91	12.73	13.71	13.61	13.00	0.56	4.52
Asia Pacific	7.14	7.67	7.13	7.17	7.52	7.37	0.23	3.24
Total OECD	**42.12**	**42.34**	**44.59**	**45.93**	**45.85**	**44.70**	**2.58**	**6.14**
China	13.19	13.15	14.27	14.83	15.02	14.32	1.13	8.56
India	4.51	4.94	4.42	4.91	5.61	4.97	0.46	10.27
Other Asia	8.13	8.36	8.98	8.49	8.56	8.60	0.47	5.75
Latin America	6.01	6.15	6.16	6.46	6.40	6.29	0.28	4.68
Middle East	7.55	7.95	7.77	8.24	7.97	7.99	0.44	5.84
Africa	4.08	4.39	4.06	4.16	4.48	4.27	0.19	4.64
Russia	3.37	3.57	3.42	3.57	3.74	3.57	0.21	6.14
Other Eurasia	1.07	1.18	1.24	1.14	1.28	1.21	0.14	12.59
Other Europe	0.70	0.78	0.72	0.73	0.79	0.75	0.06	8.26
Total Non-OECD	**48.61**	**50.48**	**51.04**	**52.52**	**53.85**	**51.98**	**3.37**	**6.94**
Total World	**90.73**	**92.82**	**95.62**	**98.46**	**99.70**	**96.68**	**5.96**	**6.56**
Previous Estimate	90.62	92.61	95.51	98.23	99.82	96.57	5.95	6.57
Revision	0.11	0.21	0.12	0.22	-0.11	0.11	0.00	-0.01

*Note: * 2021 = Forecast. Totals may not add up due to independent rounding. Source: OPEC.*

Table 4 - 2: World oil demand in 2022*, mb/d

World oil demand	2021	1Q22	2Q22	3Q22	4Q22	2022	Change 2022/21 Growth	%
Americas	24.33	24.10	25.84	26.08	25.52	25.40	1.07	4.39
of which US	*19.93*	*19.80*	*21.04*	*21.46*	*21.17*	*20.88*	*0.94*	*4.74*
Europe	13.00	12.55	13.40	14.32	14.09	13.60	0.60	4.61
Asia Pacific	7.37	7.91	7.31	7.30	7.63	7.54	0.17	2.27
Total OECD	**44.70**	**44.56**	**46.55**	**47.69**	**47.25**	**46.53**	**1.83**	**4.10**
China	14.32	14.00	15.15	15.32	15.46	14.98	0.66	4.64
India	4.97	5.40	4.82	5.29	5.93	5.36	0.39	7.86
Other Asia	8.60	9.05	9.59	9.07	8.89	9.15	0.55	6.40
Latin America	6.29	6.39	6.34	6.61	6.56	6.48	0.18	2.89
Middle East	7.99	8.29	8.01	8.49	8.20	8.25	0.26	3.31
Africa	4.27	4.57	4.19	4.28	4.61	4.41	0.14	3.27
Russia	3.57	3.67	3.47	3.62	3.79	3.64	0.07	1.83
Other Eurasia	1.21	1.25	1.28	1.17	1.32	1.25	0.05	3.72
Other Europe	0.75	0.80	0.73	0.74	0.81	0.77	0.02	2.18
Total Non-OECD	**51.98**	**53.43**	**53.60**	**54.60**	**55.56**	**54.30**	**2.32**	**4.46**
Total World	**96.68**	**97.99**	**100.15**	**102.29**	**102.81**	**100.83**	**4.15**	**4.29**
Previous Estimate	96.57	96.83	98.71	101.17	102.62	99.86	3.28	3.40
Revision	0.11	1.16	1.44	1.12	0.19	0.98	0.87	0.89

*Note: * 2021-2022 = Forecast. Totals may not add up due to independent rounding. Source: OPEC.*

OECD

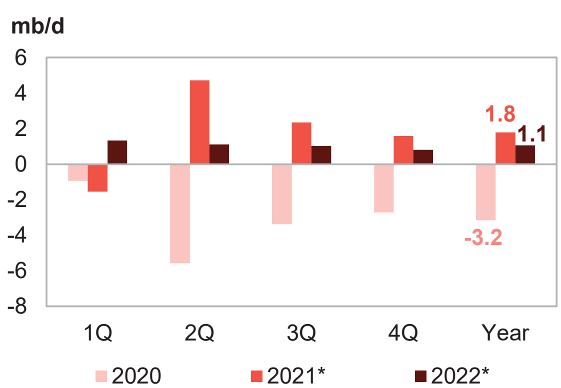
OECD Americas

Update on the latest developments

The latest available oil demand data in **OECD Americas** imply a y-o-y increase of 3.6 mb/d y-o-y in **June**, following an increase of 4.3 mb/d y-o-y in May. Gasoline demand accounted for around 27% of the overall increase, with an additional 33% originated in rising jet/kerosene and diesel requirements.

On the back of a low historical baseline, June 2021 seems to have recovered approximately 87% of the losses suffered during the same month in 2020. Oil demand in the region declined in 1Q21 as a result of rising COVID-19 infection cases before improving thereafter. Gasoline demand in June 2021 posted substantial gains of 1.0 mb/d y-o-y, rising for the fourth month in a row and in line with rebounding travel and healthy economic growth. Oil demand continued to remain below June 2019 levels, yet the differential shrank considerably to 0.5 mb/d, as compared to a hefty 3.3 mb/d in February 2021. All countries in the region posted solid gains as demand rebounded the most in the US, followed by Canada, Mexico and Chile.

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



*Note: * 2021-2022 = Forecast. Source: OPEC.*

The latest available **US** monthly demand data for **June** shows oil demand rising by approximately 3.0 mb/d y-o-y, making up 96% of the June 2020 losses, but lower than June 2019 by 0.1 mb/d. Gasoline, jet/kerosene and LPG demand accounted for the bulk of the increase, with gasoline gaining 1.0 mb/d y-o-y, while jet/kerosene increased by 0.6 mb/d and LPG by 0.5 mb/d y-o-y in June 2021. The declines of gasoline and jet/kerosene in June 2020 were around 1.4 mb/d and 1.0 mb/d y-o-y, respectively. According to the Federal Highway Administration (FHA), vehicle miles of travel in the US increased by 15.0% y-o-y in June this year after rising by 31.3% y-o-y in May. In June 2020, the indicator fell by 14.8% y-o-y. Light vehicle retail sales, as reported by Autodata and Haver Analytics, were at 15.4 million units, according to seasonally adjusted annual rates (SAAR), compared with 17.1 million units in May; historical figures show total sales of 13.3 million units in June 2020 and 17.3 million units in June 2019. Industrial production, an indicator for industrial fuel demand, was also higher by 9.9% y-o-y in June after increasing by 16.6% y-o-y in May. Diesel demand was higher by 0.4 mb/d y-o-y in June 2021 following a similar increase in May.

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

			Change Jun 21/Jun 20	
By product	**Jun 20**	**Jun 21**	**Growth**	**%**
LPG	2.66	3.14	0.48	18.0
Naphtha	0.19	0.21	0.02	10.8
Gasoline	8.52	9.45	0.92	10.8
Jet/kerosene	0.79	1.43	0.64	81.5
Diesel	3.50	3.94	0.45	12.7
Fuel oil	0.21	0.34	0.13	60.3
Other products	2.24	2.51	0.27	12.0
Total	**18.10**	**21.00**	**2.90**	**16.0**

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

Preliminary data for July based on weekly input indicates the continuation of a recovery in transportation fuel, with both gasoline and jet/kerosene increasing by almost 1.6 mb/d y-o-y collectively. Diesel is foreseen to increase by 0.2 mb/d y-o-y in July 2021.

Near-term expectations

Despite the recent uptick in COVID-19 cases, careful optimism still dominates the short-term demand outlook in the region going into 2022, mainly due to rising vaccination rates. The economy is also expected to be supported by stimulus programmes and high household savings. These factors support a positive outlook for oil demand prospects during 2H21. It should also be noted that the outlook remains challenged by COVID-19 developments, particularly during the emergence of colder weather in 4Q21, and the appearance of new variants and potential government counter-measures. While to date 3Q21 appears to be resilient in terms of travel activity, risks of COVID-19 on consumer behaviour, as well as the effectiveness of vaccination programmes, are to be monitored closely going forward.

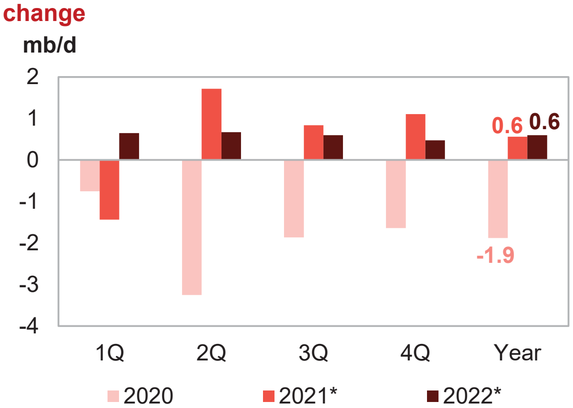
In **2022**, OECD Americas oil demand is forecasted to increase by approximately 1.1 mb/d y-o-y with US oil demand accounting for more than 0.9 mb/d y-o-y, supported by healthy economic growth. Petrochemicals and transportation will be sectors of the economy that will require more oil in 2022. Gasoline demand will be supported by better employment rates and rising vehicle sales, despite continuous penetration of alternative-fuelled vehicles. Expansion in the petrochemical industry and consequently healthy petrochemical margins will support light distillates in 2022. Conversely, reduced business travel, a continuation in fuel substitution programmes, and fuel efficiency gains are anticipated to cap oil demand growth.

OECD Europe

Update on the latest developments

OECD Europe oil demand increased by 1.4 mb/d y-o-y in **June**, following an increase of more than 1.6 mb/d y-o-y in May. Demand for most petroleum product categories showed y-o-y gains, as a result of the low historical baseline and the removal of restrictions in the region amid warmer weather and increases in vaccination rates. The strongest gains were for diesel, gasoline, jet/kerosene and light distillates. Demand for naphtha rose y-o-y and has been on a growth trajectory since 3Q20, in line with the expansions in petrochemical activities. Demand for transportation fuels returned with diesel, gasoline and jet/kerosene showing gains amid improved mobility and increased travel.

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



*Note: * 2021-2022 = Forecast. Source: OPEC.*

Initial data for July indicates that demand in the UK grew by 0.2 mb/d, while requirements in Italy, France and Germany were unchanged y-o-y. Oil demand gains were also observed in all other countries of the region, coupled with decreasing stringency indexes, travel across and within countries both on the road as well as in the air. The mobility index posted steady gains in July, reaching 128% compared to pre-pandemic levels after recording 112% in June. The industrial production index, which excludes construction, rose substantially as compared to the same month in 2020, as reported by Eurostat and Haver Analytics. New passenger car registrations gained 9% y-o-y, following a solid 52% y-o-y increase in May, while unemployment rates fell.

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

By product	Jun 20	Jun 21	Change Jun 21/Jun 20 Growth	%
LPG	0.35	0.44	0.09	25.5
Naphtha	0.53	0.54	0.00	0.8
Gasoline	1.03	1.20	0.17	16.6
Jet/kerosene	0.23	0.39	0.16	69.3
Diesel	2.92	3.18	0.26	8.9
Fuel oil	0.15	0.17	0.02	13.4
Other products	0.45	0.50	0.04	9.5
Total	**5.66**	**6.40**	**0.74**	**13.1**

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

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

Near-term expectations

The 3Q21 has proven to be robust so far as vaccination rates improve rapidly and warmer weather favoured efforts to control the pandemic. The current outlook assumes that the pandemic will remain largely under control during 4Q21 with minor localized measures depending on hospitalization capacities. Reduced international travel, teleworking enhancements, and limitations on petroleum product demand will, however, may limit oil demand in the region.

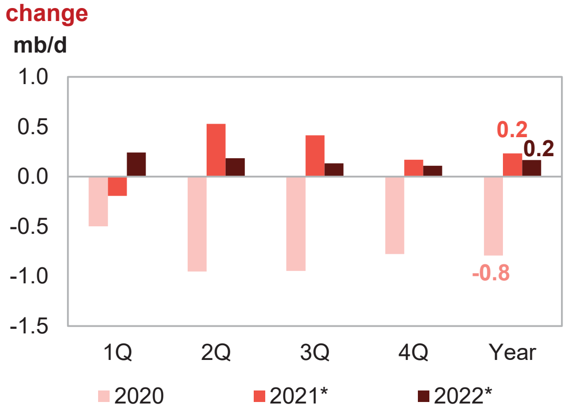
In **2022**, OECD Europe oil demand is projected to rise by around 0.6 mb/d. Developments in the economy, along with a large containment of COVID-19, are the main assumptions for OECD Europe oil demand growth in 2022, supported by improvements in mobility along with positive developments in the industrial and construction sectors. Downside risks are mostly relate to the appearance of resilient variants, economic uncertainty, including high debt levels and budgetary constraints, in addition stringent policies capping oil usage. OECD Europe oil demand will therefore remain below 2019 levels.

OECD Asia Pacific

Update on the latest developments

OECD Asia Pacific oil demand continued to rise in **June,** increasing by 0.4 mb/d y-o-y, more than the corresponding 0.2 mb/d increase recorded in May. Gains were largely attributed to rising light distillate requirements in South Korea and Japan, as well as gasoline and diesel demand in Australia and South Korea. Oil demand is expected to have gained an additional push to the upside by the Summer Olympics. Demand for light distillates in the Asia Pacific during June grew by more than 0.2 mb/d y-o-y after increasing by roughly the same volumes in May. Transportation fuel demand rose by 0.2 mb/d y-o-y in June, following similar gains in May y-o-y. Oil demand in Japan and South Korea grew by 0.2 mb/d y-o-y. Preliminary data from Japan's Ministry of Economy, Trade and Industry (METI) indicate a flat oil demand in July 2021 y-o-y.

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



*Note: * 2021-2022 = Forecast. Source: OPEC.*

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

By product	Jul 20	Jul 21	*Change Jul 21/Jul 20* Growth	%
LPG	0.36	0.38	0.02	6.5
Naphtha	0.64	0.64	-0.01	-1.0
Gasoline	0.78	0.78	0.00	-0.5
Jet/kerosene	0.19	0.17	-0.02	-8.3
Diesel	0.67	0.68	0.01	1.1
Fuel oil	0.20	0.23	0.03	17.2
Other products	0.19	0.15	-0.03	-17.4
Total	**3.02**	**3.03**	**0.01**	**0.2**

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

Near-term expectations

While Japan and South Korea seemed to have brought COVID-19 under control, recently imposed strict lockdowns in Australia and New Zealand are expected to negatively impact oil demand in 3Q21 and 4Q21. Overall demand in 2021 is projected to rebound in the region on the back of a recovery in economic activities. Petrochemical feedstock consumption remains one of the main contributors to oil demand growth in 2021, while jet/kerosene demand is projected to continue lagging 2019 levels, as international business and leisure travel will remain under pressure.

In **2022**, OECD Asia Pacific oil demand is expected to increase by 0.2 mb/d, under assumptions of expanding GDP and low impact from COVID-19-related challenges on transportation fuel demand. It is anticipated that the pandemic will be controlled in 2022. Gasoline will be the petroleum product category to increase the most, followed by industrial diesel, as well as light distillate petrochemical feedstock.

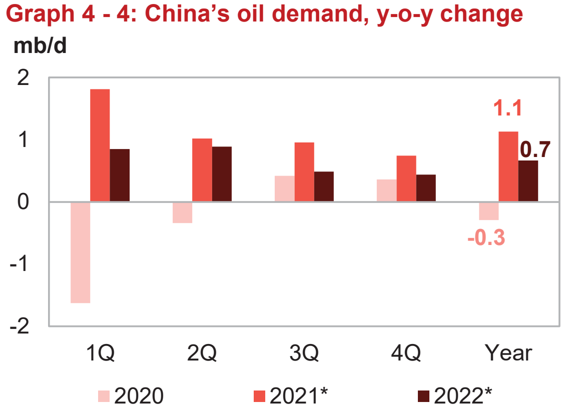
Non-OECD

China

Update on the latest developments

China's oil demand increased by around 0.2 mb/d y-o-y in **July** compared to a 0.4 mb/d y-o-y increase in June. Unlike most regions, demand was higher than pre-pandemic levels by 0.7 mb/d compared to July 2019, primarily driven by strong demand for petrochemical feedstocks, LPG and naphtha. Light distillates continued to record steady growth in July on y-o-y basis. LPG grew by more than 0.2 mb/d y-o-y while naphtha posted gains of more than 0.1 mb/d y-o-y. The performance of the petrochemical sector has been healthy since 2Q20. Higher utilization rates for Propylene Dehydrogenation Plants (PDH), recent additional PDH capacity and healthy petrochemical margins supported demand for light distillates. LPG and naphtha grew by around 0.4 mb/d y-o-y in July.

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



*Note: * 2021-2022 = Forecast. Source: OPEC.*

Looking at data from **January to July**, oil demand showed strong growth of around 1.2 mb/d compared to the same period in 2020. Most of the increase appeared in 1Q21 due to the low base line of 1Q20 amid the onset of COVID-19, which reduced substantially demand for petroleum products. Data for 1Q21 shows an increase of around 1.7 mb/d y-o-y, supported by strong growth in light distillates and recovering transportation fuel demand. Gains were registered across all petroleum products with transportation fuels accounting for the largest share. Gasoline and jet fuel increased by around 0.7 mb/d compared to the same period in 2020, supported by increases in mobility and passenger air travel in contrast to last year. The mobility index improved during the course of the year despite slowing in 1Q21 due to increased measures against COVID-19. On average the index was at 86% of pre-pandemic levels in 1Q21 before reaching to 100% in 2Q21. Light distillates continued to perform strongly throughout the year, particularly LPG, which posted gains of around 0.3 mb/d compared to the same period in 2020. Additionally, naphtha demand increased by 0.1 mb/d.

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

By product	Jul 20	Jul 21	Change Jul 21/Jul 20 Growth	%
LPG	2.12	2.36	0.24	11.5
Naphtha	1.84	1.96	0.13	6.9
Gasoline	2.84	3.01	0.17	5.9
Jet/kerosene	0.58	0.49	-0.09	-15.5
Diesel	3.28	2.86	-0.43	-13.0
Fuel oil	0.72	0.86	0.14	19.8
Other products	1.50	1.52	0.02	1.3
Total	**12.88**	**13.06**	**0.18**	**1.4**

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

Near-term expectations

With the government recently enacting measures to counter the spread of the Delta variant, coupled with the slowdown in main macro-economic indicators, oil demand in 3Q21 and marginally in 4Q21 is expected to be negatively affected. However, the overall demand for China in 2021 remained supported and the growth of petroleum products is assumed to be around 1.1 mb/d on annualized basis. The rapid containment of the spread of the Delta variant, the lifting of the fishing ban and the national holidays during the month of October are anticipated to lend support to oil demand in the coming months. The developments around COVID-19 will continue to pose a downside risk to the outlook, but the low-tolerance policy of the Chinese government is projected to speed up the recovery.

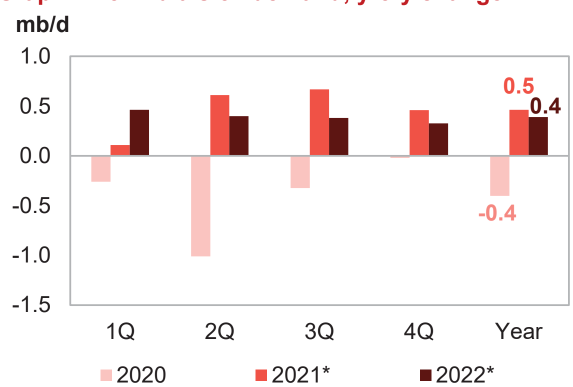
In **2022**, China's oil demand is anticipated to increase y-o-y, supported by solid economic growth forecasts. Transportation and industrial sectors are projected to rise the most with support coming from an increase in vehicle miles driven, a rise in passenger car sales and a steady industrial sector. Gasoline is estimated to increase followed by diesel. A healthy petrochemical sector is expected to lend strong support to light distillates consumption next year.

India

Update on the latest developments

Indian oil demand showed an increase of 0.3 mb/d y-o-y in **July** after rising by around 0.1 mb/d y-o-y in June. But demand remained lower than July 2019 levels by 0.3 mb/d mainly due to the lagging performance of middle distillates. Demand in July was driven by strong gains in diesel and gasoline amid the easing of regional lockdowns imposed to control May's Delta variant spread. Diesel increased the most, posting gains of around 0.2 mb/d y-o-y on the back of improved industrial and agricultural activities. The industrial production index was affected by the second wave of COVID-19 in May, recording an increase of 29.3% y-o-y compared to 134.6% y-o-y in April. Once published, July's industrial production data is expected to show a respectable rebound in line with the recovery in industrial activity and the latest manufacturing PMI for India.

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



*Note: * 2021-2022 = Forecast. Source: OPEC.*

The IHS Markit manufacturing PMI jumped to 55.3 in July from 48.1 in June. Gasoline consumption posted steady gains, rising by 0.1 mb/d y-o-y, after showing small gains in June. Demand for gasoline is now on par with pre-pandemic levels and showed a marginal increase when compared to July 2019. Increases in mobility supported by the gradual re-opening of social activities supported gasoline demand. The mobility index was trending above pre-pandemic levels at 106% in July compared to 78% of pre-pandemic levels in June.

Data from January to July indicates petroleum products demand rising by 0.5 mb/d y-o-y, led by diesel and gasoline. During the same period in 2020, oil demand posted steep declines of around 0.6 mb/d compared to a year earlier. Weaknesses in transportation fuel due to extended lockdown policies propelled those declines.

Diesel was higher by a nearly 0.2 mb/d, or by more than 11%, compared to the same period in 2020, but remained significantly lower than the normal consumption levels of 2019 by about 0.2 mb/d. Improvements in industrial and construction activities as well as the agriculture sector supported diesel demand. Of course, the low baseline of 2020 played a major role in this y-o-y increase with support from the overall recovery of economic activities. However, a strong second wave of COVID-19 across the country in May halted the recovery process and consumption fell back into the negative zone.

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

			Change Jul 21/Jul 20	
By product	**Jul 20**	**Jul 21**	**Growth**	**%**
LPG	0.80	0.83	0.04	4.9
Naphtha	0.33	0.31	-0.02	-5.7
Gasoline	0.61	0.71	0.10	16.6
Jet/kerosene	0.10	0.12	0.01	13.2
Diesel	1.47	1.62	0.15	10.3
Fuel oil	0.28	0.27	-0.01	-2.1
Other products	0.25	0.28	0.03	10.8
Total	**3.83**	**4.14**	**0.31**	**8.0**

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

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

Generally, industrial production has risen by 127.7% y-o-y from historically low readings in most of 2020, as reported by the Central Statistical Organization of India and Haver Analytics. The easing of lockdown measures and increased use of private vehicles led to improvements in mobility and boosted gasoline demand growth. Gasoline demand grew by 0.1 mb/d when compared to the same period in 2020 and was at par with 2019 levels. Mobility was at 97% of pre-pandemic levels during the analysed period while it was 64% during the same period in 2020. Light distillates, LPG and naphtha marginally increased from January to July compared to the same period last year, supported by steady petrochemical demand and increased LPG demand for home cooking.

Near-term expectations

Going forward, demand growth is expected to gain momentum in the coming months, supported by the low baseline and recovering diesel requirements in the industrial, construction and agriculture sectors. Transportation fuel demand is projected to be dependent on COVID-19 developments, particularly in 4Q21, and the government containment measures. The oil demand outlook is projected to gain momentum in light of positive policy measures encouraging private consumption and investment, in addition to 2020 baseline decline. Demand for transportation fuel will lead product demand, followed by middle distillates.

For 2022, India's oil demand is expected to rise y-o-y as total consumption exceeds pre-pandemic levels on an annualized basis. COVID-19 containment measures are projected to improve, backed by rising vaccination rates, natural immunity and improved treatment of COVID-19. Economic activity is projected to support demand for refined products, led by transportation fuels, mainly gasoline. Support will be driven by rising mobility and increased use of private vehicles. Diesel will gain strength in 2022, supported by steady developments in the industrial, construction and agriculture sectors.

Other Asia

Update on the latest developments

In Other Asia, **January to June** data shows demand rising by more than 0.5 mb/d compared to the same period last year. However, demand remained significantly lower, 0.8 mb/d, than pre-pandemic levels mostly due to the slower recovery in transportation fuels. Most of the 0.5 mb/d was driven by rebounding diesel in response to the economic pick-up after 2020. Jet fuel was the only fuel to decline, when compared to the same period last year, mainly due to the second wave of COVID-19 that led to sluggish development in the tourism sector in Indonesia, Malaysia, Philippines and Thailand. Diesel was higher by more than 0.2 mb/d, but remained lower by 0.1 mb/d compared to the same period in 2019. A slight improvement in trucking activities, construction and agriculture on the back of the uptick in economic activity supported diesel demand. However, the appearance of the Delta variant in some countries in the region led to slower growth during May and July. Naphtha recorded solid growth during the studied period. In fact, naphtha demand exceeded pre-pandemic levels by 0.04 mb/d and was higher in 2021 by more than 0.1 mb/d compared to the same period in 2020. Demand for plastics supported naphtha cracking margins, leading to increased intake rates in naphtha crackers. Gasoline grew by around 0.1 mb/d compared to the same period in 2020, but remained significantly lower than 2019 by around 0.2 mb/d. After a steady recovery in mobility during 1Q21, movement slowed down in 2Q21 due to imposed measures to contain the second wave of COVID-19 particularly in Thailand, Singapore and Indonesia.

Near-term expectations

Going forward, oil demand is anticipated to improve y-o-y supported by a positive economic outlook and recovering mobility. The recent prevalence of Delta variant in a number of countries in the regions, however, has imposed downside pressure on the transportation fuel outlook in 4Q21 has affected current data in 3Q21. Malaysia, Indonesia, Singapore and the Philippines are anticipated to account for the most of the growth in 2021, led by transportation fuels.

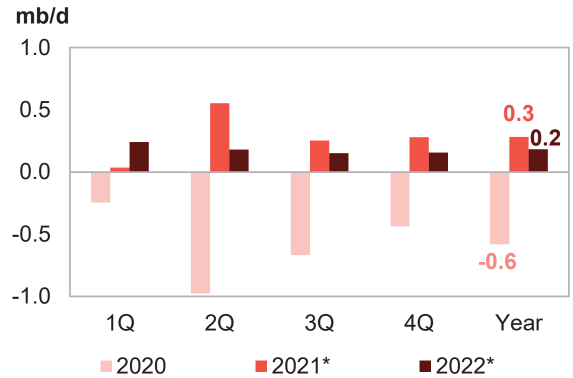
In 2022, Other Asia's oil demand is anticipated to grow and will marginally exceed 2019 levels. Firm economic expectations will provide strong support to demand next year. Transportation fuels are expected to increase amid better management of COVID-19 leading to a healthier outlook for mobility.

Latin America

Update on the latest developments

June data indicates an increase in oil requirements by 0.4 mb/d y-o-y in Latin America, following an increase of 0.5 mb/d y-o-y in May. However, demand remained below June 2019 levels by around 0.1 mb/d even though industrial fuels, diesel and fuel oil surpassed June 2019 levels. On a y-o-y basis, diesel and gasoline grew the most supported by the harvest season and improving transportation momentum. The mobility index in the region showed steady gains between May and June, rising from 90% from pre-pandemic levels in May to 95% in June. The index showed further development in July and August, thus supporting transportation fuel demand.

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



*Note: * 2021-2022 = Forecast. Source: OPEC.*

The recovery from the historic decline in 2020 was not full during the course of 2021 in Latin America at least in the 1H21 despite strong diesel performance. Oil demand showed an increase of more than 0.2 mb/d from **January to June** in contrast with the same period last year, though demand remained below pre-pandemic levels. In terms of products performance, mixed trends were registered. While diesel, gasoline and heavy distillates recorded gains, light distillates – LPG and naphtha – were flat and jet fuel remained lower compared to January to July 2020. In comparison to the same period in 2019, diesel was the only fuel outpacing 2019 levels while LPG and fuel oil were trending at levels similar to 2019. Diesel demand has been very positive in the region, led by Brazil, supported by the agriculture and transportation sectors and the overall recovery in economic activities despite increasing COVID-19 infection cases and high unemployment. Diesel posted gains of more than 0.1 mb/d compared to the same period last year, following a decrease of around similar levels during the same period in 2020. Despite the slow improvement in mobility since the beginning of the year, the region's mobility index remained lower than 2019. The index stood at 89% of pre-pandemic levels, with gasoline demand rising by around 0.1 mb/d compared to the same period last year. This was mainly impacted by the distorted baseline.

Table 4 - 8: Brazil's oil demand*, mb/d

By product	Jul 20	Jul 21	Change Jul 21/Jul 20 Growth	%
LPG	0.25	0.25	0.00	-0.3
Naphtha	0.15	0.14	0.00	-2.0
Gasoline	0.61	0.71	0.11	17.9
Jet/kerosene	0.03	0.08	0.04	133.1
Diesel	1.06	1.14	0.08	7.3
Fuel oil	0.07	0.11	0.04	60.0
Other products	0.43	0.40	-0.03	-6.9
Total	**2.60**	**2.84**	**0.24**	**9.3**

*Note: * = Inland deliveries. Totals may not add up due to independent rounding.*

Sources: JODI, Agencia Nacional do Petroleo, Gas Natural e Biocombustiveis and OPEC.

Near-term expectations

Oil demand in **2H21** is projected to be supported by rising mobility, although the increase in COVID-19 cases remains a concern. Transportation fuels are projected to gain traction but continue to lag behind 2019 levels. Industrial fuels, diesel and fuel oil are expected be supported by steady economic activities. However, risks are skewed to the downside, particularly due to issues related to COVID-19 cases, political tensions in the region and high unemployment rates.

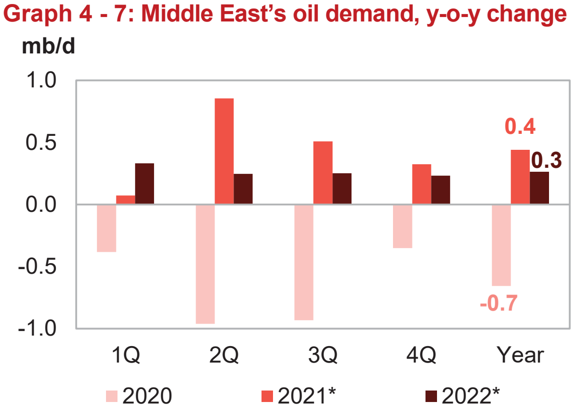
In 2022, Latin America's oil demand is anticipated to linger below 2019 levels though rise y-o-y. The increase in oil demand will be driven by a healthy economic outlook supporting demand in the region, but mostly in Brazil and Argentina. Transportation fuels are projected to account for most of the gains in 2022, supported by COVID-19 containment measures and overall gains in economic momentum.

Middle East

Update on the latest developments

In **June**, Middle East oil demand increased by 0.7 mb/d y-o-y after posting stronger y-o-y gains in May of 1.1 mb/d. June demand growth was distorted by the low base of June 2020 and remained below pre-pandemic levels by 0.1 mb/d compared to June 2019. Gasoline led the y-o-y gains in June together with the other products category, which includes the direct crude used for power generation. Improvements in mobility as well as an uptick in the seasonal summer uptick in power generation supported demand for both fuels.

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



*Note: * 2021-2022 = Forecast. Source: OPEC.*

In Saudi Arabia, oil demand data for July shows a marginal decline after strong gains a month earlier and despite a rise in direct crude consumption in the power generation sector. Diesel and fuel oil led the y-o-y decreases due to slower construction activities and higher crude burning in lieu of fuel oil. According to Yamama Cement Company and Haver Analytics, cement deliveries – a proxy for construction activities – declined by 20.2% y-o-y in July after dropping by 9.9% y-o-y in June. The indicator showed solid gains in July 2020 of around 25.7% y-o-y. Diesel and fuel oil dropped by around 0.1 mb/d y-o-y collectively, while crude oil for burning increased by around 0.05 mb/d y-o-y in July.

Table 4 - 9: Saudi Arabia's oil demand, mb/d

			Change Jul 21/Jul 20	
By product	**Jul 20**	**Jul 21**	**Growth**	**%**
LPG	0.04	0.04	0.00	-1.2
Gasoline	0.48	0.47	0.00	-0.4
Jet/kerosene	0.04	0.04	0.00	11.7
Diesel	0.54	0.49	-0.05	-9.0
Fuel oil	0.56	0.54	-0.02	-3.8
Other products	0.72	0.77	0.05	7.4
Total	**2.38**	**2.36**	**-0.01**	**-0.6**

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

Sources: JODI and OPEC.

Data from January to June show solid growth in the Middle East, supported by an increase of around 0.5 mb/d compared to the same period in 2020. All products showed steady growth, propelled by a recovery in economic activities and supported by the construction and industrial sectors, a steady recovery in mobility and the distorted baseline of 2020. Gains were led by a steady recovery in gasoline demand (+0.2 mb/d), diesel (+0.1 mb/d) and petrochemical feedstock, LPG and naphtha, (+0.1 mb/d). Recovering mobility supported gasoline demand in Saudi Arabia, Iraq and Kuwait with notable increases in 2Q21 largely due to easing lockdown measures across the region and the start of a gradual return of normality. While steady industrial activities supported healthy petrochemical demand and encouraged diesel and light distillates consumption.

Near-term expectations

The outlook for the remainder of 2021 will depend highly on developments related to COVID-19 and the government response. Currently, the COVID-19 situation is mixed in the Middle East region. On positive side, vaccination rates continue to increase across the region, supporting a return to normal activities. In Saudi Arabia, for example, the partial return to schools and higher education should in turn support demand for transportation fuels. However, the continuing ban on flights from certain locations, such as South Asia, will continue to pose downside risks to demand going forward.

In **2022**, demand is assumed to continue to recover as economic activities accelerate. The construction and industrial sectors are assumed to lend support to demand. However, the pace of the recovery will depend on challenges related to COVID-19, the potential development of new variants, and the rate as well as the effectiveness of vaccinations. That said, Middle East oil demand growth is anticipated to gain further strength in 2022 due to continued economic growth. As a result, transportation fuel, light distillates for petrochemical usage, and construction fuels are expected to be the products leading oil demand growth next year.

World Oil Supply

Non-OPEC liquids supply growth in 2021 (including processing gains) was revised down by 0.17 mb/d from the previous assessment, owing to a downward revision of 0.52 mb/d in 3Q21. The revisions are mainly due to oil production outages in North America in August, related to Hurricane Ida in the Gulf of Mexico (GoM) and an explosion and fire on an offshore platform in Mexico. Production estimates in the North Sea were also revised down, due to lower-than-expected output in 3Q21. Annual growth is now forecast at 0.9 mb/d y-o-y, to reach 63.8 mb/d. The US liquids supply forecast has been revised down by 41 tb/d and is forecast to grow by 0.08 mb/d y-o-y. The downward revision due to disruptions in production caused by Hurricane Ida was partially offset by higher-than-expected output in 2Q21. The 2021 oil supply forecast primarily sees growth in Canada, Russia, China, the US, Brazil and Norway, while output is projected to decline in the UK, Colombia, Indonesia and Egypt.

The non-OPEC supply growth forecast for 2022 is unchanged at 2.9 mb/d, amid offsetting revisions, to average 66.8 mb/d (including a recovery of 0.11 mb/d in processing gains). Including the expected growth of OPEC NGLs, liquids supply is forecast to grow by 3.1 mb/d. The main drivers of liquids supply growth are Russia (1.0 mb/d) and the US (0.78 mb/d), followed by Brazil, Norway, Canada, Kazakhstan, Guyana and other non-OPEC countries in the Declaration of Cooperation (DoC). Nevertheless, uncertainty regarding the financial and operational aspects of US production remains high.

OPEC NGLs and non-conventional liquids production in 2021 is estimated to grow by 0.12 mb/d to average 5.17 mb/d. For 2022, it is forecast to grow by 0.13 mb/d to average 5.29 mb/d. OPEC-13 crude oil production in August increased by 0.15 mb/d m-o-m to average 26.76 mb/d, according to secondary sources.

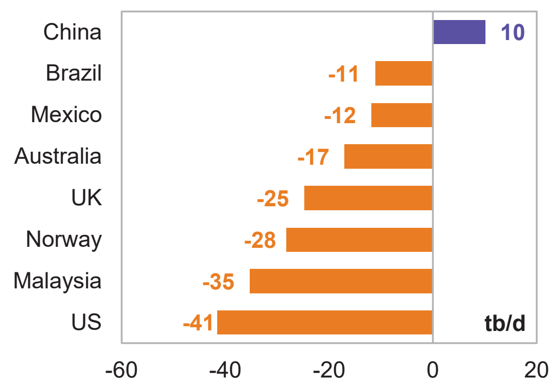
Preliminary non-OPEC liquids production in August, including OPEC NGLs, is estimated to have declined by 0.2 mb/d m-o-m to average 68.9 mb/d, up by 2.36 mb/d y-o-y. As a result, preliminary data indicates that global oil supply increased by 0.03 mb/d m-o-m to average 95.69 mb/d, up by 4.93 mb/d y-o-y.

Non-OPEC liquids production growth in 2021 was revised down by 170 tb/d from the previous assessment, because of a downward revision of 0.52 mb/d in 3Q21.

The revisions are mainly due to OECD oil production outages of 0.46 mb/d in 3Q21, following Hurricane Ida in the Gulf of Mexico and an explosion and fire at an offshore platform in Mexico, as well as lower-than-estimated oil output in the North Sea.

The non-crude supply forecast for Malaysia is also revised down in 2H21, leading to a downward revision for the year of 35 tb/d. The forecast liquids supply for the ten non-OPEC countries in the DoC, including Malaysia, was revised down by 0.05 mb/d and is now expected to grow by 0.24 mb/d y-o-y to average 17.44 mb/d. Moreover, the supply forecast for 4Q21 was revised down by 72 tb/d, led by Latin America and Other Asia, which partially offset the upward revision in the US.

Graph 5 - 1: Revisions to annual supply change forecast in 2021*, September MOMR/August MOMR



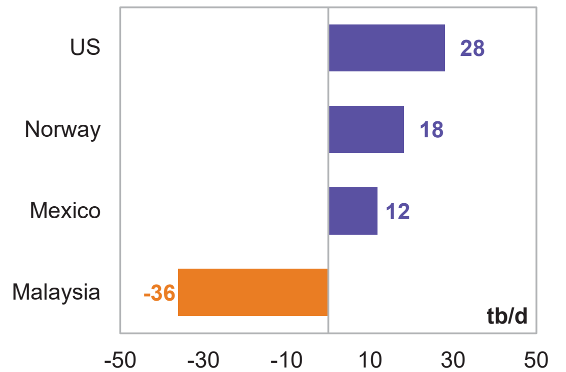
*Note: * 2021 = Forecast. Source: OPEC.*

The **non-OPEC supply growth forecast** for **2022** is unchanged at 2.9 mb/d, amid offsetting revisions, to average 66.8 mb/d.

The main downward revision was in Malaysia, due to changes in the NGLs and condensate supply forecast, as well as Other OECD Europe and Brazil, which were offset by upward revisions in the US, Norway and Mexico due to a lower base.

The liquids supply forecast for the non-OPEC DoC participating countries in 2022 was revised down by 0.02 mb/d, mainly in Malaysia, and is now expected to grow by 1.34 mb/d y-o-y to average 18.8 mb/d.

Graph 5 - 2: Revisions to annual supply change forecast in 2022*, September MOMR/August MOMR

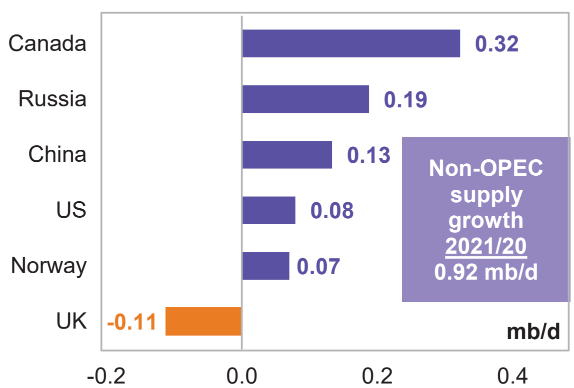


*Note: * 2022 = Forecast. Source: OPEC.*

Key drivers of growth and decline

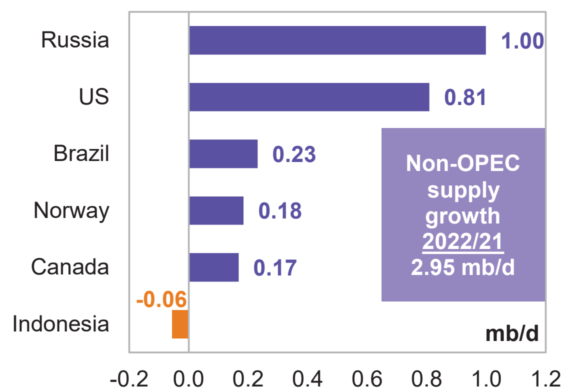
The **key drivers of non-OPEC liquids supply growth in 2021** are projected to be Canada, Russia, China, the US, Norway, Brazil and Guyana. Oil production is expected to decline mainly in the UK, Indonesia, Colombia and Egypt.

Graph 5 - 3: Annual liquids production changes for selected countries in 2021*



*Note: * 2021 = Forecast. Source: OPEC.*

Graph 5 - 4: Annual liquids production changes for selected countries in 2022*



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

For **2022**, the key drivers of non-OPEC supply growth are forecast to be Russia, the US, Brazil, Norway, Canada, Kazakhstan and Guyana, while oil production will decline mainly in Indonesia, Egypt and Thailand.

Non-OPEC liquids production in 2021 and 2022

Table 5 - 1: Non-OPEC liquids production in 2021*, mb/d

Non-OPEC liquids production	2020	1Q21	2Q21	3Q21	4Q21	2021	Change 2021/20 Growth	%
Americas	24.70	24.10	25.19	25.24	25.88	25.11	0.41	1.67
of which US	*17.61*	*16.63*	*17.94*	*17.84*	*18.31*	*17.69*	*0.08*	*0.45*
Europe	3.90	3.95	3.50	3.89	4.10	3.86	-0.04	-1.03
Asia Pacific	0.53	0.51	0.46	0.54	0.55	0.51	-0.02	-3.41
Total OECD	**29.13**	**28.55**	**29.15**	**29.67**	**30.53**	**29.48**	**0.35**	**1.21**
China	4.12	4.25	4.28	4.25	4.22	4.25	0.13	3.24
India	0.77	0.76	0.75	0.75	0.74	0.75	-0.01	-1.78
Other Asia	2.51	2.51	2.45	2.48	2.48	2.48	-0.03	-1.17
Latin America	6.04	5.96	6.00	6.24	6.47	6.17	0.13	2.07
Middle East	3.18	3.19	3.21	3.23	3.28	3.23	0.05	1.65
Africa	1.41	1.38	1.37	1.38	1.33	1.36	-0.05	-3.60
Russia	10.59	10.47	10.74	10.79	11.11	10.78	0.19	1.77
Other Eurasia	2.91	2.96	2.89	2.96	3.01	2.95	0.04	1.37
Other Europe	0.11	0.11	0.11	0.10	0.10	0.11	-0.01	-8.27
Total Non-OECD	**31.65**	**31.59**	**31.79**	**32.18**	**32.75**	**32.08**	**0.43**	**1.37**
Total Non-OPEC production	60.78	60.15	60.94	61.85	63.28	61.57	0.79	1.30
Processing gains	2.15	2.28	2.28	2.28	2.28	2.28	0.13	6.03
Total Non-OPEC liquids production	**62.93**	**62.43**	**63.22**	**64.13**	**65.56**	**63.85**	**0.92**	**1.46**
Previous estimate	62.91	62.41	63.25	64.66	65.63	64.00	1.09	1.73
Revision	0.02	0.02	-0.03	-0.52	-0.07	-0.15	-0.17	-0.27

*Note: * 2021 = Forecast. Totals may not add up due to independent rounding. Source: OPEC.*

Table 5 - 2: Non-OPEC liquids production in 2022*, mb/d

Non-OPEC liquids production	2021	1Q22	2Q22	3Q22	4Q22	2022	Change 2022/21 Growth	%
Americas	25.11	25.88	26.00	26.09	26.50	26.12	1.01	4.03
of which US	*17.69*	*18.23*	*18.56*	*18.42*	*18.76*	*18.49*	*0.81*	*4.57*
Europe	3.86	4.07	3.96	4.02	4.34	4.09	0.24	6.12
Asia Pacific	0.51	0.56	0.55	0.55	0.55	0.55	0.04	7.49
Total OECD	**29.48**	**30.51**	**30.52**	**30.66**	**31.39**	**30.77**	**1.29**	**4.37**
China	4.25	4.25	4.25	4.29	4.37	4.29	0.04	1.02
India	0.75	0.77	0.79	0.82	0.84	0.81	0.05	6.90
Other Asia	2.48	2.47	2.44	2.42	2.40	2.43	-0.05	-2.01
Latin America	6.17	6.52	6.46	6.40	6.61	6.50	0.33	5.36
Middle East	3.23	3.31	3.32	3.33	3.33	3.32	0.09	2.89
Africa	1.36	1.30	1.28	1.25	1.22	1.26	-0.10	-7.43
Russia	10.78	11.51	11.83	11.88	11.88	11.78	1.00	9.27
Other Eurasia	2.95	3.09	3.11	3.15	3.22	3.14	0.19	6.35
Other Europe	0.11	0.10	0.10	0.10	0.09	0.10	-0.01	-7.35
Total Non-OECD	**32.08**	**33.32**	**33.57**	**33.64**	**33.98**	**33.63**	**1.55**	**4.82**
Total Non-OPEC production	61.57	63.83	64.09	64.30	65.37	64.40	2.83	4.60
Processing gains	2.28	2.39	2.39	2.39	2.39	2.39	0.11	4.91
Total Non-OPEC liquids production	**63.85**	**66.22**	**66.48**	**66.69**	**67.76**	**66.79**	**2.95**	**4.61**
Previous estimate	64.00	66.39	66.63	66.83	67.89	66.94	2.94	4.60
Revision	-0.15	-0.17	-0.15	-0.14	-0.13	-0.15	0.00	0.02

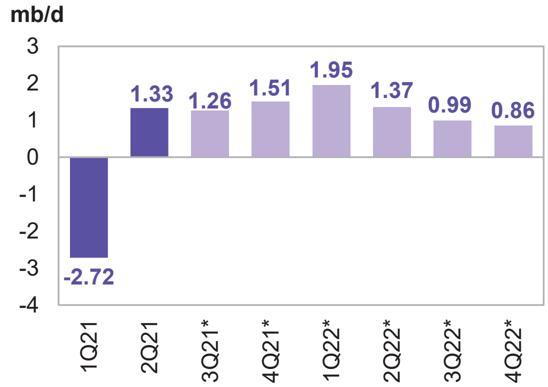
*Note: * 2021-2022 = Forecast. Totals may not add up due to independent rounding. Source: OPEC.*

OECD

OECD liquids production in 2021 is forecast to increase by 0.35 mb/d to average 29.48 mb/d, revised down by 138 tb/d m-o-m owing to a downward revision of 57 tb/d in the production forecast for OECD Americas, which is now projected to grow by 0.41 mb/d to average 25.11 mb/d. OECD Europe was revised down by 63 tb/d m-o-m and is now forecast to decline by 0.04 mb/d, with an average supply of 3.86 mb/d. Oil production in OECD Asia Pacific was also revised down by 17 tb/d m-o-m and is now forecast to decline by 0.02 mb/d y-o-y at 0.51 mb/d.

For **2022**, oil production in the OECD is revised up by 56 tb/d, and is now expected to grow by 1.29 mb/d to average 30.77 mb/d, with growth from OECD Americas of 1.01 mb/d to average 26.12 mb/d. Oil production in OECD Europe and OECD Asia Pacific is anticipated to grow respectively by 0.24 mb/d and 0.04 mb/d y-o-y to average 4.09 mb/d and 0.55 mb/d.

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



*Note: * 3Q21-4Q22 = Forecast. Source: OPEC.*

OECD Americas

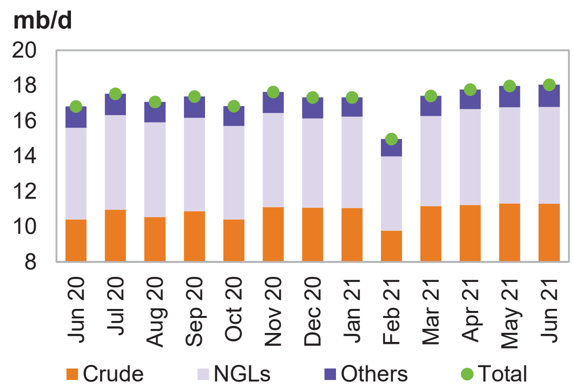
US

US liquids production in June 2021 was up by 0.06 mb/d m-o-m to average 18.05 mb/d, higher by 1.23 mb/d compared with June 2020, when US oil production suffered a drastic drop due to shut-in wells.

Crude oil production decreased in June 2021 by a minor 5 tb/d m-o-m to average 11.31 mb/d, up by 0.89 mb/d y-o-y. Meanwhile, production of non-conventional liquids (mainly ethanol) increased by 52 tb/d m-o-m to average 1.27 mb/d, according to the Department of Energy (DOE), and NGLs were up by 13 tb/d, to average 5.47 mb/d.

The production of crude oil, including field condensates, increased on the US Gulf Coast while the output declined in other four PADDs in June.

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



Source: OPEC.

Crude oil output on the US Gulf Coast grew by 37 tb/d to 8.03 mb/d in June, despite a 22 tb/d production decline in Texas, which was offset by higher output in New Mexico and the Gulf of Mexico (GoM) of 43 tb/d and 18 tb/d, respectively. Oil output from the GoM inched up to 1.83 mb/d, showing a recovery of 308 tb/d from June 2020.

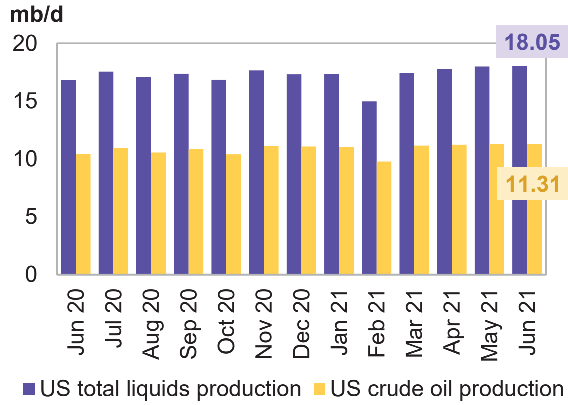
In the US Midwest, production in North Dakota increased for the fourth consecutive month, up by a slight 3 tb/d, while output in Oklahoma declined by 11 tb/d to average 390 tb/d in June. Output in Colorado's Niobrara shale fell by 16 tb/d to average 390 tb/d. On the West Coast, production in Alaska declined for the seventh consecutive month, falling 3 tb/d m-o-m to average 440 tb/d.

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

State	May 21	Jun 21	*Change* Jun 21/May 21
Oklahoma	401	390	*-11*
Colorado	406	390	*-16*
Alaska	435	431	*-4*
North Dakota	1,056	1,059	*3*
New Mexico	1,220	1,263	*43*
Gulf of Mexico (GoM)	1,807	1,825	*18*
Texas	4,813	4,791	*-22*
Total	**11,312**	**11,307**	***-5***

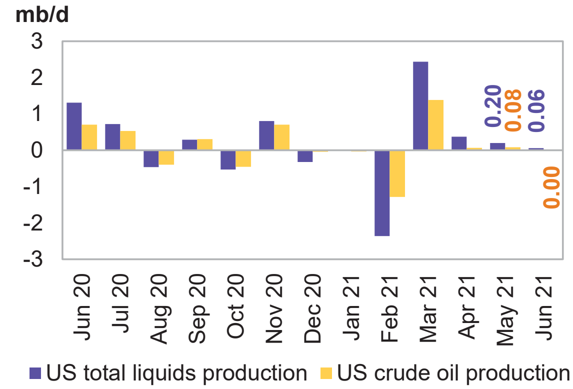
Sources: EIA and OPEC.

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



Sources: EIA and OPEC.

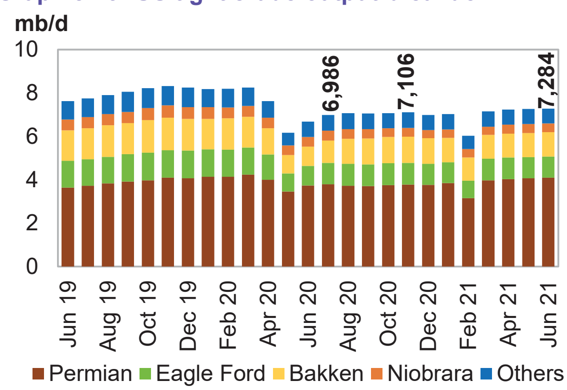
Graph 5 - 8: US monthly crude oil and total liquids supply, m-o-m changes



Sources: EIA and OPEC.

US tight crude output in June increased by 18 tb/d m-o-m to average 7.28 mb/d, 605 tb/d higher than in the same month a year earlier, according to Energy Information Administration (EIA) estimates. The m-o-m increase from shale and tight formations through horizontal wells came from the Permian, rising by 38 tb/d to average 4.1 mb/d. This came mainly from the section located in New Mexico, Wolfcamp, which added 22 tb/d m-o-m. The rest came from Spraberry and Bonespring, which rose by 11 tb/d and 5 tb/d, respectively. In the Williston Basin, production in Bakken shale was broadly steady at an average 1.12 mb/d, up by a marginal 2 tb/d m-o-m. Tight crude output at Eagle Ford in Texas and Niobrara-Condell in Colorado and Wyoming declined by 9 tb/d and 6 tb/d, respectively, to average 0.97 mb/d and 0.40 mb/d.

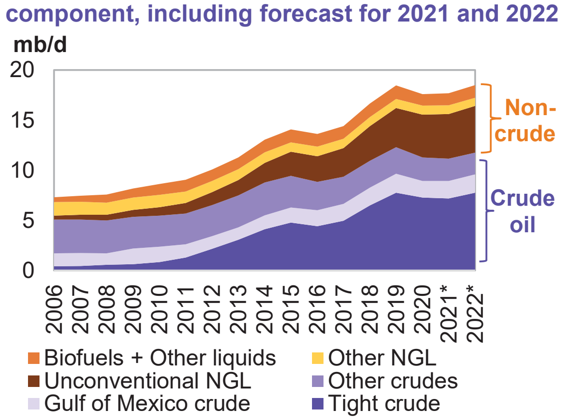
Graph 5 - 9: US tight crude output breakdown



Sources: EIA, Rystad Energy and OPEC.

The **US liquids production growth forecast for 2021** was revised down by 41 tb/d and is now expected at 0.08 mb/d, to average 17.69 mb/d, due to the oil production shut-in in the Gulf of Mexico following Hurricane Ida, which caused significant losses in oil production and refinery disruptions on the Gulf Coast. The duration of the outages will depend on how long it will take for production to be fully recovered compared to the level seen before the hurricane. In a preliminary analysis, 3Q21 output is revised down by 0.25 mb/d m-o-m, from 18.09 mb/d to an average 17.84 mb/d, indicating lower output of 100 tb/d in 3Q21 compared with 2Q21.

Graph 5 - 10: US liquids supply developments by component, including forecast for 2021 and 2022



*Note: * 2021-2022 = Forecast. Source: OPEC.*

US liquids production in 2022, excluding processing gains, is anticipated to grow by 0.81 mb/d y-o-y to average 18.49 mb/d, revised up by 0.03 mb/d due to the low base. This is almost the same level of average liquids supply in 2019, assuming the current pace of drilling and well completion in oil fields continues up to 3Q22, with possible higher spending in the prolific Permian Basin, Eagle Ford and Bakken shale sites. Operational activities in 4Q22 are likely to improve compared to the first three quarters.

It is worth noting that the EIA has upwardly revised its oil supply figures in 2019 and 2020 by 0.03 mb/d and 0.01 mb/d respectively, to average 1.81 mb/d and -0.86 mb/d.

With reported well production data for June 2021 provided by the EIA, **US crude oil production in 2021** is expected to decline by 0.08 mb/d to average 11.21 mb/d, revised down by 0.04 mb/d m-o-m. The downward change in the GoM oil supply forecast by 0.04 mb/d led to this revision. Oil supply in the GoM is now expected to grow by 0.09 mb/d to average 1.74 mb/d. At the same time, the US tight crude and conventional crude oil forecast is updated to account for the latest production and activity trends, along with the early communication on 2022 capital plans provided in the 2Q21 earnings season. US crude oil production is expected to exit December at 11.54 mb/d (as of September 2021), although production might again be affected negatively in October, as was seen in 2020. US tight crude and conventional crude oil is forecast to see a contraction of 0.09 mb/d each to average 7.20 mb/d and 2.24 mb/d, respectively.

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

US liquids	2020	*Change* 2020/19	2021*	*Change* 2021/20	2022*	*Change* 2022/21
Tight crude	7.28	-0.47	7.20	-0.09	7.76	0.56
Gulf of Mexico crude	1.64	-0.25	1.74	0.09	1.84	0.11
Conventional crude oil	2.36	-0.28	2.24	-0.12	2.17	-0.07
Total crude	11.28	-1.01	11.17	-0.11	11.77	0.59
Unconventional NGLs	4.27	0.35	4.45	0.18	4.65	0.20
Conventional NGLs	0.91	0.00	0.86	-0.04	0.81	-0.05
Total NGLs	5.17	0.35	5.31	0.13	5.46	0.15
Biofuels + Other liquids	1.15	-0.20	1.20	0.05	1.27	0.07
US total supply	**17.61**	**-0.86**	**17.69**	**0.08**	**18.49**	**0.81**

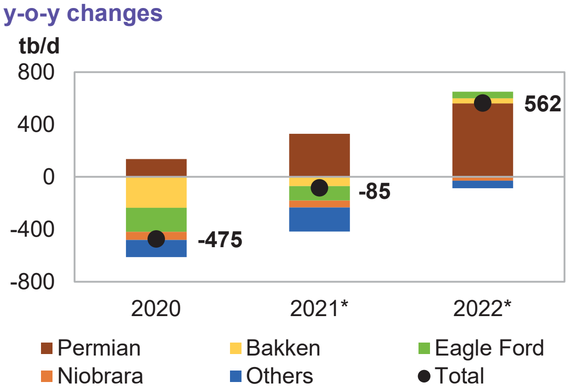
*Note: * 2021-2022 = Forecast. Sources: EIA, OPEC and Rystad Energy.*

US NGLs production remains unchanged from the last month's assessment at average of **5.31 mb/d** with annual growth of **0.15 mb/d** for this year and in 2022.

US biofuels and other non-conventional liquids production is forecast to recover by **0.05 mb/d** in 2021 to average 1.20 mb/d and see further recovery in 2022, rising by **0.07 mb/d** to average 1.27 mb/d.

US tight crude production in 2021 and 2022 is expected to show continuous y-o-y growth in the Permian Basin, unchanged from last month's assessment, to average 4.18 mb/d and 4.74 mb/d, respectively. Bakken shale production fell by 0.23 mb/d in 2020 and is expected to contract by 70 tb/d in 2021, while for 2022, output is expected to grow by 40 tb/d to average 1.15 mb/d. Eagle Ford in Texas is a prolific shale region that is expected to decline this year, but is forecast to grow next year by 50 tb/d to average 0.99 mb/d. Production in other shale plays is not expected to grow in 2021 or 2022, given current drilling and completion activities. US tight crude saw a contraction of 475 tb/d in 2020 and is expected to decline by 85 tb/d y-o-y this year, but is forecast to grow by 0.56 mb/d in 2022 to average 7.76 mb/d.

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



*Note: * 2021-2022 = Forecast.*
Sources: EIA, Rystad Energy and OPEC.

Permian tight oil production increased in June, thanks to around 35 tb/d coming from the New Mexico side of the basin. It should be noted that Permian oil production in New Mexico reached new record-high levels in nearly every month in the first half of the year. Meanwhile, Permian Texas oil production (including conventional oil) only recovered by 100 tb/d (3%) in 1H21, compared with an increase of 220 tb/d (22%) in Permian New Mexico in the same period.

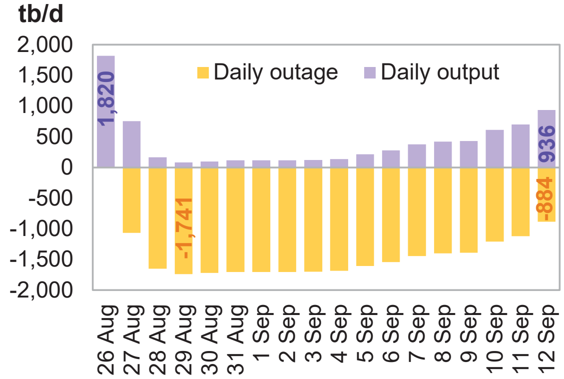
Disciplined spending programmes with conservative reinvestment rates are expected to persist in 2022, with most public producers targeting maintenance programmes or only very conservative single-digit growth rates.

Hurricane Ida's dramatic impact on oil production in the Gulf of Mexico

Ida, the ninth storm of the 2021 Atlantic hurricane season, made landfall on the Louisiana coast on 29 August, battering areas on the Louisiana coast that is home to 17% of US oil production, 5% of natural gas output and 15% of US refining capacity.

According to the US Bureau of Safety and Environmental Enforcement (BSEE), based on data from 25 offshore operator reports, personnel were evacuated from a total of 288 production platforms, 51.4% of the 560 manned platforms in the GoM. Personnel were also been evacuated from 11 existing rigs, and 11 dynamically positioned rigs that were moved out of the storm's projected path as a precaution. Seventeen days after the first day of the production shut-in, 25.3 mb/d of oil production was cumulatively lost, and the full recovery will take longer than expected due to oil leakage. Average daily production shut-in for September is estimated at 700–750 tb.

Graph 5 - 12: Production shut in the Gulf of Mexico related to Hurricane Ida



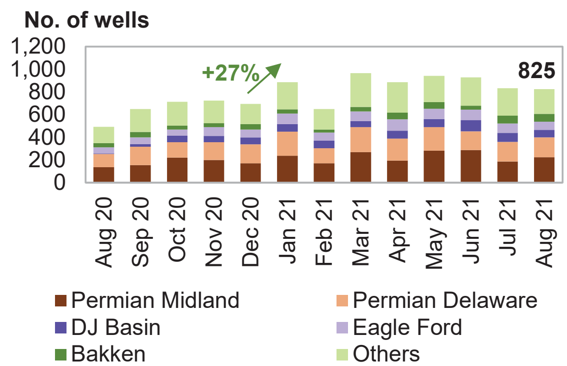
Sources: BSEE and OPEC.

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

Regarding identified **US oil and gas fracking operations by region**, Rystad Energy reported that following 932 fracked wells in June and 829 wells in July, 794 wells started fracking in August. This preliminary number is based almost exclusively on analysis of high-frequency satellite data.

The number of frac starts in the Permian in August shows an increase of 39 fracked wells in Midland m-o-m, while in Delaware the number of starts dropped from 174 to 171 fracked wells. Around 50% of fracking activity in the US was in the Permian, and in August the rest was in other regions, including Eagle Ford at 71, Bakken at 65, DJ Basin at 71. In the gas fields, in Haynesville and Marcellus shale, 47 and 34 wells were fracked in August, respectively.

Graph 5 - 13: Fracked wells count per month



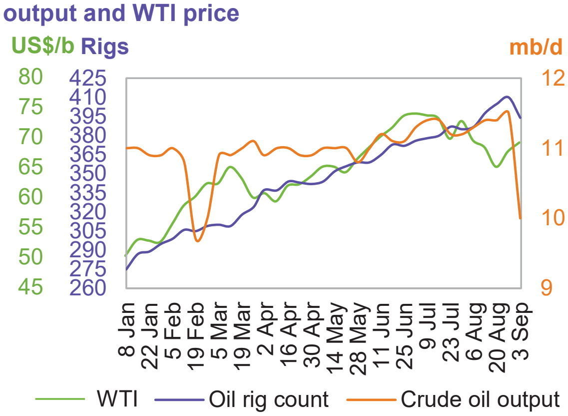
Note: August 2021 = Preliminary data.
Sources: Rystad Energy Shale Well Cube and OPEC.

Total **US active drilling rigs** were down by 11 w-o-w to 497 rigs in the week to 3 September. The lion's share of the 16 oil rigs that went inactive in that week were in the US Gulf of Mexico, where crews stopped work to get out of the way of Hurricane Ida as it swept through the region. It marked the biggest weekly rig drop since early June last year, according to the Baker Hughes' weekly survey on 3 September. This includes 495 active onshore rigs and only 2 offshore rigs.

However, on a monthly basis, the **US oil rig count** increased by seven units since the last MOMR, to 394 rigs in the week ending 3 September, higher by 213 rigs y-o-y.

Rigs targeting oil in the Permian Basin rose by 125 rigs y-o-y to 250 rigs. The total rig count is 94% higher than this time last year and up more than 100% since falling to a record low of 244 rigs in August 2020.

Graph 5 - 14: US weekly rig count vs US crude oil output and WTI price

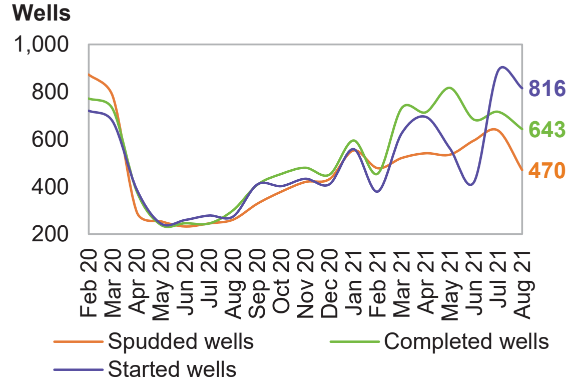


Sources: Baker Hughes, EIA and OPEC.

With regard to **drilling and completion (D&C) activities for spudded, completed and started wells** in all US shale plays, 471 horizontal wells were spudded in August, down from 642 in July, but 80% higher than June 2020.

In August 2021, preliminary data indicates a lower number of completed wells at 619, as well as a lower number of started wells at 801. However, the number of completed and started wells increased respectively by 100% and 180% y-o-y. While the total number of spudded, completed, and started wells was recorded at 4,337, 5,338 and 4,949 wells in the first eight months of the current year, respectively, during the same period in 2019, some 7,152, 6,709 and 6,493 wells were spudded, completed and started.

Graph 5 - 15: Spudded, completed and started wells in US shale plays



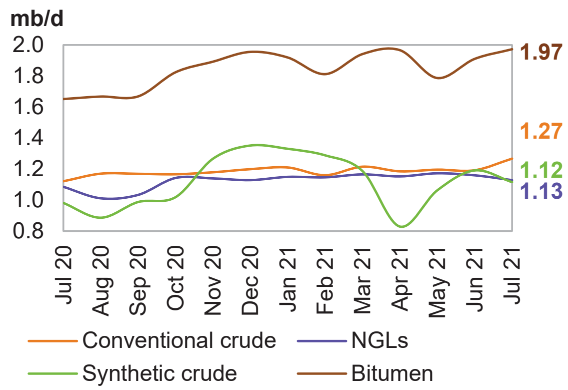
Sources: Rystad Energy and OPEC.

Canada

Canada's liquids production in July rose by 0.03 mb/d m-o-m to 5.52 mb/d. This is due to a remarkable increase in conventional crude oil output of 75 tb/d, m-o-m, to average 1.27 mb/d, and close to the pre-pandemic production level of 1.37 mb/d in March 2020. Crude bitumen also increased by 62 tb/d to average 1.97 mb/d, according to the Alberta Energy Regulator (AER). In contrast, synthetic crude and NGLs output decreased by 75 tb/d and 31 tb/d, respectively, to average 1.12 mb/d and 1.13 mb/d. Despite a minor revision in historical production data in 2Q21, the forecast remains unchanged from a month ago, with forecast growth by 0.32 mb/d, y-o-y in 2021, to average 5.49 mb/d.

For **2022**, Canadian production is forecast to increase at a slower pace compared with the current year, rising by 0.17 mb/d to average 5.66 mb/d. This is unchanged from the previous month's assessment.

Graph 5 - 16: Canada's monthly liquids production development by type

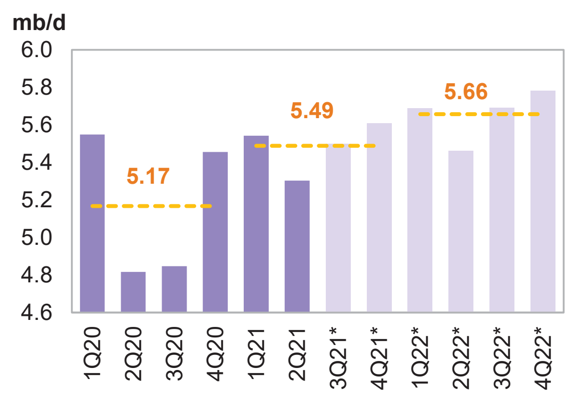


Sources: National Energy Board and OPEC.

According to Enbridge Inc., North America's largest pipeline company, the delayed 390 tb/d Line 3 pipeline expansion project is nearly complete. The pipeline will transfer more Canadian crude to US refineries. From a supply point of view, the project is also critical for Alberta, where oil production has exceeded existing pipeline capacity in recent years, which has led to massive discounts for oil sands crude relative to US blends and a loss of government royalty revenues.

Oil producers are still hopeful that the federally owned 590 tb/d Trans Mountain pipeline expansion will be complete and operational at the end of 2022, which would further reduce the need for oil-by-rail shipments out of Western Canada.

Graph 5 - 17: Canada's quarterly liquids production and forecast



*Note: * 3Q21-4Q22 = Forecast. Source: OPEC.*

According to IHS Markit, the combination of Line 3 and Trans Mountain will add more than 900 tb/d of pipeline capacity out of Western Canada but "rail is expected to remain a key part of the western Canadian export system." Shipping of crude by railways cars peaked at around 412 tb/d in February 2020, before the COVID-19 pandemic.

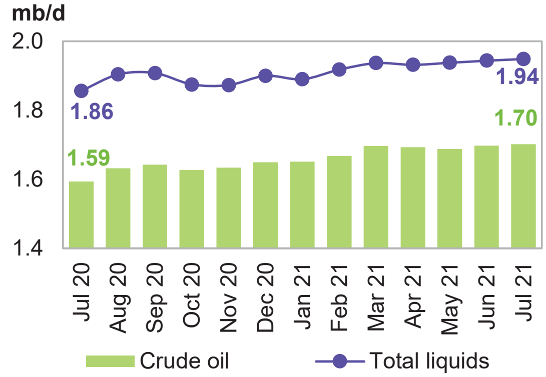
Mexico

Mexico's liquids output in July averaged 1.95 mb/d, up by 0.01 mb/d m-o-m and higher by 0.09 mb/d y-o-y. Crude oil output was almost flat, showing a minor increase of 3 tb/d to average 1.7 mb/d, according to PEMEX. However, the supply forecast has been revised down in 3Q21 due to the explosion and fire at the Ku-Maloob-Zaap complex platform in Gulf of Mexico. This caused production shut-in for eight days after the incident on 22 August. According to PEMEX' updated production report, production from KMZ fully recovered on 30 August.

For **2021**, liquids production in Mexico is forecast to grow by 0.01 mb/d to average 1.93 mb/d, revised down by 12 tb/d.

For **2022**, the supply forecast was revised up by 0.01 mb/d to average 1.96 mb/d, representing a yearly growth of 0.04 mb/d. PEMEX is scheduled to bring on stream a string of smaller developments, but is suffering some delays resulting from pandemic related financial and operational hurdles.

Graph 5 - 18: Mexico's monthly liquids and crude production development



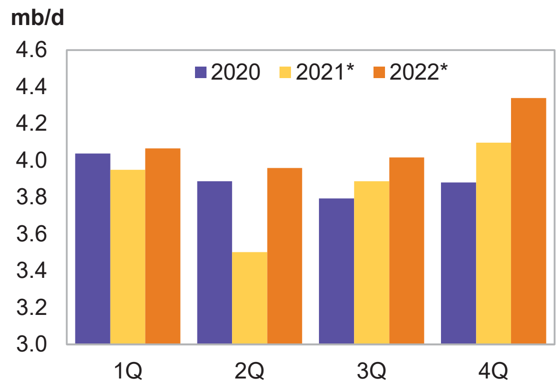
Sources: PEMEX and OPEC.

OECD Europe

OECD Europe's liquids production in 2021 is revised down by 0.06 mb/d from the last assessment. The downward revision is due to lower-than-expected oil output in 2Q21 by 112 tb/d, mainly from the UK. Additionally, the forecast for 3Q21 was revised down by 140 tb/d, due to extended field maintenance, which started in May, and has led to a slow production recovery in 3Q21. Output is now projected to decline by 0.04 mb/d to average 3.86 mb/d, owing to a contraction in UK output of 0.11 mb/d and a slowdown in Norway's production growth compared with remarkable growth of 0.26 mb/d in 2020. Oil production in Denmark and other OECD Europe will each see a slight decline of 0.01 mb/d in 2021.

For **2022**, production is expected to grow by 0.24 mb/d and surge to 4.09 mb/d, through continued production ramp-ups in Norway, the UK, and other OECD Europe.

Graph 5 - 19: OECD Europe quarterly liquids production and forecast



*Note: * 2021-2022 = Forecast. Source: OPEC.*

Norway

Norwegian crude production in July grew by 85 tb/d m-o-m to 1.75 mb/d, up by 15 tb/d y-o-y. Production of NGLs and condensates also rose by 97 tb/d m-o-m to average 0.27 mb/d.

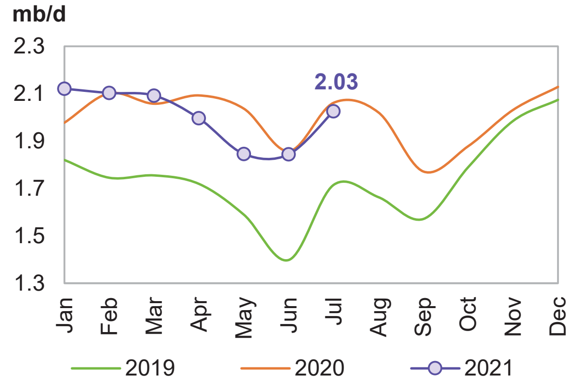
As a result, total liquids increased by 0.19 mb/d m-o-m to average 2.03 mb/d, which indicates that the output mostly returned from seasonal maintenance in July, but was not fully restored compared to 1Q21 at 2.11 mb/d.

On 31 August, the Norwegian government proposed a revamp of the country's petroleum fiscal regime. The changes are primarily related to how the petroleum tax is calculated, and the new system tries to be more cash-flow based. This measure could lower the breakeven price for new projects, while the removal of cash-back on exploration expenses would hit companies that focus mainly on exploration, according to Rystad Energy.

For **2021**, Norway's growth forecast has been revised down by 28 tb/d m-o-m due to lower output in 2Q21 and forecast revision for 3Q21. Production is now expected to average 2.07 mb/d, with growth of 0.07 mb/d y-o-y.

For **2022**, Norway's tax incentives initiated last year in response to the pandemic have led to increased investment in oil and gas projects. Consequently, Norwegian liquids production is expected to grow by 0.18 mb/d to average 2.26 mb/d, through the anticipated start-up of new offshore projects such as Nova, Hod (redevelopment), Njord Future, Bauge and Fenja-phase 1. Moreover, Johan Sverdrup phase-2 is expected to come onstream in late 2022, and is projected to lift Norwegian crude oil production to more than 2 mb/d.

Graph 5 - 20: Norway's monthly liquids production development



Sources: NPD and OPEC.

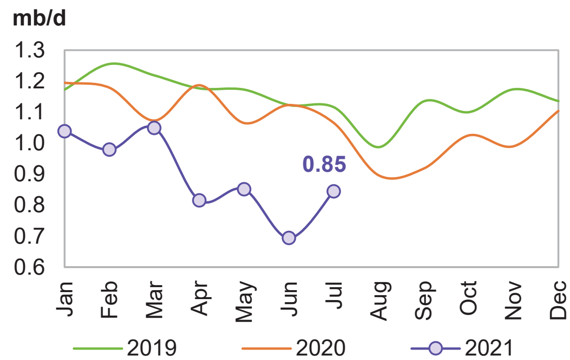
UK

UK liquids production in July was up by 0.16 mb/d m-o-m from the lowest ever output in June at 0.69 mb/d to average 0.85 mb/d. This was much lower than last July's level of 1.07 mb/d. Crude oil output rose by 121 tb/d to average 0.75 mb/d, but was 0.17 mb/d lower y-o-y. NGLs output also increased by 30 tb/d to average 67 tb/d m-o-m, lower by 43 tb/d y-o-y.

For this month, the historical production data in 2Q21 was revised down by 59 tb/d. At the same time, lower than expected output in 3Q21 led to another revision by 40 tb/d to the 3Q supply forecast for the UK.

For **2021**, UK oil production is forecast to contract by 0.11 mb/d to average 0.95 mb/d, revised down by 25 tb/d on a yearly base, due to several outages on top of maintenance during 1H21.

Graph 5 - 21: UK monthly liquids production development



Sources: Department of Energy & Climate Change and OPEC.

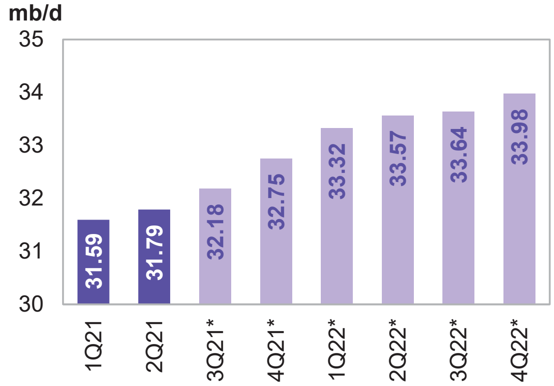
For **2022**, UK liquids production is forecast to grow by 0.03 mb/d to average 0.99 mb/d following two consecutive years of heavy declines. Production ramp-ups will take place in some small fields and the Penguins oil field (Redevelop) and Buzzard Phase 2 (20/06-3), each with a peak capacity of 30 tb/d, are due to start up.

Non-OECD

Non-OECD liquids production for 2021 was revised down by 0.3 mb/d this month, on the back of the new adjustments for countries participating in the DoC, and is now forecast to grow by 0.43 mb/d to average 32.08 mb/d. The key driver will be Russia, with y-o-y forecast growth of 0.19 mb/d to average 10.78 mb/d, followed by Latin America, which is expected to see growth of 0.13 mb/d to average 6.17 mb/d.

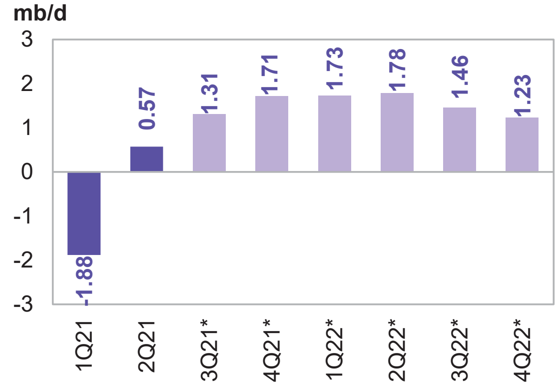
Production in China is expected to grow by 0.13 mb/d to average 4.25 mb/d. Oil production is forecast to increase in the Middle East by 0.05 mb/d to average 3.23 mb/d, while production is expected to decline in other Asia by 0.03 mb/d, to average 2.48 mb/d. Africa is also projected to decline by 0.05 mb/d to average 1.36 mb/d in 2021. Oil production in Other Eurasia is projected to return to positive territory, with minor growth of 0.04 mb/d to average 2.95 mb/d, while Other Europe is anticipated to decline by 0.01 mb/d to average 0.11 mb/d in 2021.

Graph 5 - 22: Non-OECD quarterly liquids production and forecast



*Note: * 3Q21-4Q22 = Forecast. Source: OPEC.*

Graph 5 - 23: Non-OECD quarterly liquids supply, y-o-y changes



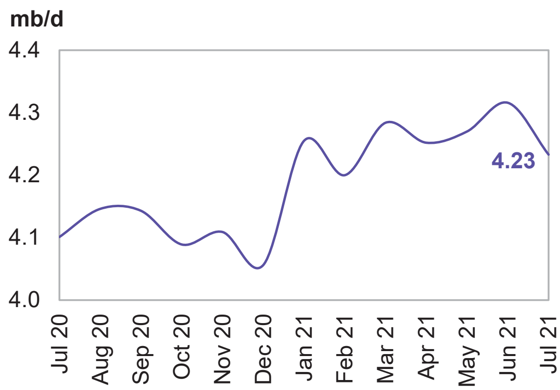
*Note: * 3Q21-4Q22 = Forecast. Source: OPEC.*

For **2022**, liquids production in non-OECD countries is forecast to grow by 1.55 mb/d to average 33.63 mb/d, revised down by 52 tb/d mainly in the other Asia supply forecast. The key drivers will again be Russia with growth of 1.0 mb/d to average 11.78 mb/d, followed by Latin America with 0.33 mb/d, Other Eurasia at 0.19 mb/d and the Middle East at 0.09 mb/d. China and India are expected to grow by 0.04 mb/d and 0.05 mb/d, respectively.

China

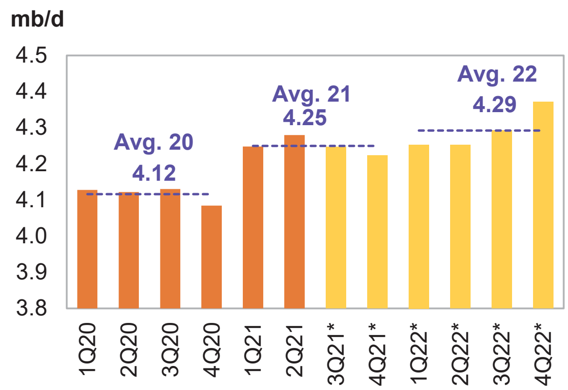
China's **liquids production** in **July** was down by 0.09 mb/d m-o-m to average 4.23 mb/d, but higher by 0.13 mb/d y-o-y, according to official data. Crude oil output in July decreased by 83 tb/d to average 3.97 mb/d. Nevertheless, the output was up by around 0.1 mb/d, y-o-y. Production in 1H21 averages at 4.00 mb/d, indicating that NOCs have increased their investment following the planned strategy for raising domestic oil production. For instance, "PetroChina has been raising oil and gas output in the Changqing field and is expected to achieve its 2025 production target this year", according to the FGE monthly report. "Capex investments in technology to enhance oil recovery in previous years have also prevented a steep decline in production at aging oil fields", FGE reported.

Graph 5 - 24: China's monthly liquids production development



Sources: CNPC and OPEC.

Graph 5 - 25: China's quarterly liquids production and forecast



*Note: * 3Q21-4Q22 = Forecast. Sources: CNPC and OPEC.*

For **2021**, China's liquids supply is projected to see growth of 0.13 mb/d, revised up by 0.01 mb/d due to an upward revision in the 3Q21 supply forecast, to average 4.25 mb/d. According to a list of new projects for the current year, three (namely Liuhua 16-2, Luda 21-2 and Caofeidian 6-4, all offshore) should start production in 2021.

For **2022**, y-o-y growth of 0.04 mb/d is anticipated to average 4.29 m/d. For the next year, two other offshore projects of CNNOC Ltd – Wushi 17-2, with peak capacity of 24 tb/d, and Lufeng 14-4/14-8, with 23 tb/d at peak capacity – are planned to come on stream.

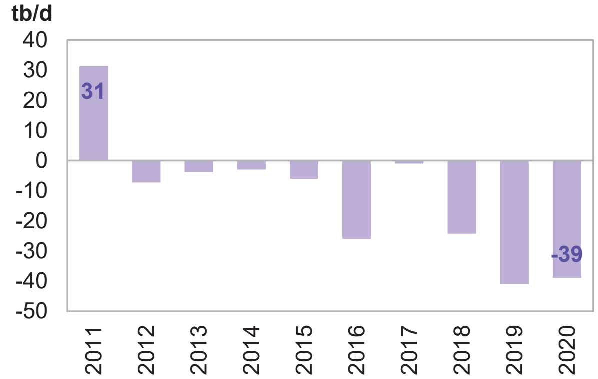
India

India's crude oil production has been in decline since 2012 and the annual output in 2019 and 2020 stood at 655 tb/d, and 616 tb/d, respectively, according to official data. This indicates a decline rate of 6% per annum in 2019 and 2020.

India's crude oil production continued to slide in 1H21 to average 0.60 mb/d, down by 0.02 mb/d or 2.9%, y-o-y, mainly due to continued declines at state-run Oil and Natural Gas Corp.'s (ONGC) mature fields, the country's largest oil and gas producer.

Oil output in July was down by 19 tb/d, or around 3.1%, y-o-y, to average 603 tb/d, according to Ministry of Petroleum and Natural Gas data published on 24 August.

Graph 5 - 26: India's yearly decline in crude oil production



Source: OPEC.

Latin America

Latin America's total liquids supply in July was up by 0.17 mb/d m-o-m to average 6.12 mb/d. Oil output increased in Brazil and Colombia, while it dropped or was flat in other countries of the region. Liquids output was down by 0.05 mb/d y-o-y.

For **2021**, liquids production has been revised down by 14 tb/d m-o-m and is projected to grow by 0.13 mb/d y-o-y to average 6.17 mb/d. Oil production in Brazil, Guyana, Ecuador, Argentina and Peru is forecast to increase, while declines are expected in Colombia and other countries in the region. Production in Colombia recovered in July to average 0.75 mb/d, as the national strike and protests had ended. Crude oil production had been affected through May and June.

For **2022**, Latin America's total liquids supply forecast is projected to grow by 0.33 mb/d y-o-y to average 6.50 mb/d. One of the key drivers is Brazil, with expected growth of 0.23 mb/d, including biofuels, to average 3.97 mb/d. Guyana would be the second country in the region experiencing growth next year, with output rising by 0.09 mb/d, through the start-up of Liza Phase 2, which remains on target for early 2022. Oil production in other countries in the region will decline, or see only minor growth.

Brazil

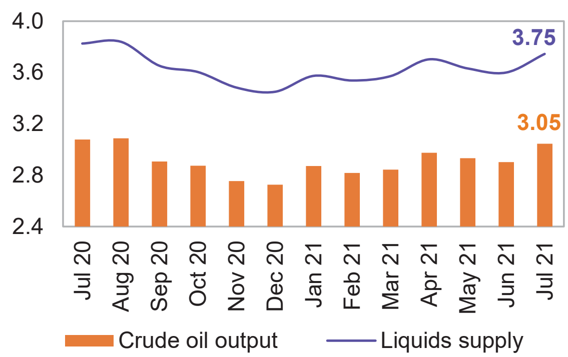
Brazil's crude output rose by 0.14 mb/d m-o-m to average 3.05 mb/d in July as unplanned maintenance and COVID-19 related outages eased, but is lower by 33 tb/d, y-o-y. Another reason for rising production was production reaching maximum capacity at P-70 FPSO, which is located in the Atapu field in the Santos Basin. Production started in the Sepia field in the Santos Basin on 23 August, expanding production capacity by 0.18 mb/d at the Carioca FPSO. Therefore, total oil supply in 3Q21 is expected to be higher than 2Q21, even if production was halted for a while for maintenance in other fields.

In **July**, total liquids production was pegged at an average of 3.75 mb/d, including biofuels and NGLs, up by 0.15 mb/d m-o-m, but lower by 0.08 mb/d, y-o-y.

Brazilian liquids supply in **2021**, including biofuels, is forecast to grow by 0.07 mb/d y-o-y, to an average 3.74 mb/d, revised down by 11 tb/d in this month.

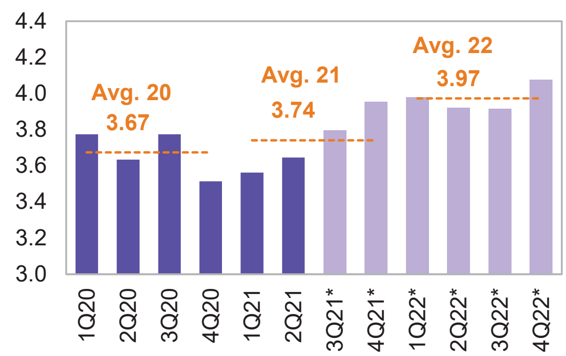
For **2022**, Brazil's liquids supply forecast, including biofuels, is set to increase by 0.23 mb/d y-o-y to average 3.97 mb/d. Crude oil production is expected to rise through two new project start-ups: Mero-1 (Guanabara), which was initially planned to start up in 2021; and Peregrino-Phase 2.

Graph 5 - 27: Brazil's monthly liquids production development by type



Sources: ANP, Petrobras and OPEC.

Graph 5 - 28: Brazil's quarterly liquids production and forecast



*Note: * 3Q21-4Q22 = Forecast. Sources: ANP and OPEC.*

Russia

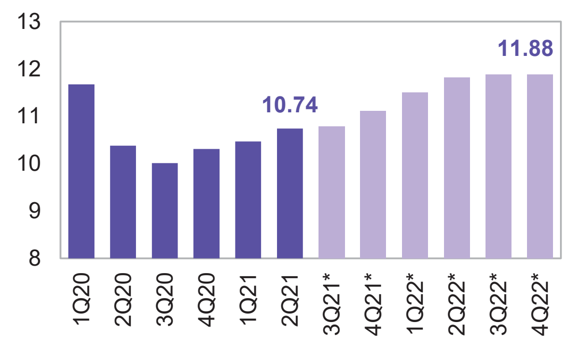
Preliminary data for **Russia's liquids production in August** shows a decrease of 0.03 mb/d m-o-m to average 10.72 mb/d, higher by 0.57 mb/d y-o-y.

Total condensate and NGLs output from gas condensate fields is estimated at 1.13 mb/d, the same as July, up by 0.03 tb/d y-o-y.

Annual liquids production in **2021** is forecast to increase by 0.19 mb/d y-o-y to average 10.78 mb/d, unchanged, m-o-m.

For **2022**, Russian liquids output is expected to increase by 1.0 mb/d to average 11.78 mb/d, with 3Q22 and 4Q22 both expected to reach 11.88 mb/d, the same as in the last MOMR. Although insufficient drilling and brownfield declines may yet impact the forecast.

Graph 5 - 29: Russia's quarterly liquids production and forecast



*Note: * 3Q21-4Q22 = Forecast.*
Sources: Nefte Compass and OPEC.

Caspian

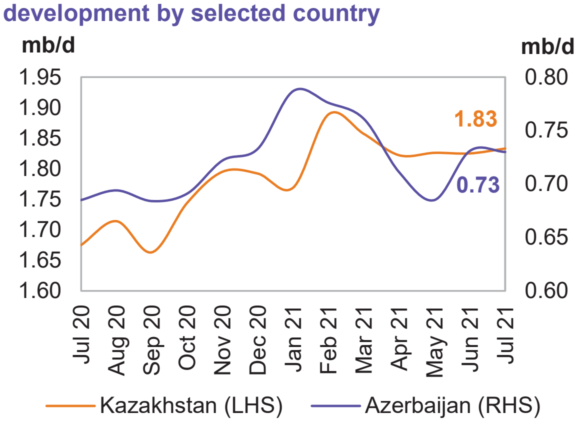
Kazakhstan & Azerbaijan

Liquids production in **Kazakhstan** was flat in **May to July** at 1.83 mb/d. Kazakh crude oil output in July was marginally higher by 16 tb/d to average 1.49 mb/d. NGLs output in July was down by 8 tb/d to average 343 tb/d.

The Kazakhstan liquids supply forecast is expected to grow by 0.03 mb/d and average 1.85 mb/d in **2021**.

In **2022**, liquids supply is likely to grow by 0.13 mb/d to average 1.98 mb/d. CPC export data shows a lower volume in August by 0.21 mb/d, than reported by other sources. Any maintenance in Tengiz, with a current production level of around 0.59 mb/d, or in Kashagan at 0.33 mb/d, would affect the monthly oil output in 3Q21.

Graph 5 - 30: **Caspian monthly liquids production development by selected country**



Sources: Nefte Compass and OPEC.

Azerbaijan's liquids production in **July** was flat to average 0.73 mb/d m-o-m, up by 0.04 mb/d y-o-y. While crude production averaged 608 tb/d, NGLs production was also steady at an average of 122 tb/d.

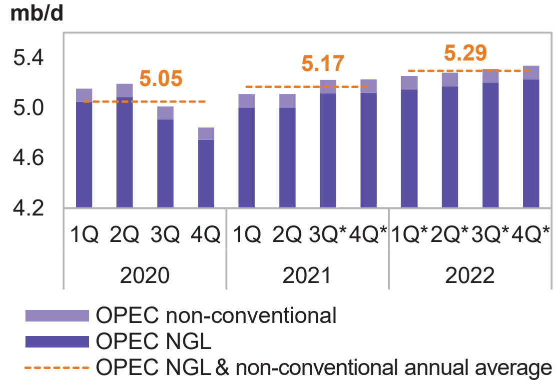
In **2021**, Azerbaijan's liquids supply is expected to show growth of 0.02 mb/d for the year to average 0.75 mb/d. Liquids supply is forecast to grow by 0.07 mb/d to average 0.82 mb/d in **2022**.

OPEC NGLs and non-conventional oils

OPEC NGLs and non-conventional liquids are estimated to grow by 0.12 mb/d in **2021,** following a decline of 0.17 mb/d in 2020, to average 5.17 mb/d, revised down from last month's assessment by 24 tb/d.

The preliminary **2022** forecast indicates growth of 0.13 mb/d to average 5.29 mb/d. NGLs production is expected to grow by 0.13 mb/d to average 5.19 mb/d, while non-conventional liquids will remain unchanged at 0.11 mb/d.

Graph 5 - 31: OPEC NGLs and non-conventional liquids quarterly production and forecast



*Note: * 3Q21-4Q22 = Forecast. Source: OPEC.*

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

OPEC NGL and non-coventional oils	2020	Change 20/19	2021	Change 21/20	1Q22	2Q22	3Q22	4Q22	2022	Change 22/21
OPEC NGL	**4.94**	*-0.18*	**5.06**	*0.11*	5.15	5.17	5.20	5.23	**5.19**	*0.13*
OPEC non-conventional	**0.10**	*0.01*	**0.11**	*0.00*	0.11	0.11	0.11	0.11	**0.11**	*0.00*
Total	**5.05**	***-0.17***	**5.17**	***0.12***	**5.25**	**5.28**	**5.31**	**5.33**	**5.29**	***0.13***

Note: 2021-2022 = Forecast. Source: OPEC.

OPEC crude oil production

According to secondary sources, total **OPEC-13 crude oil production** averaged 26.76 mb/d in August 2021, higher by 0.15 mb/d m-o-m. Crude oil output increased mainly in Iraq, Saudi Arabia, the UAE and Angola, while production decreased primarily in Nigeria.

Table 5 - 6: OPEC crude oil production based on *secondary sources*, tb/d

Secondary sources	2019	2020	4Q20	1Q21	2Q21	Jun 21	Jul 21	Aug 21	*Change Aug/Jul*
Algeria	1,022	897	857	870	886	902	911	920	*9*
Angola	1,401	1,255	1,172	1,141	1,110	1,103	1,067	1,110	*43*
Congo	324	288	273	271	263	264	262	249	*-14*
Equatorial Guinea	117	115	112	107	109	110	101	101	*0*
Gabon	208	195	191	185	186	176	180	180	*1*
IR Iran	2,356	1,988	2,003	2,214	2,443	2,470	2,493	2,485	*-8*
Iraq	4,678	4,049	3,817	3,881	3,940	3,926	3,965	4,056	*90*
Kuwait	2,687	2,432	2,293	2,328	2,356	2,383	2,424	2,441	*17*
Libya	1,097	367	911	1,175	1,151	1,163	1,158	1,163	*5*
Nigeria	1,786	1,579	1,434	1,413	1,423	1,401	1,385	1,271	*-114*
Saudi Arabia	9,794	9,182	8,962	8,445	8,503	8,906	9,420	9,488	*69*
UAE	3,094	2,802	2,515	2,610	2,644	2,681	2,722	2,777	*55*
Venezuela	796	500	408	517	511	544	523	523	*0*
Total OPEC	**29,361**	**25,650**	**24,948**	**25,156**	**25,525**	**26,029**	**26,611**	**26,762**	***151***

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

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

Direct communication	2019	2020	4Q20	1Q21	2Q21	Jun 21	Jul 21	Aug 21	*Change Aug/Jul*
Algeria	1,023	899	862	874	886	901	915	921	*6*
Angola	1,373	1,271	1,186	1,136	1,125	1,073	1,103	1,129	*26*
Congo	329	300	285	275	264	262	247	272	*25*
Equatorial Guinea	110	114	106	104	99	100	100	101	*1*
Gabon	218	207	178	183	179	183	185	179	*-6*
IR Iran	..	..	..	..	..	..	..	..	..
Iraq	4,576	3,997	3,796	3,846	3,890	3,862	3,886	3,961	*75*
Kuwait	2,678	2,438	2,293	2,327	2,355	2,384	2,423	2,445	*22*
Libya	..	389	972	1,214	1,213	1,243	1,273	1,223	*-50*
Nigeria	1,737	1,493	1,301	1,404	1,343	1,313	1,323	1,239	*-85*
Saudi Arabia	9,808	9,213	8,975	8,473	8,535	8,928	9,474	9,562	*88*
UAE	3,058	2,779	2,501	2,610	2,645	2,681	2,722	2,768	*46*
Venezuela	1,013	569	463	533	556	633	614	641	*27*
Total OPEC	**..**	**..**	**..**	**..**	**..**	**..**	**..**	**..**	**..**

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

Commercial Stock Movements

Preliminary data shows total OECD commercial oil stocks up by 10.5 mb m-o-m in July. At 2,912 mb, inventories were 305.9 mb lower than the same month a year ago; 122.0 mb below the latest five-year average; and 57.2 mb lower than the 2015-2019 average. Within the components, crude stocks fell by 5.6 mb m-o-m, while product stocks rose by 16.1 mb.

At 1,404 mb, crude stocks in the OECD were 106.9 mb below the latest five-year average and 80.0 mb below the 2015-2019 average. OECD product stocks averaged 1,508 mb, representing a deficit of 15.1 mb compared with the latest five-year average, but 22.7 mb above the 2015-2019 average.

In terms of days of forward cover, OECD commercial stocks rose 0.1 days m-o-m to stand at 63.7 days in July. This is 11.6 days below the same month last year and 1.2 days below the latest five-year average, but 1.5 days above the 2015-2019 average.

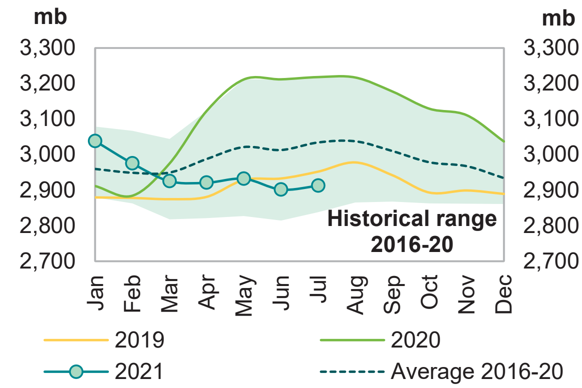
Preliminary data for August showed that total US commercial oil stocks fell m-o-m by 23.8 mb to stand at 1,244 mb. This is 193.8 mb, or 13.5%, lower than the same month a year ago and 85.0 mb, or 6.4%, below the latest five-year average. Crude and products stocks fell by 13.8 mb and 10.0 mb, m-o-m, respectively.

OECD

Preliminary July data sees **total OECD commercial oil stocks** up by 10.5 mb m-o-m. At 2,912 mb, they were 305.9 mb lower than the same time one year ago and 122.0 mb lower than the latest five-year average.

Within the components, crude stocks fell by 5.6 mb m-o-m, while product stocks were up by 16.1 mb. Total commercial oil stocks in July rose in OECD America and OECD Europe, while they declined in OECD Asia Pacific.

Graph 9 - 1: OECD commercial oil stocks



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

OECD **commercial crude stocks** fell m-o-m in July by 5.6 mb, to stand at 1,404 mb. This is 183.5 mb lower than the same time a year ago and 106.9 mb below the latest five-year average. Compared with the previous month, OECD Americas and OECD Asia Pacific registered stock draws of 8.7 mb and 4.1 mb, respectively, while OECD Europe saw a stock build of 7.2 mb.

In contrast, **total product inventories** rose by 16.1 mb m-o-m in July to stand at 1,508 mb. This is 122.4 mb less than the same time a year ago, and 15.1 mb lower than the latest five-year average. Within the OECD, product stocks in OECD Americas and OECD Europe rose by 16.9 mb and 5.0 mb, respectively, while OECD Asia Pacific fell by 5.8 mb, m-o-m.

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

OECD stocks	Jul 20	May 21	Jun 21	Jul 21	*Change Jul 21/Jun 21*
Crude oil	1,588	1,442	1,410	1,404	*-5.6*
Products	1,631	1,490	1,492	1,508	*16.1*
Total	**3,218**	**2,932**	**2,902**	**2,912**	***10.5***
Days of forward cover	75.3	64.5	63.6	63.7	*0.1*

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

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

In terms of **days of forward cover**, OECD commercial stocks rose m-o-m by 0.1 days in July to stand at 63.7 days. This is 11.6 days below July 2020 levels, and 1.2 days below the latest five-year average. OECD Americas and OECD Asia Pacific were below the latest five-year average: the Americas by 1.5 days at 62.5 days and Asia Pacific by 6.8 days at 48.5 days. OECD Europe, however, showed a surplus of 1.9 days above the latest five-year average, at 73.5 days.

OECD Americas

OECD Americas total commercial stocks rose m-o-m by 8.2 mb in July to settle at 1,556 mb. This is 156.5 mb less than the same month last year and 41.1 mb lower than the latest five-year average.

Commercial crude oil stocks in OECD Americas fell m-o-m by 8.7 mb in July to stand at 796 mb, which is 87.7 mb lower than in July 2020, and 28.5 mb less than the latest five-year average. The stock draw came on the back of higher crude runs in July.

In contrast, **total product stocks** in OECD Americas rose m-o-m by 16.9 mb in July to stand at 760 mb. This was 68.7 mb lower than the same month one year ago and 12.6 mb below the latest five-year average. Lower total consumption in the region was behind the stock build.

OECD Europe

OECD Europe total commercial stocks rose m-o-m by 12.2 mb in July to settle at 1,013 mb. This is 79.6 mb less than the same month last year, and 6.3 mb below the latest five-year average.

OECD Europe's **commercial crude stocks** in July rose m-o-m by 7.2 mb to end the month at 427 mb, which is 44.1 mb lower than one year ago and 20.3 mb below the latest five-year average. The build in crude oil inventories came despite higher m-o-m refinery throughputs in the EU-14 plus the UK and Norway, which increased by around 110 tb/d to 9.34 mb/d in July.

OECD Europe's **commercial product stocks** also rose m-o-m by 5.0 mb to end July at 586 mb. This is 35.5 mb lower than a year ago, but 13.9 mb above the latest five-year average.

OECD Asia Pacific

OECD Asia Pacific's total commercial oil stocks fell m-o-m by 9.8 mb in July to stand at 344 mb. This is 69.8 mb lower than a year ago, and 74.6 mb below the latest five-year average.

OECD Asia Pacific's **crude inventories** fell by 4.1 mb m-o-m to end July at 181 mb, which is 51.7 mb lower than one year ago, and 58.1 mb below the latest five-year average.

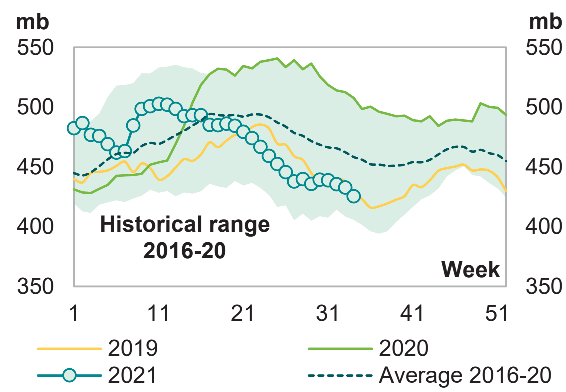
OECD Asia Pacific's **total product inventories** also fell by 5.8 mb m-o-m, to end July at 163 mb. This is 18.2 mb lower than the same time a year ago and 16.5 mb less than the latest five-year average.

US

Preliminary data for August showed that **total US commercial oil stocks** fell m-o-m by 23.8 mb to stand at 1,244 mb. This is 193.8 mb, or 13.5%, lower than the same month a year ago and 85.0 mb, or 6.4%, below the latest five-year average. Crude and products stocks fell by 13.8 mb and 10.0 mb, m-o-m, respectively.

US **commercial crude stocks** in August fell m-o-m by 13.8 mb to stand at 425.4 mb. This is 79.0 mb, or 15.7%, lower than the same month last year, and 32.4 mb, or 7.1%, below the latest five-year average. The stock draw came on the back of lower crude imports, which declined by around 200 tb/d to an average of 6.3 mb/d. Higher crude runs also contributed to this crude stock draw.

Graph 9 - 2: US weekly commercial crude oil inventories



Sources: EIA and OPEC.

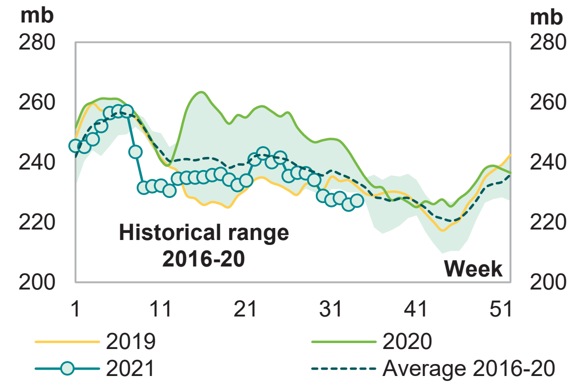
Total product stocks in August also fell m-o-m by 10.0 mb to stand at 818.4 mb. This is 114.8 mb, or 12.3%, below August 2020 levels, and 52.6 mb, or 6.0%, lower than the latest five-year average. The stock draw was mainly driven by higher consumption in the US.

Gasoline stocks in August fell m-o-m by 1.7 mb to settle at 227.2 mb. This is 10.3 mb, or 4.3%, below the same month last year, and 5.1 mb, or 2.2%, lower than the latest five-year average. The monthly stock draw came mainly on the back of higher gasoline consumption.

Distillate stocks also fell m-o-m by 2.0 mb in August to stand at 136.7 mb. This is 43.0 mb, or 23.9%, lower than the same month last year, and 14.4 mb, or 9.5%, below the latest five-year average.

Jet fuel also fell m-o-m by 0.9 mb, ending August at 42.4 mb. This is 2.3 mb, or 5.9%, higher than the same month last year, and 0.8 mb, or 1.9%, above the latest five-year average.

Graph 9 - 3: US weekly gasoline inventories



Sources: EIA and OPEC.

Residual fuel oil stocks fell m-o-m in August, decreasing by 0.4 mb. At 28.7 mb, this was 5.7 mb, or 16.4%, lower than a year ago, and 3.9 mb, or 12.0%, below the latest five-year average.

Table 9 - 2: US commercial petroleum stocks, mb

US stocks	Aug 20	Jun 21	Jul 21	Aug 21	*Change* *Aug 21/Jul 21*
Crude oil	**504.4**	**448.0**	**439.2**	**425.4**	***-13.8***
Gasoline	237.5	237.2	228.9	227.2	*-1.7*
Distillate fuel	179.8	140.1	138.7	136.7	*-2.0*
Residual fuel oil	34.4	31.1	29.1	28.7	*-0.4*
Jet fuel	40.1	44.7	43.3	42.4	*-0.9*
Total products	**933.2**	**823.5**	**828.4**	**818.4**	***-10.0***
Total	**1,437.6**	**1,271.5**	**1,267.7**	**1,243.8**	***-23.8***
SPR	**647.5**	**621.3**	**621.3**	**621.3**	***0.0***

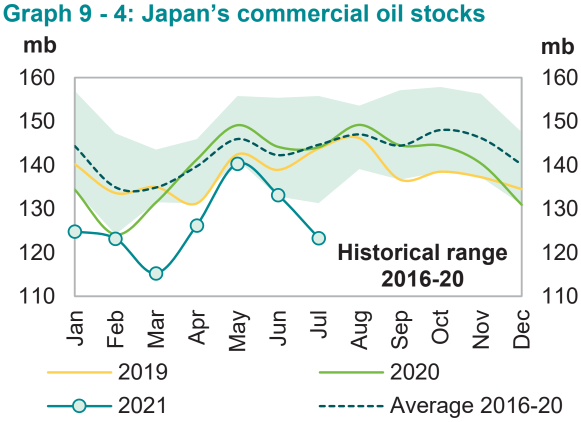
Sources: EIA and OPEC.

Japan

In **Japan**, **total commercial oil stocks** in July fell m-o-m by 9.8 mb to settle at 123.3 mb. This is 20.8 mb, or 14.4%, lower than the same month last year, and 21.3 mb, or 14.7%, below the latest five-year average. Crude and products stocks fell m-o-m by 4.1 mb and 5.8 mb, respectively.

Japanese **commercial crude oil stocks** fell in July to stand at 66.5 mb. This is 17.0 mb, or 20.3%, below the same month a year ago, and 17.8 mb, or 21.2%, lower than the latest five-year average. The fall came on the back of higher crude throughput, which increased by 9.7%.

Graph 9 - 4: Japan's commercial oil stocks



Sources: METI and OPEC.

Japan's **total product inventories** also fell m-o-m by 5.8 mb to end July at 56.8 mb. This is 3.8 mb, or 6.2%, lower than the same month last year, and 3.5 mb, or 5.8%, below the latest five-year average.

Gasoline stocks fell m-o-m by 4.4 mb to stand at 10.0 mb. This was 2.0 mb, or 16.8%, lower than a year ago, and 0.4 mb, or 4.3%, below the latest five-year average. Higher domestic gasoline sales, which rose by 9.6%, were behind the fall in gasoline stocks.

Distillate stocks also fell by 0.6 mb m-o-m to end July at 26.5 mb. This is 2.1 mb, or 7.3%, lower than the same month a year ago, and 1.0 mb, or 3.7%, below the latest five-year average. Within distillate components, **jet fuel and gasoil stocks** fell m-o-m by 4.5% and 17.7%, respectively, while **kerosene stocks** were up by 14.9%.

Total residual fuel oil stocks remained unchanged m-o-m in July to stand at 11.8 mb. This is 0.5 mb, or 3.8%, lower than the same month last year, and 1.0 mb, or 7.6%, below the latest five-year average. Within the components, fuel oil A fell by 2.6%, while fuel oil B.C stocks rose by 2.0%.

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

Japan's stocks	Jul 20	May 21	Jun 21	Jul 21	Change Jul 21/Jun 21
Crude oil	**83.5**	**75.6**	**70.6**	**66.5**	***-4.1***
Gasoline	12.0	14.9	14.4	10.0	*-4.4*
Naphtha	7.7	9.5	9.3	8.5	*-0.8*
Middle distillates	28.6	27.5	27.1	26.5	*-0.6*
Residual fuel oil	12.3	12.8	11.8	11.8	*0.0*
Total products	**60.6**	**64.7**	**62.6**	**56.8**	***-5.8***
Total**	**144.1**	**140.3**	**133.2**	**123.3**	***-9.8***

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

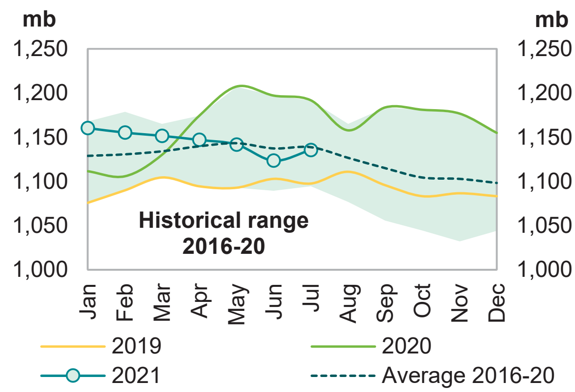
Sources: METI and OPEC.

EU-14 plus UK and Norway

Preliminary data for July showed that **total European commercial oil stocks** rose m-o-m by 12.2 mb to stand at 1,136 mb. At this level, they were 56.1 mb, or 4.7%, below the same month a year ago, and 3.2 mb, or 0.3%, lower than the latest five-year average. Crude and product stocks went up by 7.2 mb, and 5.0 mb, m-o-m, respectively.

European **crude inventories** rose in July to stand at 471.4 mb. This is 31.3 mb, or 6.2%, lower than the same month a year ago and 22.2 mb, or 4.5%, lower than the latest five-year average. The build in crude oil inventories came despite higher m-o-m refinery throughputs in the EU-14 plus the UK and Norway, which increased by around 110 tb/d to 9.34 mb/d in July.

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



Sources: Argus, Euroilstock and OPEC.

Total European product stocks also rose m-o-m by 5.0 mb to end July at 664.2 mb. This is 24.8 mb, or 3.6%, lower than the same month a year ago, but 19.1 mb, or 3.0%, above the latest five-year average.

Gasoline stocks rose m-o-m by 0.8 mb in July to stand at 114.3 mb. This is 2.1 mb, or 1.8%, lower than the level registered the same time a year ago, but 1.9 mb/d, or 1.7%, above the latest five-year average.

Distillate stocks also rose m-o-m by 3.5 mb in July to stand at 452.3 mb. This is 14.9 mb or 3.2% below the same month last year, but 16.6 mb, or 3.8%, above the latest five-year average.

Naphtha stocks rose by 1.4 mb m-o-m in July, ending the month at 31.5 mb. This is 0.4 mb, or 1.3%, below July 2020 levels, but 3.8 mb, or 13.6%, higher than the latest five-year average.

In contrast, **residual fuel stocks** fell m-o-m by 0.7 mb in July to 66.0 mb. This is 7.4 mb, or 10.0%, lower than the same month one year ago and 3.1 mb, or 4.5%, below the latest five-year average.

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

EU stocks	Jul 20	May 21	Jun 21	Jul 21	Change Jul 21/Jun 21
Crude oil	**502.7**	**470.5**	**464.1**	**471.4**	***7.2***
Gasoline	116.4	115.7	113.6	114.3	*0.8*
Naphtha	31.9	31.6	30.1	31.5	*1.4*
Middle distillates	467.2	456.2	448.8	452.3	*3.5*
Fuel oils	73.4	67.7	66.8	66.0	*-0.7*
Total products	**689.0**	**671.2**	**659.2**	**664.2**	***5.0***
Total	**1,191.7**	**1,141.7**	**1,123.4**	**1,135.6**	***12.2***

Sources: Argus, Euroilstock and OPEC.

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

Singapore

In July, **total product stocks in Singapore** fell m-o-m by 3.2 mb to 47.3 mb. This is 6.4 mb, or 11.9%, lower than the same month a year ago.

Light distillate stocks rose m-o-m by 0.9 mb in July to stand at 13.7 mb. This is 2.3 mb, or 14.3%, lower than the same month one year ago.

In contrast, **middle distillate stocks** fell by 2.9 mb in July to stand at 10.9 mb. This is 3.0 mb, or 21.8%, lower than a year ago.

Residual fuel oil stocks also fell by 1.2 mb, ending July at 22.7 mb, which is 1.1 mb, or 4.5%, lower than in July 2020.

ARA

Total product stocks in ARA fell for the fifth consecutive month in July and were down by 5.3 mb m-o-m to 41.2 mb. This is 8.6 mb, or 17.3%, lower than the same month a year ago.

Gasoline stocks in July fell m-o-m by 2.1 mb to stand at 6.6 mb, which is 5.2 mb, or 44.0%, lower than the same month one year ago.

Gasoil stocks also fell m-o-m by 2.0 mb in July to stand at 15.6 mb, which is 3.5 mb, or 18.5%, lower than in July 2020.

Residual fuel oil stocks also fell m-o-m by 2.2 mb to end July at 7.2 mb. This is 1.0 mb, or 12.1%, lower than the level seen one year ago.

In contrast**, jet oil stocks** rose m-o-m by 0.4 mb to end July at 9.0 mb. This is 1.6 mb, or 21.6%, higher than the level registered one year ago.

Fujairah

During the week ending 30 August 2021, **total oil product stocks in Fujairah** fell by 0.60 mb w-o-w to stand at 17.68 mb, according to data from Fed Com and S&P Global Platts. At this level, total oil stocks were 7.44 mb lower than the same time a year ago. While light distillates witnessed a stock build w-o-w, middle and heavy distillate stocks showed a stock draw.

Light distillate stocks rose by 0.13 mb w-o-w to stand at 5.76 mb in the week to 30 August 2021, which is 1.80 mb lower than the same period a year ago. In contrast, **middle distillate stocks** fell by 0.29 mb to stand at 3.68 mb, which is 0.57 mb lower than a year ago. **Heavy distillate stocks** also fell by 0.44 mb to stand at 8.25 mb, which is 5.07 mb lower than the same time last year.

Balance of Supply and Demand

Demand for OPEC crude in 2021 was revised up by 0.3 mb/d from the previous month to stand at 27.7 mb/d, around 4.9 mb/d higher than in 2020.

According to secondary sources, OPEC crude production averaged 25.2 mb/d in 1Q21, about 0.1 mb/d below demand for OPEC crude in the same period. In 2Q21, OPEC crude production averaged 25.5 mb/d, 1.8 mb/d lower than demand for OPEC crude.

Demand for OPEC crude in 2022 was revised up by 1.1 mb/d from the previous month to stand at 28.7 mb/d, around 1.1 mb/d higher than in 2021.

Balance of supply and demand in 2021

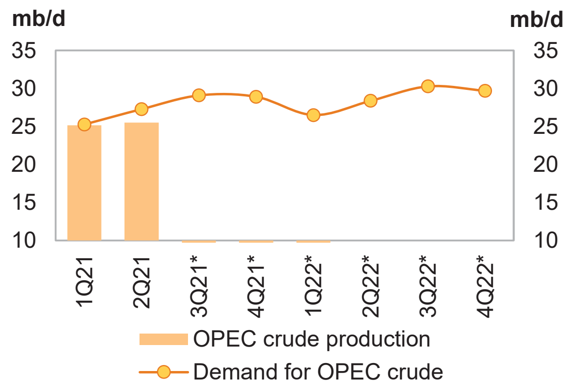
Demand for OPEC crude in 2021 was revised up by 0.3 b/d from the previous month to stand at 27.7 mb/d, around 4.9 mb/d higher than in 2020.

1Q21, 2Q21 and 3Q21 were revised up by 0.2 mb/d, 0.1 mb/d and 0.7 mb/d, respectively, while 4Q21 remained unchanged compared with the previous assessment.

When compared with the same quarters in 2020, demand for OPEC crude in 1Q21 and 2Q21 is estimated to be 3.8 mb/d and 10.1 mb/d higher, respectively. In 3Q21 and 4Q21, there is an expected rise of 4.1 mb/d and 1.7 mb/d, respectively, compared with the same quarters a year earlier.

According to secondary sources, OPEC crude production averaged 25.2 mb/d in 1Q21, about 0.1 mb/d below demand for OPEC crude in the same period. In 2Q21, OPEC crude production averaged 25.5 mb/d, 1.8 mb/d lower than demand for OPEC crude.

Graph 10 - 1: Balance of supply and demand, 2021–2022*



*Note: * 3Q21-4Q22 = Forecast. Source: OPEC.*

Table 10 - 1: Supply/demand balance for 2021*, mb/d

	2020	1Q21	2Q21	3Q21	4Q21	2021	Change 2021/20
(a) World oil demand	**90.73**	**92.82**	**95.62**	**98.46**	**99.70**	**96.68**	***5.96***
Non-OPEC liquids production	62.93	62.43	63.22	64.13	65.56	63.85	*0.92*
OPEC NGL and non-conventionals	5.05	5.11	5.11	5.22	5.23	5.17	*0.12*
(b) Total non-OPEC liquids production and OPEC NGLs	**67.98**	**67.54**	**68.33**	**69.36**	**70.79**	**69.01**	***1.04***
Difference (a-b)	**22.75**	**25.28**	**27.29**	**29.10**	**28.92**	**27.67**	***4.92***
OPEC crude oil production	**25.65**	**25.16**	**25.53**				
Balance	**2.90**	**-0.12**	**-1.77**				

*Note: * 2021 = Forecast. Totals may not add up due to independent rounding. Source: OPEC.*

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Oil Market Report - September 2021

Flagship report — September 2021

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About this report

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

Highlights

- Global oil demand is estimated to have declined for three straight months due to a resurgence of Covid-19 cases in Asia. As a result, 3Q21 has been revised down by 200 kb/d since last month's Report. Already signs are emerging of Covid cases abating with demand now expected to rebound by a sharp 1.6 mb/d in October, and continuing to grow until end-year. Global oil demand is now expected to rise by 5.2 mb/d this year and by 3.2 mb/d in 2022.
- World oil supply fell 540 kb/d m-o-m in August to 96.1 mb/d and is expected to hold steady in September as unplanned outages offset increases from OPEC+. Hurricane Ida shut in 1.7 mb/d of oil production along the US Gulf Coast at end-August, with potential supply losses from the storm approaching 30 mb. An uptrend in supply should resume in October as OPEC+ continues to unwind cuts, outages are resolved and as other producers increase.
- A steep fall in China's refinery activity in July, followed by Hurricane Ida's impact on US refining in August and September resulted in an 830 kb/d revision to the 3Q21 global refining throughput, which now stands at 78.5 mb/d, up 1.5 mb/d from 2Q21. In August, the first significant decline in crude prices since September 2020 boosted product cracks and refinery margins across the board.
- OECD total industry stocks drew by 34.4 mb in July and stood at 2 850 mb, 185.7 mb lower than the 2016-2020 average and 120.3 mb below the pre-Covid five-year average. Preliminary data for the US, Europe and Japan show industry stocks decreased by a further 31.1 mb while crude oil held in short-term floating storage decreased by 20.3 mb to 101.7 mb in August.
- Prices fell on average in August, trading in a wide $8-9/bbl range, and the forward price curve flattened substantially. The drop reflects concerns about economic growth, inflation prospects and weaker oil demand linked to rising Covid infections. By early September, supply losses from Hurricane Ida lifted prices almost back to early July levels. North Sea Dated prices lost $4.24/bbl in August to $70.75/bbl and WTI at Cushing fell $4.73/bbl m-o-m to $67.73/bbl.

After the storm

Unexpected outages during August forced a decline in supply for the first time in five months and extended the sharp drawdown in global oil stocks. The most severe by far was Hurricane Ida, which wreaked havoc on the key US Gulf Coast oil producing region at the end of August, knocking 1.7 mb/d offline. Concerns over the impact of rising Covid-19 cases on oil demand kept a lid on prices, however, with benchmark crudes falling month-on-month before edging marginally higher in early September. At the time of writing, Brent futures traded at around $73.80/bbl and WTI at $70.70/bbl.

Hurricane Ida is still causing problems for US and global markets. Offshore installations and refineries have been slow to restart due to the severity of the storm, forcing massive stock draws of both crude and products in key markets. The biggest impact on supply will be seen in September, with total supply losses estimated at around 30 mb.

Already in August, production outages led to further sharp declines in inventories. Preliminary data show OECD oil stocks falling by more than 30 mb last month, extending steep losses over June and July. By the end of July, OECD total industry stocks stood 185.7 mb below the most recent five-year average. With nearly 900 kb/d of crude output and 700 kb/d of refinery capacity offline at the time of writing, hefty draws are expected to continue through September.

The US Department of Energy announced on 23 August a sale of up to 20 mb from its Strategic Petroleum Reserve (SPR) as part of its programme to use the SPR to finance spending. The deliveries will take place between 1 October and 15 December and could offset some of the losses from Hurricane Ida. The US government is also loaning barrels from the SPR to the region's refiners to help offset crude shortfalls. China, too, is tapping into its strategic reserves. For the first time ever, it will sell oil from state-owned tanks in an effort to dampen domestic oil prices and inflationary pressures. It is unclear how many barrels will be made available to the market.

At the same time, demand growth in China and elsewhere in Asia is under pressure from resurgent Covid cases. We have revised down our world oil demand forecast for August and September by nearly 600 kb/d as China and a number of other South Eastasian countries enforce more mobility restrictions. Strong pent-up demand and continued progress in vaccination programmes should underpin a robust rebound from 4Q21. Our annual growth forecast is revised marginally lower since last month's Report for 2021 (-110 kb/d) to 5.2 mb/d while 2022 growth is slightly higher, at 3.2 mb/d.

The market should shift closer to balance starting from October if OPEC+ continues to unwind production cuts. Even so, it is only by early 2022 that supply will be high enough to allow oil stocks to be replenished. In the meantime, strategic oil stocks from the US and China may go some way to help plug the gap.

IEA World Oil Supply and Demand Forecasts: Summary (Table)
2021-09-14 08:00:00.2 GMT

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

	4Q 2022	3Q 2022	2Q 2022	1Q 2022	4Q 2021	3Q 2021	2Q 2021	1Q 2021	2022	2021
Demand										
Total Demand	100.2	100.3	98.9	98.2	98.8	97.2	95.1	93.4	99.4	96.1
Total OECD	46.2	46.6	45.7	45.4	46.0	45.7	43.9	42.3	46.0	44.5
Americas	25.1	25.6	25.1	24.5	25.0	25.2	24.3	22.8	25.1	24.3
Europe	13.2	13.6	13.4	13.0	13.3	13.5	12.6	11.9	13.3	12.8
Asia Oceania	7.9	7.4	7.2	7.9	7.8	7.0	7.0	7.7	7.6	7.4
Non-OECD countries	54.0	53.6	53.2	52.8	52.7	51.5	51.2	51.1	53.4	51.6
FSU	5.1	5.0	4.7	4.7	4.9	4.8	4.7	4.5	4.9	4.7
Europe	0.8	0.8	0.8	0.7	0.8	0.8	0.7	0.7	0.8	0.8
China	15.5	15.5	15.6	15.1	15.2	14.8	15.2	14.6	15.4	14.9
Other Asia	14.3	13.6	14.1	14.3	13.9	12.6	13.0	13.6	14.1	13.3
Americas	6.2	6.3	6.1	5.9	6.1	6.1	5.9	5.8	6.1	6.0
Middle East	8.0	8.5	8.0	7.9	7.9	8.4	7.8	7.7	8.1	8.0
Africa	4.1	3.9	4.0	4.1	4.0	3.8	3.9	4.1	4.0	4.0
Supply										
Total Supply	n/a	n/a	n/a	n/a	n/a	n/a	94.2	92.3	n/a	n/a
Non-OPEC	67.3	67.2	66.6	65.6	65.3	64.1	63.5	61.9	66.7	63.7
Total OECD	29.9	29.4	29.2	29.1	28.9	28.0	27.8	27.4	29.4	28.0
Americas	25.8	25.5	25.2	25.0	24.8	24.2	24.2	23.3	25.4	24.1
Europe	3.6	3.4	3.4	3.6	3.6	3.3	3.1	3.6	3.5	3.4
Asia Oceania	0.5	0.5	0.5	0.5	0.5	0.5	0.5	0.5	0.5	0.5
Non-OECD	32.0	32.0	31.9	31.6	31.2	30.5	30.5	30.2	31.9	30.6
FSU	14.8	14.8	14.8	14.5	14.2	13.6	13.7	13.4	14.7	13.7
Europe	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1
China	4.1	4.1	4.1	4.1	4.1	4.1	4.1	4.1	4.1	4.1
Other Asia	2.8	2.8	2.8	2.8	2.9	2.8	2.9	3.0	2.8	2.9
Americas	5.7	5.6	5.6	5.5	5.5	5.5	5.3	5.3	5.6	5.4
Middle East	3.3	3.3	3.3	3.3	3.2	3.2	3.1	3.1	3.3	3.1
Africa	1.3	1.3	1.3	1.3	1.3	1.3	1.3	1.3	1.3	1.3
Processing Gains	2.4	2.4	2.4	2.4	2.3	2.3	2.2	2.1	2.4	2.3
Total OPEC	n/a	n/a	n/a	n/a	n/a	n/a	30.8	30.4	n/a	n/a
Crude	n/a	n/a	n/a	n/a	n/a	n/a	25.5	25.3	n/a	n/a
Natural gas liquids NGLs	5.5	5.5	5.5	5.5	5.3	5.3	5.3	5.2	5.5	5.3
Call on OPEC crude and stock change *	27.3	27.6	26.9	27.1	28.2	27.8	26.4	26.3	27.2	27.2

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

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IEA: August Crude Oil Production in OPEC Countries (Table)
2021-09-14 08:00:00.1 GMT

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

	Aug. 2021	July 2021	Aug. MoM
Total OPEC	26.89	26.68	0.21
Total OPEC10	22.68	22.43	0.25
Algeria	0.92	0.91	0.01
Angola	1.13	1.10	0.03
Congo	0.26	0.25	0.01
Equatorial Guinea	0.10	0.10	0.00
Gabon	0.19	0.18	0.01
Iraq	4.07	3.97	0.10
Kuwait	2.44	2.42	0.02
Nigeria	1.24	1.32	-0.08
Saudi Arabia	9.56	9.46	0.10
UAE	2.77	2.72	0.05
Iran	2.50	2.50	0.00
Libya	1.14	1.18	-0.04
Venezuela	0.57	0.57	0.00

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

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IEA REPORT WRAP: OPEC+ Oil Supply Boosts Undone by Ida, Outages
2021-09-14 08:30:04.501 GMT

By Stephen Voss
(Bloomberg) -- Summary including stories from IEA's monthly
Oil Market Report on Tuesday:
* IEA says world must wait for extra oil as Ida offsets OPEC
hike
** World oil supply fell in August amid hurricane and unexpected
outages
** World supply uptrend to resume in October as OPEC+ unwinds
cuts
** Little change to world demand growth est. for 2021, 2022
** World demand seen rising 5.2m b/d this year, 3.2m b/d next
** Click here for summary of key IEA supply/demand forecasts
* OPEC crude output +210k b/d m/m in August led by Saudi, Iraq
** See full table
* OPEC+ alliance crude supply -150k b/d m/m in August to 41.58m
b/d
** Losses from Kazakhstan, Mexico, Nigeria

** Gains from Saudi, Russia, Iraq
* Compliance with pledged cutbacks in August:
** OPEC 118%; non-OPEC 112%; combined OPEC+ 116%
** Saudi Arabia 103%, Russia 92%
* Russia's crude output rose in August, condensate dropped
* Hurricane Ida shutdowns to curb U.S. oil supply by 30m bbl
* U.K. oil output to hit 7-year low in 2021 on Forties work
* European refinery runs to recover by only 120k b/d in 2021
* Refinery closures in U.S., Europe tighten gasoline supplies
* Iran could sell 137m barrels of stored oil if sanctions end
* China had 'notable' slowdown in oil demand in July, August
* IEA Table: World supply/demand forecasts by quarter
* NOTE: OPEC's own monthly report was issued Monday
* NOTE: The 23-nation OPEC+ alliance led by Saudi Arabia and Russia agreed in July to revive the rest of the production they halted during the pandemic in careful installments, of 400k b/d each month

--With assistance from Kristian Siedenburg, Alex Longley, Sherry Su, Prejula Prem, Dina Khrennikova, James Herron, Brian Wingfield, Bill Lehane and Christopher Sell.

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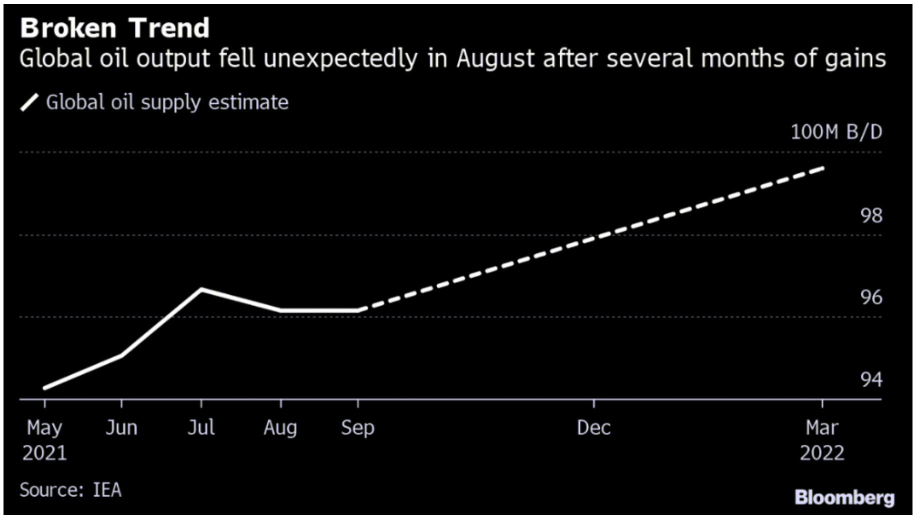
World Must Wait for Extra Oil as Ida Offsets OPEC Hike, IEA Says
2021-09-14 08:00:00.26 GMT

By James Herron
(Bloomberg) -- The world will have to wait until October for additional oil supplies as output losses from Hurricane Ida wipe out increases from OPEC+, the International Energy Agency said.
Consumers should have been enjoying "solid gains" in production as the Organization of Petroleum Exporting Countries and its allies continued their revival of idle capacity, the agency said in its monthly report. Instead, global supply fell by 540,000 barrels a day in August due to unexpected disruptions and will be flat this month.
"Unplanned production outages have temporarily halted an uptrend in world oil supply that began in March, but growth is

set to resume in October," said the Paris-based IEA, which advises developed economies on energy policy.



The supply disappointment hasn't had a big impact on prices because of bearish trends in fuel consumption. Global oil demand has been falling since July as rising Covid-19 cases prompt mobility restrictions in Asia, the IEA said. Crude has traded near $70 a barrel in New York for most of this month.
World fuel consumption will contract by 310,000 barrels a day on average each month from July to September, the IEA said.
Yet there are signs that the coronavirus resurgence is abating and the agency expects a sharp rebound in demand of 1.6 million barrels a day next month, with continued growth to the end of the year.
The matching shifts in supply and demand meant this year's prevailing oil-market trend -- shrinking inventories -- continued unabated. Fuel stockpiles in developed economies fell by 30 million barrels last month, putting them 186 million barrels below the five-year average, according to preliminary IEA estimates. There should be "hefty draws" again this month, the agency said.
"It is only by early 2022 that supply will be high enough to allow oil stocks to be replenished," according to the report. "In the meantime, strategic oil stocks from the U.S. and China may go some way to help plug the gap."

Supply Problems

Hurricane Ida, a Category 4 storm that hit the U.S. Gulf Coast on Aug. 29, initially shut down 1.7 million barrels a day of oil production. Weeks later, the industry is still struggling to restart many of the affected fields and the region's crude output is expected to be down as much as 650,000 barrels a day on average this month, the IEA said.
While most of OPEC boosted output in August, a handful of

members plus several allied producers saw production drop.
Overall OPEC+ crude supply fell by 150,000 barrels a day to 41.58 million barrels a day in August as increases from Saudi Arabia, Iraq and Russia failed to offset losses in Nigeria, Kazakhstan and Mexico.
The group is scheduled to revive another 400,000 barrels a day of idle capacity this month, but members including Nigeria, Angola and Malaysia continue to struggle to boost output, the IEA said.

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IEA World Oil Supply/Demand Key Forecasts
2021-09-14 08:00:00.4 GMT

By Kristian Siedenburg
(Bloomberg) -- World oil demand 2022 fcast was revised to 99.4m b/d from 99.3m b/d in Paris-based Intl Energy Agency's latest monthly report.
* 2021 world demand was revised to 96.1 from 96.2m b/d
* Demand change in 2022 est. 3.4% y/y or 3.2m b/d
* Non-OPEC supply 2022 was unrevised at 66.7m b/d
* Call on OPEC crude 2022 was revised to 27.2m b/d from 27.1m b/d
* Call on OPEC crude 2021 was revised to 27.2 m b/d from 27.0m b/d
** OPEC crude production in Aug. rose by 210k b/d on the month to 26.89m b/d
* Detailed table: FIFW NSN QZEULUT1UM12 <GO>
* NOTE: Fcasts based off IEA's table providing one decimal point

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OPEC Output Rose 210k B/d in Aug. Led By Saudi Arabia, Iraq: IEA
2021-09-14 08:00:00.27 GMT

By Christopher Sell
(Bloomberg) -- OPEC's crude production rose by 210k b/d in August to 26.89m b/d, led by Saudi Arabia and Iraq, the International Energy Agency said in its monthly oil-market report.
* Saudi Arabia's output climbed 100k b/d m/m to 9.56m b/d, just below its August quota of 9.6m b/d
* Iraq increased production by 100k b/d to 4.07m b/d, 10k b/d above its quota
* The UAE increased supply by 50k b/d to 2.77m b/d, while Kuwait's output edged 20k b/d higher to 2.44m b/d
* Iran, which is exempt from cuts, held output steady at 2.5m b/d
* In Africa, OPEC members struggled to meet their production targets:
** Nigeria posted the biggest drop, with supply falling 80k b/d to 1.24m b/d, mainly due to operational issues at the Forcados terminal
** Angola's output edged up to 1.13m b/d, but remains 200k b/d below its quota
* Libya, also exempt from OPEC+ cuts, curbed output by 40k b/d to 1.14m b/d
* Production inched up in Algeria, Congo and Gabon
* Total OPEC+ supply fell by 150k b/d to 41.58m b/d, as losses from Kazakhstan, Mexico and Nigeria offset gains from Saudi Arabia, Iraq and Russia
** "An uptrend in supply should resume in October as OPEC+ continues to unwind cuts, outages are resolved and as other producers increase"

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Russia's Crude Output Rose in August, Condensate Dropped: IEA
2021-09-14 08:00:00.11 GMT

By Dina Khrennikova

(Bloomberg) -- Russia's crude output rose in August while its condensate production fell, the International Energy Agency says in its monthly oil market report.
* NOTE: Russia's crude-only output target for Sept. is 9.704m b/d
* Its August crude-only supply rose by 90k b/d to 9.71m b/d vs. a quota of 9.6m b/d
* Nation's compliance with OPEC+ deal seen at 92%, falling to "the lowest rate among major OPEC+ producers"
* Russia's total condensate production in August fell to 710k b/d after a fire at Gazprom's processing plant in West Siberia
* IEA sees Russia's major producers ramping up drilling to keep increasing production
* "Under the new OPEC+ deal, the crude oil supply targets of Russia and Saudi Arabia are due to rise by roughly 100k b/d per month," the report says. "Russia will have to trim crude oil supply in September to meet its target of 9.7m b/d. The country's major oil producers are gearing up to pump more in the months ahead by ramping up drilling efforts"
* Combined spare capacity of Rosneft, Lukoil and Gazprom Neft at ~350k b/d
* READ: Aug.25, Russia's August Oil Output Falls After Gazprom's Siberian Fire
* READ: Aug. 27, Lukoil Can Return to Pre-Pandemic Output With Capacity Intact
* READ: Sept. 12, Russia Is the Canary in the OPEC+ Oil Mine: Julian Lee

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Hurricane Ida Shutdowns to Curb U.S. Oil Supply by 30M Bbl: IEA
2021-09-14 08:00:00.13 GMT

By Brian Wingfield
(Bloomberg) -- Hurricane Ida, which initially took out 1.7m b/d of U.S. Gulf oil production when it hit the region late last month, will continue to affect the region's supply in the weeks to come, IEA said in its monthly Oil Market Report.
* Total supply losses are estimated at around 30m bbl
** The biggest impact will be seen this month, with Gulf supply

set to be down by as much as 650k b/d
** Port Fourchon, main receiving point for GoM production, "could see shut-ins last for several more weeks"
** Deliveries from recent Strategic Petroleum Reserve sale, expected between Oct. 1-Dec. 15, could offset some of the losses from Ida
* Three refineries with 700k b/d of combined capacity, which haven't yet restarted, are expected to resume processing in the coming weeks
** The hardest hit, Phillips 66's Alliance plant, "faces months of repairs"
** U.S. refining runs are forecast to fall by 400k b/d in September, following 170k b/d m/m decline in August
* U.S. ethane demand is forecast 170k b/d lower in September as a result of the storm, "with some impact persisting into October"
* Gasoline output losses estimated at 200k b/d in September and diesel at 140k b/d

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U.K. Oil Output to Hit 7-Year Low in 2021 on Forties Work: IEA
2021-09-14 08:00:00.12 GMT

By Sherry Su
(Bloomberg) -- Crude production in the U.K. expected to fall to a seven-year low of 900k b/d in 2021 due largely to the heavy maintenance that curbed flows of the Forties grade, the IEA said in its monthly Oil Market Report.
* Output from U.K. biggest producing field, Buzzard, dropped to zero during the planned maintenance in Forties Pipeline System; Forties flows were also disrupted in August
** Ithaca Energy said maintenance at its Captain field would take place in September; Enquest unveiled a production enhancement program for the Magnus field following poor performance, but new wells will not be drilled until 2022
* Despite fewer workovers planned for 2022, "the weak level of investment, lack of new projects and low rate of infill drilling to sustain base production mean that supply is expected to recover by only 20k b/d," IEA said

* Industry body Oil & Gas U.K. warned that more upstream investment would be needed to avoid supply falling off a "cliff edge" that is inconsistent with a smooth energy transition
* Spending fell 35% in 2020, to a 46-year low, and is expected to recover by only 20% in 2021, IEA said, citing Rystad Energy

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European Refinery Runs to Recover by Only 120K B/D in 2021: IEA
2021-09-14 08:00:00.28 GMT

By Prejula Prem
(Bloomberg) -- European refinery intake is expected to recover by only 120k b/d this year from the steep fall of 1.5m b/d observed in 2020, the IEA said in its monthly oil market report.
* Regional refinery runs rose by 1m b/d y/y in June and preliminary data for July show an increase of 460k b/d m/m
* Average refinery utilization rates in Europe at 82%, with that of only France and Italy below 75% among the continent's major refiners
* Oil demand in Europe is forecast to rebound by only 400k b/d in 2021 from the 1.9m b/d of consumption lost last year

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Refinery Closures in U.S., Europe Tighten Gasoline Supplies: IEA
2021-09-14 08:01:00.800 GMT

By Bill Lehane
(Bloomberg) -- The North Atlantic gasoline market is "certainly experiencing tighter supplies" as production drops in

key exporting regions of Europe and the U.S., IEA says in monthly report.
* Combined refinery runs in the main gasoline exporting nations of northwest Europe are forecast to fall for a fourth year in 2021; they've shed 1.2m b/d in throughputs since 2017; another 400k b/d has been lost from U.S. and Canada east-coast refineries
* Gasoline cracks have also maintained strong premium over ultra-low sulfur diesel in Europe in recent months even though middle distillates account for a much larger proportion of region's oil demand
* Demand trends for the two products diverged just before the pandemic, IEA says, with European gasoline demand reaching its highest since 2011 while diesel for road use has been flat since 2017 thanks to the "dieselgate" scandal and emergence of electric vehicles

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Iran Could Sell 137m Barrels of Stored Oil If Sanctions End: IEA
2021-09-14 08:00:00.6 GMT

By Alex Longley
(Bloomberg) -- Iran could sell about 59m bbl of crude and condensate stored on tankers and another 78m bbl of stocks on land if a nuclear deal is revived and sanctions are lifted, the IEA said in its monthly oil market report.
* The nation could ramp up oil production 2-6 months after sanctions are eased
* Output will "swiftly" rise toward a sustainable capacity of 3.8m b/d
* Production was at 2.5m b/d in August, up 510k b/d y/y
* READ: Tehran Signals Nuclear Talks to Resume Soon: Iran Snapshot

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China Had 'Notable' Slowdown in Oil Demand in July, August: IEA
2021-09-14 08:00:00.5 GMT

By Sherry Su
(Bloomberg) -- Chinese oil demand fell by 440k b/d m/m in July, and by 890k b/d in August, with the spread of the delta coronavirus variant, the IEA said in its monthly oil market report.
* Gasoil/diesel deliveries declined by 300k b/d m/m in July, before recovering by 30k b/d in August
** Gasoline demand was up 90k b/d in July, but it fell by an estimated 570k b/d in August because of a significant decline in travel
** Jet/kerosene deliveries rose by 70k b/d in July, but decreased by 130k b/d in August
* Overall intercity mobility in China rose by 8% in July, helped by strong gains in the country's south, but it fell by a "significant" 30% in August as Covid restrictions increased
* IEA estimate that Chinese 3Q oil demand is likely to fall by 350k b/d q/q, but it will still be up 275k b/d y/y
* Demand is likely to recover nearly all its losses in 4Q, rising by 305k b/d q/q, and finish the year 1.1m b/d higher

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China to Sell First Batch of Crude Oil From Reserves Sept. 24
2021-09-14 20:12:26.590 GMT

(Caixin Global)

(Bloomberg) — China will make the first sale of oil from its strategic reserves Sept. 24 in an unprecedented intervention by the world's top crude importer to lower prices. Authorities disclosed the historic move last week.

The initial auction will be for 7.38 million barrels of crude, the National Food and Strategic Reserves Administration said late Tuesday in a statement (link in Chinese). Grades include Qatar Marine, Forties, Oman, Murban and Upper Zakum, which are in tanks at Dalian and were put into storage last year, the agency said.

Brent oil dipped immediately after the announcement before recovering to trade near $74 a barrel. The Chinese agency said last week that it would tap its giant oil reserves to "ease the pressure of rising raw material prices." China faces surging costs of commodities, not just for crude but also coal and natural gas as inflation is rapidly rising.

Companies participating in the auction need to comply with national refinery industry policy and have a sufficient import quota, the agency said. Buyers should also have a good credit record, and the crude purchased should be for their own use, not for resale. The volume being sold is less than what China typically imports in one day.

China has built up a 220 million barrel oil reserve over the past decade, according to Energy Aspects Ltd. The buffer differs from strategic petroleum reserves, known as SPR, held in the U.S. and Europe, which are tapped only during supply outages and wars. China is signaling it's willing to use its reserve to try to influence the market.

Contact editor Bob Simison (bobsimison@caixin.com)

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OIL DEMAND MONITOR: New York Traffic Swells, Topping 2019 Levels

- Volume on Spanish toll roads much higher than two years ago
- U.S. refinery processing crimped by recent hurricane in Gulf

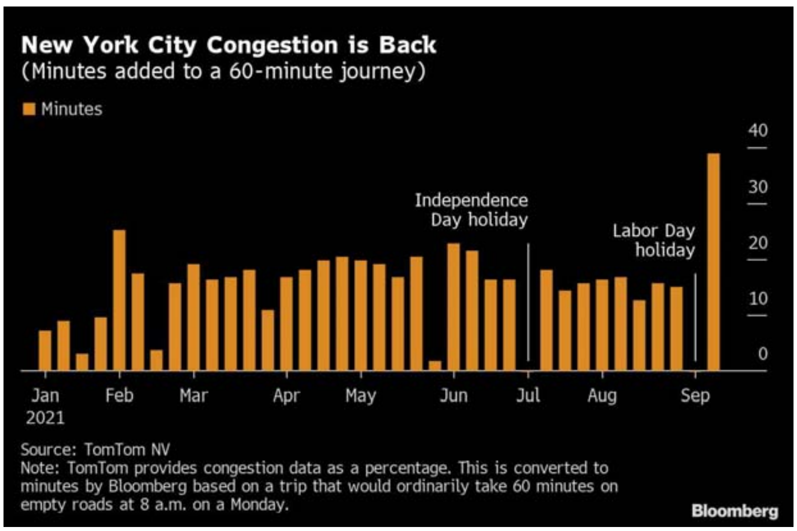
Sep 14, 2021 12:41:58

By Stephen Voss

(Bloomberg) -- New York City traffic got busy again with Monday morning congestion the highest so farthis year. The recent nationwide blip in jet fuel demand hasn't yet been replicated in other countries across the globe.

Congestion in the Big Apple at 8 a.m. local time on Monday added an extra 39 minutes on top of a journey that would take 60 minutes on empty roads, according to data provided by location technologycompany TomTom NV. That's the first time this year that reading has exceeded the pre-pandemic 2019average of 31 added minutes for that time of the week. Congestion was non-existent the prior Monday because of a public holiday.

City congestion also exceeded 2019 levels in London and Paris, and got noticeably more intense in thepast week in Tokyo, Los Angeles, Rome, Madrid and Mexico City.



Other data herald a return to normal in American driving habits. The number of miles traveled on interstate highways has been close to the same as 2019 levels for many weeks now, and estimated U.S. demand for gasoline was just 2% below pre-pandemic levels in early September, according to government data.

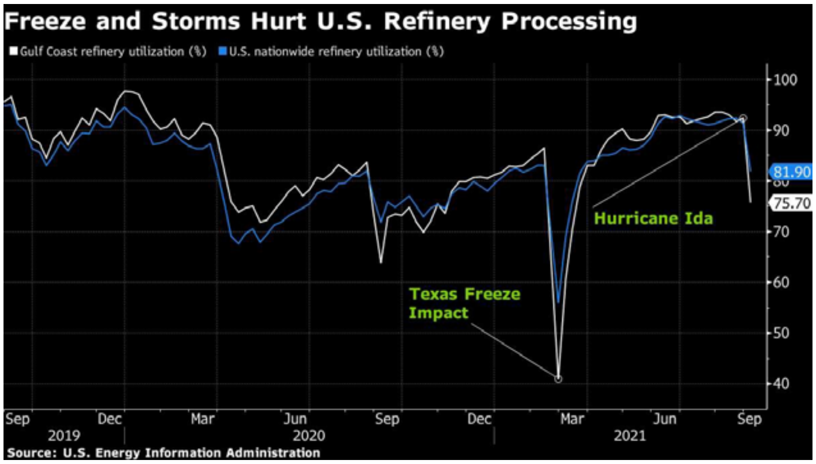
Weekly toll road data from Atlantia Group for six nations across Europe and Latin America reveal France has now joined the other five with higher traffic volume than the equivalent week in 2019. Spain is the most remarkable, with toll highway traffic up 54% versus 2019 for the week ended Sept. 5.

U.S. Refineries

U.S. refinery processing took another huge dip, though that's less to do with poor demand and mostly a result of Hurricane Ida's damage to oil facilities and power networks along the Gulf Coast in late

August. The same region was hobbled in mid-February when it was unprepared for unusually cold weather.

Nationwide, the U.S. used about 82% of refinery capacity in the week ended Sept. 3, about 13 percentage points less then the same week in 2019. More recent data for the Shandong region of Chinashowed independent refineries were using about 72% of capacity, about 5 percentage points more thanin 2019, according to Chinese researcher SCI99.



Total oil products demand in the U.S. took a step back from the prior week's all-time high, according to estimates from the Energy Information Administration. Compared against the same week of 2019, gasoline demand was down 2% while jet fuel had recovered completely, to register a gain of 7.1%. Nevertheless, such estimates are volatile because they're based on changes in other measurable data such as production and stockpiles and imports, rather than a bona fide recording of consumption.

Jet Fuel

The apparent recovery in jet fuel demand comes as the number of passengers moving through U.S. airports is still struggling to stay above 2 million per day, after comfortably exceeding that threshold for most of July, daily turnstile readings from the Transportation Security Administration show. While many more than a year ago, the number of people passing through U.S. airports is still about one-fifthlower than in 2019.

Elsewhere, increased travel hasn't yet resulted in aviation fuel demand returning to normal. Pipeline operator Exolum reported that Spanish jet fuel consumption in August -- as measured by deliveries from its system -- was still 41% less than in the same month of 2019, though 77% more than August 2020.

The global trend for air travel and aviation fuel demand remains one of slow, gradual recovery, with worldwide plane seat capacity rising to 79 million seats in the latest week to a level that's still about 31% lower than it was for the equivalent week in 2019, according to DAG Aviation.

"Much of this increase continues to be driven by the continued recovery in China's domestic market,"OAG said in a note. Eleven out of the 20 major markets it tracks had a week-on-week increase in capacity. All of them show capacity below 2019 levels. The smallest deficits are in China and Mexico.

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	2019	m/m	Freq.	of Date	Latest Value	Source
Gasoline demand	U.S.	+15	-2	+1.9	w	Sept. 3	9.61m b/d	EIA
Distillates demand	U.S.	-0.8	-3.1	-1.3	w	Sept. 3	3.69m b/d	EIA
Jet fuel demand	U.S.	+88	+7.1	+27	w	Sept. 3	1.62 b/d	EIA
Total oil products demand	U.S.	+6.8	-6.9	+2.3	w	Sept. 3	20m b/d	EIA
All vehicles miles traveled	U.S.		+1.4		w	Sept. 5	16.9b miles	DoT
Passenger car VMT	U.S.		-2		w	Sept. 5	n/a	DoT
Truck VMT	U.S.		+13		w	Sept. 5	n/a	DoT
All motor vehicle use index	U.K.	+6.4	unch	+2	d	Sept. 6	100	DfT
Car use	U.K.	+6.7	-4	+2.1	d	Sept. 6	96	DfT
Heavy goods vehicle use	U.K.	+4.8	+9	+4.8	d	Sept. 6	109	DfT
Gasoline (petrol) avg sales per filling station	U.K.	+7.3	-3.6	+3.2	m	Aug. 29	7,001 liters/d	BEIS
avg sales per station	U.K.	-0.5	-8.5	+0.3	m	Aug. 29	[illegible] 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	+11	-6.6	-4.9	m	August 2021	16m tons	PPAC
Passenger car traffic	Poland	+3	+9	-9.6	w	Sept. 12	24,889	GDDKiA
Heavy goods traffic	Poland	+5	+9	+7.3	w	Sept. 12	4,770	GDDKiA
Toll roads volume	Italy	+10.2	+6.9		w	Aug. 30-Sept. 5	n/a	Atlantia
Toll roads volume	Spain	+45	+54		w	Aug. 30-Sept. 5	n/a	Atlantia
Toll roads volume	France	+15	+7		w	Aug. 30-Sept. 5	n/a	Atlantia
Toll roads volume	Brazil	+7.5	+11		w	Aug. 30-Sept. 5	n/a	Atlantia
Toll roads volume	Chile	+63	+14		w	Aug. 30-Sept. 5	n/a	Atlantia
Toll roads volume	Mexico	+8.7	+1.9		w	Aug. 30-Sept. 5	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	+14	+4.7		m	August	558k m3	Exolum
Diesel	Spain	+7.9	-2.3		m	August	2147k m3	Exolum
Jet fuel	Spain	+77	-41		m	August	448k 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:

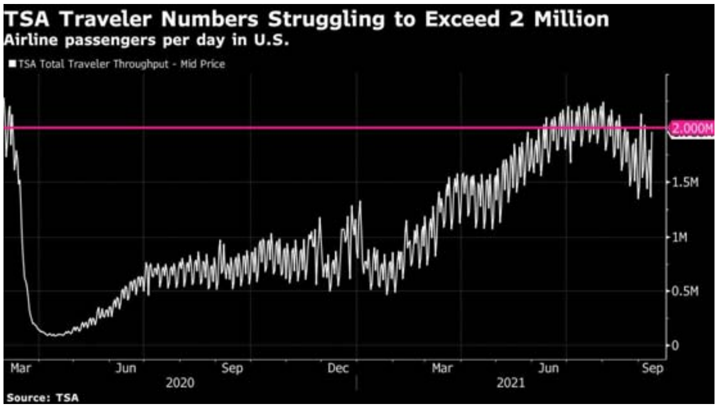
Measure	Location	% chg vs 2019	% chg m/m	Sept. 13	Sept. 6	Aug. 30	Aug. 23	Aug. 16	Aug. 9	Aug. 2	Jul. 26	Jul. 19	Jul. 12
		(Sept. 13)		Minutes of congestion at 8am local time									
Congestion	Tokyo	-15	+179	32	28	28	28	11	7	28	28	29	31
Congestion	Mumbai	-70	+50	11	10	5	8	7	7	9	7	9	5
Congestion	New York	+25	+210	39	0	15	16	13	17	16	16	14	18
Congestion	Los Angeles	-14	+28	31	2	29	27	24	17	16	16	18	17
Congestion	London	+17	+196	44	37	1	16	15	19	15	19	25	19
Congestion	Rome	-16	+1600	41	31	13	5	2	7	16	22	23	23
Congestion	Madrid	-7	+1275	33	20	6	3	2	2	5	5	8	13
Congestion	Paris	+18	+480	52	49	27	14	9	7	17	16	22	29
Congestion	Berlin	-5	+10	32	38	32	38	29	26	16	14	13	16
Congestion	Mexico City	-43	+38	28	27	24	23	20	19	20	19	20	22
Congestion	Sao Paulo	-38	+10	27	10	30	26	25	25	21	22	22	22

Source: TomTom. Click here for a PDF with more information on sources, methods.
Note: m/m comparisons are Sept. 13 vs Aug. 16. It was a public holiday in New York and Los Angeles on Sept. 6 and in Sao Paulo on Sept 7. Tomtom has been unable to provide Chinese data since 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.	+129	-22	-16	d	Sept. 13	1.67m people	TSA
Commercial flights	Worldwide	+37	-22	+4.7	d	Sept. 13	93,718	FlightRadar24
Air traffic (flights)	Europe		-29	+0.8	d	Sept. 13	24,771	Eurocontrol
Seat capacity	Worldwide	+39	-31		w	Sept. 13	79.03m	OAG
Seat cap.	U.S.	+79	-15		w	Sept. 13	18.60m	OAG
Seat cap.	China	+0.8	-4.6		w	Sept. 13	15.60m	OAG
Seat cap.	India	+60	-24		w	Sept. 13	3.06m	OAG
Seat cap.	Spain	+93	-28		w	Sept. 13	2.55m	OAG
Seat cap.	Japan	-11	-51		w	Sept. 13	2.05m	OAG
Seat cap.	U.K.	+45	-50		w	Sept. 13	1.93m	OAG
Seat cap.	Brazil	+93	-26		w	Sept. 13	1.89m	OAG
Seat cap.	Germany	+60	-48		w	Sept. 13	1.81m	OAG
Seat cap.	Mexico	+55	-9.9		w	Sept. 13	1.54m	OAG
Seat cap.	France	+37	-38		w	Sept. 13	1.51m	OAG
Seat cap.	Australia	+37	-74		w	Sept. 13	539k	OAG
Seat cap.	S. Africa	+175	-52		w	Sept. 13	293k	OAG
Seat cap.	Singapore	+158	-81		w	Sept. 13	152k	OAG

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



Refineries:

Measure	Location/area	y/y chg	vs 2019 chg	m/m chg	Latest as of Date	Latest Value	Source
		Changes in ppt unless noted					
Crude intake	U.S.	+12%	-18%	-12%	Sept. 3	14.3m b/d	EIA
Utilization	U.S.	+10	-13	-9.9	Sept. 3	81.9 %	EIA
Utilization	U.S. Gulf	+12	-21	-18	Sept. 3	75.7 %	EIA
Utilization	U.S. East	+18	+17	-6.3	Sept. 3	85.1 %	EIA
Utilization	U.S. Midwest	-0.3	-11	-1.4	Sept. 3	88.9 %	EIA
Apparent Oil Demand	China	-2.3%		-2.5%	July 2021	13.47m b/d	NBS
Indep. refs run rate	Shandong, China	-2.8	+5.1	+4.5	Sept. 10	71.5 %	SCI99
State refs run rate	East China	unch	-3.1	-2.8	Aug. 31	79.5 %	SCI99
State refs run rate	South China	-2	+4	-1	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. Changes are shown in percentage point except for the rows crude intake and apparent oil demand, which are shown in percent change.

https://www.mrt.com/business/oil/article/Here-s-Why-U-S-Crude-Oil-Supplies-Took-Such-a-16458158.php?utm_campaign=CMS%20Sharing%20Tools%20(Premium)&utm_source=t.co&utm_medium=referral

Here's why U.S. oil supplies took such big hit from Ida

Sergio Chapa and David Wethe, Bloomberg

Sep. 14, 2021

Comments

A refinery surrounded by water after Hurricane Ida near Cocodrie, La., in 2021.Bloomberg photo by Mark Felix

(Bloomberg) -- Hurricane Ida unleashed such furious winds and waves that almost two weeks later oil drillers, power suppliers and refiners are still picking up the pieces. They won't be done any time soon.

The damage to offshore platforms, pipelines and even heli-pads was so severe that two out of every three barrels of crude normally pumped from the U.S. sector of the Gulf of Mexico are unavailable. The ripple effects are still playing out as refiners and brokers scour the globe for replacements and the Gulf's biggest oil producer, Royal Dutch Shell Plc, tells some customers it can't honor supply commitments.

It will be weeks -- maybe longer -- before normal conditions can be restored off the Louisiana coast and in the warren of oil-processing and chemical plants that occupies a 100-mile (160-kilometer) corridor from New Orleans to Baton Rouge. Recovery efforts may be hindered by Tropical Storm Nicholas, which gained power Monday as it headed toward the coast of Texas, likely bringing flooding rains to Houston and Louisiana.

"What's different is this is lasting longer," Bert Winders, 63, a Baker Hughes Co. health and safety director, said in reference to how Ida's disruption compared with previous hurricanes. "It's just demanding on people. Three to five days, they can deal with. But when you start talking two, three, even four weeks, that's really tough on a family."

The recovery efforts are being closely watched around the world in large part because of the unprecedented scale and duration of the oil outages. Within days of the hurricane, traders were seizing on arbitrage opportunities created by the disappearance of some U.S. Gulf grades of oil such as Mars blend. For example, crude from Russia's Ural Mountains is a popular alternative to Mars because they share similar characteristics.

Ida's drawn-out aftermath offers a chastening glimpse of what may be in store as climate change fuels ever-more furious storms along low-lying coastal regions dotted with heavy industry and vital fuel-making facilities.

Typically, when tropical storms and hurricanes menace the oil-producing region of the Gulf, drillers batten down hatches, shut off the subsea wells funneling oil up to platforms and evacuate crews. When the skies clear, they often can chopper inspection teams back out in a matter of hours or days and resume production shortly thereafter.

When Louisiana was battered by Hurricane Laura last year, offshore crude output bounced back quickly.

Direct Hit

After Ida, that wasn't remotely possible. The monster storm's direct hit on Port Fourchon a few hours before sundown on Aug. 29 completely disabled the primary jumping-off point for helicopters and vessels that service hundreds of offshore platforms and rigs.

Even the lone road connecting Port Fourchon to the rest of the state -- Louisiana Highway 1 -- was knocked out of commission by Ida's massive wall of sea water and the tons of sand it swept ahead.

"When Port of Fourchon is out of service, it breaks a link in the chain," said Winders, a Louisiana native who's been working in the oil industry for four decades.

Into Darkness

At the height of the disaster, more than a million homes and businesses were cast into darkness as Ida's 150 mile-per-hour (240 kph) winds destroyed most of the transmission infrastructure in southeast Louisiana.

But by late Friday, there were still almost 200,000 without power or air conditioning -- a telling illustration of the extent of the destruction. As for Port Fourchon, the area isn't expected to get full electricity restored until the end of this month, according to utility company Entergy Corp.

Out on the high seas, drilling has returned to just 29% of pre-Ida levels. There were four rigs operating in the U.S. sector of the Gulf as of Friday, well below the 14 plying the waters before the storm, according to data from Baker Hughes, which has been tracking drilling activity since 1944.

Hobbled Refineries

Shell is gearing up to reopen many of the Gulf pipelines that carry crude to shore in the next week, according to a person familiar with the operations, a key step to potentially restoring offshore crude output. Still, a crucial conduit for Mars oil and other grades will remain shut as damage assessments continue, the person said. The company declined to comment.

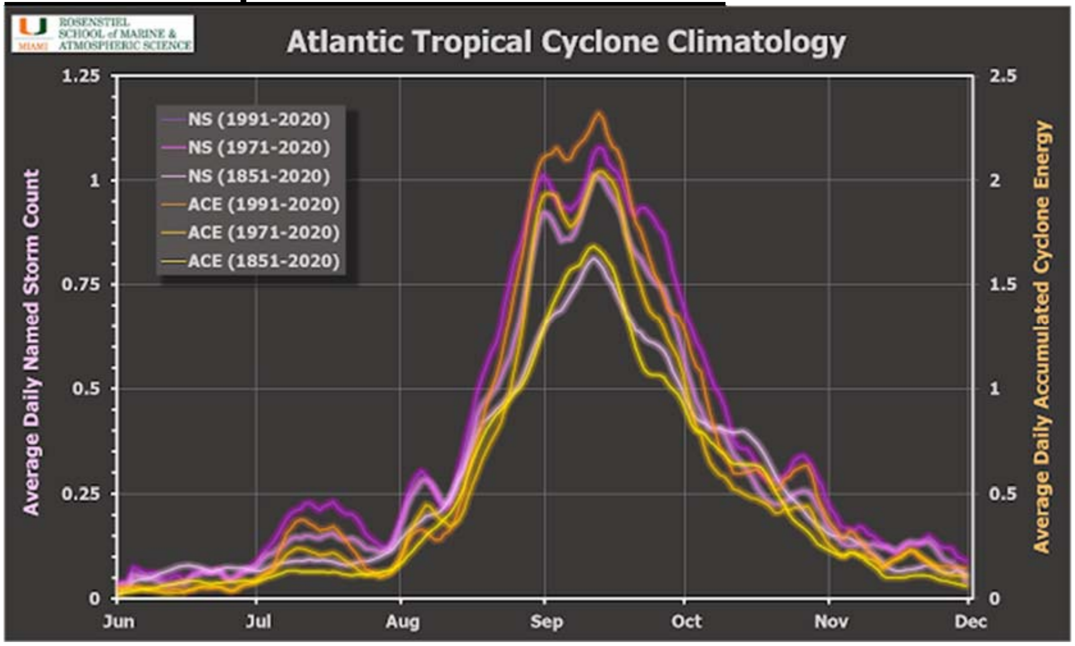
Further inland, the crippling effects of the cyclone are still being assessed. A New Orleans-area refinery owned by Phillips 66 suffered so much damage and flooding that the company may not even restart it, depending on how expensive it'll cost to repair.

Shell's Norco refining and chemical complex north of New Orleans may remain shut for several more weeks because of extensive damage.

Meanwhile, Marathon Petroleum Corp. managed to resume fuel production at its massive Garyville facility on Friday, although five other Louisiana refineries with combined daily capacity to process one million barrels remain shut.

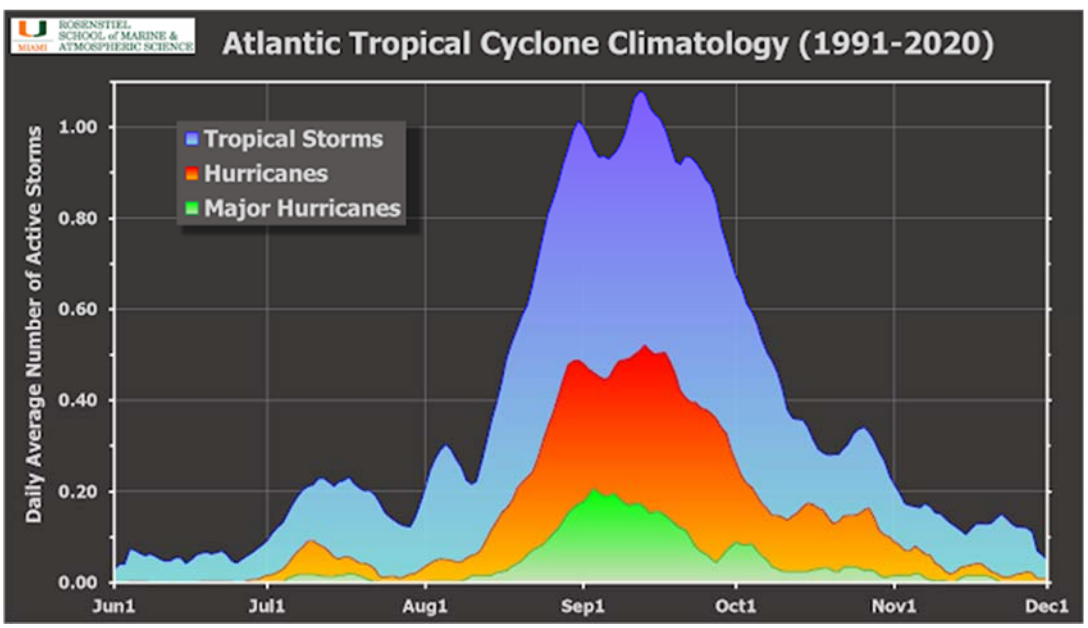
http://bmcnoldy.blogspot.com/2021/09/when-is-peak-of-hurricane-season.html
09 September 2021

When is the peak of hurricane season?

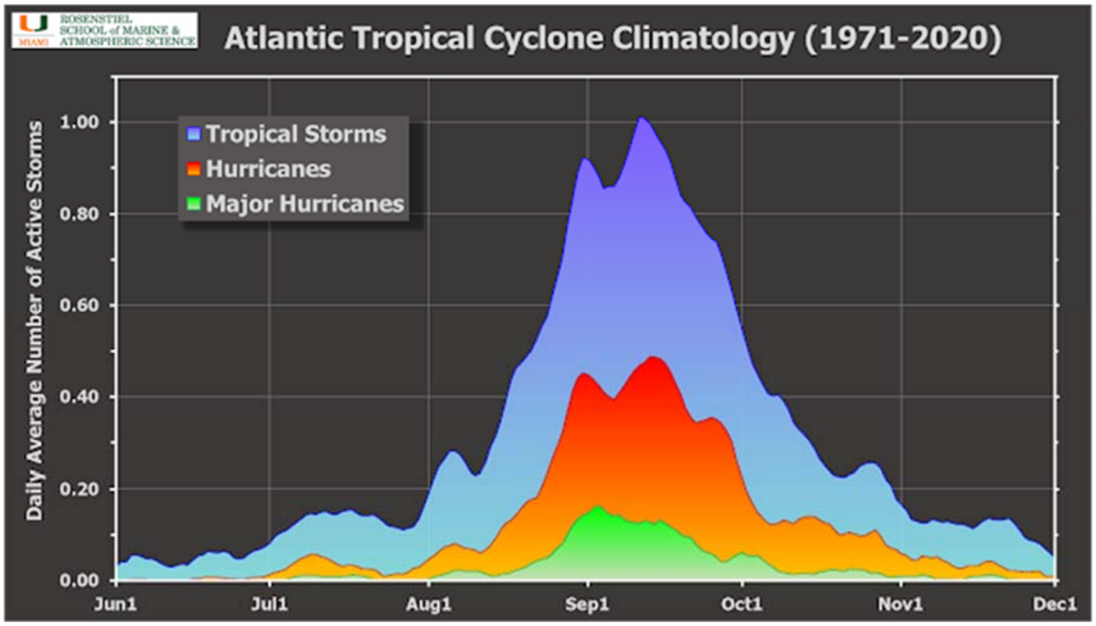


When is the peak of hurricane season? It turns out there is no single or correct answer. It depends on what metric you prefer and which time period you use. But no matter how you slice it, the peak of the Atlantic hurricane season occurs during the second week of September. *For all of the plots and data presented here, I use a 7-day centered average*, because there is quite a bit of noise when strictly using daily values. Let's break down what all of those curves are in the chart above.

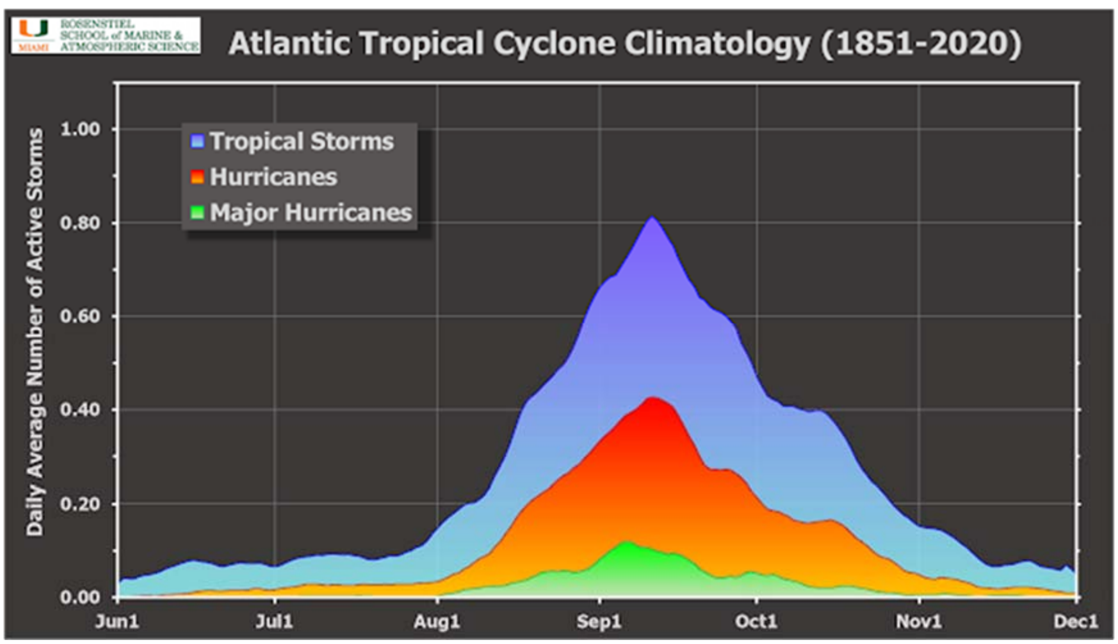
One common metric would be the daily average of named storm (NS) activity. Using the new **1991-2020** "climate normal", that peaks on **September 12th**, with a secondary peak on August 31st. But the daily average of major hurricanes peaks on September 3rd, and one might argue that those are much less prone to being over/under counted and are definitely more impactful when close to land.



Using the past fifty years, **1971-2020** (which is still entirely during the satellite era), that chart smooths out a bit and the peak is a tie between **September 11th and 12th**. There's a secondary peak on August 31st-September 1st.



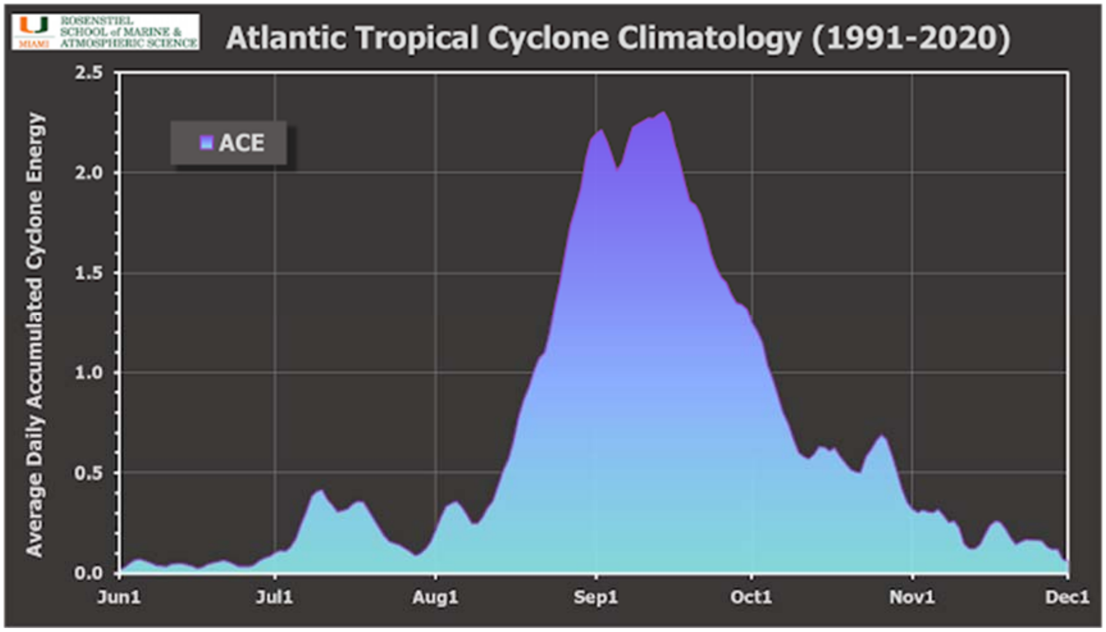
But zooming out and using the full **1851-2020** period of record (with all the nuances and disclaimers about data from the pre-satellite era), it looks like this: a definitive peak on **September 11th** for named storms, and a September 5th-7th peak for major hurricanes.



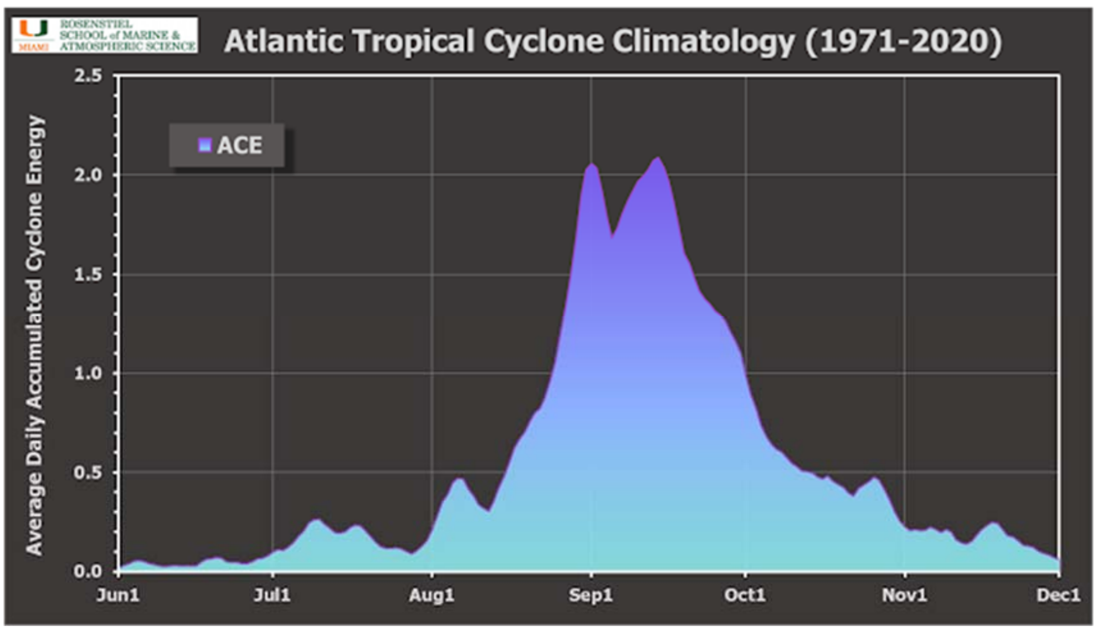
So for named storms, one could conclude that the peak falls on September 11-12, but the September 1-14 period encompasses the various peaks that arise depending on the choice of time period.

Another common metric is the Accumulated Cyclone Energy (ACE). That is not dependent on the number of storms, but rather is an integrated measure of the intensity and duration of all storms. Weak, short-lived storms barely make a dent in it, while long-track intense hurricanes make large contributions.

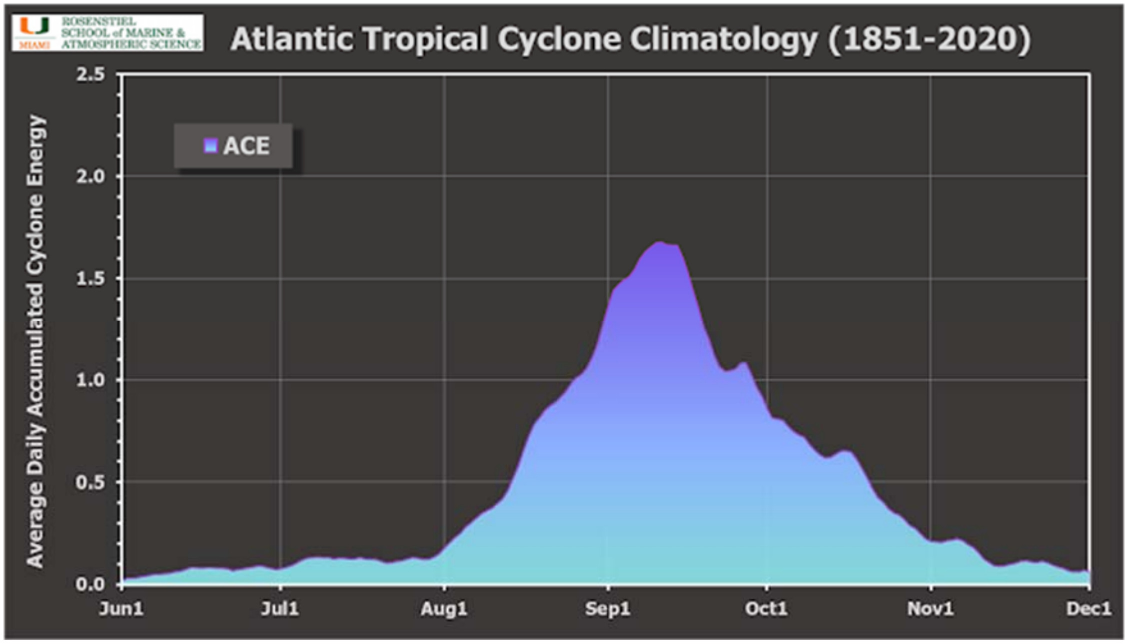
Again beginning with the **1991-2020** climate normal, that metric peaks on **September 14th**. Also notice the much more pronounced and dramatic rise and fall surrounding the peak of the season compared to the named storm counts. This speaks to the point that the real "meat" of hurricane season typically falls between mid-August and mid-October -- those two months account for 75% of the total ACE of the six-month-long season!



Using the longer **1971-2020** period, the data expectedly smooth out a bit, and there are three dates that are essentially tied: September 14th, September 13th, and September 1st, though **September 14th** is technically the highest by a hair.



And the full **1851-2020** period of record results in a much smoother time series, with a broad peak centered on **September 10-11**. An exaggerated feature of this period is the abrupt increase of activity during early August, then a much more relaxed decline of activity into November.



If we think of the peak of the season as when 50% of the total ACE has occurred, *the peak is September 12th for all three of the time periods* considered here (1991-2020, 1971-2020, and 1851-2020).

In summary, rather than assigning a specific date to it, we can conclude that the peak of the Atlantic hurricane season is the second week of September... accounting for different metrics, different averaging periods, evolving observing technology, and the relatively short period of record. But if you feel the need to assign a specific date to the peak, it would logically be September 12th.

Keep in mind that this is all based on historic storms and the best record we have of their existence and intensity. Individual seasons will rarely follow the "average", and very significant hurricanes can and have occurred outside of the peak of the season. Even the six-month hurricane season doesn't always encompass all of the activity, nor was it designed to.

Independent Statistics & Analysis
U.S. Energy Information Administration

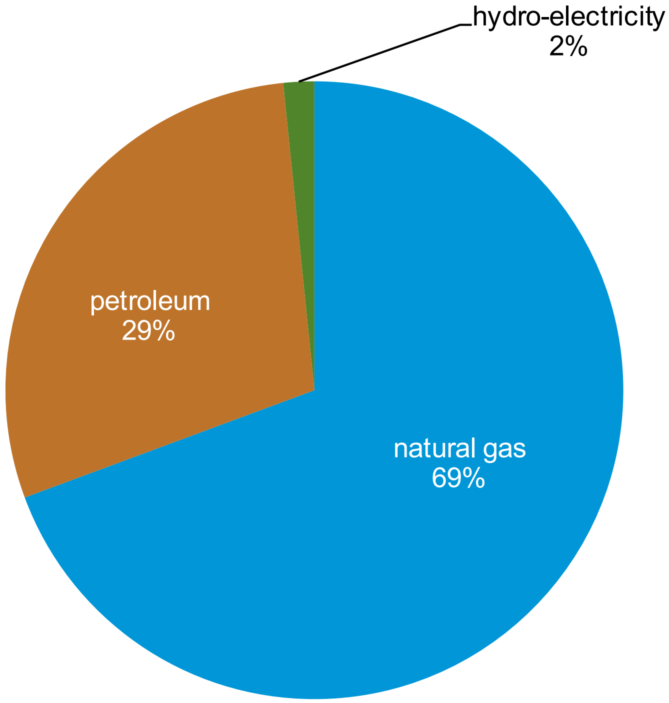
Country Analysis Executive Summary: Azerbaijan

Last Updated: September 13, 2021

Overview

- Azerbaijan is a net energy exporter; crude oil and natural gas production and exports are central to Azerbaijan's economy and government revenues.
- Natural gas accounts for over two-thirds of Azerbaijan's total domestic energy consumption. Oil supplies less than one-third of total energy consumption (Figure 1).[1]
- In 2018, the five countries bordering the Caspian Sea met regarding a decades-old delimitation dispute over the maritime and seabed boundaries of the Caspian. In early 2021, the foreign ministers of Turkmenistan and Azerbaijan signed a memo of understanding, which signified collaboration for joint exploration in the previously contested deep-water block along the Caspian maritime borders for both countries. The agreement is likely to attract foreign investment for exploratory drilling and development in the Dostluk field.[2]

Figure 1. Azerbaijan's total primary energy consumption, 2020



Source: Graph by EIA based on data from *BP Statistical Review of World Energy 2021.*
Note: Chart does not include traditional biomass and waste, such as burning firewood and waste.

Petroleum and other liquids

- Azerbaijan's proved crude oil reserves were estimated at 7 billion barrels in January 2021, according to the *Oil & Gas Journal* (OGJ).[3]

Sector organization

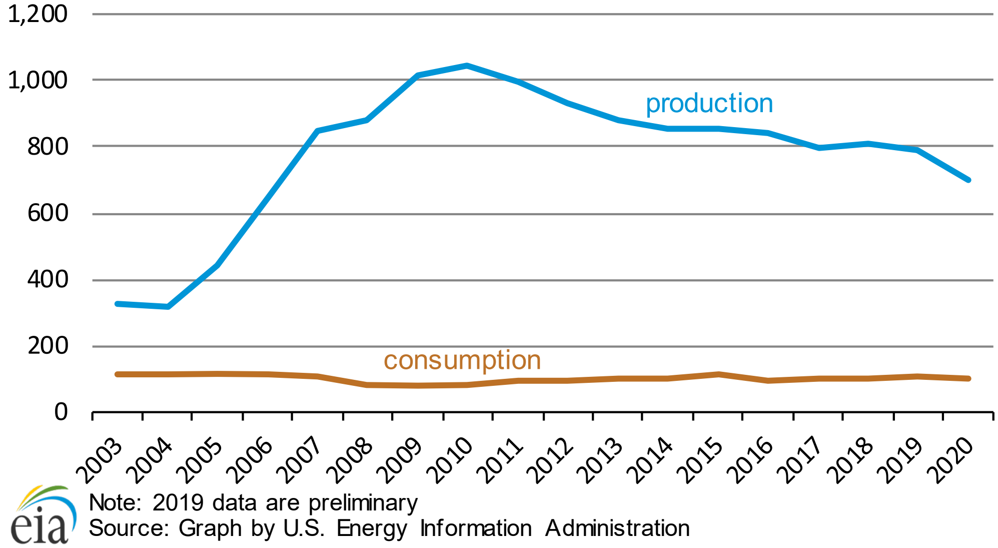
- The State Oil Fund of the Republic of Azerbaijan (SOFAZ) manages currency and assets from oil and natural gas activities, and it had $43.564 billion in managed assets at the start of January 2021, an increase of over 5% from the beginning of 2020 ($41.349 billion).[4] The national oil company, the State Oil Company of the Azerbaijan Republic (SOCAR), explores and produces oil and natural gas in the country. In 2019, SOCAR produced about 154,000 barrels per day (b/d) of oil, about 20% of Azerbaijan's total oil output.[5]

Exploration and production

- In 2020, Azerbaijan's petroleum and other liquids production was an estimated 716,000 barrels per day (b/d) of which domestic use averaged about 92,000 b/d (Figure 2).[6]

Figure 2. Azerbaijan petroleum and other liquids consumption and production

thousand barrels per day

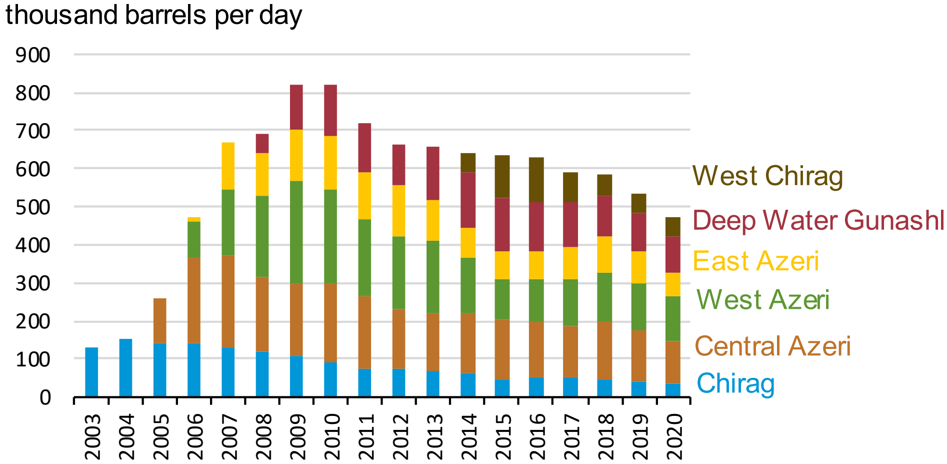


Note: 2019 data are preliminary

Source: Graph by U.S. Energy Information Administration

- Most oil production occurs offshore in the Caspian Sea and is exported to the West. In 2017, the production-sharing agreement (PSA) for Azerbaijan's main offshore Azeri-Chirag-Gunashli (ACG) fields was extended through 2049, indicating that with added investment and enhanced recovery, Azerbaijan will continue to produce crude oil and petroleum liquids.[7] Under the new PSA, SOCAR's share in the ACG complex increased to 25%. The next stage of development is the Azeri Central East (ACE) platform, located between the existing Central Azeri and East Azeri platforms, and will include pipelines to transfer oil and gas to the land-based Sangachal Terminal. The ACE platform was the first major investment decision since the signing of the PSA. The $6 billion development is set to achieve first production in 2023 and is designed to process 100,000 barrels per day.[8]
- In 2020, more than 67% of Azerbaijan's total oil output—about 477,000 b/d—came from the ACG fields, down from 535,000 b/d in 2019 (Figure 3).

Figure 3. Azeri-Chirag-Gunashli production



Source: Graph by the U.S. Energy Information Administration, based on BP

Pipelines

- Most of Azerbaijan's oil is exported through the Baku-Tbilisi-Ceyhan pipeline (BTC). The pipeline runs well below its capacity of 1.2 million b/d, with exports in 2020 averaging 578,000 b/d, including oil from Turkmenistan, Russia and Kazakhstan.[9]

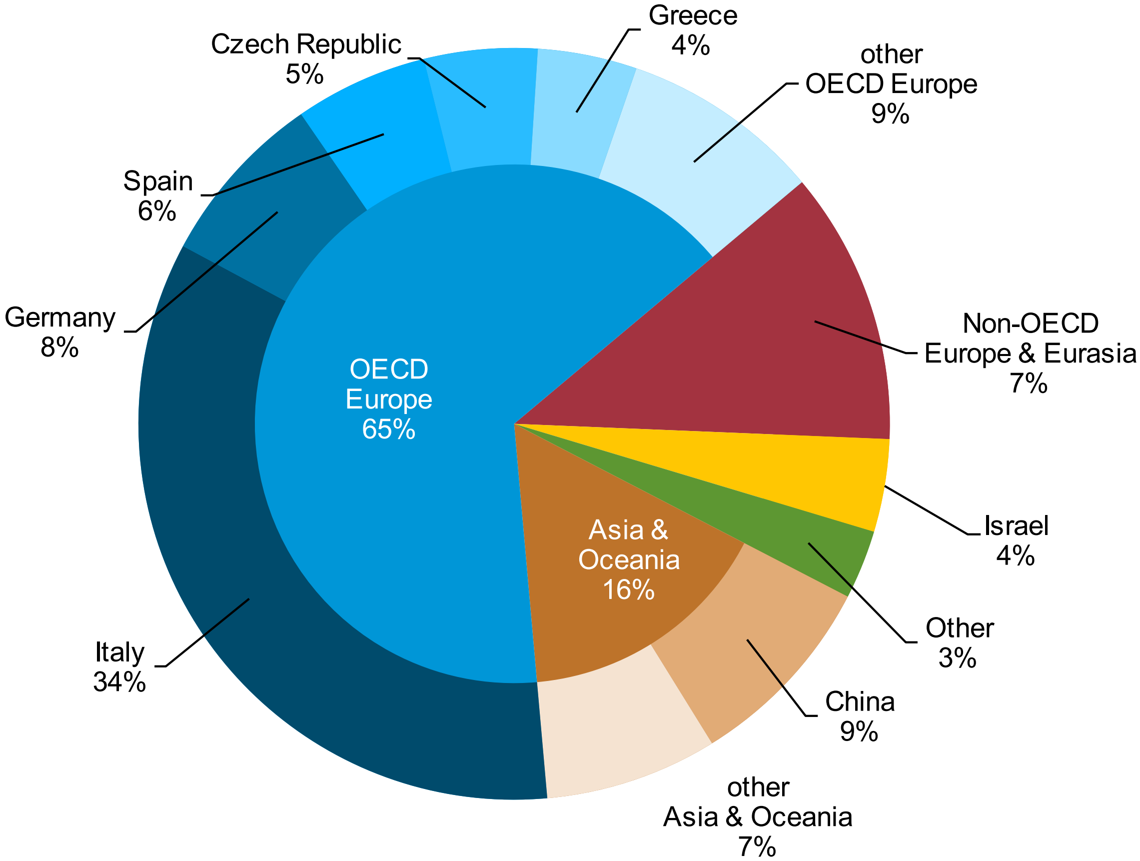
Refining

- Azerbaijan's crude oil refining capacity was 120,000 b/d in 2020 at SOCAR's New Baku refinery, according to the OGJ.[10]

Trade

- Azerbaijan's crude oil exports were about 568,000 b/d in 2020 (Figure 4).[11] Most of the exports were destined for European countries, with Italy receiving 34% of Azerbaijan's crude oil exports in 2020.

Figure 4. Azerbaijan crude oil exports by destination, 2020



Note: Sum of individual percentages may not equal 100 because of independent rounding.
Source: Graph by the U.S. Energy Information Administration, based on Azerbaijani partner country import statistics, Global Trade Tracker

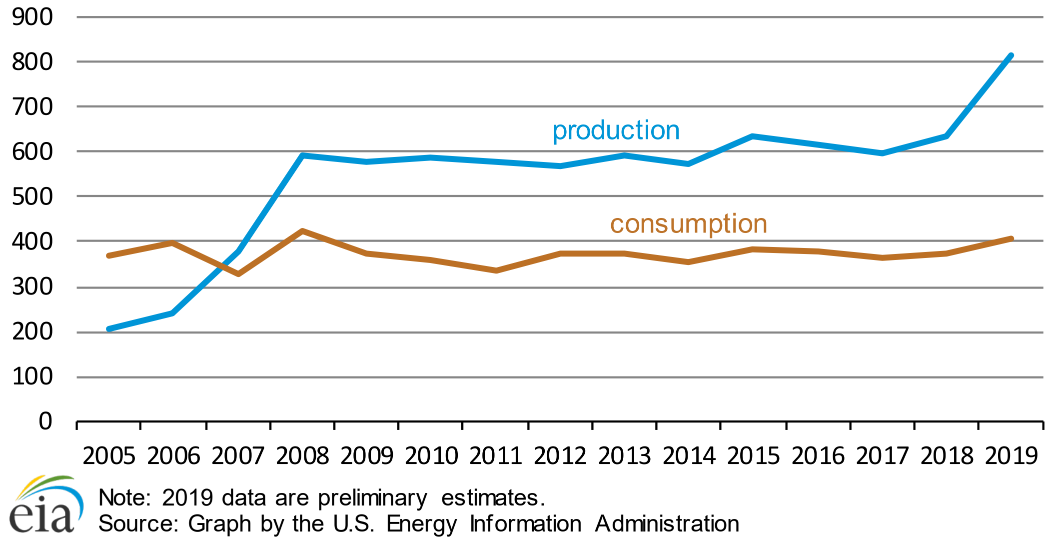
Natural gas

- Most of Azerbaijan's proved natural gas reserves, which were estimated at about 60 trillion cubic feet (Tcf) in January 2021, are located in the Shah Deniz offshore natural gas and condensate field.[12]

Exploration and production

- Preliminary 2020 estimates show an increase in the country's natural gas consumption of 9% and in production of 28% from 2018 to 2019 (Figure 5). In the first quarter of 2021 alone, the Shah Deniz field produced about 16.7 billion cubic feet (Bcf) of natural gas and 7.8 million barrels of condensate.[13]

Figure 5. Azerbaijan dry natural gas consumption and production
billion cubic feet



Note: 2019 data are preliminary estimates.
Source: Graph by the U.S. Energy Information Administration

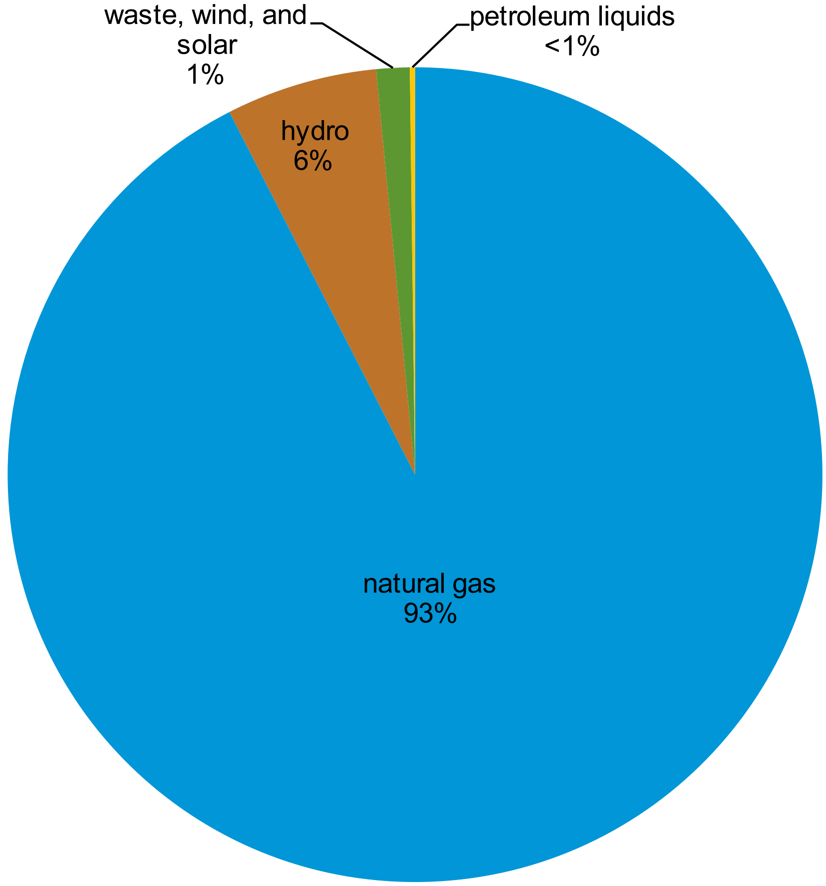
Trade

- Azerbaijan's natural gas exports totaled about 418 Bcf of natural gas in 2019.[14] The country ships most of its natural gas exports from the Caspian through Georgia to Turkey and southern Europe. The expansion of the Baku-Tbilisi-Erzurum (BTE) pipeline connects to the Trans-Anatolian Pipeline (TANAP), which crosses Turkey, and to the Trans Adriatic Pipeline (TAP) that runs from the Turkish border under the Adriatic Sea to southeast Europe and Italy. The TANAP makes up the longest stretch of the Southern Gas Corridor, carrying gas from Azerbaijan's Shah Deniz II field to Europe.[15] In 2020, the majority of Azerbaijan's natural gas was exported to Turkey and Georgia with a lesser volume exported to Iran and Greece. The completion of TAP in October 2020, allowed exports of natural gas to flow from Azerbaijan to Bulgaria and Italy in 2021.[16]

Electricity

- Use of electricity in Azerbaijan increased from 21.7 to 22.5 billion terawatthours (Twh) in 2019 (Figure 6).[17]
- In 2019, 93% of Azerbaijan's electric power came from natural gas-fired generation, hydropower accounted for 6%, and about 1% came renewable sources and petroleum.[18]

Figure 6. Azerbaijan electricity generation by fuel type, 2019



Source: Graph by the U.S. Energy Information Administration, based on International Energy Agency

Notes

- In response to stakeholder feedback, the U.S. Energy Information Administration has revised the format of the *Country Analysis Briefs*. As of September 2021, updated briefs are available in two complementary formats: the Country Analysis Executive Summary provides an overview of recent developments in a country's energy sector and the Background Reference provides historical context. Archived versions will remain available in the original format.
- Data presented in the text are the most recent available as of September 2021.
- Data are EIA estimates unless otherwise noted.

Endnotes

[1] BP, Statistical Review of World Energy 2021.
[2] Upstream, "Deep-water friendship: Turkmenistan and Azerbaijan bury Caspian Sea hatchet" (January 21, 2021).
[3] *Oil & Gas Journal*, "Worldwide Look at Reserves and Production," (December 7, 2020), p. 16.
[4] State Oil Fund of the Republic of Azerbaijan, SOFAZ Revenue and Expenditure Statement for January-December 2020; State Oil Fund of the Republic of Azerbaijan, SOFAZ Revenue and Expenditure Statement for January-June 2020.
[5] SOCAR, Economics & Statistics: Oil Production, (accessed August 3, 2021).
[6] BP, Statistical Review of World Energy 2021.
[7] BP, "The Azerbaijan government and co-venturers sign amended and restated Azeri-Chirag-Deepwater Gunashli PSA,"(accessed September 11, 2018)
[8] BP, Azeri Central East (ACE) development project, (accessed August 4, 2021).
[9] BP, 2020 year-end results, (accessed August 4, 2021).
[10] *Oil & Gas Journal*, "2020 Worldwide Refining Survey," (December 2020), p. 1.
[11] The State Statistical Committee of the Republic of Azerbaijan, Energy: Commodity balance of crude oil, (accessed August 3, 2021).
[12] *Oil & Gas Journal*, "Worldwide Look at Reserves and Production," (December 7, 2020), p. 16.
[13] BP, Shah Deniz, (accessed August 4, 2021).
[14] The State Statistical Committee of the Republic of Azerbaijan, Energy: Export of Energy Products, (accessed August 4, 2021).
[15] Reuters, "Turkey and Azerbaijan mark completion of TANAP pipeline to take gas to Europe," (November 30, 2019).
[16] BP, Statement on TAP, (October 13, 2020).
[17] International Energy Agency (IEA), World Energy Balances 2019 edition.
[18] International Energy Agency (IEA), World Energy Balances 2019 edition.

SAF Group created transcript of excerpts from Bloomberg's Alix Steel interview with Chevron CEO Mike Wirth on Sept 16. https://www.bloomberg.com/news/videos/2021-09-16/full-digital-chevron-chairman-ceo-mike-wirth-warns-on-high-energy-prices-and-supply-crunches-video

Items in "*italics*" are SAF Group created transcript.

At 3:20 min. Steel asks what type of prices did you model if you are looking for double digit? Note double digit is the Chevron target for the new energies. Wirth "*modest oil prices, I mean oil prices that look no higher than we have today, and similar for gas".*

At 3:50 min. Steel asks if its $55 to $75? Wirth "*that's a reasonable fairway"*

At 5:10 min. Steel asks what is the premium right now the end user is prepared to pay for green energy? Wirth ".. *renewable natural gas in California, it's substantial BUT it comes via a credit system that is not very transparent to the customer and so the price that we ultimately receive on some of these products is higher than it is for conventional natural gas but its not necessarily borne directly by the customer, it comes through a series of tradeable credits and things*"

At 9:30 min. Steel had asked about risk for stranded oil and gas assets. Wirth doesn't see that and says "*our view is the world, and most people's view is the world will continue to use our products for many decades to come. And the change is likely to be very gradual and trends that are seeable. And I think capital allocation within the industry, if and when those trends become apparent, will reflect that just as they have as the world has grown"*

At 11:20 min. Wirth "*we reiterated our guidance that, over the next five years, we expect to generate $25b in excess cash above our capital spending and our dividend payout, even with this new allocation of capital to energy transition.*

At 13:30 min. Steel notes the current supply gap in LNG and other energy and asks if the energy transition be longer, harder and more inflationary than we thought, are we moving too fast or too slow? Wirth "*it's a hard question to answer are we moving too fast or too slow. But, the point that it does illustrate is the existing system delivers the energy we rely on in a way that's affordable, that's reliable, and that has become cleaner over time, steadily. As we transition the system to a different mix, reliability matters and affordability matters. So if costs go up, consumers don't like that. And if reliability goes down, it creates real problems. So its one of the reasons we have to be very thoughtful about changing the mix. and I think what we're seeing in Europe right now is, wind and solar are great, but if the sun's not shining or the wind's not blowing , you need to have, people still need electricity. And so the alternate sources and how do you manage the grid through the variations which are much harder when these intermittent sources of power than things like nuclear or coal or natural gas that have a much more steady output. We've got to find a way to manage that and not create risk for economies and citizens"*

At 17:40 min. Steel asks do you think we are going to see a supply gap that OPEC can't plug at some point? Wirth "*I think that's an issue to watch. I think, in the short to medium term, we've still have OPEC and OPEC+ bringing production back. Longer term if we get strong demand growth, strong economic growth and we don't have reinvestment to bring new supply to the market, we could see a tighter market.*

A - Roderick Green {BIO 6898494 <GO>}

(Question And Answer)

A - Michael K. Wirth {BIO 3445929 <GO>}

Okay. We will begin with Jeanine Wai from Barclays. Good morning, Jeanine.

Q - Jeanine Wai {BIO 16974257 <GO>}

Hi. Good morning. Thanks for all the time today. We appreciate it.

A - Michael K. Wirth {BIO 3445929 <GO>}

You bet.

Q - Jeanine Wai {BIO 16974257 <GO>}

My first question is on -- Our first question is on RNG. And you referenced double-digit returns for RNG, assuming a CI score of minus 250, and for your non-California project-- are you assuming that policy support grows outside of California or do you expect to generate California LCFS credits for all of your plan -- projects?

And maybe if you can talk about your returns on the California projects versus out-of-state projects and whether your conversations with customers really show a willingness to support a price on gas that will generate a return for those projects outside of any additional policy support?

And then our second question. I know there's a lot in that first one. Our second question is more of a general question. Your free cash flow outlook that's unchanged over the period, but you obviously have an increased focus on the growing energy transition businesses. So, our question is, how should we think about the priorities of excess free cash flow above that $25 billion?

And, specifically, should we now think about incremental renewable investments beyond that $10 billion that you mentioned today if we should think about those as competing directly with incremental oil and gas shareholder returns -- oil and gas investments and shareholder returns? Thank you.

A - Michael K. Wirth {BIO 3445929 <GO>}

Okay. Jeanine, thank you. And let me take the second question, and then I'll hand the first one over to Mark for a little bit more details and certainly downstream-related.

We did reiterate our overall enterprise guidance for greater than 10% return on capital employed by 2025 -- $25 billion in excess cash of '21 through '25. And I would encourage you to think about the use of that cash or cash beyond that $25 billion in a way that's very consistent with the financial frame that we've long held and used to allocate capital. So, the first call on that is to ensure we've got a strong and growing dividend.

The second is for organic reinvestment. I'll come back to that.

The third is keep the balance sheet strong, which we've seen recently is so important to whether the unpredictable commodity markets that are business faces. And then, finally, share repurchases which we've restarted this year and 14 of the last 18 years we've engaged in.

So, overall, priorities stay very consistent with that. Excuse me. Within the organic capital, Jeanine, we've outlined an increase to $15 billion to $17 billion. So, we've clicked up the range by a $1 billion from our prior guidance.

And I think you should assume that these projects will all compete, be they in the new energy space or in our traditional space based on returns and how we see the best use of dollars to set the company up for the future. Generating cash out of our existing portfolio to fund the future is very important.

So, I think our traditional business will compete well for capital, but we also do see opportunities that deliver the prospect of good returns in new energies. And so we'll look across all of that. I can't give you a simple formula. It's the way we always look at our portfolio and the trade-offs in returns risk, execution, etcetera.

On your first question, I'll just say: California does have a more supportive policy environment than just about anywhere else we do business today, and that results in investments and activity.

Over time, we expect a combination of cost reductions, technology improvement, market acceptance, and policy advancement in other geographies all to enable the growth of these businesses, and we have customers that are looking for solutions. And so, they've been willing to pay for the solutions in California, and we see evidence of that elsewhere.

Mark, you might want to go a little more specifically into RNG and returns.

A - Mark A. Nelson {BIO 17910242 <GO>}

Thanks, Mike. And, Jeanine, thank you for the RNG question. If you think back to our Investor Day discussions, we talked about why we were so interested in RNG and being a leader in that space.

It started with the concept that this is one of the most cost and carbon-efficient fuels from an RFS and LCFS perspective that it was lower-risk, both from a capital and execution standpoint, and it leverages our strength, both partnerships, value chain thinking, and understanding policy, and we started in California because that's where it's[ph] certainly supported the most.

But we can make this economic across the United States because it's lower-cost outside of the United -- outside of the California, even though it only has D3 RINs, in California we get both LCFS and RFS support and can make it economic there as well even though costs are a little bit more expensive.

And that's why you see us announce this deal with Mercuria, where we are expanding outside to follow our customers and they have been willing to pay, and we've been able to secure double-digit returns across this offering, and we expect that to continue in the future.

A - Michael K. Wirth {BIO 3445929 <GO>}

All right. Thank you, Jeanine. And, next up, we've got Phil Gresh from JPMorgan. Good morning, Phil. Phil -- Okay. There we go. I see you. Are you unmuted?

Q - Phil Gresh {BIO 15118761 <GO>}

How about now? Sorry.

A - Michael K. Wirth {BIO 3445929 <GO>}

That works.

Q - Phil Gresh {BIO 15118761 <GO>}

Good morning. All right.

A - Michael K. Wirth {BIO 3445929 <GO>}

Welcome to 2021.

Q - Phil Gresh {BIO 15118761 <GO>}

Yeah. First question just your European and Canadian peers have all committed to a net zero target, Chevron still has not done so here. So, I'm wondering what you see as the gating items that would need to happen to commit to a net zero target.

And then my second question is a bit of a follow-up on the financial side, with the higher capital spending of about a $1 billion per year through 2025, $4 billion incremental spending you're still reiterating your post dividend free cash flow target. So, what are the offsets you see here relative to the Analyst Day that allow you to maintain the cash flow target? Thank you.

A - Michael K. Wirth {BIO 3445929 <GO>}

Okay. Thank you, Phil. So, let me start with, with net zero. We showed a pathway to 35% reduction in our upstream Scope 1 and Scope 2 emission intensity by 2028. And we also outlined further reductions, post-2028 that bring emissions down even further, some of these are not economic today the technologies may not be mature or they just don't prioritize versus the other more efficient investments we have prioritized in the near term.

We see a pathway to get down to somewhere in the order of 20 million tons overall in our upstream portfolio and getting to zero beyond that will require new technologies, more ambitious policies, we were talking about a minute ago, development of larger offset markets. These are all things that we're working on. They're all part of the new energies portfolio that Jeff will be leading and we see real progress on all the fronts necessary there. You know, it's a significant improvement in just this decade that we've outlined.

And so, these net zero aspirations that most people have made 2050 is the date that they've targeted them for and we're going to make significant progress just this decade. There are two decades that follow for more work on technology, on policy and things like offset market. So, we've got greater confidence today that those things are maturing. They're accelerating and as you can see, we're committing more capital to them.

So, the specific net zero aspiration is a topic that we have discussed with our Board many times and continue to discuss with our Board. And we're going to update our climate report later this year. And I think you can expect to see in that report a response to shareholder votes from this year's annual meeting and will update our thinking on net zero. So, stay tuned for more there, Phil.

On the overall financial performance of the enterprise, we're seeing real delivery of benefits from the transformation that we went through last year and strong performance in our base business that is online, on track or even in some instances ahead of pace with what our aspirations were. As we allocate more capital to new energies, it'll affect cash from operations to a certain degree, because some of these projects going to take some time to deliver their benefits.

But the overall assessment of our portfolio with the strong performance in our core business, the benefits from the transformation. And what will be a scaled in investment into new energies. We're still confident that the overall guidance can be delivered, and that's really a testament to the strength of our core business in the traditional side of our energy portfolio.

Okay, next, we're going to go to Neil Mehta from Goldman Sachs.

Q - Neil Mehta {BIO 16213187 <GO>}

Thanks a lot. My first question is around M&A capability. It has historically been a strength of the organization at least recent years on the traditional oil and gas side. Do you think you have that capability as it relates to the clean energy side and do these partnerships, create that foundation? And the follow-up question is around carbon capture. As you said, you had some experience around this in Australia. Can you talk about lessons learned? And how do you think about progressing that technology going forward? Which is, as you said, important to achieving some of the carbon targets we set out.

A - Michael K. Wirth {BIO 3445929 <GO>}

Sure. So, let me talk about M&A and then I'm going to ask Jeff as responsible for CCUS to make some comments on that. Neil, I think the short answer is yes, the discipline that we have exhibited in traditional M&A is a discipline, you can expect us to exercise in new energy M&A. And so, we have people that are very commercially capable and I think negotiating deals is something we've done across up, mid and downstream for many years.

These are new technologies but the fundamentals of the commercial transaction remains similar. I think there is a -- where we've seen a pretty well valued, I'll call it market for a lot of these start-ups in green energy here in recent times we've seen, special purpose acquisition vehicles used to take many of them into public markets, and we need to be mindful of some of the lessons we've learned in our industry, as we looked back over the last decade plus as valuations have start up and we need to be sure that we remain disciplined. But I would expect you to see the similar performance in terms of discipline and commercial skills that our organization has in the M&A space.

On CCUS, we've been working with CO2 for decades in terms of enhanced oil recovery. So, transportation of carbon dioxide, injection of carbon dioxide, management of subsurface reservoir behavior of CO2. We got big projects, is were mentioned in the remarks today in both, Canada and Australia.

And I think there have been a lot of lessons. Jeff, you may just want to comment on how those lessons read across to some of the things that we're working on now to expand our CCUS portfolio.

A - Jeff B. Gustavson {BIO 21990800 <GO>}

Thanks, Mike, and thanks Neil for the question, good to see you again. Yeah, there's two pieces to our carbon capture utilization and storage or sequestration strategy. First, we'll focus on existing Chevron assets Mike talked about Gorgon there are a lot of very valuable lessons learned from that project that will carry forward into future projects.

We've got a number of carbon capture pilots underway in our San Joaquin Valley upstream operation and if those turn out to be successful, which we hope they will, we can scale those across the rest of the enterprise. So, we'll focus on our existing businesses, but we're also going to focus on third-party customer businesses, a new third-party customer business, specifically around regional hubs for CCUS.

So, these are large concentrated industrial areas with a number of different emitters. We'd like to come in there on a standalone basis or in a partnership consortium, identify the storage location for the CO2. Obviously, we bring a lot of capabilities subsurface and other in that area.

But also build out the CO2 transportation and distribution infrastructure to then be able to go out to all of those potential customers and provide a full of CO2, CCUS service, or provide a customized solution depending on what the customers' needs may be, in this space, it's about the assets, our capabilities and also the customers that we can bring into the CCUS market, but also into all of these new energies businesses that we're going to scale over time.

A - Michael K. Wirth {BIO 3445929 <GO>}

Okay. Hey Neil, thank you very much. We are going next to Devin McDermott from Morgan Stanley. Good morning, Devin.

Q - Devin McDermott {BIO 19137879 <GO>}

Good morning. Thanks for taking my question and thanks for the helpful update today. So, my first question is actually on carbon neutral LNG. I think you had a remark earlier about a deal you would sign for emissions, tagging for some of the LNG sales.

And one of the things we've seen evolved in that market has been emissions offsets paired with certain cargos, when you look at your LNG business and also the emissions trading or offset business. Do you have in place you talk a little bit about the evolution of the opportunity set there tied to carbon neutral LNG and also whether or not you're seeing buyers willing to pay a premium for low-carbon or no carbon cargos.

That's question one, and then question two is on the downstream side and some of the renewable fuels investments. I think you mentioned that the Bunge partnership covers about 30% of your feedstock needs. If you talk a little bit about the plans for that other 70% and what you've done to secure feedstock costs?

A - Michael K. Wirth {BIO 3445929 <GO>}

Okay. Yeah. Thanks, Devin. I -- look, broadly speaking, we are seeing more interest from customers in paired contracts, and looking to understand the full value chain, carbon footprint of products. And I think that's a trend that we're likely to see continued to LNG, but also in other products. And I think you raised a really important question, which is generally, there is a cost that comes with these things and to what extent is the market willing to bear that cost.

I think that's something we're going to discover over time and I think customers in the first instance would like to have everything at the same cost. I think that's probably not going to turn out to be realistic across most energy products. But Jeff, maybe you can comment little bit more on that because it was in your portion of our remarks today. And then from there, we'll just go straight over to Mark to handle the question about Bunge, and the rest of our renewable feedstock sourcing.

A - Jeff B. Gustavson {BIO 21990800 <GO>}

Thanks, Mike and thanks for the question. We are seeing an increase, a significant increase in demand for (Inaudible) what we've referred to as voluntary carbon credits attached to the -- to our products. We -- I talked about an agreement we have with Pavilion Energy, a five-year LNG sales agreement. That's a great example where Pavilion expressed an interest to carbon footprint, the volumes that were being sold to them and that could lead to an advancement of attaching credits to those volumes going forward.

We're also in discussions with a lot of other customers and not just in the LNG space, but across our upstream, midstream and downstream in chemicals businesses. There's three sources of demand we're already -- we already have a lot of experience in the credits arena in meeting our compliance commitments. And I talked about some of the key geographies around the world where we already do that.

We're building experience in the voluntary segment, which is another source of demand. And we're looking to build a much bigger carbon credit business by investing in nature-based projects building that business being able to attach more of these credits to other products that we sell to meet the voluntary demand. But also to trade some of these credits over time. So, we -- Mike talked about this in his comments. We see this as a part of the new energy space that could scale significantly in the years to come.

I'll hand it over to Mark now to talk about Bunge.

A - Mark A. Nelson {BIO 17910242 <GO>}

Devin, thanks for the question. You may recall back in our Investor Day, we talked about when it came to renewable fuels and especially renewable diesel and sustainable aviation fuel that we have three beliefs that were really important to us. One was that feedstocks were going to be critical. The second was the margins were going to normalize and so we needed to be capital efficient.

And then, of course, we had to have a good place to sell the product. And I think you'll see that we're activating all of those elements in our discussions earlier today, and we're really excited about the Bunge partnership. The 50/50 bench rate just to step back for a moment, it essentially secures supply today from existing crushers. It allows us a platform for growth with Bunge. It allows us to partner with a leader who cares about sustainable agriculture. And finally, it allows us to participate in the margin for -- of crushing and pretreatment.

And I know you all know this, but just two years ago, three quarters of the soybean-based renewable diesel margin was in the R&M side, the refining and the marketing side of the business. And here, in the last two months. Excuse me.

It's actually been in the pretreatment and Crusher side of the equation and starting to work its way back. And so, the Bunge relationship allows us to secure supply from existing assets, allows us to grow with Bunge and allows us to participate in that margin structure. In addition to growing with Bunge, we have a desire to be a part of all of the generations of feedstocks.

So the arrangement with Bunge focuses today on the first generation, which would be soy, we would expect to grow into second generation of tallow type of bio feedstock and then finally, maybe into algae. So, we'll continue to grow both with Bunge and in regard to these other generations of feedstocks. It was really nice about this Bunge relationship is the facilities in Destrehan, Louisiana and Cairo, Illinois. These are proven high-quality high-performing assets with waterway access and 7,000 tons per day of output and we can grow that with them. In fact, we've committed to do that by 2024. So, the 30% is a start, we'll continue to grow with Bunge and we'll look for other sources as well. Thanks for the question.

A - Michael K. Wirth {BIO 3445929 <GO>}

Yeah, Devin. I think just to close out on that. You know, some of the points Mark makes are important. The fundamentals in some of these value chain businesses don't change. So, reliable of high-quality feedstocks matter margins move across those value chains capital efficiency matters.

And then, we do want to be able to source from multiple sources and the relationship with Bunge is a great start and one that can grow, but it doesn't preclude other, other similar kinds of arrangements that you could see us enter into as well. Okay.

Let's go to Doug Leggate with Bank of America next. Good morning, Doug.

Q - Doug Leggate {BIO 1842815 <GO>}

Good morning, Mike. Hopefully you can see me okay. Thanks for taking my questions.

A - Michael K. Wirth {BIO 3445929 <GO>}

I can.

Q - Doug Leggate {BIO 1842815 <GO>}

So, you've given us about a $1 billion of cash flow for the run rate at the end of 2028. Can you give us an idea what you think the incremental returns are going to look like relative to the broader business. And I guess what I'm really trying to understand is, how you came up with the scaling of how much you want to allocate to this business, because it's still -- I guess you're going to get the comment that it's still quite a bit lower as a percentage of your spending compared to say your European peers? So that's my first question.

My second question is really more California-centric. The scoping committee meeting that carp[ph] held on the 17th of August, and I guess the meeting report on the 2nd of August. There are some interesting things in there regarding what may or may not be included for LCFS credits going forward. One of the things that caught our attention was the carbon capture and storage may not be included as one potential scenario. I just wonder to what extent you've taken, you know, those -- the range of possibilities and to attend as you put together your strategy?

A - Michael K. Wirth {BIO 3445929 <GO>}

Okay. Thanks, Doug. So, first of all on scale and returns. We think these are going to deliver competitive returns within our portfolio. And we're serious about delivering higher returns. And a number of these investments today offer double digit returns. And we would expect broadly speaking to see that out of this portfolio, as we get out to the end of the decade.

Now, I said in my comments, some projects are no doubt going to work out better than others. And these are less mature technologies, these are emerging markets, these are new value chains. And so, I would say there's a higher beta around the outcomes here and we may find some that exceed our expectations and I'm certain there will be some that we learn a lot and fall short. But as a portfolio, we feel like these will be delivering double-digit in competitive returns.

In terms of scale, Doug, you know, I recognize the point about comparing it to our traditional business. Just look at the scale of our traditional business and the scale of these businesses today and throwing more money at them faster, in some cases, isn't going to accelerate technology or market adoption. And so, we've outlined or we believed our ambitious growth targets off of a small base, because these are (Inaudible) businesses.

This is different than wind and solar, which you'll get two decades or more of technology and market developments that make them relatively mature compared to the kinds of things that we're talking about today. So, $10 billion over the next several years is a sizable commitment into growing these technologies. And look, I hope the returns in the market development policy are so good that we find more than that.

And this is what we believe today. We've got a robust pipeline of discussions underway. You've seen a number of announcements here in the last several weeks that reflect a large body of commercial activity that's been underway for some time and is beginning to mature. So, we'll continue to update you on both returns on capital commitment. This is our best view today, and we've been working on this for quite some time, so we've got confidence in what we're outlining.

But as I said, well one more year from now, two years from now and update you on that. Your question on CARB and the evolution of policy in California. I'm going to ask Bruce to add a little bit of detail to this in a minute.

Well, I'll just say Doug is, we've been on a journey with the state of California for decades. As California has sought to be a leader in environmental policy on water, on fuel, on emissions, on criteria pollutants, and now on greenhouse gas emissions. And we have a long and very collaborative and constructive working relationship with the Air Resources Board. We understand their priority on carbon neutrality. And we certainly agree with that and support that and there's no doubt that partnerships will be vital and essential in delivering on California's aspiration to become carbon neutral. And so, we intend to be a good partner there and to work with the Air Resources Board and with many other partners in the state to make that happen.

Bruce, you may want to comment a little more specifically on the state of rulemaking and the other aspects of Doug's question.

A - Bruce L. Niemeyer {BIO 20504934 <GO>}

Sure, Mike. The question of the role of carbon capture in the state's journey to carbon neutrality has really been on the table from the outset. And as you look at every scenario, carbon capture is an important element in achieving carbon neutrality for the state. We have assets and capabilities that position us to be a partner with the state and importantly, other parts of the economy in the state to seek and allow the entire economy to achieve carbon neutrality.

Jeff mentioned, the project Mendota, which is our first tangible effort in the state, which will deal with and support the agricultural industry in the center of the state. We have other project concepts, he also mentioned hubs. And those hubs provide platforms for us to partner with other Industries in the state and help the state move effectively towards carbon neutrality. And so, as Mike said, we'll continue to work with regulators and a variety of settings as we work to support the state's overall efforts. Thanks for the question.

Q - Doug Leggate {BIO 1842815 <GO>}

With specific to the --

A - Michael K. Wirth {BIO 3445929 <GO>}

Okay, we'll move to Alastair Syme from Citi.

Q - Alastair Syme {BIO 1729060 <GO>}

Thanks, Mike. And thanks for the presentation. Can I ask on the $10 billion of incremental capital, roughly how that splits between upstream Scope 1 reduction? What you're doing in the downstream, and I guess what's rest, which I guess is on offsets and hydrogen.

And then, secondly, and I guess similarly on the $1 billion of cash flow. Are we including upstream Scope 1 reduction gains in there? For example, if you capture gas that was previously flared and sell that as a revenue source? Thank you.

A - Michael K. Wirth {BIO 3445929 <GO>}

Yeah. So, Alistair. Broadly speaking, we got a chart in there the bars are a little, little bit fuzzy because these things are not entirely precise. But on the $10 billion you can think of that is roughly $3 billion on carbon capture and storage, and offsets another $3 billion on renewable fuels, about $2 billion on hydrogen, and about $2 billion on greenhouse gas reduction activities within our own portfolio. That's the view today.

And as you look forward on the $1 billion in cash flow. I think by 2028, we will see roughly half of that coming from renewable fuels, which are little bit easier to drop into value chains today, a little bit more mature and certainly something that we're growing aggressively and you'll see another portion of that coming from CCUS as it begins to penetrate and then hydrogen would make up to the balance.

And there's this, I think a small contribution, I'd to be honest with you. I can't recall, we can have Roderick clarify for you. Whether are let's say methane that is captured. Bruce talked about replacing methane with nitrogen in tank blankets, for instance. I can't remember where that drops in.

But renewable fuels clearly in the early part of this are going to be the larger contributor to cash flow, hydrogen CCUS are going to take longer to get some of these projects up to scale and they become bigger contributors of further out and the capital allocation is as I indicated. Thanks very much for the question. Let's move next to Manav Gupta from Credit Suisse.

Q - Manav Gupta {BIO 20380315 <GO>}

Hey guys, thank you for the presentation. It's interesting you've put out 100,000 barrels between SAF and R&D. Can you help us clarify what percentage would be R&D and what would be SAF? And the reason I'm asking this question is, because at this point there's more government support for RD than SAF you get 1.6 for SAF and 1.7 for RD. So, do you expect some kind of policy change from the government, which would help you grow SAF at a faster rate than RD?

A - Michael K. Wirth {BIO 3445929 <GO>}

Yeah Manav, I'll just take that one. And I'll say, you do have stronger policy support today for RD than for Sustainable Aviation Fuel. Discussions underway on trying to create similar kinds of incentives for Sustainable Aviation Fuel. Big part of our business is to create flexibility and options here.

And whether you're talking about the overall rate of demand growth for energy in the world or the mix in the broadest sense between coal, oil and gas, renewables, hydro, or you get right down into fuels like distillates and you're looking at renewable diesel to Sustainable Aviation Fuel or conventional versions of those fuels.

We have the capabilities to deliver across the spectrum and we're investing in our refineries and Mark made mentioned mention of this to create flexibility in our processing units to process traditional or renewable feedstocks and to convert that into a variety of products. Ultimately the allocation was products will be a function of market signals, policy and customer demand.

And we didn't get more specific than a 100,000, because we intend to be flexible and have the capacity. But at this point it's not entirely clear, how the split will break down. And we'll continue to update you on these things as they evolve. But we don't intend to get locked into point solutions, which if policy doesn't show up.

Now, we've got capital that we perhaps shouldn't have invested. We're going to try to be very efficient in our capital investment, create flexibility and create options. And then as markets clarify and demand emerges, we will meet that and perhaps lean into that with subsequent investments.

Thank you very much. Next, we're going to Paul Cheng at Scotia Bank. Good morning, Paul. Paul, you might be muted.

Q - Paul Cheng {BIO 1494607 <GO>}

Can you hear me?

A - Michael K. Wirth {BIO 3445929 <GO>}

Yes, I think I can. Go ahead. Yes.

Q - Paul Cheng {BIO 1494607 <GO>}

So I have to apologize first, because I have some connection issues. So, you may have already answered the questions. If you have, please let me know. When we looking at higher return, lower carbon that slogan. And can you give us -- because the nature of the business in your $10 billion investment is different than your traditional projects.

How the return qualify or that how the criteria is there any different? Or how you look at those business and how you judge whether it is a good business? So that's the first question. Trying to understand that is that when you're looking at those $10 billion investment from a return criteria, are they different than or how do they different than when you're looking at what is more important in different?

The second one is that when we look at the renewable diesel business. Everyone seems like yes, going into that, the barrier of entry is close to zero. As long as you have money, you can preview a renewable diesel plan. We have recently conducted an exercise and what we find is quite abnormal that with not even mentioned that you guys joined the view a lot new renewable diesel capacity, just on the existing plan. Seems now, we're going to have a major problem with the feedstock and also the LCFS credit probably going to become oversupply, and that margin is going to come down a lot. So, how you going to save that on that? Thank you.

A - Michael K. Wirth {BIO 3445929 <GO>}

Okay. Paul. Thank you. So, look, these are businesses that are emerging. And so, the returns in -- I'll start with your -- the latter part of your question and work back to the broader issue. You may not have heard Mark say, but earlier in response to other question. He said, we expect margins to normalize which is code for come down. And for the reasons you identified.

Mark also said, we're going to be very efficient in our deployment of capital, we're making conversion of existing refinery units at modest capital investments to create the flexibility here as opposed to Greenfield plants where you've got a very different capital profile. And so, we're mindful of the way these markets can evolve and we've been in the commodity business for a long time.

So we've seen over build vis-a-vis demand and what that does, and we're very conscious of that and I think savvy investors in new energies need to recognize that at its core these are all commodity markets. And they're going to have commodity attributes that drive financials.

And that's something that we are building our business with that very much in mind. If I interrupt the broader topic Paul did say earlier, we expect these to be competitive with our other businesses and frankly the kinds of things we're looking at now, bit renewable, fuels, carbon capture, hydrogen offsets. We've got expectations for double-digit returns out of these things.

If we look at renewable power, it's hard to find even levered returns that get into the double digits on wind and solar, which is one of the reasons why that's not part of our strategy. We think there's plenty of capital. We think there's plenty of capability and there's good developers out there. We don't see the opportunity to create competitive advantage or strong returns that benefit our portfolios.

So, over time, we're going to find out how the returns in these businesses mature and they'll be a function of the things we've already mentions, right, technology advancements, market development, policy, customer demand, and we've got assumptions on these things today. We've got our best view, but I've got to say, the error bars around them are wider than they would be around our traditional business because, these are new businesses, and they're emerging businesses. And we're stepping into this with our eyes wide open.

We talked about where we're going to start, and it's where you've got existing policy, you've got existing markets, you've got existing customers that are looking for these products and we'll then build out learn there and look for opportunities to extend those lessons into other markets, where we see the same kinds of trends emerging. So, a little bit of a different set of risks that we will be managing through here, but we haven't lowered the bar for returns. That's the bottom line.

Okay, next we're going to go to Biraj Borkhataria from RBC. Good morning, Biraj.

Q - Biraj Borkhataria {BIO 17234528 <GO>}

Hey, thanks for taking my question. Your strategy involves a growing reliance on monetary carbon market and this is driven by customer demand, I guess. But there's been some criticisms around those markets because of transparency or consistency and what it takes to generate a credit and pricing and things like that.

So, could you talk about your experience so far? And it seems like you and a number of your peers will have a large presence in these markets going forward and they're evolving pretty quickly. So, I was wondering if any concerns have come out so far and how you're thinking about those evolving markets? Thank you.

A - Michael K. Wirth {BIO 3445929 <GO>}

Yeah, Biraj. Thank you for the question. I'm going to ask Jeff to speak to this little bit more, because although as he said he's new in his role, this is an area where he's been getting a lot smarter fast. This is -- we need to have markets that have strong assurance and that people can trust.

And so, it is -- you can look at the history of the renewable fuel standard in RINs and the early days in RINs for a while there, it was more successful in stimulating kind of dodgy and questionable RIN activity than it was in actually stimulating new technologies. And so, as these markets come into existence, there need to be agreed standards and assurance mechanisms that market participants can rely on. They are -- these kinds of things are being worked.

Jeff, maybe you can talk a little bit about where we are now and how we see this evolving in the coming years.

A - Jeff B. Gustavson {BIO 21990800 <GO>}

Yeah. Thanks Mike and thanks for the question, Biraj. It's a really -- it's a really good one, and I think one that, that's sometimes overlooked. The importance of growing this sector really depends on having a very stable base, a very transparent reporting, standardized reporting around the world, convergence around the world. So, we know, what a good credit is, what a quality credit is and what one isn't, and we can work towards generating more quality credits versus non-quality, non-standard less transparent, transparent ones.

So, this is something that that will support the future growth of these markets, and it's something that Chevron's been working on for a number of number of years going back decades, in fact, internally foot printing our own carbon emissions. And you've seen the progress that we've made if you look back at just in the last few years, the transparency and the data quality, where we've taken things inside the company, we've seen significant improvement there.

We're also taking that knowledge so that you might think of that as an asset and a capability of the company. We're also involved in many external organizations that are working this issue globally. And we'll share the lessons that we've learned managing this inside the company to help grow the transparency and standardized reporting around the world, which, as you said, will support growth in this market, going forward. So, thank you for the question.

A - Michael K. Wirth {BIO 3445929 <GO>}

Yeah, Biraj. Thank you. We've got -- we go all the way back to I recall under the UN clean development mechanism. I think it was our garage at geothermal project in Indonesia nearly 20 years ago. We were certifying tradable offsets. And so, this is an area, where we've got deep expertise and are working with many others now to extend it into a lot of the emerging fields that hopefully can help us create these offsets that can be part of the solution.

Okay. Let's go to Jason Gabelman from Cowen. Good morning, Jason.

Q - Jason Gabelman {BIO 18730121 <GO>}

Good morning. Thanks for taking my question. The first just on the carbon reductions that you've laid out 30 million tons. It appears 25 million tons of that through 2030 is from carbon capture. So, is all the remaining activities just reducing emissions by 5 million tons

And then, sorry, I know you're short of time, but can I just ask one other question? Is this -- this update today, does this effectively rule out your participation in solar or wind or would you revisit that at some point or other if the opportunities arose or as I know a dead duck?

A - Michael K. Wirth {BIO 3445929 <GO>}

Okay. So, let me try to get through those efficiently. It's interesting, Jon. Now as we sanctioned projects, part of the discussion is the carbon intensity of the asset. And few years ago, that wasn't necessarily part of the part of the conversation. And when you make it part of your FID criteria, guess what, your project development teams find ways to reduce carbon intensity.

And as Bruce gave a number of examples, we actually see a better economic outcomes, because we're reducing the count of equipment, we're reducing the footprint of some of our facilities we're ensuring that we're using the resource even more efficiently. And so, as we seek lower-carbon we're actually finding that there are economic benefits that often play into projects. And sometimes there are trade-offs and there's a point at which just like any other design parameter, you reached a point of diminishing returns, but there's an active consideration of that in everyone of our upstream investment decisions.

On the question of Australia, you're right, those are remote facilities that generate a lot of power, because you got a lot of compression required and into that power generation right now is natural gas. And so, they have a higher carbon intensity than some of our other facilities that don't have that same power demand. Over time, we're going to look for ways to address that. And we may not have said it specifically, but we're looking at renewables as part of the power equation in Australian LNG and seeing how that may change things when we sequester CO2 at Gorgon right now, are there ways to leverage that with some of the combustion emissions. All of these things are being reviewed. And over time, I think you'll see us look for ways to address them.

And I'll just take the Scope 3 question and say, when we update our climate report here in the fourth quarter, we will address Scope 3 and I think you'll see you make a really important point that a good way to look at things is Scope 1, 2 and 3 because there are trade-offs among them at times and the real goal is to get them all down and find a pathway to lower emissions in aggregate. And so, we'll say more about that when we release the report.

Finally on solar and wind, I would say that for the foreseeable future unless it enables our operations and that could be green hydrogen, that could be reducing the carbon footprint of an existing asset to the topic we're just talking about, I think that's where you're going to see solar wind in our portfolio. As a merchant developer, there are, just plenty of people doing that; it's a crowded space. We don't bring much to it. And I don't think you'll see us venture into that. We just got better places to spend our people and our capital.

Okay, Sam Margolin. We're going to sneak you in just under the wire from Wolf Research. Last question

Q - Sam Margolin {BIO 17168841 <GO>}

Appreciate it. Thank you. Question is on -- it's a sort of a follow-up on upstream project selection question and the unit intensity of emissions. The Permian is a real benefit to you on that metric, very favorable unit emissions intensity. But the tension is that, it's not supported, it's not always supported domestically under different, under various political regimes.

So, to the -- is that something that's influencing your mix in the Permian? How do you see yourself sort of advancing the Permian number, battling the tension between favorable unit intensity, but sort of uncertainty around the local regulatory regime? And I'll leave it there.

A - Michael K. Wirth {BIO 3445929 <GO>}

Yeah. Thanks, Sam. We've really kind of only had two administrations so far as our Permian business has been growing. And maybe you can argue it began under a third. But like most of our long life to assets, it will produce for many, many, many administrations and we've got a history of working with administrations from both sides of the aisle to meet environmental, economic, and energy security policies.

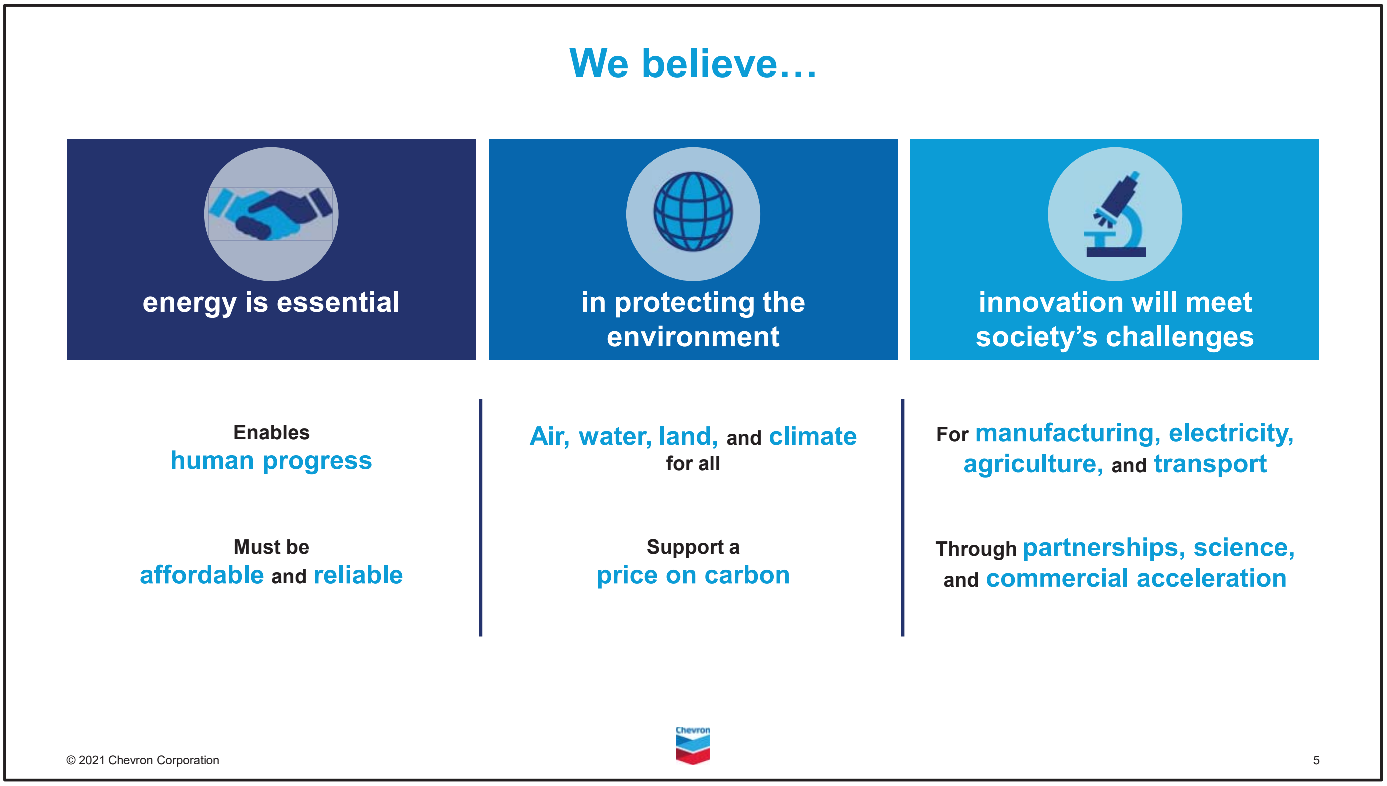
And so, look, the Permian is a really important assets to the country and it's an important assets to our company, it's a low-carbon intensity asset today and it can be a lower-carbon intensity asset in the future. Bruce talked about how we're bringing renewables into greater supply for our drilling and completion needs, our ongoing facility needs. And the example he cited from the DJ Basin in Colorado of advanced facility design can come in and create even further contributions.

So, from an energy security standpoint, domestic investment standpoint, employment standpoint, the Permian is a great asset for the United States. And there are ways for us to continue to bring the carbon intensity of that production down even further.

And so, I think any administration that we work with is going to look at that in totality as opposed to an isolation. And I think we've got a pathway to a really bright future. It's a great asset for us in an energy transition. It's got flexible capital. It's got the ability to bring the carbon intensity down. And it's a very, very large resource. So, I think it's a tremendous asset as I said both for the country and the company.

Okay. We are running right up against the wire. I want to thank everybody for your time today. I want to thank you for the questions. We will continue to engage with you on subjects related to energy transition. We are absolutely committed to delivering high returns to our shareholders, absolutely delivered -- committed on delivering lower carbon as a part of that and delivering a business that creates value for shareholders both in the short term and enduring into the long term in a lower-carbon future. We've got a strong portfolio, we've got the capabilities, the assets, and the customer relationships to do that long into the future.

So, thank you very much for joining us today, and I look forward to seeing you all soon.



Let me start with some of our most important beliefs and intents.

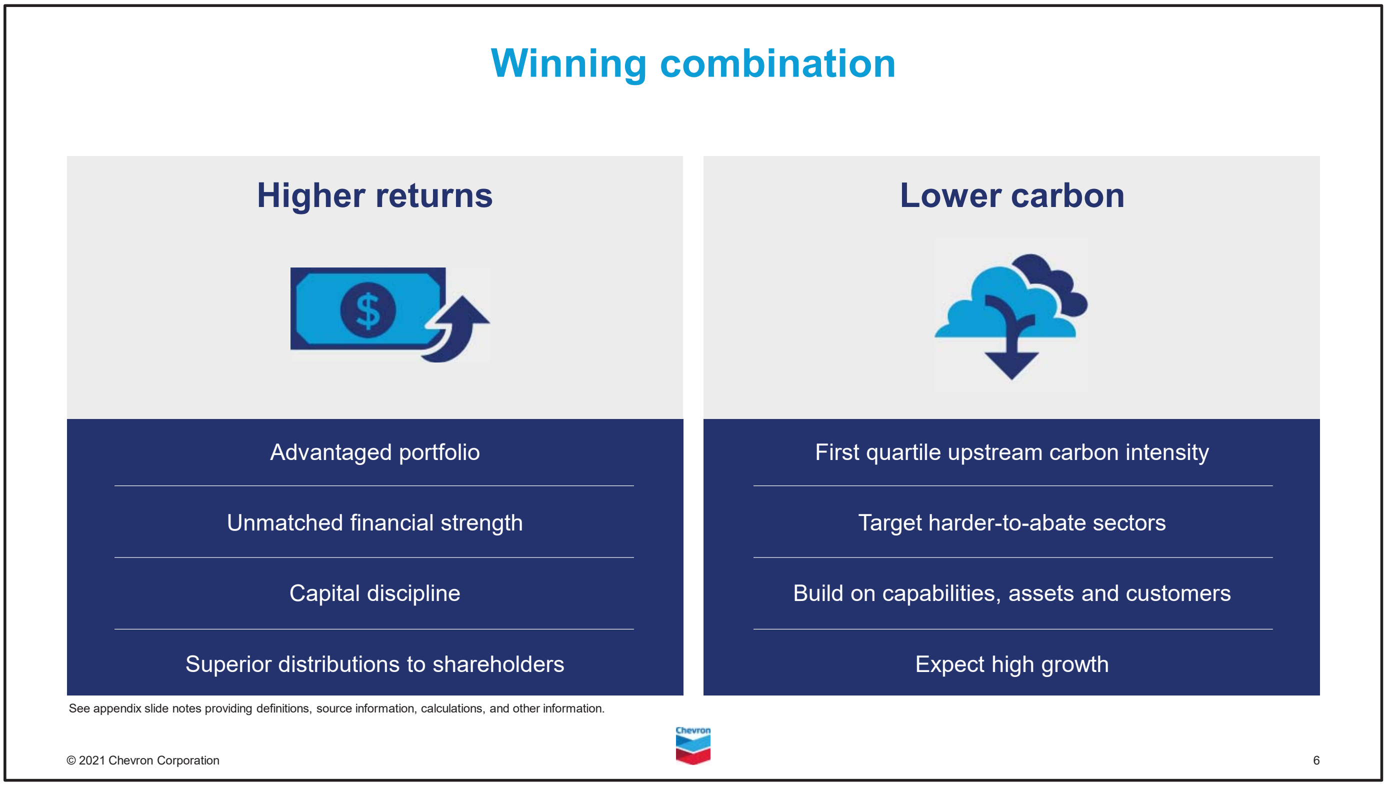
We believe climate change is real and that human activity, including the use of fossil fuels, contributes to it. We believe the future of energy will be lower carbon and intend to be a leader today and in that future.

We believe energy enables modern life. Affordable, reliable energy will continue to be essential to power a growing economy, and to lift billions out of poverty. This will include lowering the carbon intensity of oil and gas operations and new lower-carbon energy solutions.

Government action is essential to enable evolution of the energy system. We support well-designed climate policies and believe a price on carbon is the most efficient mechanism to harness market forces to reduce emissions.

We believe innovation, technology and policy will be the key drivers of change. Each will continue to evolve, and developments may surprise us. We'll know more a year from now than we do today and even more a year after that. We'll continue to apprise you of how developments impact our plans and progress.

Finally, we intend to be responsible stewards of our shareholders' capital. That means a focus on investing with discipline to deliver both higher returns and lower carbon. We plan to establish targets and ambitions to do both, and regularly update you on our progress.



Chevron begins in a different place than others in our sector, with:

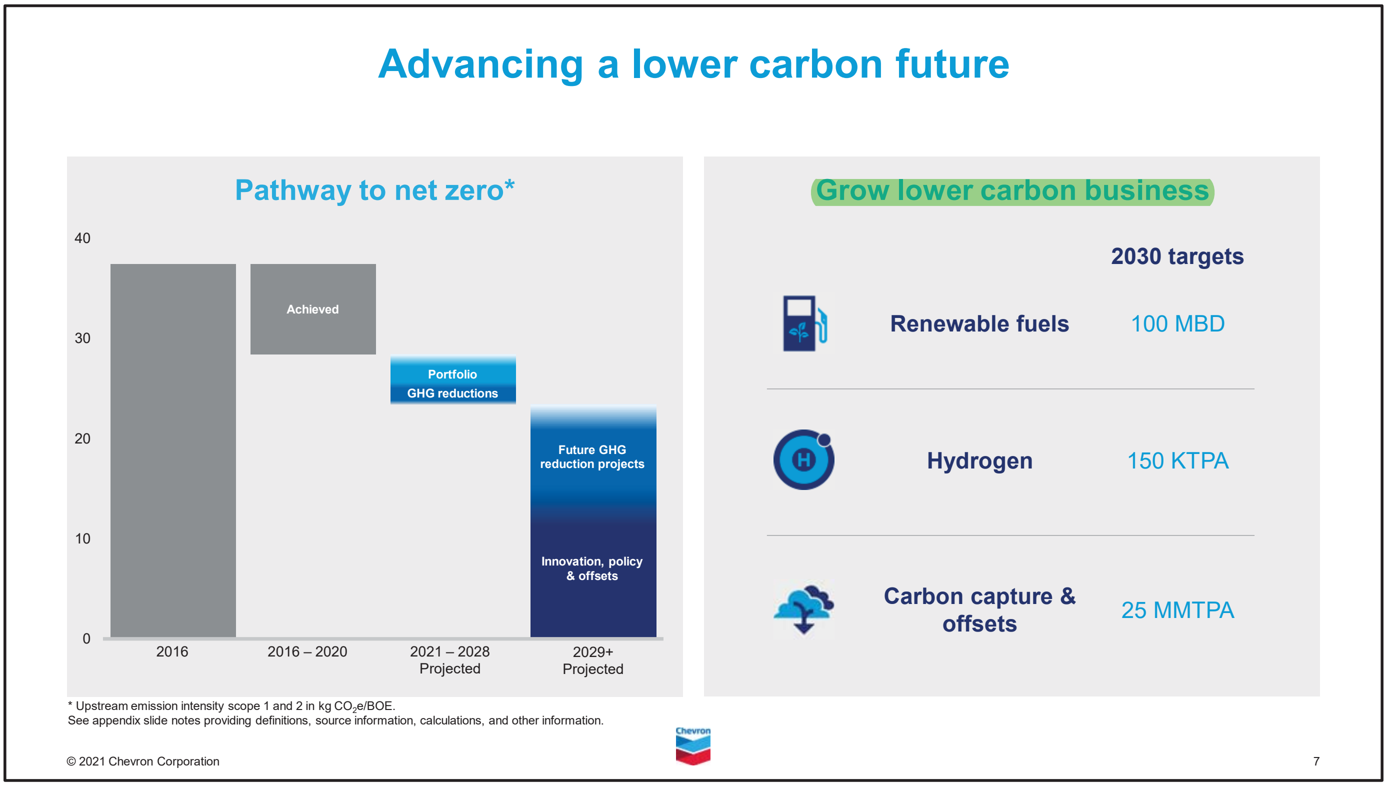
- an advantaged portfolio that is diverse, resilient, low-cost, large-scale and long-lived
- a low net debt ratio heading below 20%
- capital efficient investments that grow cash flows; and
- a dividend up 12% over 2 years, the only one among the integrated energy companies that's higher since the COVID outbreak last March [2020].

And this quarter we resumed our share repurchase program, making this year the 14th out of the past 18 that we've bought back shares.

Our Energy Transition strategy is also different with a goal to maintain first quartile upstream carbon intensity and to grow lower carbon businesses where we believe we can build competitive advantages and that target sectors of the economy that cannot be easily electrified.

A strategy that combines a high-return, low-growth, lower carbon-intensity traditional business together with faster-growing, profitable, lower carbon, new energy businesses that leverage our strengths.

We believe this is the right combination for our investors.



Today, we'll go deeper into the two parts of our Energy Transition strategy.

Bruce will cover the actions expected to drive a 35% reduction in upstream carbon intensity by 2028. Additional abatement projects after 2028 can reduce our emission intensity further.

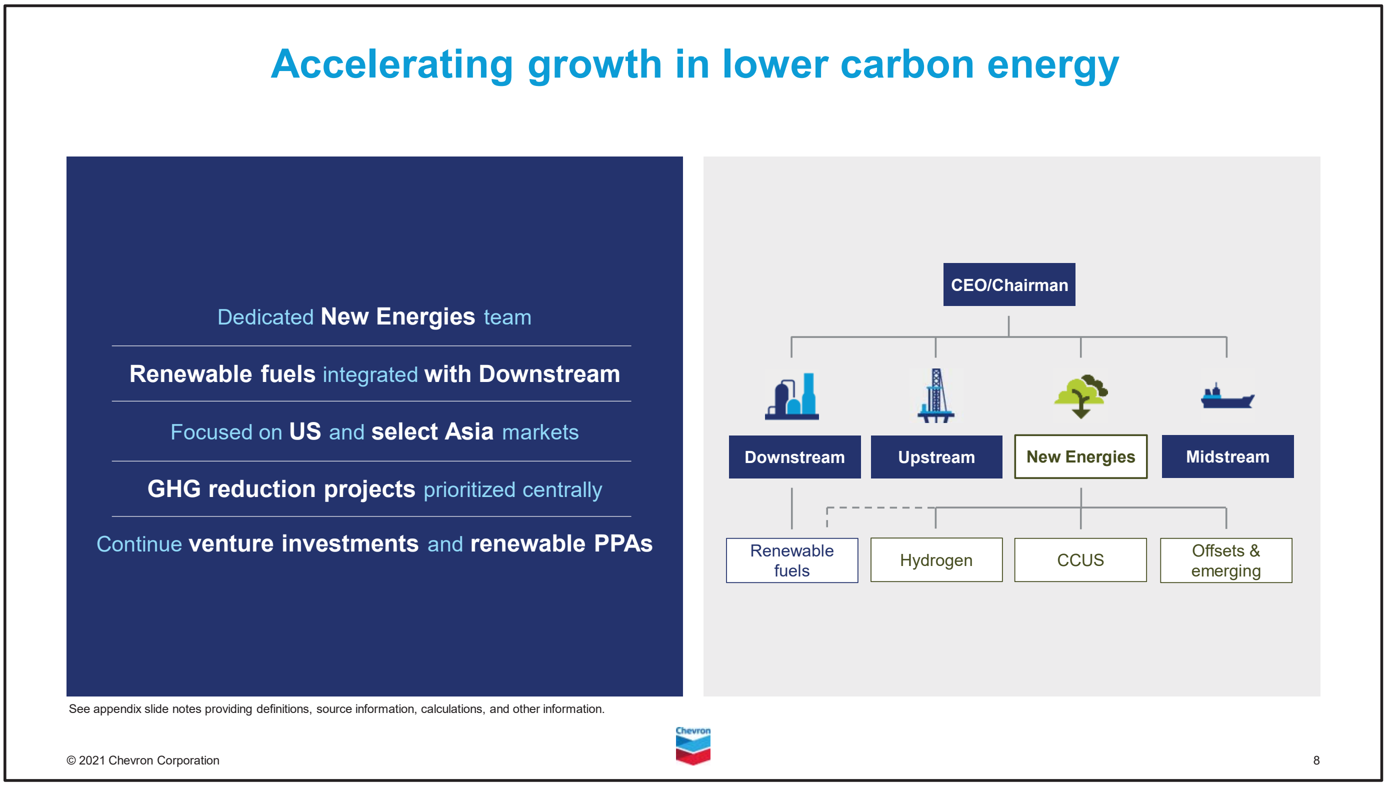
Our ultimate pathway to net zero will require technology advancements, more ambitious government policy and development of large offset markets. Following review with our Board of Directors, we plan to publish next month an update to our Climate Change Resilience Report, which will include Chevron's response to recent shareholder votes on net zero and Scope 3 emissions.

Mark and Jeff then will describe how we plan to grow renewable fuels, hydrogen and carbon capture and offsets. These business lines are earlier in life than renewable power, have value chains that will often connect with our traditional ones and are areas where we believe we can earn double-digit returns.

Because these are still earlier in development, the opportunity and potential for advantage is greater.

It's a straightforward strategy: Be a leader in efficient and lower-carbon production of traditional energy, in high demand today and for years to come, while growing the lower-carbon businesses that will be a bigger part of the future.

A strategy that's both profitable and enduring in the short and long term for our shareholders and all stakeholders.



At the core, our lower carbon strategy focuses on harder-to-abate sectors. Manufacturing, aviation, and heavy-duty transportation are much more difficult to electrify than light-duty transportation. To accelerate progress, we formed Chevron New Energies, reporting directly to me, dedicated to growing businesses in hydrogen, carbon capture and offsets.

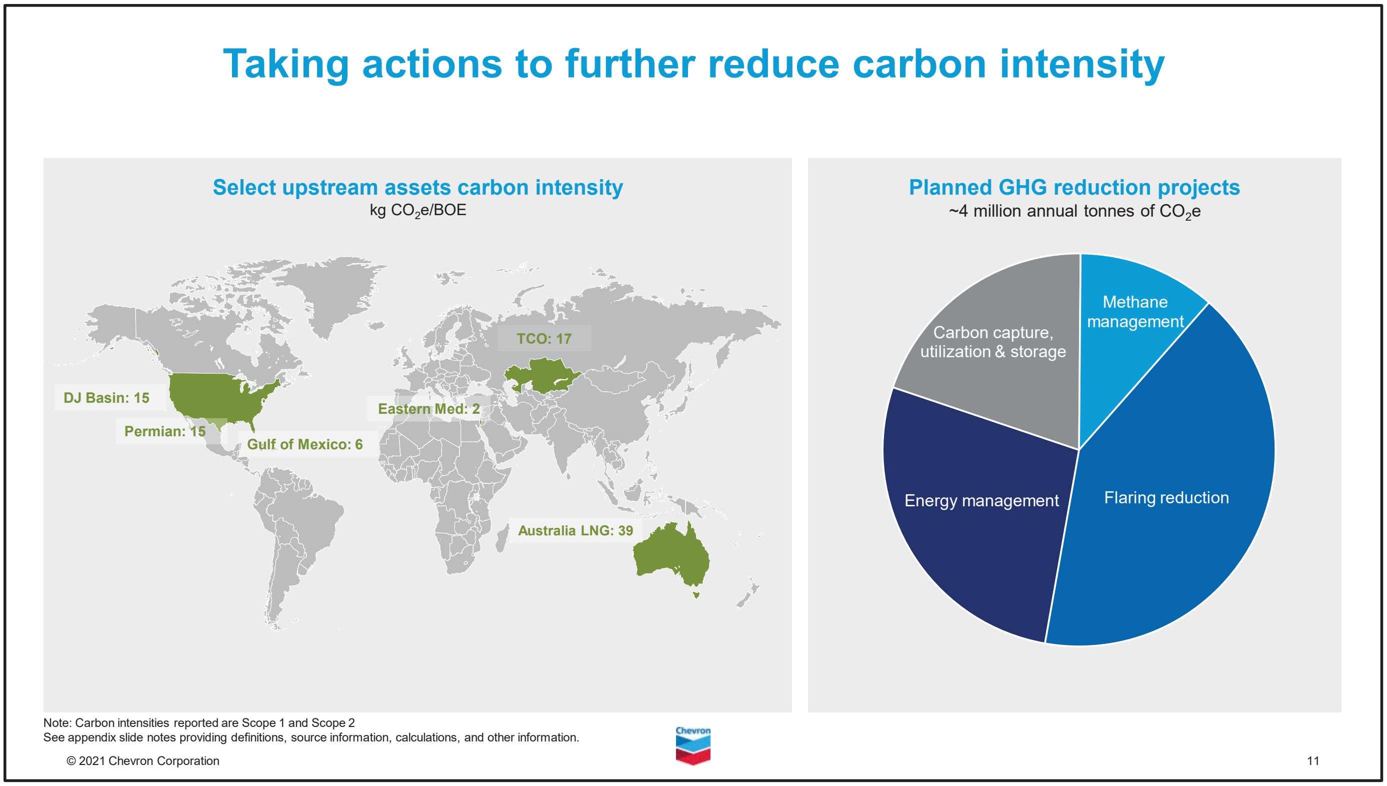
Renewable fuels will continue to be managed by our downstream team. These businesses are linked to existing assets, infrastructure and markets. Mark will share how we can leverage our refining system and customer relationships to profitably grow in renewable fuels.

We've focused first on the US West Coast, where there's already strong policy enablement and also on the US Gulf Coast and select markets in Asia, where we have big businesses and expect policy support to increase over time.

We'll continue to prioritize centrally our greenhouse gas reduction projects guided by marginal abatement costs to reduce the most carbon emissions for every dollar we spend. As Bruce will show, many of these projects also have economic benefits as they enable outcomes like higher production or lower costs.

We'll continue making venture investments, as we've done for over 20 years, working with companies that are developing potential breakthrough technologies. And we expect to increase the use of renewable power to supply our traditional operations and also a growing hydrogen business.

Chevron has world class capabilities – and we intend to fully apply them to accelerate growth in lower carbon energy. Now, I'll pass it on to Bruce.



On our path to net zero, we're taking actions to reduce the carbon intensity of our portfolio.

Over the next four years, we expect to allocate more than two-thirds of our upstream capital to the six assets highlighted in green on the map to help lower our overall upstream carbon intensity.

In addition, we're investing in many greenhouse gas reduction projects intended to reduce methane emissions and flaring, as well as improve energy management.

On the next slides, I'm going to spotlight examples of our current efforts in each of these categories.

Carbon capture will also be important to our net zero efforts. Later, Jeff will cover how CCUS can reduce our emissions as part of regional hubs that Chevron New Energies is developing.

Methane management

TCO tank farm

Expect to reduce GHG emissions by 95%

Additional fuel gas recovery

Incorporated into future designs

2028 Targets

>50% reduction
from 2016

2 kg CO_2e/BOE

Methane detection

TCO, Permian, and DJ Basin

Multiple technologies and methods

Partnering with industry and universities

12

Methane management is critical in the journey to a lower carbon future. We've set a 2028 methane target of 2 kilograms CO_2 equivalent per barrel, which is a 50% reduction from our 2016 baseline.

One of our projects is shown on the left. Throughout the industry, oil is stored in tanks prior to shipment. For safety, a layer of natural gas is typically present on top of the oil to prevent air from entering the tank. This project will replace the natural gas blanket with nitrogen and is expected to reduce tank methane emissions by 95%.

We're also expanding our methane detection capabilities because better detection will help us focus on the best opportunities to further lower emissions. In addition to traditional ground sensors, we're deploying airborne sensors using satellites, aircraft and drones to achieve broader coverage.

Examples include TCO, where we're using satellite technology to survey the production facilities. In the Permian region, we're collaborating in aerial flyovers that cover thousands of sites. In the DJ Basin, we're partnering in a university study that includes modeling, aerial flyovers and site visits to validate and improve methane detection. We're also developing aerial campaigns for the Gulf of Mexico and Argentina.

Methane detection capability is critical to the world's efforts to reduce carbon emissions, and our work with industry and academic partners is an important contribution to the accuracy and credibility of global methane reporting.

Flaring reduction

Increasing Agbami gas compression

Expect to reduce annual emissions by >300KT CO_2e

Increase oil recovery

Improve operational reliability

Targets

>60% reduction
from 2016 to 2028

3 kg CO_2e/BOE
for overall flaring by 2028

Zero routine flaring
by 2030

DJ Basin tankless, flareless design

Expect to reduce carbon intensity by 95%

Expect 15-20% lower lifecycle cost

Scalable to other assets

See appendix slide notes providing definitions, source information, calculations, and other information.

Reducing flaring is also a focus area. We're working to reduce overall flaring by more than 60%. We're also proud to be a signatory to the World Bank's Zero Routine Flaring Initiative. I'll talk about two projects as examples of how we're working toward these goals.

At the Agbami deepwater production facility in Nigeria, produced natural gas is compressed and reinjected into the reservoir. When a compressor goes down for any reason, gas is routed to the flare system. This project will enable reinjection to continue, even when a compressor is offline. In addition to emissions reduction, the reinjected gas also supports oil reservoir pressure and is stored for potential use in the future. We expect this project to reduce equity emissions by more than 300,000 tonnes of CO_2 equivalent per year.

In the DJ basin in Colorado, we've developed a new facility design which is expected to reduce overall carbon intensity by up to 95% when compared to original designs. It requires no production tanks, no flowback equipment and no flare system. Additionally, this design requires a smaller footprint, which optimizes land use and is expected to reduce lifecycle costs by 15-20%. The new design is already being shared with teams working with similar assets across our portfolio.

Energy management

Australia gas turbine optimization

Expect to reduce annual emissions by ~15KT CO_2e

Improved fuel efficiency

Lower lifecycle cost

Moving to **lower carbon intensity energy sources**

New approach to facility design

Permian energy management

Expect to reduce annual emissions by >400KT CO_2e

Reduction in power costs

Solar, wind and lower carbon fuel alternatives

Energy use accounts for about 70% of our Scope 1 and 2 upstream emissions. I'll cover two examples of how we're using energy management to improve efficiency and reduce emissions.

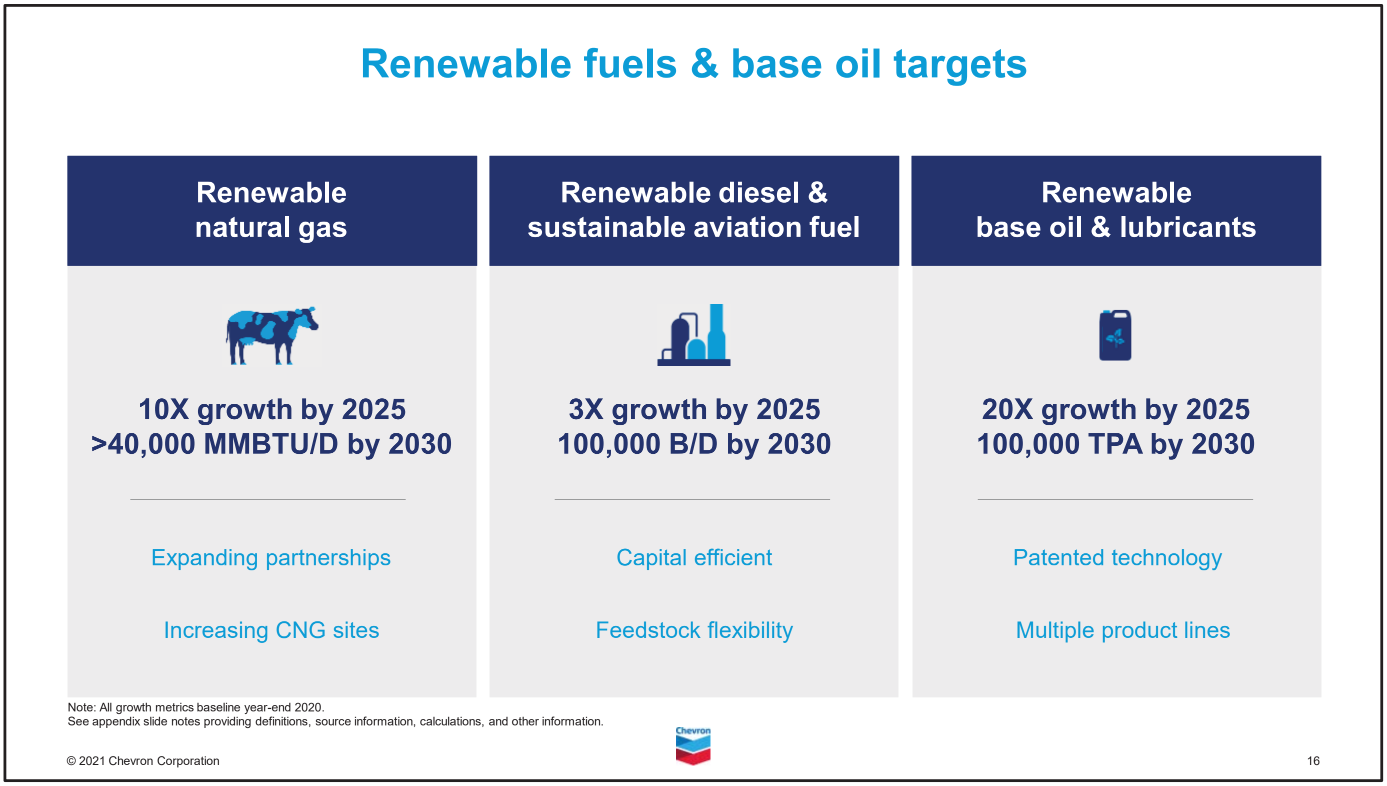
In Australia, we've completed a gas turbine optimization at the Wheatstone LNG plant to reduce the number of running turbines from four to three and optimize each machine's combustion parameters. The project is expected to deliver emission reductions of approximately 15,000 tonnes of CO_2 equivalent each year.

In 2019, we began procuring renewable power for our operations in the Permian Basin. Initially, we started by buying 65 megawatts of wind-generated power. More recently, we're partnering with Algonquin to build an additional 120 megawatts of solar sourced energy. These efforts are expected to reduce emissions by 300,000 tonnes per year. As this effort continues, we believe that 70% of our Permian demand can be met with renewable power.

We're also changing the way we consume energy. All of our operated drilling rigs and completion spreads in the Permian have been converted to direct electric, natural gas, or dual-fuel power, displacing diesel use and further reducing expected emissions by another 100,000 tonnes per year.

I've presented just a few examples of the projects underway to lower emissions to highlight our disciplined approach to lowering carbon while improving returns – from improving methane detection, rethinking facility designs, optimizing equipment, utilizing renewable power and deploying new operational practices – all aligned to reduce carbon intensity on our pathway to net zero.

And now over to Mark.



I'll start with a bit of a summary which expands upon our Investor Day guidance.

In renewable natural gas, we're ahead of our plan to grow RNG production tenfold by 2025 and we intend to produce over 40,000 million BTUs per day by 2030.

For renewable diesel, we now expect to grow volumes 3 times by 2025, ahead of our original target to double. And with our complex refining system, we believe we'll have the capacity to produce 100,000 barrels per day of RD and sustainable aviation fuel by 2030.

Finally, with renewable base oil, we remain on track for our 2025 target with upside to grow annual production to 100,000 tonnes per year by 2030.

I'll go into more detail about each of these on the next few slides.

Leading in renewable natural gas

Current operations

~2,100 MMBTU/D

Multiple partnerships

Recent actions

~10,000 MMBTU/D committed by 2025

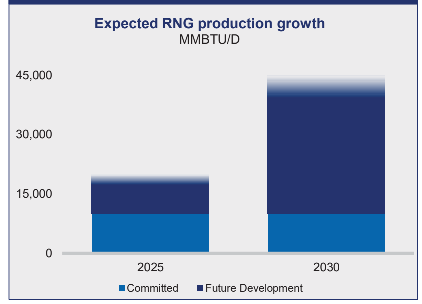
Mercuria CNG joint venture

Future developments

Target >40,000 MMBTU/D by 2030

Expanding feedstock mix

BRIGHTMARK
REIMAGINE WASTE
Clean Energy
MERCURIA
CALIFORNIA BIOENERGY
Helping dairies fuel a renewable future



See appendix slide notes providing definitions, source information, calculations, and other information.

We're a leader in renewable natural gas, building our value chain from feedstock to customer in partnership with others, like Brightmark and CalBio in production and Clean Energy and Mercuria in marketing.

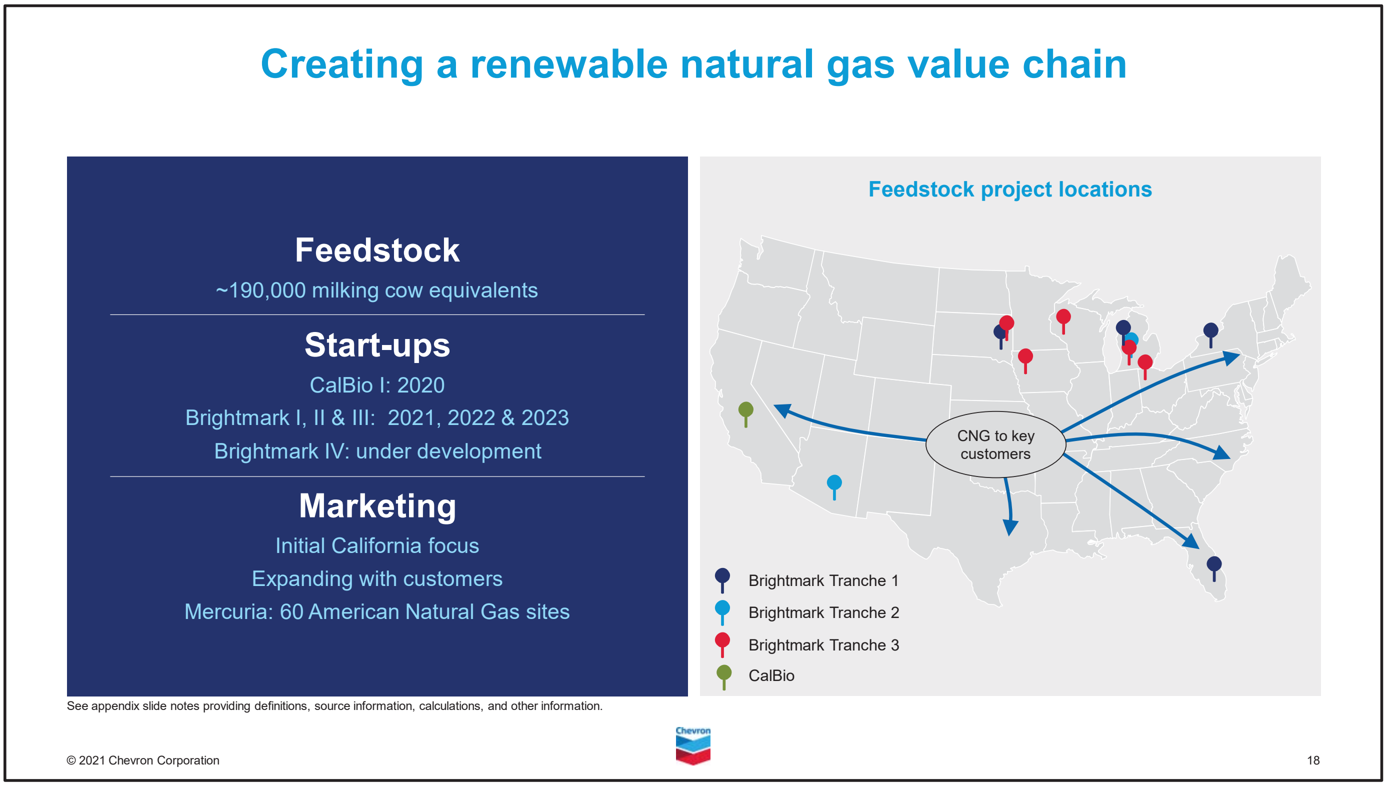
Today, we're producing RNG with CalBio and expect numerous project start-ups with Brightmark over the next two years on our way to future production targets. These projects capture methane that is currently emitted to the atmosphere and turn it into valuable fuel, with negative carbon intensity.

We're getting the RNG to market through fleet sites in California and into trucks converted to compressed natural gas under our Adopt-A-Port program. And we're adding CNG to a number of our Chevron branded retail sites.

To expand to markets beyond California, we recently announced a partnership with Mercuria, adding 60 American Natural Gas CNG sites to our portfolio.

While our primary focus is on lower carbon-intensity dairy feedstocks, we expect to diversify our feed mix over time likely to include wastewater and landfill gas.

Now, let's go a little deeper into how we're building this business.



For roughly half a billion dollars committed to date, we're building an RNG business expected to produce about 10,000 million BTUs per day in less than five years, with expected double-digit returns and an average carbon intensity feedstock score of around negative 250 under California's Low Carbon Fuel Standard.

With our partners, we contract with farms that have scale and proximity to natural gas pipelines to enable a commercial project. Each project is scored for its carbon intensity – which can vary depending on factors like manure management and gas handling, all of which drive the economics.

Chevron completes the value chain by getting the natural gas to customers. We began by growing our CNG network in California because of our strong brand presence and California's cap-and-trade and low-carbon-fuels programs.

With comparable policy support, we'll be able to offer a similar value proposition to customers nationwide supporting the likes of Amazon, Pepsi and Walmart in their key distribution hubs.

To sum up, we believe Chevron is well positioned to be a US market leader in RNG – a fast growing, lower carbon transport fuel.

Building a value chain for renewable diesel & sustainable aviation fuel

Feedstock integration

Bunge MOU

Crushing and pre-treatment margins

Capital efficient manufacturing

Leverage existing assets

Product flexibility

Supply capacity

West Coast diesel as RD

US jet as SAF

See appendix slide notes providing definitions, source information, calculations, and other information.

Like with RNG, building a value chain in RD and SAF starts with the feedstock and ends with the customer.

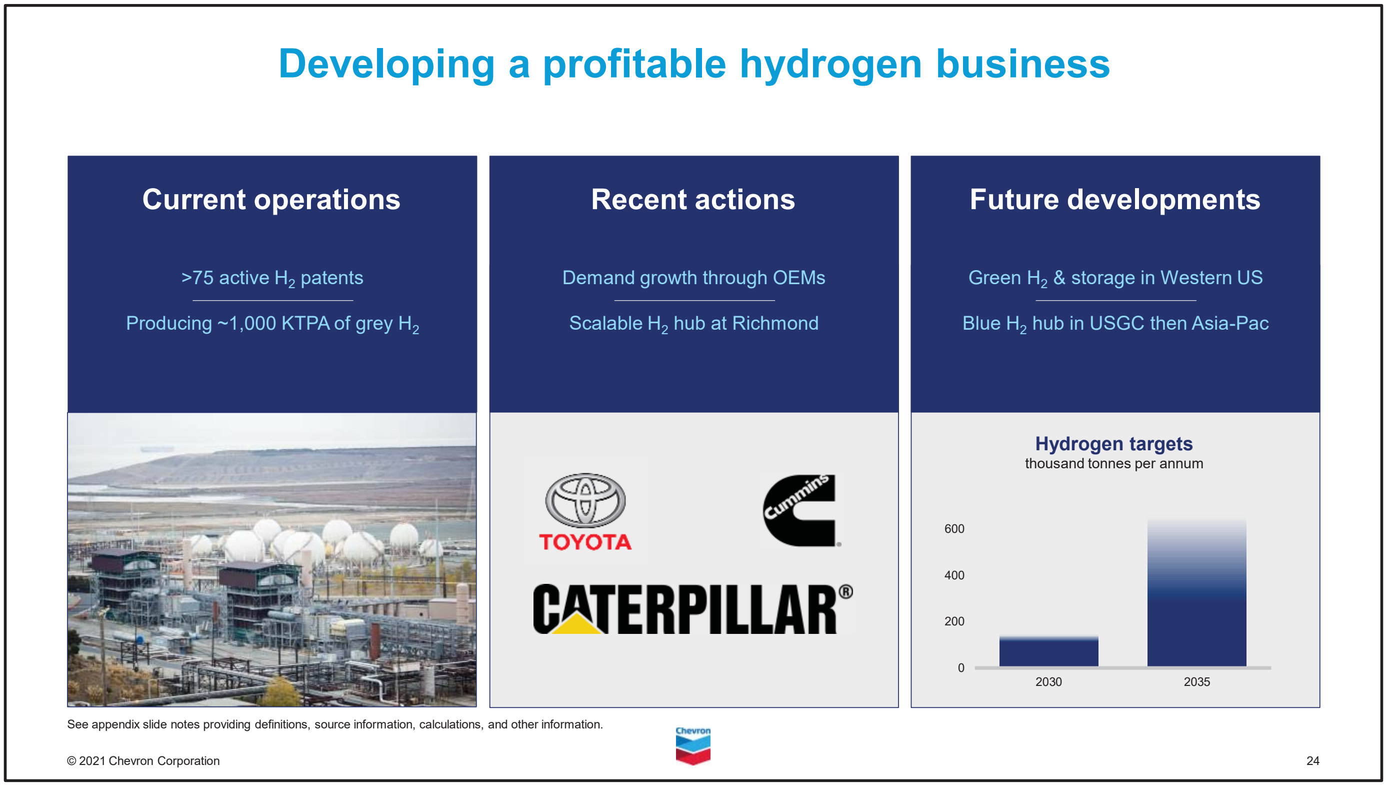
We're excited about collaborating with Bunge to help meet the demand for renewable fuels and to develop lower carbon intensity feedstocks. This relationship is a significant step in integrating renewable feedstocks into our system.

The proposed 50/50 venture is expected to include existing crushers, in Louisiana and Illinois, with the ability to add further crushers and pretreatment facilities sharing margins in those parts of the value chain. We expect roughly 30% of our biofeedstock to be supplied via this path in the near term with future expansion opportunities down the road.

We're also working with Gevo to create an option to produce sustainable aviation fuel using an alcohol-to-jet process, with Chevron having the right to offtake roughly 10 MBD. As we convert more of our process units to have renewable capability coupled with the new feedstock agreements and pre-treatment options, we're evolving our refining system to have greater feedstock and product flexibility, producing renewable or conventional products depending upon the economics and policy drivers.

To put this in perspective, capacity of 100 MBD in 2030 is enough to supply all of Chevron's current West Coast diesel customers with RD and US jet fuel customers with a 5% SAF blend.

And we're doing it with smart partnerships, low capital investment and margin exposure across the value chain.

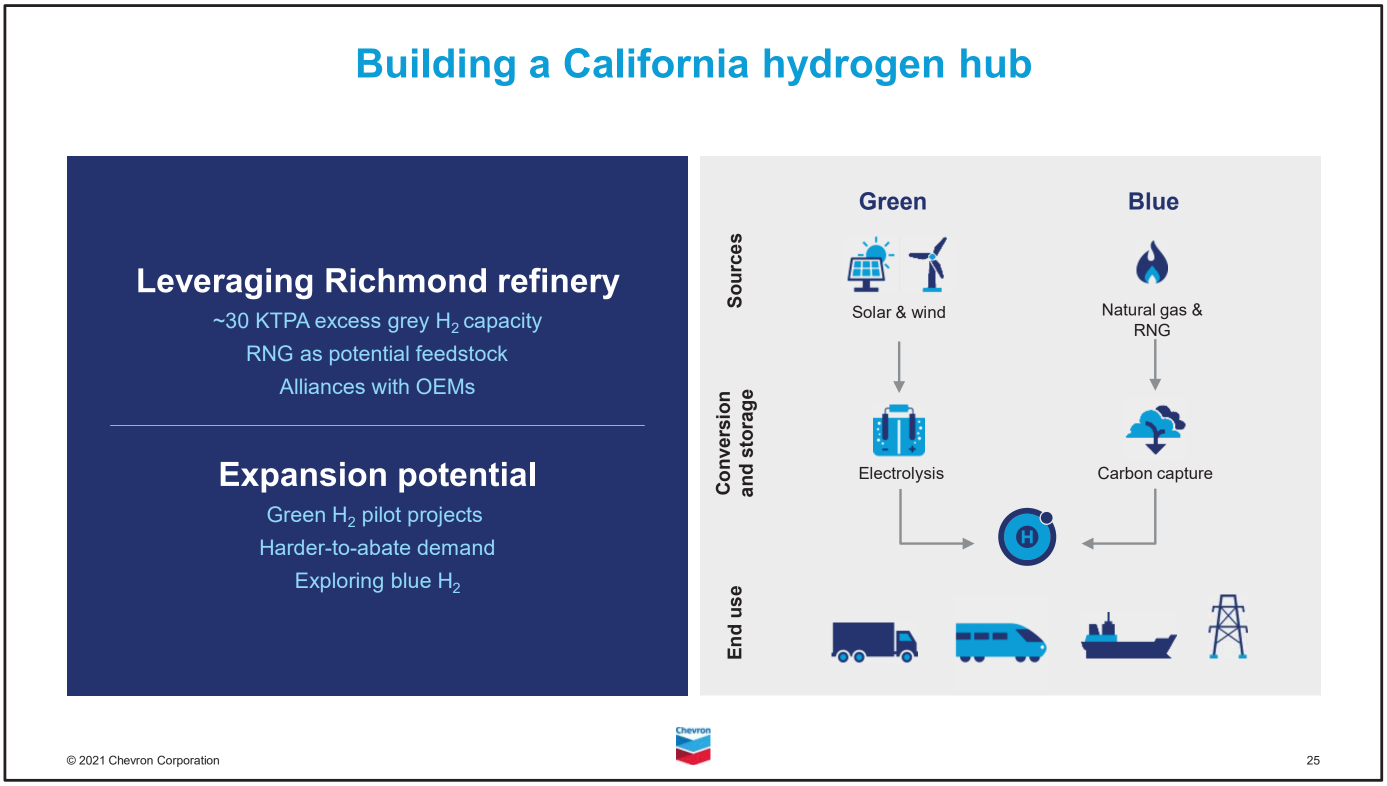


We currently produce around 1 million tonnes per year through our traditional business and have experience in retail hydrogen going back to 2005. Chevron has been investing in hydrogen R&D for decades and holds patents from early commercial ventures that are applicable to our future development plans.

We're fostering transportation and industrial demand growth through OEM alliances with Toyota, Cummins, and Caterpillar, with many more expected to follow. And our Richmond refinery is an initial area of focus which I'll cover on the next slide.

We're developing large green hydrogen projects in the western US, such as our recently announced potential entry into the ACES project in Utah. We're assessing development of blue hydrogen production hubs in the US and Asia linked to existing storage assets, equity natural gas volumes or both.

We see the potential to produce 150 thousand tonnes per year, our equity share, by the end of this decade and we believe we're well positioned to participate across the value chain.



At Richmond, excess capacity in the new hydrogen unit, coupled with our strong distribution network, are expected to put us in an advantaged position to grow a profitable business in an attractive market.

We plan to use Richmond's volumes, combined with existing and future strategic partnerships, as the foundation to support demand growth in the heavy-duty transportation, industrial and power sectors.

But our vision for Richmond is bigger. We recently initiated two green hydrogen pilot projects – one utilizing a gasified waste stream and another a solar powered electrolyzer. And, we're exploring the development of a regional CCUS hub that could enable blue hydrogen.

Entry into Advanced Clean Energy Storage (ACES)

Fully integrated H_2 venture

Mitsubishi Power & Magnum Development

Green H_2 production

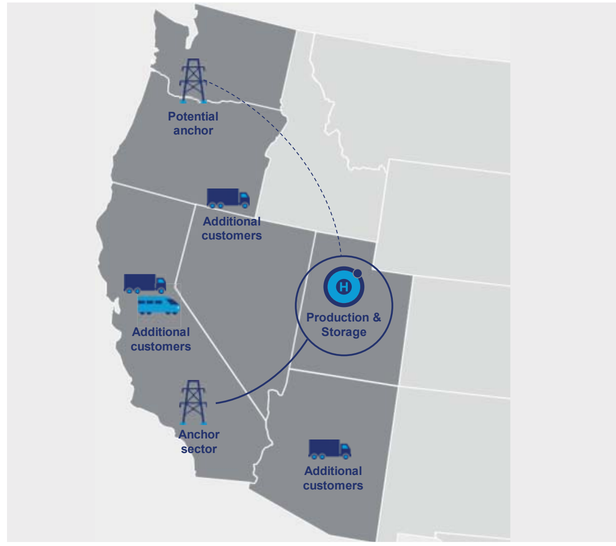
Salt dome storage

Strategic positioning

Scalable to meet demand

Targets multiple sectors and markets

Upside potential



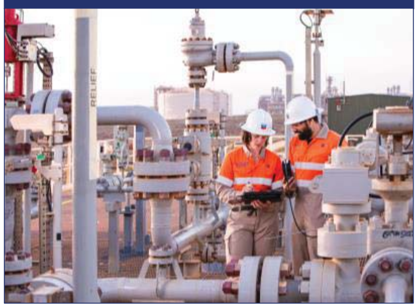
Our potential entry into ACES is a significant hydrogen milestone and aims to develop green hydrogen production, storage and transportation infrastructure in the Western US. We're excited about taking steps to join partners Magnum and Mitsubishi, and believe we bring complementary strengths to one of the world's first large-scale green hydrogen projects.

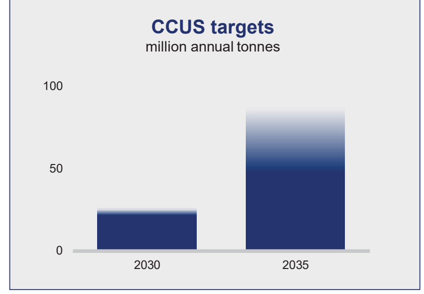
The anticipated project plans to produce green hydrogen to generate lower carbon dispatchable electricity for California. Key enablers of the project include low-cost renewable power combined with hydrogen storage capacity in salt domes. There are also multiple expansion opportunities anticipated across the hydrogen value chain into West Coast markets.

We expect this opportunity to generate attractive returns and to provide cost-effective entry into a scalable hydrogen production platform with existing and future demand sources.

Expanding our CCUS business

Current operations	Recent actions	Future developments
5 MMT CO_2 gross stored at Gorgon	Gas turbine carbon capture in San Joaquin	Partnering in US West & Gulf Coast hubs
6 MMT CO_2 gross stored at AOSP	Project lead on Mendota BECCS	Exploring hubs in Asia-Pacific





See appendix slide notes providing definitions, source information, calculations, and other information.

Moving to carbon capture, we view CCUS opportunities in two areas, reducing the carbon intensity of our existing assets and growing our carbon capture business, primarily through hubs with third party emitters as partners and customers.

Our initial carbon capture projects have been focused on decarbonizing existing assets. An example is Gorgon, one of the largest sequestration projects in the world – with the capacity to store up to 4 million tonnes of CO_2 per year – providing us with key operational experience. And we've recently completed FEED for a commercial scale project in the San Joaquin Valley to capture exhaust from gas turbines, one of several projects in our pipeline.

We're targeting 25 million tonnes of CO_2 per year in equity storage by the end of this decade. To achieve these ambitions, we're exploring several hub opportunities in the US and abroad, each including multiple large customers and with facility nameplate capacities between 5 and 20 million tonnes of CO_2 per year.

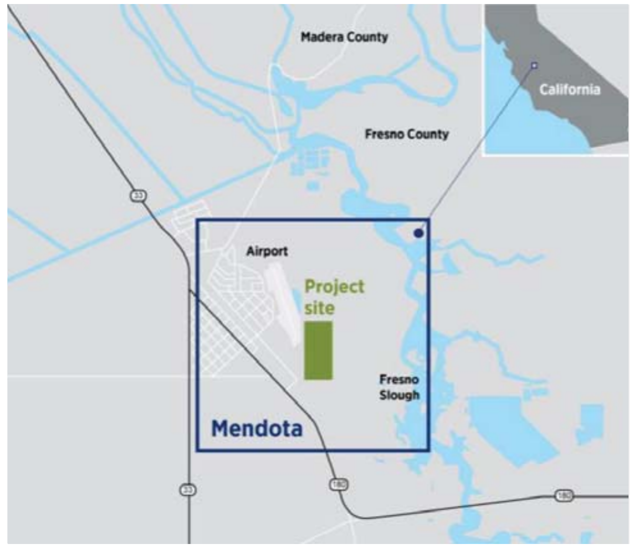
CCUS is a critical enabler of global net zero and our CCUS targets reflect its importance.

Progressing Mendota Bioenergy CCS

Strategic fit
Schlumberger, Microsoft, & Clean Energy Systems
Abate agri-waste emissions

Scope
Potential to capture 300 KTPA CO_2
FEED decision expected by early 2022

Scalability
Demonstrate commercial feasibility
Provide solutions to other emitters



Mendota Bioenergy is a good example of a project where Chevron is partnering with others to capture and then permanently store CO_2.

It's a Biomass to Electricity with CCS project, located in Mendota, CA. The plant is designed to use agricultural waste, like almond trees, to generate negative emission electricity. More than 99% of the carbon emissions are expected to be captured for safe, permanent underground storage in nearby deep geologic formations. We believe the project will position us to demonstrate capability and establish Chevron as a CCUS leader in California.

This effort illustrates another important point.

Mendota is expected to generate about 300,000 LCFS credits per year on top of qualifying for IRS-45Q tax benefits showing how the pace of growth in New Energies can be influenced by policy.

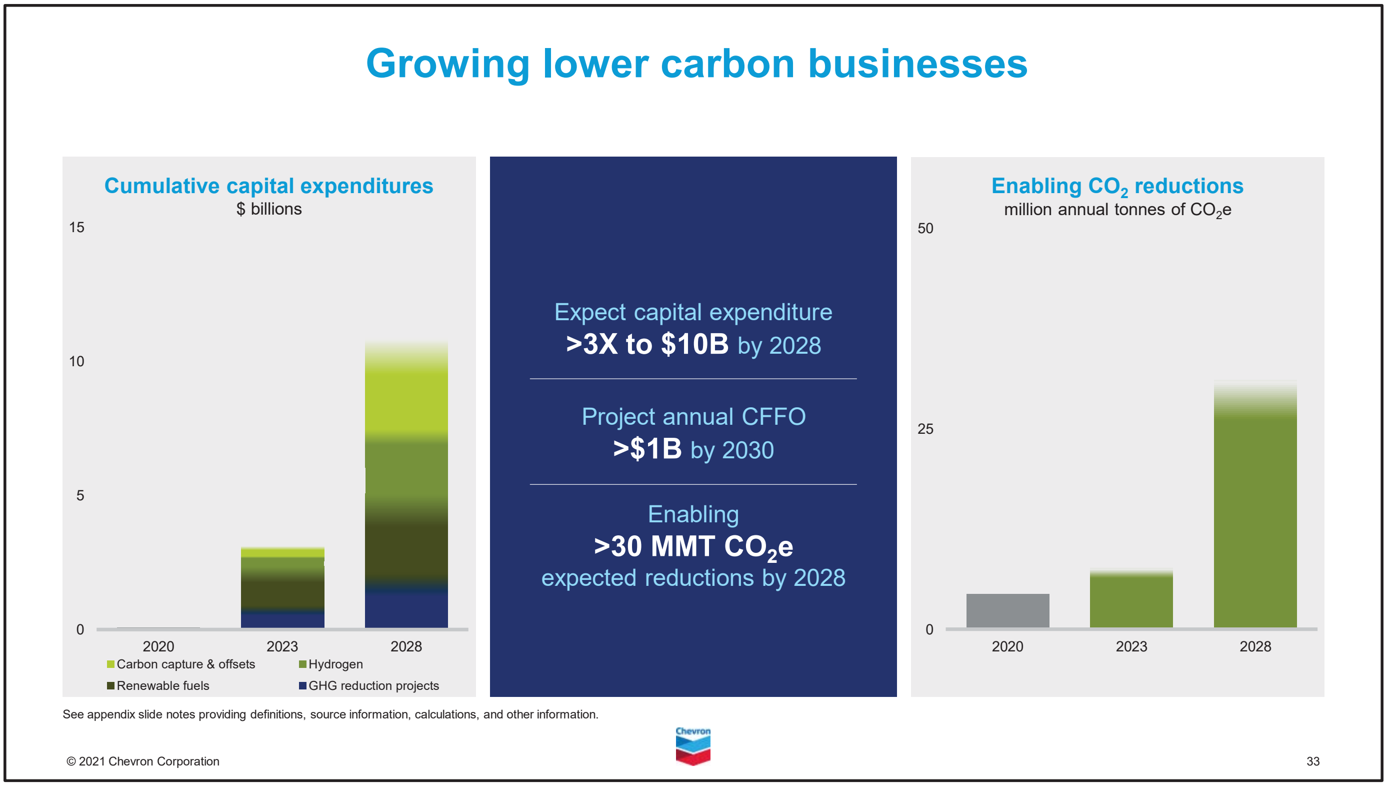
Like CCUS, offsets will be required to achieve net zero.

Chevron's experience developing and using offsets dates back nearly two decades, and is an important part of our operations in areas like Australia, Canada, Colombia and California. And customers are beginning to ask for offsets paired with product supply. We recently signed a 5-year LNG sales and purchase agreement with Pavilion Energy, where each LNG cargo delivered will be accompanied by a statement of its GHG emissions.

We expect to be a portfolio supplier of offsets by providing more customers with offset-paired products. In addition, we have a global carbon trading organization and actively participate on multiple registries and exchanges.

We're also planning to invest directly in scalable, nature-based solutions – like soil carbon storage, reforestation, and mangrove restoration – generating high-quality credits.

Offsets are critical to complement other efforts to reduce Chevron's carbon intensity. We believe this is a space that can significantly grow, both in compliance requirements and value generation.



Let's put this all together. Between now and 2028, we plan to increase our lower carbon capital investments to over $10 billion, more than triple our prior guidance and are increasing our overall annual capital guidance to $15-$17 billion for 2022 through 2025.

We expect returns to be competitive with our alternatives, and projected cash flow from these businesses to exceed $1 billion annually by 2030. Undoubtedly, there will be a range of outcomes with some projects working out better than others.

Our focus is on learning, growing capability and proving that these businesses work commercially and technically, and can be replicated over time to achieve lower costs and greater scale.

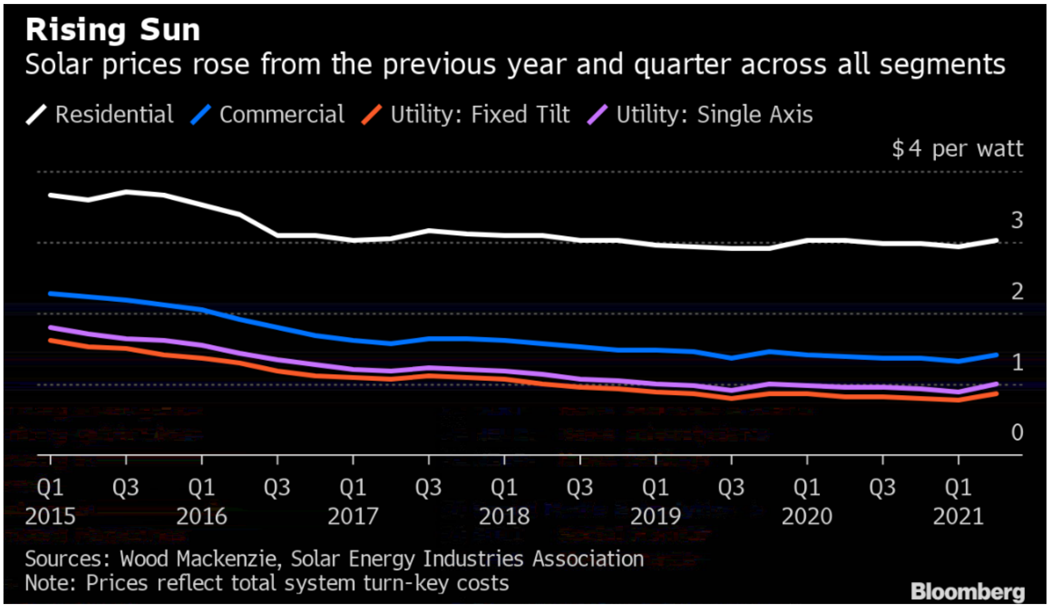
Growth in renewable fuels, hydrogen and carbon capture is expected to enable some 30 million tonnes of annual CO_2 equivalent emission reductions by 2028 an amount roughly equivalent to 18% of New York State's annual reported emissions*. You can think of this as the total emission reductions – Scopes 1, 2 and 3 – from the use of these solutions as compared to conventional fuels.

To sum up, we believe that these investments will advance a lower carbon future and be good for our shareholders.

*Source: EIA, *Rankings: Total Carbon Dioxide Emissions, 2018 (million metric tons)*

U.S. Solar Gets More Expensive in Threat to Climate Change Fight
2021-09-14 04:01:00.3 GMT

By Dan Murtaugh
(Bloomberg) -- Solar prices are rising for the first time in years in the U.S. amid global supply-chain woes, threatening to undermine efforts to fight climate change.
Prices rose in every solar-market segment during the second quarter -- the first time that's happened since at least 2014, according to a report from Wood Mackenzie and the Solar Energy Industries Association. While many solar developers have sufficient inventory for 2021 projects, they will begin to see cost increases next year, the report said.



More expensive solar panels pose significant challenges for efforts worldwide to phase out fossil fuels that cause global warming. Global solar installations have boomed almost 19-fold over the last decade, forcing many coal and natural-gas plants to close. That's in part because panel prices declined 89% during that time, making solar one of the cheapest sources of power available. Now that advantage is fading.
The reason is largely due to the same factors driving up costs for everything from meats to motor vehicles: Shipping costs and commodity prices have surged amid the pandemic. For solar developers, that means paying more for steel, aluminum and the key ingredient in panels: polysilicon. Some developers have tried to renegotiate contracts amid the price hike, while others have just accepted narrower margins, the report said.
And yet, the U.S. is on pace for a record year despite the supply-chain headwinds. About 5.7 gigawatts of solar capacity was installed from April to June, up 45% from that period in 2020 and a record for the second quarter, according to the report.
Chinese companies that dominate the solar supply chain have been investing in new polysilicon factories that are expected to ease supply constraints and eventually lower prices.

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To view this story in Bloomberg click here:
https://blinks.bloomberg.com/news/stories/QZ6U6YDWX2PS

5 ELECTRICITY

Table 5.5. Availability and consumption of electricity

TWh

		Public distribution system									Other generators			All electricity suppliers		
				Sales of electricity to consumers												
YEAR	MONTH	Electricity available	Transmission distribution and other losses[1]	England and Wales	Scotland	Northern Ireland	Total	Industrial[2]	Domestic	Other[4]	Electricity available[5]	Losses and statistical differences	Consumption of electricity[6]	Electricity available	Losses and statistical differences	Consumption of electricity
2019	January	30.24	3.42	23.80	2.28	0.74	26.82	7.66	11.11	8.05	2.52	-0.06	2.58	32.76	3.36	29.40
2019	February	25.48	2.17	20.69	1.98	0.64	23.31	7.01	9.26	7.04	2.03	0.15	1.88	27.51	2.32	25.19
2019	March	26.71	1.80	22.14	2.10	0.67	24.91	7.66	9.52	7.73	2.10	0.16	1.95	28.81	1.96	26.85
2019	April	24.31	2.10	19.70	1.87	0.64	22.21	6.83	8.17	7.20	2.45	0.13	2.32	26.77	2.24	24.53
2019	May	23.54	1.90	19.34	1.70	0.60	21.63	6.86	7.54	7.24	2.29	0.13	2.17	25.83	2.03	23.80
2019	June	21.96	1.69	18.09	1.59	0.60	20.28	6.53	6.78	6.98	2.16	0.12	2.04	24.12	1.80	22.32
2019	July	22.85	1.82	18.80	1.65	0.58	21.03	7.15	6.60	7.28	2.35	0.20	2.15	25.20	2.02	23.18
2019	August	22.51	1.80	18.51	1.60	0.60	20.70	6.99	6.62	7.10	2.30	0.20	2.10	24.80	2.00	22.80
2019	September	22.64	1.87	18.53	1.64	0.60	20.77	6.79	6.91	7.07	2.36	0.20	2.16	25.00	2.07	22.93
2019	October	26.09	2.25	21.25	1.99	0.59	23.83	7.27	8.74	7.82	1.81	-0.23	2.03	27.89	2.03	25.87
2019	November	28.00	2.44	22.85	2.11	0.60	25.56	7.28	10.04	8.24	1.89	-0.24	2.13	29.89	2.20	27.69
2019	December	28.33	2.55	23.06	2.13	0.58	25.77	6.94	10.88	7.95	1.92	-0.24	2.16	30.25	2.31	27.94
2020	January	29.44	3.49	23.03	2.20	0.72	25.94	7.29	10.73	7.92	2.58	0.34	2.25	32.02	3.83	28.19
2020	February	27.26	3.19	21.35	2.05	0.66	24.07	6.84	9.75	7.48	2.32	0.30	2.02	29.58	3.50	26.08
2020	March	26.83	1.98	22.09	2.09	0.67	24.85	6.91	10.05	7.89	2.26	0.29	1.97	29.09	2.28	26.82
2020	April	20.37	1.71	16.54	1.58	0.54	18.66	4.94	8.58	5.15	3.01	0.95	2.06	23.39	2.66	20.73
2020	May	20.19	1.75	16.47	1.45	0.51	18.44	5.27	7.85	5.31	2.98	0.94	2.04	23.17	2.69	20.48
2020	June	20.17	1.94	16.25	1.44	0.54	18.22	5.60	7.05	5.58	3.12	0.98	2.13	23.28	2.93	20.36
2020	July	21.30	1.97	17.27	1.51	0.54	19.33	6.21	6.98	6.13	3.04	0.99	2.05	24.35	2.97	21.38
2020	August	21.80	1.84	17.84	1.55	0.57	19.96	6.50	6.96	6.50	2.94	0.96	1.98	24.75	2.80	21.95
2020	September	22.21	1.90	18.11	1.62	0.59	20.31	6.34	7.35	6.62	3.09	1.01	2.08	25.30	2.91	22.39
2020	October	25.08	2.25	20.35	1.91	0.57	22.83	6.81	9.18	6.83	3.18	0.81	2.37	28.26	3.06	25.20
2020	November	25.34	1.80	21.04	1.95	0.55	23.54	6.82	10.24	6.49	3.21	0.82	2.39	28.55	2.62	25.94
2020	December	27.72	2.49	22.51	2.13	0.59	25.22	6.58	11.32	7.32	3.59	0.91	2.67	31.30	3.41	27.89
2021	January	29.45	3.48	23.07	2.19	0.72	25.97	7.13	12.04	6.81	2.19	0.52	1.66	31.64	4.00	27.64
2021	February	25.50	2.39	20.46	1.95	0.69	23.11	6.67	10.51	5.92	1.85	0.44	1.41	27.35	2.84	24.52
2021	March	26.18	1.95	21.53	2.04	0.66	24.23	7.20	10.64	6.39	1.92	0.46	1.46	28.10	2.41	25.69
2021	April	23.22	1.96	18.83	1.80	0.62	21.26	6.23	9.18	5.85	2.56	0.71	1.85	25.77	2.66	23.11
2021	May	23.11	2.09	18.78	1.66	0.58	21.02	6.29	8.33	6.40	2.53	0.70	1.83	25.64	2.79	22.85
2021	June p	21.33	1.98	17.25	1.53	0.58	19.36	6.06	6.92	6.38	2.64	0.73	1.91	23.97	2.71	21.27

Source: UK National Statistics. Energy Trends: UK Electricity

Return to contents page

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.fueleconomy.gov/feg/Find.do?action=sbs&id=44493&id=44491&id=44495

www.fueleconomy.gov
the official U.S. government source for fuel economy information

Fuel Economy | Energy and Environment | Safety | Specs

	2022 Lucid Air Dream R AWD w/19in wheels	2022 Lucid Air Dream P AWD w/19in wheels	2022 Lucid Air G Touring AWD w/19in wheels
Personalize	Electric Vehicle  Automatic (A1)	Electric Vehicle  Automatic (A1)	Electric Vehicle  Automatic (A1)
EPA Fuel Economy 1 gallon of gasoline=33.7 kWh [Show electric charging stations near me]	**Electricity** 125 MPGe combined city/highway; 126 city, 125 highway; 27 kWh/100 mi; Electricity 520 miles Total Range	**Electricity** 116 MPGe combined city/highway; 117 city, 114 highway; 29 kWh/100 mi; Electricity 471 miles Total Range	**Electricity** 131 MPGe combined city/highway; 130 city, 132 highway; 26 kWh/100 mi; Electricity 516 miles Total Range
	About All-Electric Cars	About All-Electric Cars	About All-Electric Cars
Unofficial MPG Estimates from Vehicle Owners Learn more about "My MPG" Disclaimer	User MPG estimates are not yet available for this vehicle	User MPG estimates are not yet available for this vehicle	User MPG estimates are not yet available for this vehicle
You save or spend* Note: The average 2021 vehicle gets 27 MPG	**You SAVE** **$6,250** in fuel costs over 5 years compared to the average new vehicle	**You SAVE** **$6,000** in fuel costs over 5 years compared to the average new vehicle	**You SAVE** **$6,250** in fuel costs over 5 years compared to the average new vehicle
Annual Fuel Cost*	$500	$550	$500
Cost to Drive 25 Miles	$0.87	$0.95	$0.84
Cost to Fill the Tank			
Tank Size			

*Based on 45% highway, 55% city driving, 15,000 annual miles and current fuel prices. Personalize.
MSRP and tank size data provided by Edmunds.com, Inc.
Range on a tank and refueling costs assume 100% of fuel in tank will be used before refueling.

https://www.consumerreports.org/car-recalls-defects/chevrolet-bolt-recalled-again-due-to-fire-concerns-a3566085147/

GM Recalls All Chevrolet Bolts Due to Fire Concerns

The automaker has expanded an existing recall to include all 2017-2022 models

By Jeff S. Bartlett
Published July 23, 2021 | Updated September 16, 2021


Photo: Chevrolet

General Motors expanded an existing Chevrolet Bolt recall to now include all cars from the 2017-2022 model years due to the risk of a battery-related fire. This action now includes the new Bolt EUV, as well. This marks an expansion of two previous recalls, more than doubling the number of cars involved to about 110,000. Further, the company is directing all Bolt and Bolt EUV owners to park their vehicle outside, away from structures, and to not charge the vehicle overnight.

A GM spokesman told CR that the company is advising customers, "In an effort to reduce potential damage to structures and nearby vehicles in the rare event of a potential fire, we recommend parking on the top floor or on an open-air deck and park 50 feet or more away from another vehicle. Additionally, we still request you do not leave your vehicle charging unattended, even if you are using a charging station in a parking deck."

Before this recall was announced, Consumer Reports purchased a 2022 Bolt EUV for our testing program and as a result of the recall, we are following all of GM's recommendations about charging and parking.

A spokeswoman for LG, the battery supplier, told CR, "GM and LG have identified the presence of two rare simultaneous defects, found in the same battery cell, made during module manufacturing process." She explained this as the root cause of battery fires in certain Chevy Bolt EVs. She also said that this particular problem is not related to one reported with the Hyundai Kona EV, and that the defects have been taken care of in manufacturing.

GM explained that the cause is a torn anode tab and folded separator within the battery modules.

There are five lithium-ion modules within the battery pack that will be replaced, a GM spokesman explained to CR. The battery pack is made up of many individual components, including the case, electronics, and wiring that are not defective and therefore do not need replacing.

These new modules will come with an 8-year, 100,000-mile limited warranty.

This expanded recall comes after CR reported in July that GM was aware of this risk; the automaker now has identified a solution. Owners can find more details on the automaker's dedicated web page. And GM will notify customers, prioritizing those determined to be at the greatest risk.

"We're working with our supplier and manufacturing teams to expedite additional battery production capacity to begin repairs on the entire recall population as quickly as possible," said the GM spokesman. He could not speculate on a specific time when the repairs can be done.

GM directs owners to still have the software fix performed, and they will notify owners when replacement batteries are available.

Until then, GM advises:

• Customers should, whether or not they received the current software update, set their vehicle to the 90 percent state of charge limitation using Hilltop Reserve mode (2017 and 2018 model years) or Target Charge Level mode (2019-2022 model years). If customers are unable to successfully make these changes, or do not feel comfortable making these changes, we are asking them to visit their dealer to have these adjustments completed.

• Recharge the battery after each use and not wait until the battery is almost run down (deep discharge mode) before charging it back up.

• Customers should continue to park their vehicles outside immediately after charging and not leave their vehicles charging overnight.

The Details

Vehicles recalled: About 110,000 Chevrolet Bolt and Bolt EUV EVs from the 2017 through 2022 model years.

The problem: The vehicle's batteries may catch fire.

The fix: The original recall is a software update. This latest action calls for five defective lithium-ion battery modules to be replaced by the dealership at no charge to the owner.

How to contact the manufacturer: Call Chevrolet EV customer service at 833-382-4389.

NHTSA campaign numbers: For 2017 to 2019 21V560000 and for 2020-2022 21V650000. GM's number for this recall is N212343880.

Check to see whether your vehicle has an open recall: NHTSA's website will tell you whether your vehicle has any open recalls that need to be addressed.

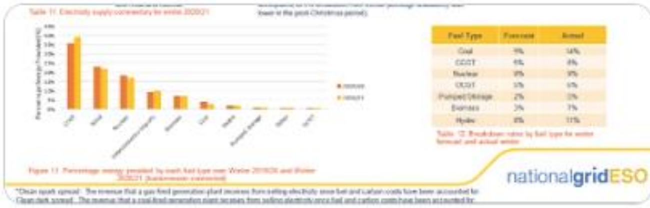
If you plug your car's 17-digit vehicle identification number (VIN) into NHTSA's website and a recall doesn't appear, it means your vehicle doesn't currently have any open recalls. Because automakers issue recalls often, and for many older vehicles, we recommend checking back regularly to see whether your vehicle has had a recall issued.

Stay informed about recalls that might affect your vehicle using our Car Recall Tracker. Create a free account now to become a CR member.

SAF

Dan Tsubouchi @Energy_Tidbits · 2h

Here's why @KwasiKwarteng #Wind assumption is key to #NatGas security of supply. #NatGas is needed to fill in when UK #wind generation produces less than expected. Note @NationalGridESO recap of winter 20/21 vs 20/19 and how #NatGas filled in for low wind.



Dan Tsubouchi @Energy_Tidbits · 3h

Note @KwasiKwarteng thread, no "immediate concern" on #NatGas supply. wonder what he assumes re #Wind generation this winter. @NationalGridESO, low wind was the common denominator on 5 bad power days in winter 20/21. ...

SAF

Dan Tsubouchi @Energy_Tidbits · 3h

Note @KwasiKwarteng thread, no "immediate concern" on #NatGas supply. wonder what he assumes re #Wind generation this winter. @NationalGridESO, low wind was the common denominator on 5 bad power days in winter 20/21. #NatGas #LNG will be needed even if $$ twitter.com/KwasiKwarteng/...

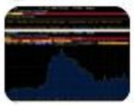
Dan Tsubouchi @Energy_Tidbits · Sep 18

Read carefully. do not anticipate any "increased" risk of supply emergencies this winter. noted high global spot prices that balance supply/demand, but no mention of affordability is priority ie. infers will pay up to get supply. Looks like expensive #NatGas ...

1 2

Dan Tsubouchi @Energy_Tidbits · 5h

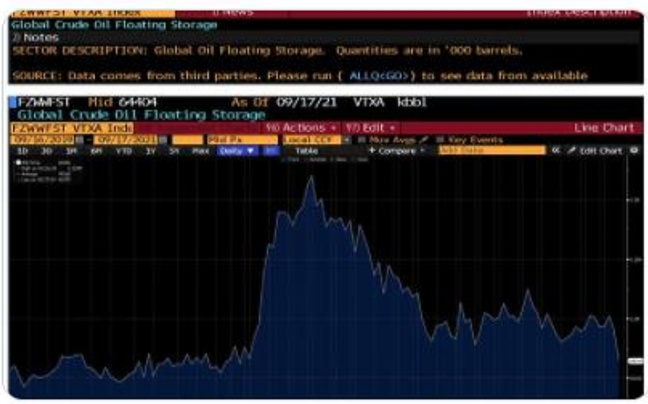
Still massive -23.63 mmb WoW drop in floating #Oil storage to 67.30 mmb on Sept 17 in REVISED @Vortexa today vs Originally estimated yesterday 64.40 mmb. Still scramble to get other floating views before trading tonight. Bullish if no more changes. Thx @Vortexa @TheTerminal #OOTT

> **Dan Tsubouchi** @Energy_Tidbits · 16h
>
> 
>
> Scramble for #Oil markets to get other floating oil storage views before Sun night trading. @Vortexa estimates massive -26.21 mmb WoW to 64.40 mmb on 09/17. Back to 03/13/19 of 62.37 mmb. So massive made me look twice. Very bullish if no change. Thx ...

1 1 5

Dan Tsubouchi @Energy_Tidbits · 16h

Scramble for #Oil markets to get other floating oil storage views before Sun night trading. @Vortexa estimates massive -26.21 mmb WoW to 64.40 mmb on 09/17. Back to 03/13/19 of 62.37 mmb. So massive made me look twice. Very bullish if no change. Thx @TheTerminal @Vortexa #OOTT

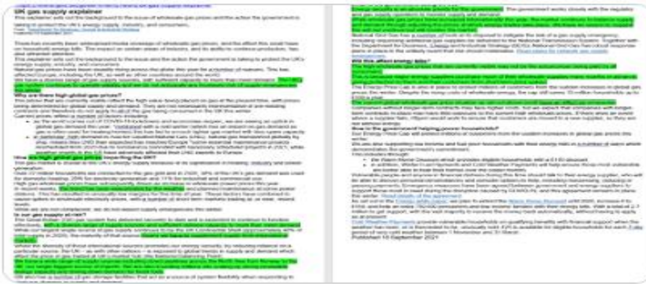


4 11 43

SAF

Dan Tsubouchi @Energy_Tidbits · Sep 18

Read carefully. do not anticipate any "increased" risk of supply emergencies this winter. noted high global spot prices that balance supply/demand, but no mention of affordability is priority ie. infers will pay up to get supply. Looks like expensive #NatGas #Electricity for UK.



> **Kwasi Kwarteng** @KwasiKwarteng · Sep 18
>
> Energy security is an absolute priority. We are working closely with @ofgem and gas operators to monitor supply and demand
>
> This explainer sets out the background, and the action we are taking to protect energy supply, industry, and consumers 👇 ...
>
> Show this thread

5 · 8

SAF

Dan Tsubouchi @Energy_Tidbits · Sep 18

Positive to #LNG. India to expand #NatGas distribution to cover 96% of population. Fits move to double #NatGas share of energy mix to 15% by 2030, which #Petronet CEO est adds 13 bcf/d #LNG demand. See twitter.com/Energy_Tidbits...

> **Ministry of Petroleum and Natural Gas** @Petroleum... · Sep 18
>
> This 11th round of bidding is the largest in terms of coverage of area, population and the number of districts in the country.
>
> Once completed, the CGD network in India shall cover 86% of the Country's area and 96% of the population.
>
> Show this thread

5 · 6

Dan Tsubouchi @Energy_Tidbits · Sep 17

Continued slow but steady return of #Oil #NatGas to come back since #HurricaneIda. 19 days since max shut-in, but @BSEEgov shows still shut-in #Oil is 0.42 mmb/d (23.2% of GoM) & 0.77 bcf/d (34.4% of GoM). Cumulative shut-in 28.2 mmb & 35.1 bcf. #OOTT

2021-08-28	279	49.82%	11	100.00%	[illegible]	[illegible]	[illegible]	[illegible]
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%
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%
2021-09-07	79	14.11%	4	36.36%	1,443,800	79.33%	1,736.8	77.89%
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%
2021-09-12	63	11.25%	1	9.09%	883,755	48.56%	1,212.9	54.39%
2021-09-13	47	8.39%	1	9.09%	793,522	43.60%	1,151.0	51.61%
2021-09-14	39	6.69%	0	0.00%	720,217	39.57%	1,074.8	48.20%
2021-09-15	36	6.43%	0	0.00%	537,193	29.52%	878.7	39.40%
2021-09-16	42	7.50%	0	0.00%	513,878	28.24%	878.6	39.40%
2021-09-17	41	7.32%	0	0.00%	422,078	23.19%	765.5	34.43%

2

Dan Tsubouchi @Energy_Tidbits · Sep 17

July was not a good mth for #Bakken #Oil. Production -5% MoM to 1.078 mmbd despite all time record high 16,881 wells on production. Big reduction in NDIC est wells waiting on completion -159 MoM & big increase +243 MoM in inactive wells. See definitions below. #OOTT

Jan	1,640,981	1,561,274	2,071,820	2,726,492	3,019,938	11.0%	2,847,719	-5.1%
Feb	1,609,221	1,704,191	2,106,121	2,631,118	3,109,750	18.2%	2,704,840	-13.0%
Mar	1,710,823	1,730,674	2,119,751	2,837,170	3,128,393	10.3%	2,873,370	-8.2%
Apr	1,616,769	1,836,286	2,242,093	2,833,131	2,711,851	-4.3%	2,949,005	8.7%
May	1,643,530	1,853,528	2,315,381	2,819,443	1,929,122	-31.6%	2,981,592	54.6%
June	1,662,917	1,851,543	2,301,354	2,885,293	1,971,818	-31.7%	2,987,829	51.5%
July	1,698,638	1,896,129	2,393,757	2,944,816	2,302,456	-21.8%	2,874,922	24.9%
Aug	1,640,387	1,949,865	2,443,010	3,014,419	2,635,250	-12.6%		
Sept	1,611,882	1,945,017	2,527,434	2,946,391	2,815,112	-4.5%		
Oct	1,717,763	2,065,409	2,561,988	3,070,616	2,881,717	-6.2%		
Nov	1,759,524	2,096,440	2,521,128	3,136,585	2,890,376	-7.8%		
Dec	1,537,831	2,084,925	2,651,375	3,061,412	2,888,626	-5.6%		

Source: North Dakota Industrial Commission, North Dakota Pipeline Authority

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

https://www.dmr.nd.gov/oilgas/directorscut/directorscut-2021-09-17.pdf

NORTH Dakota | Mineral Resources

Release Date: 9/17/2021
Director Lynn Helms

Wells

	June	July	August	Revised Revenue Forecast
Permitted	75 drilling 0 seismic	40 drilling 0 seismic	79 drilling 0 seismic	-
Completed	41 (Final)	47 (Revised)	53 (Preliminary)	30→40→50→60
Inactive[2]	1,839	2,082	-	-

7 10

Dan Tsubouchi @Energy_Tidbits · Sep 17

great sunrise looking over the Bow River in #Canmore in Cdn Rockies. big male elk on his herd slept overnight in the field. didn't expect to catch him planning for 2022. but still a great sunrise

11

Dan Tsubouchi @Energy_Tidbits · Sep 17

1/3. Imagine if #NatGas home power/heat bills were going up 20 or 30x? @adsteel asks $CVX CEO Wirth what is premium end user prepared to pay for green energy? "#RenewableNaturalGas in CA, it's substantial BUT it comes via a credit system that is not very transparent.. #NatGas

1 2 2

Dan Tsubouchi @Energy_Tidbits · Sep 17

2/2. ... to the customer and so the price that we ultimately receive on some of these products is higher than it is for conventional natural gas but its not necessarily borne directly by the customer, it comes through a series of tradeable credits and things" Thx @adsteel #NatGas

1 1

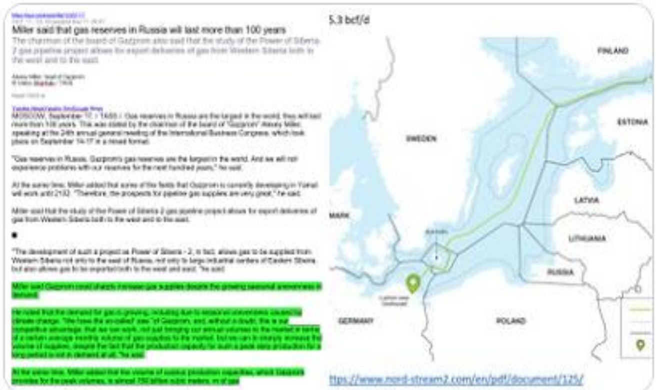
Dan Tsubouchi @Energy_Tidbits · Sep 17

3/3. $CVX ~$0.5b to build #RenewableNaturalGas of ~10 mmcf/d in <5 yrs & expect double digit returns. Vs a $5 million dry #Marcellus #NatGas wells with 1st yr ave production >10 mmcf/d. Costs ultimately flow thru to consumer/taxpayer. #EnergyTransition will be expensive.

2 1 6

Dan Tsubouchi @Energy_Tidbits · Sep 17

#Gazprom says help can be on the way to lower record #Electricity prices for winter? Gazprom can "sharply increase" #NatGas exports & volume of surplus production capacities for peak demand is ~150 bcm. Hmm! 150 bcf = 5.3 bcfd, which just happens to be #NordStream2 capacity. #LNG



2 10 26

Dan Tsubouchi @Energy_Tidbits · Sep 16

what fence? local #Canmore male elk joins his herd for an afternoon feast. great day in the cdn rockies.

3

Dan Tsubouchi @Energy_Tidbits · Sep 16

Looks like #Nicholas slowed down the return of shut-in GoM #Oil #NatGas to come back since #HurricaneIda. 18 days since max shut-in, but @BSEEgov shows still shut-in #Oil is 0.51 mmb/d (28.2% of GoM) & 0.88 bcf/d (39.4% of GoM). Cumulative shut-in 27.8 mmb & 34.4 bcf. #OOTT

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%
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2021-09-14	39	6.69%	0	0.00%	720,217	39.57%	1,074.8	48.20%
2021-09-15	36	6.43%	0	0.00%	537,193	29.52%	878.7	39.40%
2021-09-16	42	7.50%	0	0.00%	513,878	28.24%	878.6	39.40%
Cumulative (mmb and bcf)					27.8		34.4	

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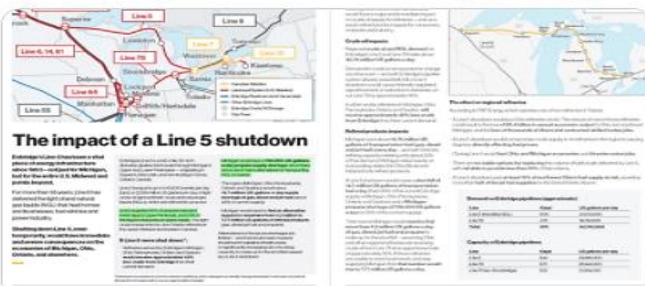
Dan Tsubouchi @Energy_Tidbits · Sep 16

Better hope for a hot winter in Michigan if @GovWhitmer succeeds in her effort to shut down $ENB #Line5. Otherwise it won't just be very expensive #Propane this winter but potentially some propane shortages. Line 5 supplies 65% of Upper Peninsula & 55% of statewide propane #OOTT



Helen Robertson @HelenCRobertson · Sep 16

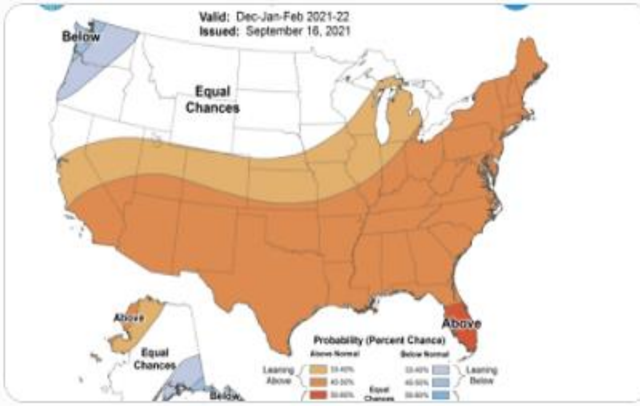
Americans who rely on propane for heating are facing the most expensive winter in years as prices jump bloomberg.com/news/articles/... via @MikeJeffers

#OOTT

2 4

Dan Tsubouchi @Energy_Tidbits · Sep 16

Updated @NOAA Dec/Jan/Feb probability outlook is for a warmer than normal DJF. Not likely to impact #NatGas price much right now as storage -592 bcf lower YoY and start up of feedgas for Sabine Pass LNG #6 at 0.7 bcfd & Calcasieu Pass #LNG at 1.3 bcfd this winter.



1 4 10

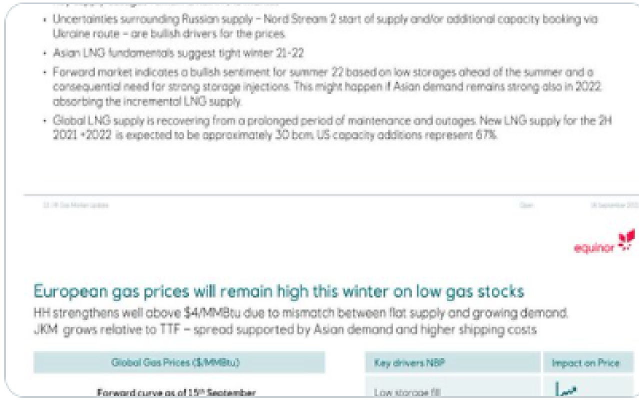
Dan Tsubouchi @Energy_Tidbits · Sep 16

Crazy spot #LNG prices. Better hope its not a cold winter in Asia. @SStapczynski reports "Tohoku Elec. purchased an #LNG cargo on a DES basis for Dec. delivery to Japan at about $29/mmbtu, according to traders with knowledge of the matter." Great finish to 2021 #NatGas prices.

1 6

Dan Tsubouchi @Energy_Tidbits · Sep 16

#Equinor #NatGas market update: high gas prices to continue during winter 21/22, EU storage 70-75% full entering winter "leaves market exposed to high prices when demand rises". notes supply uncertainties on pipeline supply & #LNG supply, but didn't mention #Wind variability.



1 2 5

Dan Tsubouchi @Energy_Tidbits · Sep 15

Here is the press release for Alberta just announced New vaccine requirements and COVID-19 measures in Alberta.

New vaccine requirements and COVID-19 measure...

Alberta has declared a state of public health emergency and will implement new health measur...

alberta.ca

1

Dan Tsubouchi @Energy_Tidbits · Sep 15

Key upside to 2022/23 HH/AECO #NatGas prices. Feedgas start up for Sabine Pass LNG Train 6 (0.7 bcfd) & Calcasieu Pass LNG (1.3 bcfd). @business Christine Buurma says $LNG requested @FERC authorization to start feedgas. #LNG See SAF July 25 Energy Tidbits safgroup.ca/news-insights/

6

Dan Tsubouchi @Energy_Tidbits · Sep 15

For those not near their laptop, @EIAgov weekly #Oil #Gasoline #Distillates inventory data as of Sept 10 just out. Prior to release, WTI was $72.88. #OOTT

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

Oil/Products Inventory Sept 10: EIA, Bloomberg Survey Expectations, API

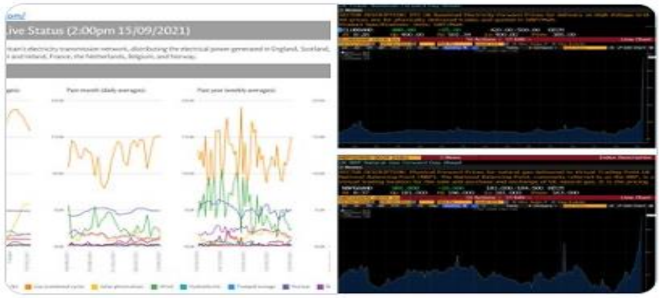
(million barrels)	EIA	Expectations	API
Oil	-6.42	-3.57	-5.44
Gasoline	-1.86	-2.90	-2.76
Distillates	-1.69	-1.95	-2.89
	-9.97	-8.42	-11.09

Note: In addition, there was 0.5 mmb draw from the SPR for Sept 10 week
Note: Included in the data, Cushing had a draw of 1.10 mmb for Sept 10 week
Source EIA, Bloomberg
Prepared by SAF Group

1 2

Dan Tsubouchi @Energy_Tidbits · Sep 15

Record UK power prices in shoulder season. Yes record #NatGas prices a key factor. But @nationalgriduk data shows #Wind below normal and, that without #NatGas cranking up supply to fill import gap, it would be no power, not high price power. #NatGas #LNG will be needed for longer

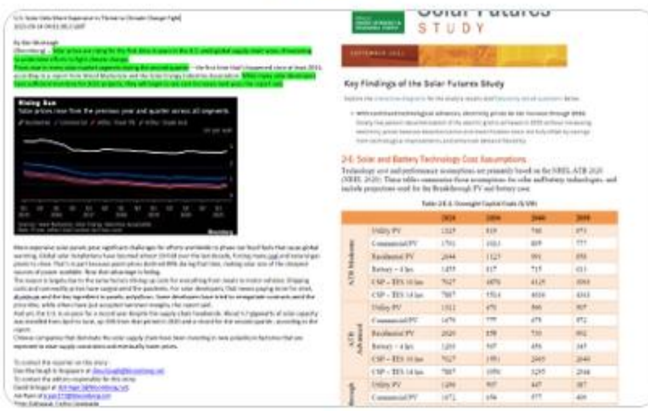


> **Dan Tsubouchi** @Energy_Tidbits · Jul 25
>
> 
>
> Hmmm! Why doesn't UK #NationalGridESO want to call out #Wind as key wildcard for reliable power? Fcast lower reserve for winter 21/22. "reflecting on last winter" say main issue #Coal #CCGT #NatGas plants. Yet common denominator for their 5 winter 20/21 ba...

1 3

Dan Tsubouchi @Energy_Tidbits · Sep 14

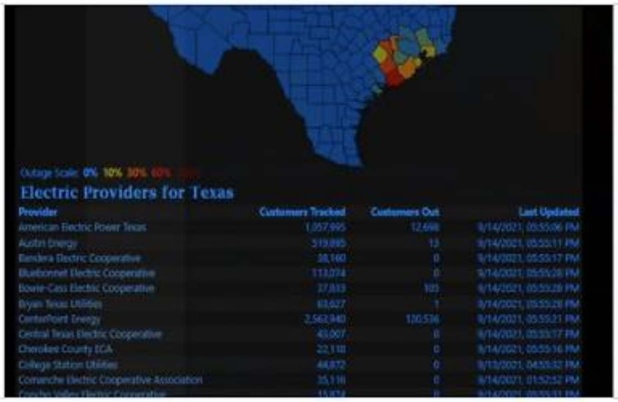
No surprise, US #solar costs up across all segments in 2021 & expected up again in 2022. Is this reflected in #EnergyTransition plans like DOE Solar Futures Study that say electricity costs aren't going up? Hmmm! #NatGas will be needed for longer. Thx @danmurtaugh



2 6

Dan Tsubouchi @Energy_Tidbits · Sep 14

Starting to see power outages from #Nicholas. As just seen with #HurricaneIda, the lasting impact on #Oil #NatGas #LNG operations tends to be from power outages & flooding, not wind damage. Thx @PowerOutage_us for interactive mapping. #OOTT



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Dan Tsubouchi @Energy_Tidbits · Sep 14

Good reminder why taking longer for #Oil #NatGas to recover from #HurricaneIda. #PortFourchon was hit hard by Ida and it is the primary jump off point helicopters/vessels to service offshore GoM platforms. Thx @DavidWethe @SergioChapa #OOTT

> David Wethe @DavidWethe · Sep 12
>
> "What's different is this is lasting longer," Bert Winders, a Louisiana native and oil-patch veteran of 4 decades, says of Ida's impact. "When Port of Fourchon is out of service, it breaks a link in the chain." bloomberg.com/news/articles/... w/ @SergioChapa via @markets

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SAF

Dan Tsubouchi @Energy_Tidbits · Sep 14

Another slow but steady return day of shut-in GoM #Oil #NatGas to come back since #HurricaneIda. 16 days since max shut-in, but @BSEEgov shows still shut-in #Oil is 0.72 mmb/d (39.6% of GoM) & 1.07 bcf/d (48.2% of GoM). Cumulative shut-in 26.8 mmb & 32.6 bcf. #OOTT

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%
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Cumulative (mmb and bcf)					26.8		32.6	

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SAF

Dan Tsubouchi @Energy_Tidbits · Sep 13

Record UK power prices in Sept, a low #Electricity consumption month. @SStapczynski notes below normal wind. Common denominator for #NationalGridESO for their 5 winter 20/21 bad power days was low wind. Replacing 24/7 #coal with intermittent wind/solar brings spikes. Need #NatGas

Stephen Stapczynski @SStapczynski · Sep 13

UK power prices surge to a record high 🇬🇧 📈

Electricity contracts for 7-8pm on Tuesday hit a whopping £1,750/MWh due to:

...

Show this thread

2 · 5

Dan Tsubouchi @Energy_Tidbits · Sep 13

If exit polls are right, Norway's @jonasgahrstore Labour party can form slim majority coaltion (89 of 169 seats) with Centre & Socialist Left parties. Probably best case result for #Oil #Gas sector as he won't necessarily need farther left Green & Red parties. #OOTT

> The Guardian @guardian · Sep 13
>
> Left-leaning coalition predicted to win Norwegian parliamentary vote
>
> theguardian.com/world/2021/sep...

1 1

Dan Tsubouchi @Energy_Tidbits · Sep 13

Only modest return today of shut-in GoM #Oil #NatGas to come back since #HurricaneIda. 15 days since max shut-in, but @BSEEgov shows still shut-in #Oil is 0.79 mmb/d (43.6% of GoM) & 1.15 bcf/d (51.6% of GoM). Cumulative shut-in 26.1 mmb & 31.5 bcf. #OOTT

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SAF

Dan Tsubouchi @Energy_Tidbits · Sep 13

Europe better hope its not a cold start to winter. @business @bjennen1 report DE regulator BNA now has 4 mths to review on 5.3 bcfd #NordStream2 certification. Given high profile, hard to see a quick rubber stamp. if so, NS2 won't bring near term relief to #NatGas #LNG prices

2 6 15

SAF

Dan Tsubouchi @Energy_Tidbits · Sep 12

3rd good day in a row for return of shut-in GoM production. 13 days post peak shut-in but @BSEEgov data is down to 0.88 mmb/d #Oil & 1.21 bcf/d #NatGas. Plus looks like #TropicalStormNicholas will miss most platforms. #OOTT

	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
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Note: 09-01 was corrected, originally reported 249 platforms, 1,455,279 b/d, 1.8772 bcfd shut in

Source BSEE

1 1 2

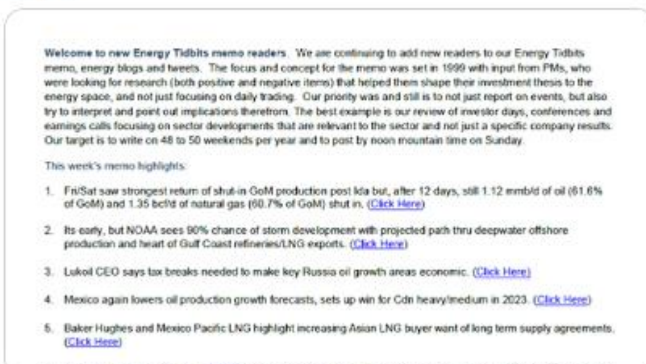
SAF **Dan Tsubouchi** @Energy_Tidbits · Sep 12

#TropicalStormNicholas has emerged. @NHC_Atlantic project path is west of major offshore GoM #Oil #NatGas platforms, but moving toward major Corpus Christi/Houston refineries/#LNG. fast moving 15 mph so hopefully doesn't drop too much precipitation. #OOTT

2

SAF **Dan Tsubouchi** @Energy_Tidbits · Sep 12

Our weekly SAF Sept 12, 2021 Energy Tidbits memo was just posted to our SAF Group website. This 50-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/



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.

This week's memo highlights:

1. Fri/Sat saw strongest return of shut-in GoM production post Ida but, after 12 days, still 1.12 mmb/d of oil (61.6% of GoM) and 1.35 bcf/d of natural gas (60.7% of GoM) shut in. (Click Here)
2. Its early, but NOAA sees 90% chance of storm development with projected path thru deepwater offshore production and heart of Gulf Coast refineries/LNG exports. (Click Here)
3. Lukoil CEO says tax breaks needed to make key Russia oil growth areas economic. (Click Here)
4. Mexico again lowers oil production growth forecasts, sets up win for Cdn heavy/medium in 2023. (Click Here)
5. Baker Hughes and Mexico Pacific LNG highlight increasing Asian LNG buyer want of long term supply agreements. (Click Here)
6. Please follow us on Twitter at [LINK] for breaking news that ultimately ends up in the weekly Energy Tidbits memo

2 3