SAF GROUP

Energy Tidbits

BLK CEO Need to Rapidly Admit We Will Not Survive With the Society We are Accustomed Without Hydrocarbons Right now

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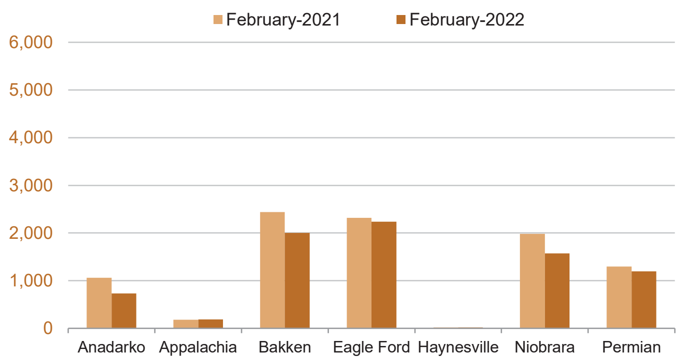
Year-over-year summary

January 2022

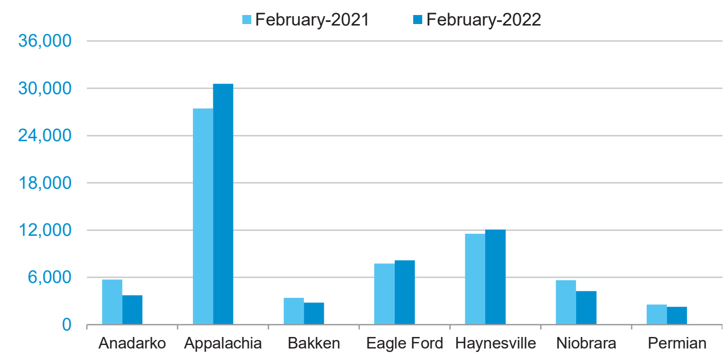
Drilling Productivity Report

drilling data through December
projected production through February

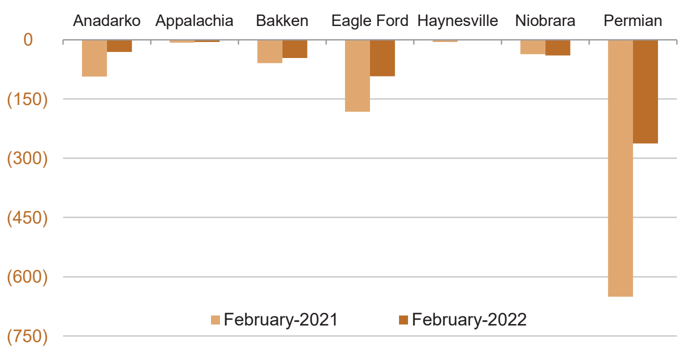
New-well oil production per rig
barrels/day



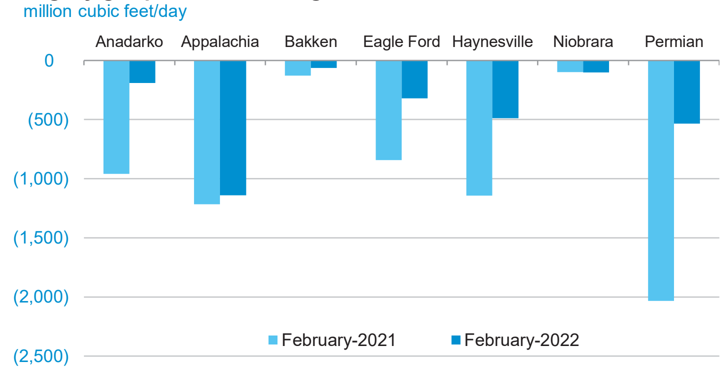
New-well gas production per rig
thousand cubic feet/day



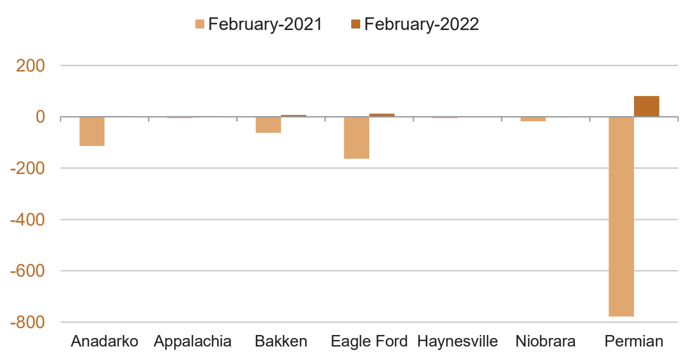
Legacy oil production change
thousand barrels/day



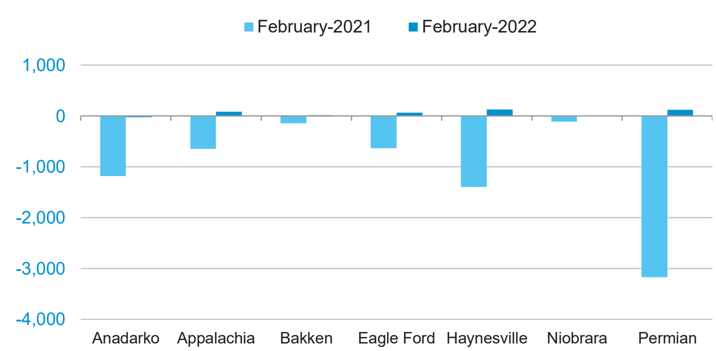
Legacy gas production change
million cubic feet/day



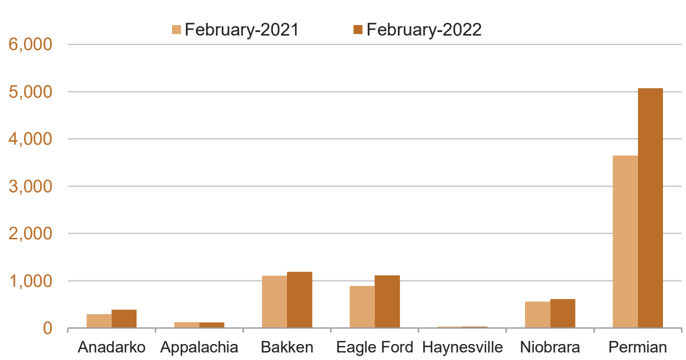
Indicated monthly change in oil production (Feb vs. Jan)
thousand barrels/day



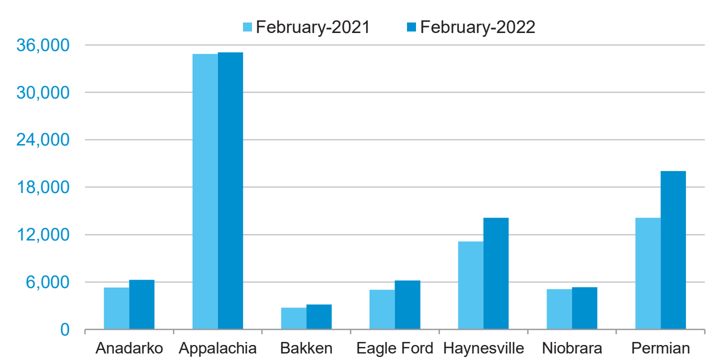
Indicated monthly change in gas production (Feb vs. Jan)
million cubic feet/day



Oil production
thousand barrels/day



Natural gas production
million cubic feet/day



Anadarko Region

Drilling Productivity Report

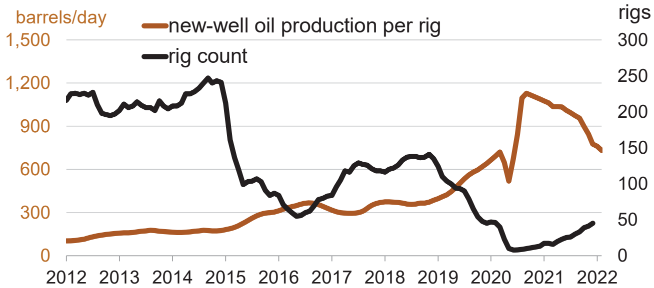
January 2022

drilling data through December
projected production through February

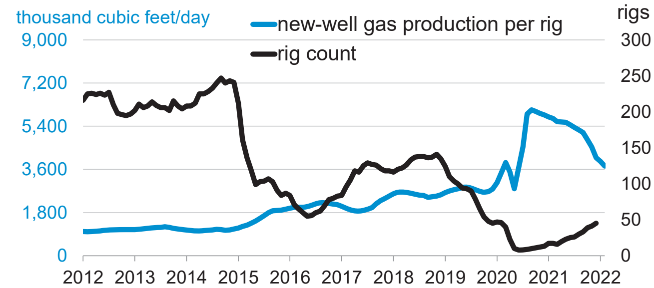
Oil			Gas
Oil -31 barrels/day month over month	**731** *February* **762** *January* barrels/day	**3,744** *February* **3,941** *January* thousand cubic feet/day	**Gas -197** thousand cubic feet/day month over month

Monthly additions from one average rig

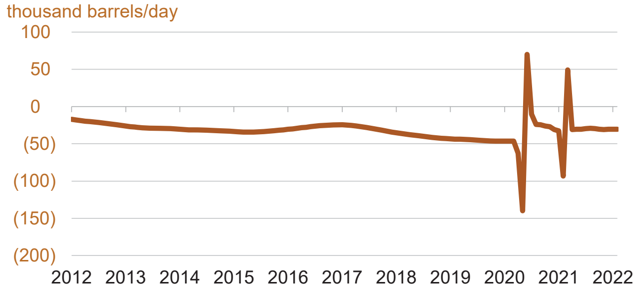
Anadarko Region
New-well oil production per rig **Rig count**



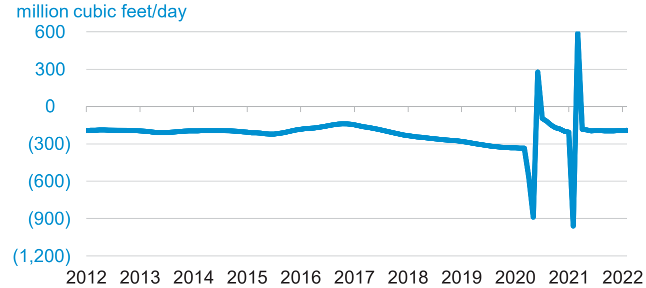
Anadarko Region
New-well gas production per rig **Rig count**



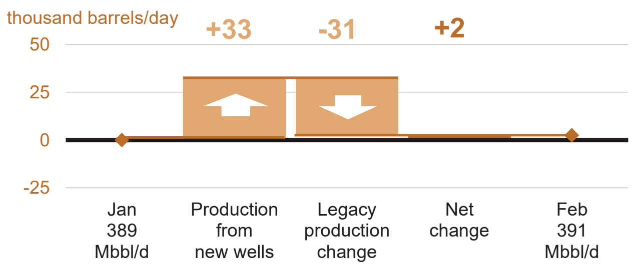
Anadarko Region
Legacy oil production change



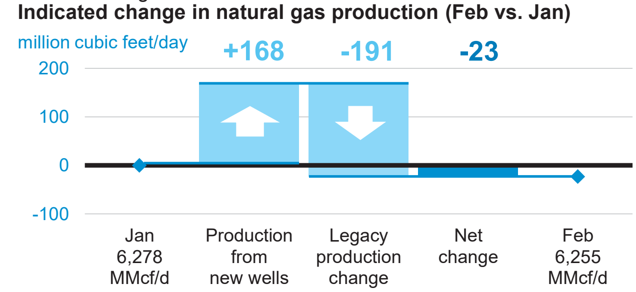
Anadarko Region
Legacy gas production change



Anadarko Region
Indicated change in oil production (Feb vs. Jan)

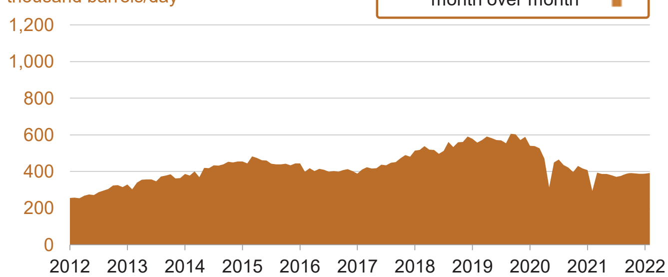


Anadarko Region
Indicated change in natural gas production (Feb vs. Jan)



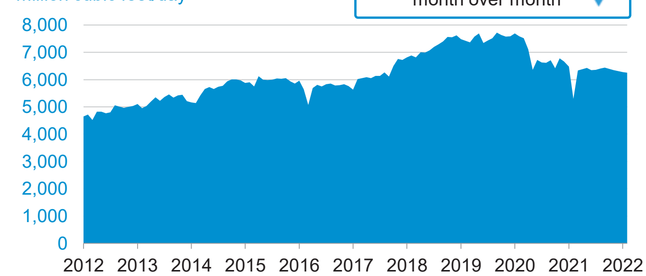
Anadarko Region
Oil production

Oil +2 thousand barrels/day month over month



Anadarko Region
Natural gas production

Gas -23 million cubic feet/day month over month



Appalachia Region
Drilling Productivity Report

January 2022
drilling data through December
projected production through February

Oil **0** barrels/day month over month

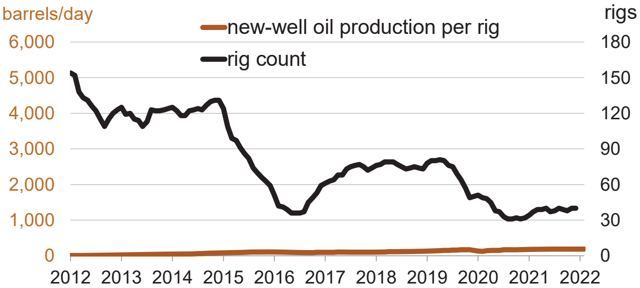
188 *February*
188 *January*
barrels/day

Monthly additions from one average rig

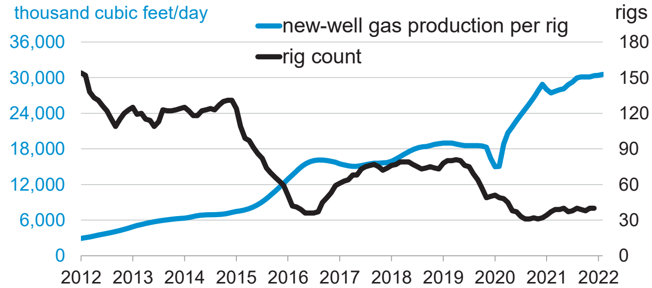
February **30,551**
January **30,399**
thousand cubic feet/day

Gas **+152** thousand cubic feet/day month over month

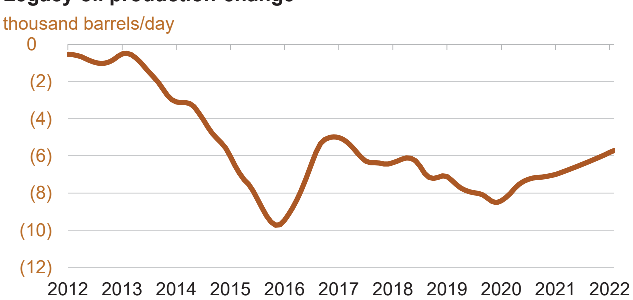
Appalachia Region
New-well oil production per rig



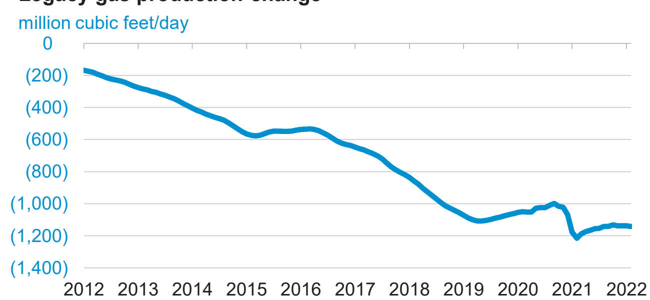
Appalachia Region
New-well gas production per rig



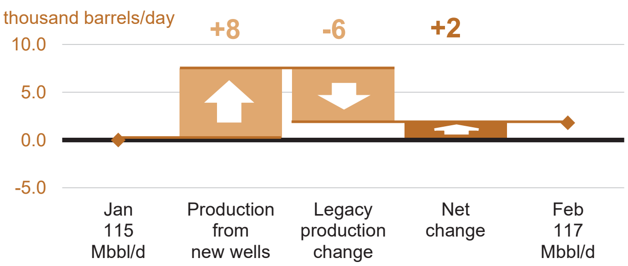
Appalachia Region
Legacy oil production change



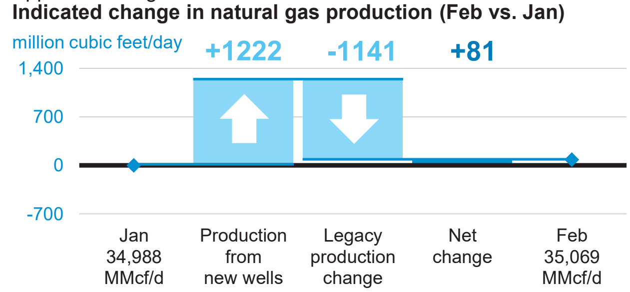
Appalachia Region
Legacy gas production change



Appalachia Region
Indicated change in oil production (Feb vs. Jan)

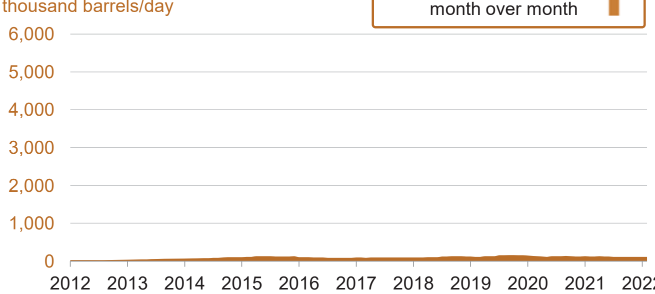


Appalachia Region
Indicated change in natural gas production (Feb vs. Jan)



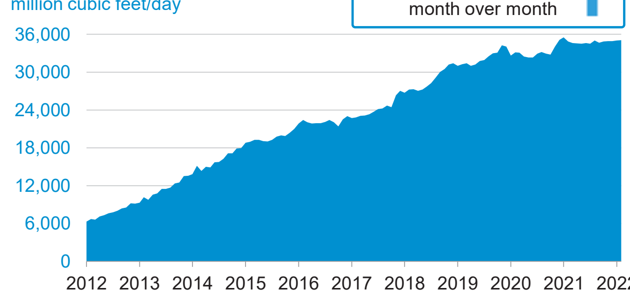
Appalachia Region
Oil production

Oil +2 thousand barrels/day month over month



Appalachia Region
Natural gas production

Gas +81 million cubic feet/day month over month



Bakken Region
Drilling Productivity Report

January 2022
drilling data through December
projected production through February

Oil
-106
barrels/day
month over month

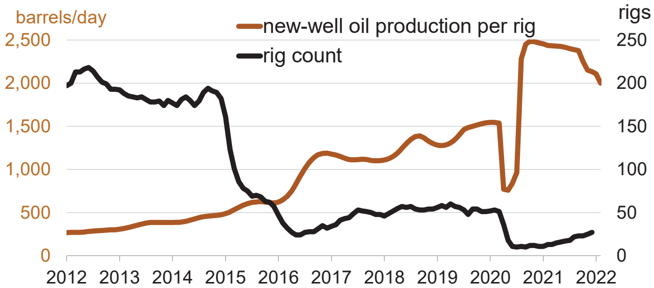
2,000 *February*
2,106 *January*
barrels/day

Monthly additions from one average rig

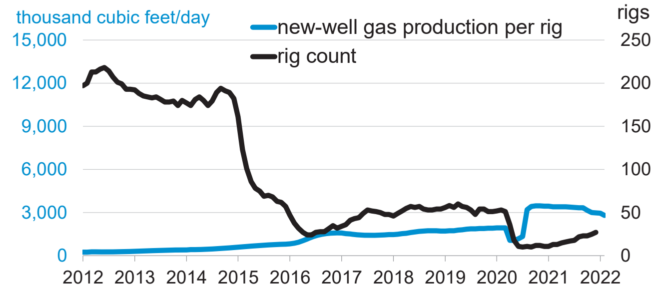
February **2,800**
January **2,948**
thousand cubic feet/day

Gas
-148
thousand cubic feet/day
month over month

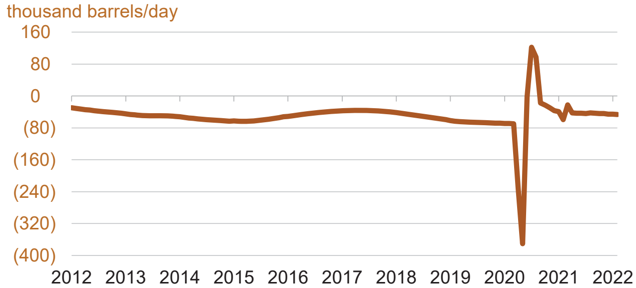
Bakken Region
New-well oil production per rig **Rig count**



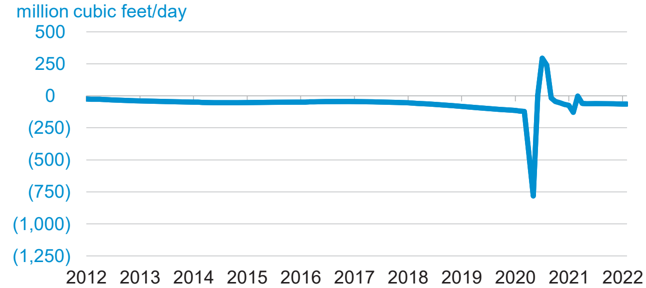
Bakken Region
New-well gas production per rig **Rig count**



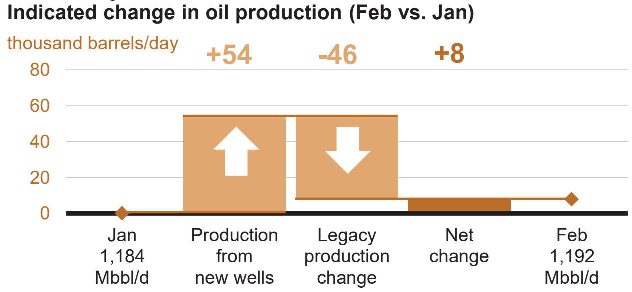
Bakken Region
Legacy oil production change



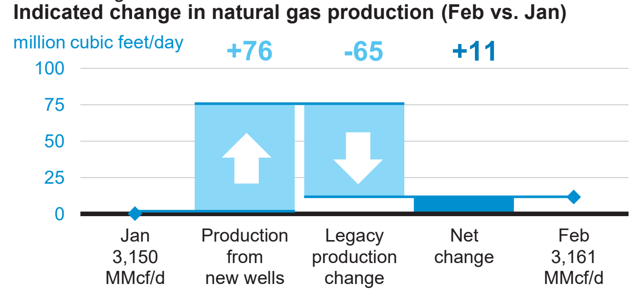
Bakken Region
Legacy gas production change



Bakken Region
Indicated change in oil production (Feb vs. Jan)

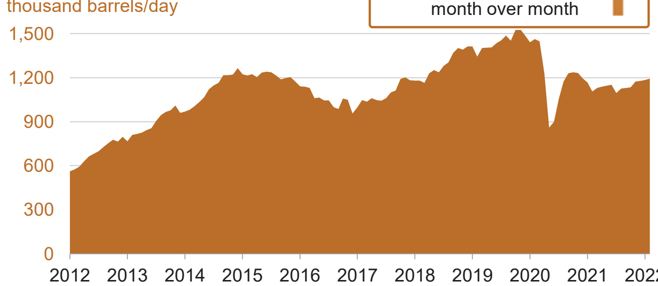


Bakken Region
Indicated change in natural gas production (Feb vs. Jan)



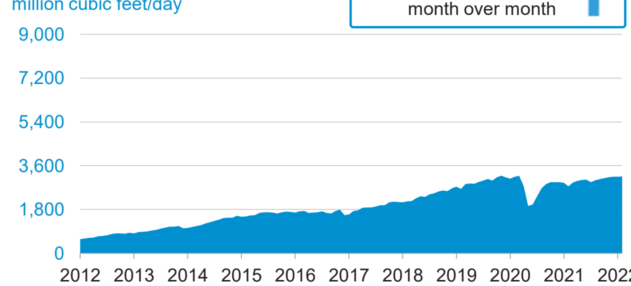
Bakken Region
Oil production

Oil +8
thousand barrels/day
month over month



Bakken Region
Natural gas production

Gas +11
million cubic feet/day
month over month



Eagle Ford Region

Drilling Productivity Report

January 2022

drilling data through December
projected production through February

Oil
-69
barrels/day
month over month

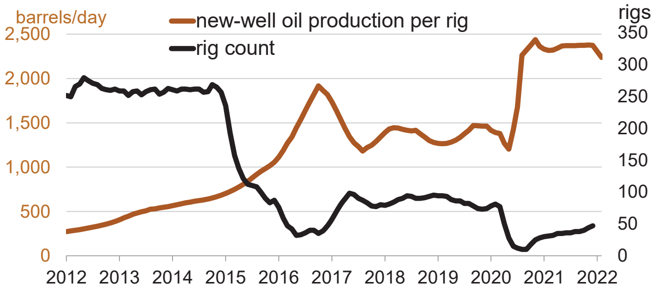
2,235 *February*
2,304 *January*
barrels/day

Monthly additions from one average rig

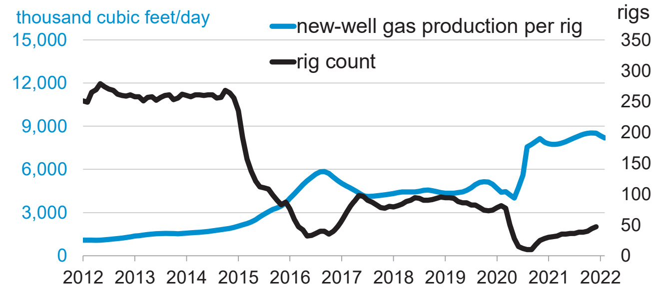
February **8,181**
January **8,348**
thousand cubic feet/day

Gas
-167
thousand cubic feet/day
month over month

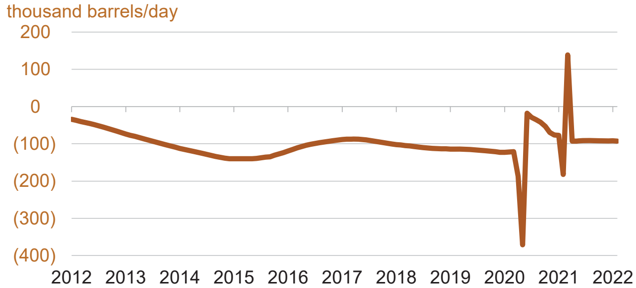
Eagle Ford Region
New-well oil production per rig
Rig count



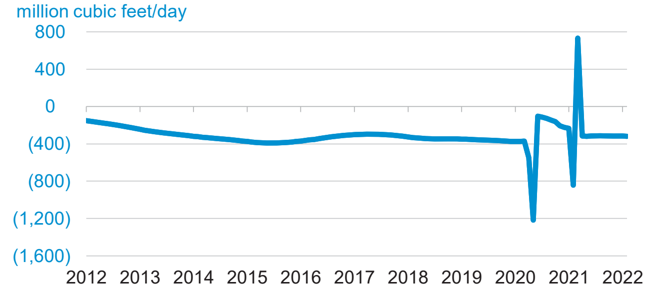
Eagle Ford Region
New-well gas production per rig
Rig count



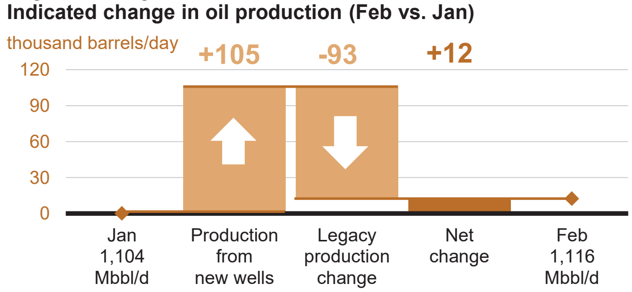
Eagle Ford Region
Legacy oil production change



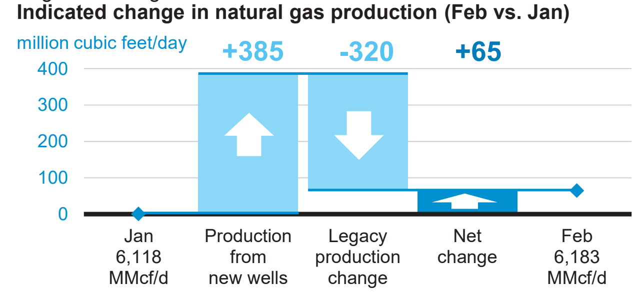
Eagle Ford Region
Legacy gas production change



Eagle Ford Region
Indicated change in oil production (Feb vs. Jan)

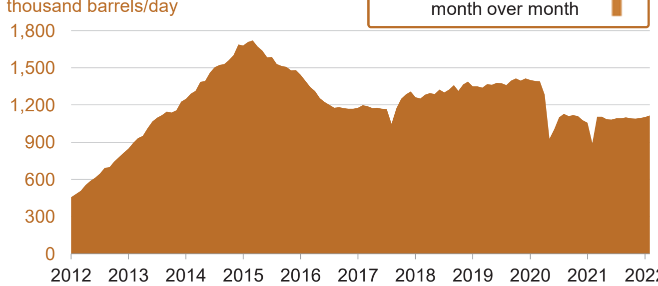


Eagle Ford Region
Indicated change in natural gas production (Feb vs. Jan)



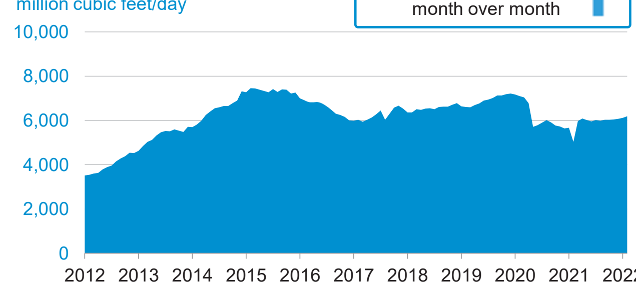
Eagle Ford Region
Oil production

Oil +12
thousand barrels/day
month over month



Eagle Ford Region
Natural gas production

Gas +65
million cubic feet/day
month over month



Haynesville Region

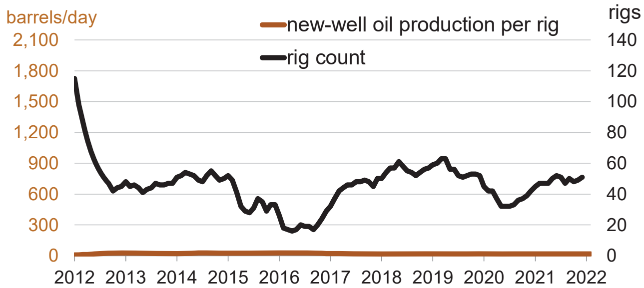
Drilling Productivity Report

January 2022

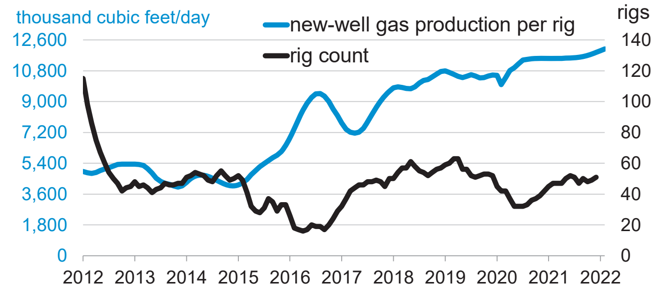
drilling data through December
projected production through February

Oil	February / January	Monthly additions from one average rig	February / January	Gas
0 barrels/day month over month	19 *February* / 19 *January* barrels/day		*February* 12,073 / *January* 11,971 thousand cubic feet/day	+102 thousand cubic feet/day month over month

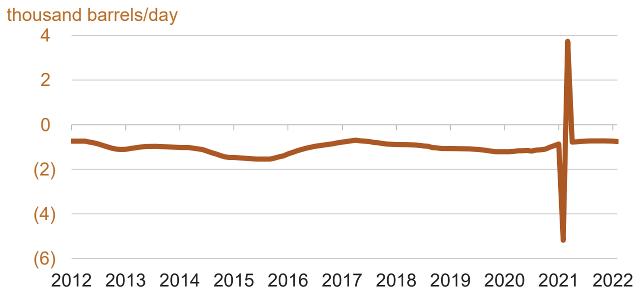
Haynesville Region
New-well oil production per rig



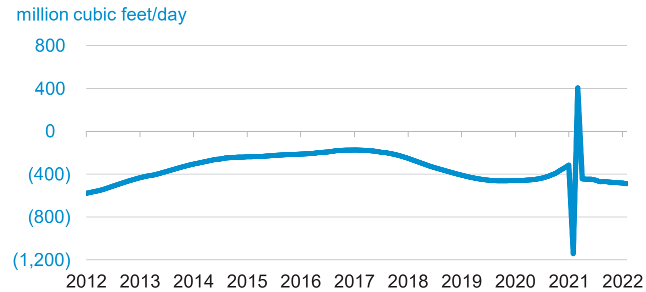
Haynesville Region
New-well gas production per rig



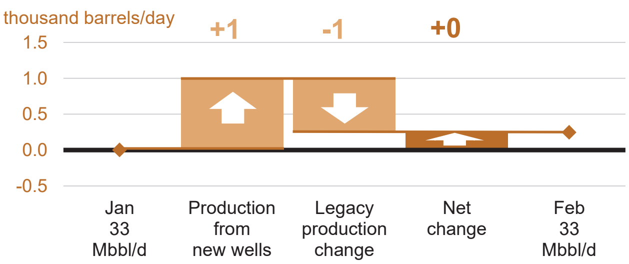
Haynesville Region
Legacy oil production change



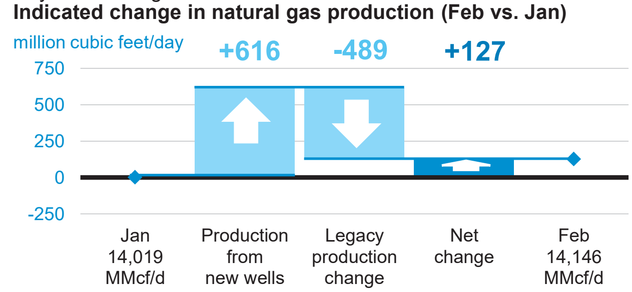
Haynesville Region
Legacy gas production change



Haynesville Region
Indicated change in oil production (Feb vs. Jan)

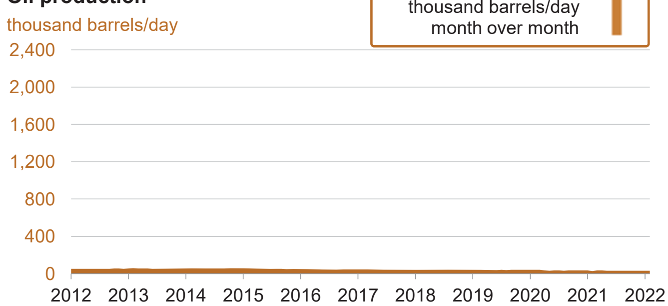


Haynesville Region
Indicated change in natural gas production (Feb vs. Jan)



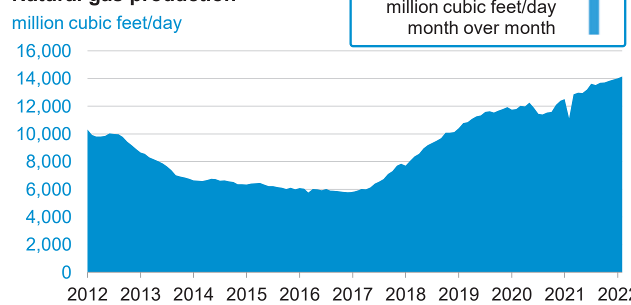
Haynesville Region
Oil production

Oil +0
thousand barrels/day
month over month



Haynesville Region
Natural gas production

Gas +127
million cubic feet/day
month over month



Niobrara Region

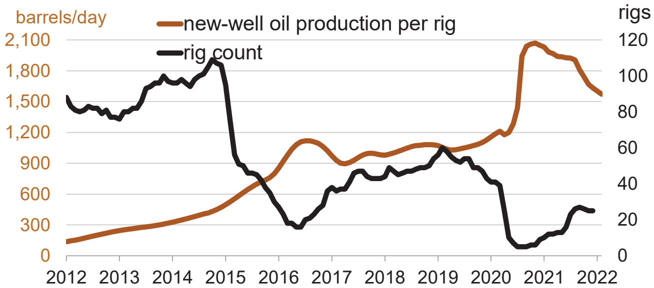
Drilling Productivity Report

January 2022

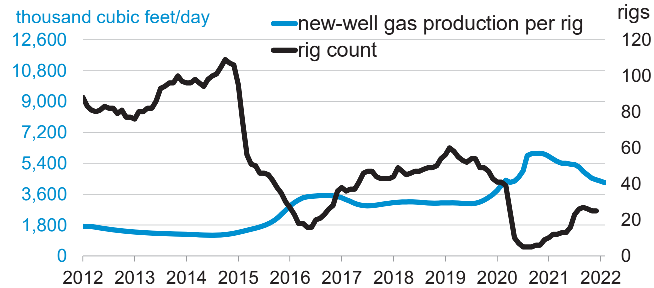
drilling data through December
projected production through February

Oil	February / January	Monthly additions from one average rig	February / January	Gas
Oil -33 barrels/day month over month	**1,570** *February* **1,603** *January* barrels/day		*February* **4,264** *January* **4,351** thousand cubic feet/day	**Gas -87** thousand cubic feet/day month over month

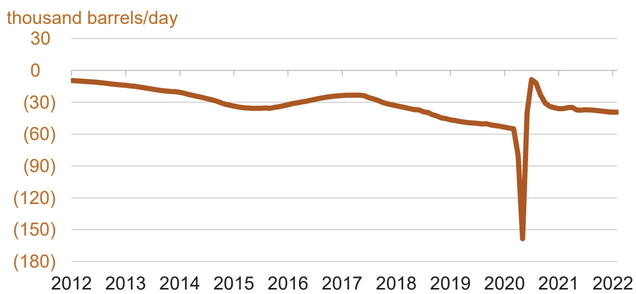
Niobrara Region
New-well oil production per rig **Rig count**



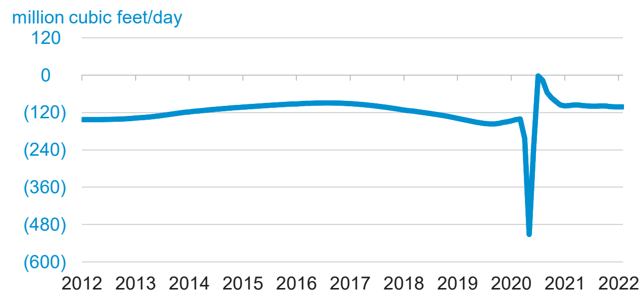
Niobrara Region
New-well gas production per rig **Rig count**



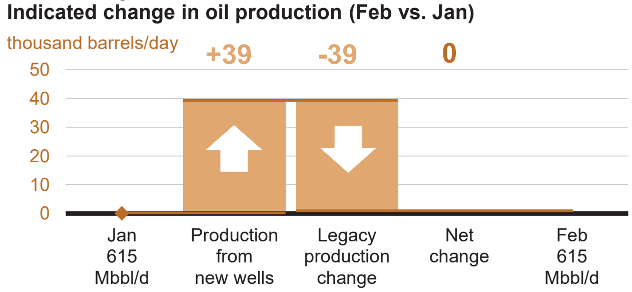
Niobrara Region
Legacy oil production change



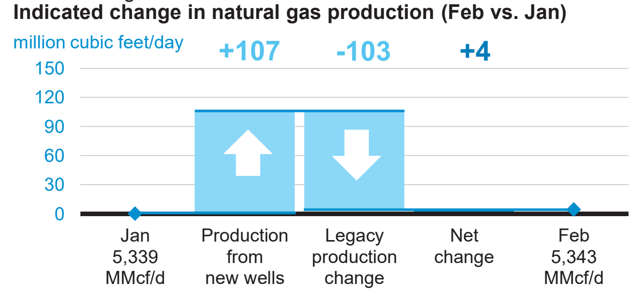
Niobrara Region
Legacy gas production change



Niobrara Region
Indicated change in oil production (Feb vs. Jan)

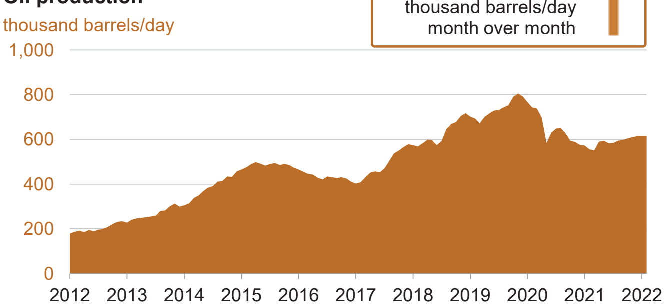


Niobrara Region
Indicated change in natural gas production (Feb vs. Jan)



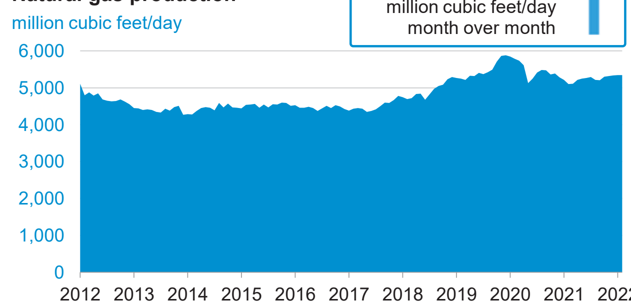
Niobrara Region
Oil production

Oil 0
thousand barrels/day
month over month



Niobrara Region
Natural gas production

Gas +4
million cubic feet/day
month over month



Permian Region

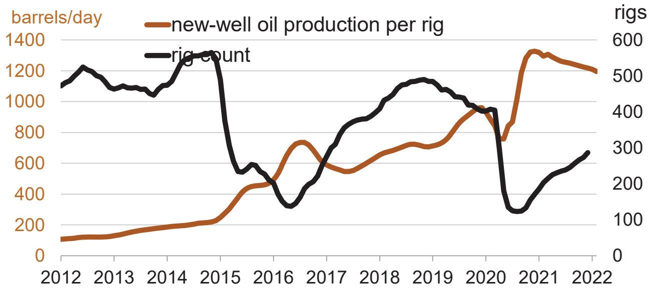
Drilling Productivity Report

January 2022

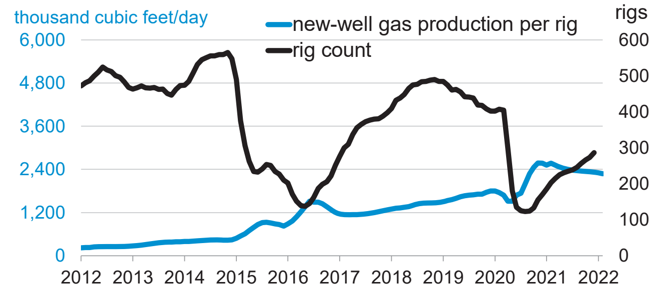
drilling data through December
projected production through February

Oil			Monthly additions from one average rig			Gas
Oil -15 barrels/day month over month	**1,195** *February* **1,210** *January* barrels/day			*February* **2,281** *January* **2,309** thousand cubic feet/day		**Gas -28** thousand cubic feet/day month over month

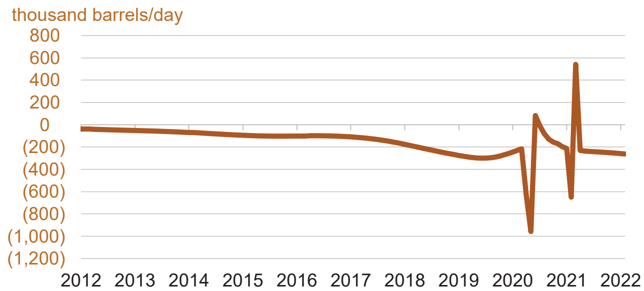
Permian Region
New-well oil production per rig **Rig count**



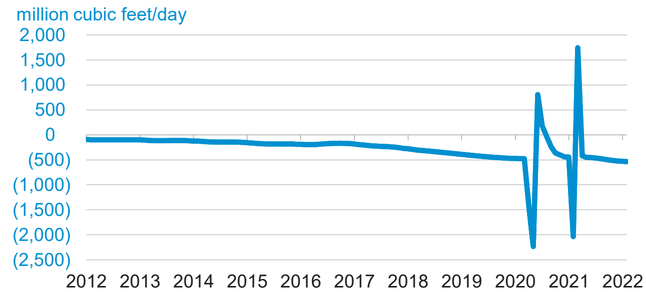
Permian Region
New-well gas production per rig **Rig count**



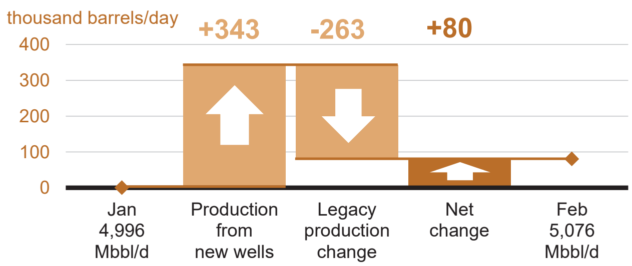
Permian Region
Legacy oil production change



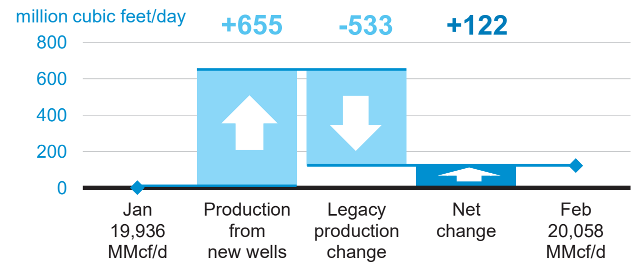
Permian Region
Legacy gas production change



Permian Region
Indicated change in oil production (Feb vs. Jan)

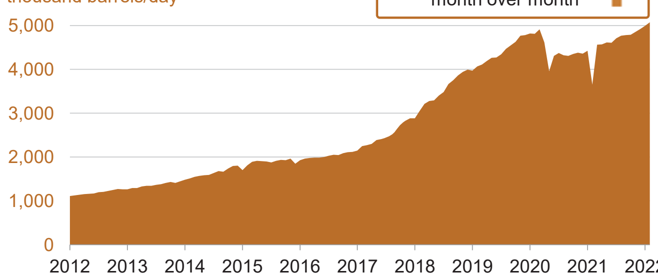


Permian Region
Indicated change in natural gas production (Feb vs. Jan)



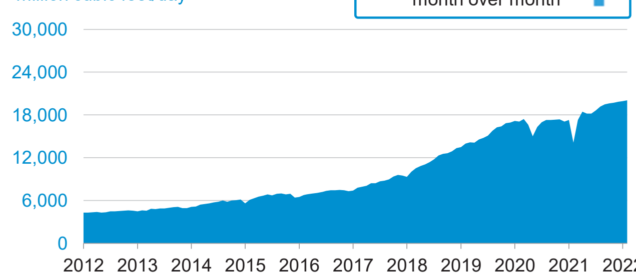
Permian Region
Oil production
thousand barrels/day

Oil +80
thousand barrels/day
month over month



Permian Region
Natural gas production
million cubic feet/day

Gas +122
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 https://www.reuters.com/markets/funds/venture-globals-calcasieu-pass-plant-louisiana-close-producing-lng-2022-01-21/

January 21, 20226:10 AM MSTLast Updated 3 hours ago

Venture Global's Calcasieu Pass plant in Louisiana close to producing LNG

Reuters

Jan 21 (Reuters) - U.S. liquefied natural gas (LNG) company Venture Global's Calcasieu Pass export plant in Louisiana is close to producing its first LNG, energy traders said after the amount of feed gas to the facility increased rapidly this week.

The amount of gas flowing to Calcasieu rose to 88 million cubic feet per day (mmcfd) on Friday, from an average of about 38 mmcfd during the prior week, according to pipeline data from Refinitiv.

Calcasieu has been pulling in gas since around August, according to Refinitiv data, as the company tests equipment before the facility enters commercial service later in 2022.

Officials at Venture Global were not immediately available for comment.

Venture Global is installing 18 modular liquefaction trains configured in nine blocks at Calcasieu to produce about 10 million tonnes per annum (MTPA) of LNG, equivalent to about 1.5 billion cubic feet per day of natural gas. Analysts estimate the plant cost about $4.5 billion.

Federal regulators have approved the commissioning of at least two blocks so far. read more

In total, Venture Global has about 70 MTPA of LNG export capacity under construction or development in Louisiana, including the 10-MTPA Calcasieu Pass, 20-MTPA Plaquemines, 20-MTPA Delta and 20-MTPA CP2.

Venture Global has already started early site work on the $8.5 billion Plaquemines project, which analysts expect to start producing first LNG in 2024.

Venture Global has entered long-term agreements to sell LNG to units of several companies around the world, including China National Offshore Oil Corp (CNOOC), China Petroleum and Chemical Corp (Sinopec) (600028.SS), Royal Dutch Shell PLC (RDSa.L), BP PLC , Edison SpA (EDNn.MI), Galp Energia SGPS SA (GALP.LS), Repsol SA (REP.MC) and Polish Oil and Gas Co (PGNiG). read more know, reconciliations of operating income and other GAAP to non-GAAP measures can be found in our earnings release.

With that, I will turn the call over to Lorenzo.

Lorenzo Simonelli {BIO 15243700 <GO>}

Thank you, Jud. Good morning, everyone, and thanks for joining us.

We are pleased with our fourth quarter results as we generated another quarter of strong free cash flow, solid margin rate improvement, and strong orders performance from TPS.

During the quarter, TPS continued to operate at a high level; OFE successfully executed on its cost improvement initiatives; and OFS performed extremely well despite continued pressure on supply chain and commodity inflation. For the full year, we were pleased with our financial performance. We took several steps in 2021 to accelerate our strategy and help position the company for the future. Last year proved to be successful on many fronts for Baker Hughes with key commercial successes and developments in the LNG and new energy markets, as well as record cash flow generation and peer-leading capital allocation.

After a quiet start to the year, LNG activity played an important role in helping TPS book almost $7.7 billion in orders in 2021, which was just below the record levels achieved in 2019. Perhaps more importantly, we believe that the step-up in LNG order activity provides a solid indication that a new LNG cycle is beginning to take shape. We also believe that the uptick in orders along with other recent policy movements, particularly in Europe confirms that natural gas is gradually gaining greater acceptance as a transition and destination fuel for a net-zero world.

In new energy frontiers, we started to see more pronounced commercial successes from our energy transition efforts, generating approximately $250 million in new orders across our TPS, OFS, and DS product companies, primarily in the areas of hydrogen and CCUS. We remain confident in our ability to grow this business over the next decade to ultimately total $6 billion to $7 billion of orders by 2030.

I'm also very pleased to report that Baker Hughes delivered its strongest ever free cash flow year, generating over $1.8 billion in 2021, which represents almost 70% conversion from adjusted EBITDA. We are pleased to see this performance as our cash restructuring and separation payments wound down and we continue to make progress on improving our working capital and broader cash processes.

Our strong free cash flow profile provides the company with ample flexibility and optionality when it comes to our broader capital allocation strategy. As evidence of this, we returned almost $1.2 billion back to shareholders through dividends and buybacks in 2021 while also making multiple acquisitions and investments across the industrial and new energy spaces.

On the industrial front, we completed the acquisition of ARMS Reliability and a major investment in Augury, which will help Baker Hughes, continue to build out its industrial asset management platform and deliver an expanded set of asset performance capabilities.

On the new energy front, we were active this year in pursuing early-stage technologies in CCUS and in hydrogen. In CCUS, we acquired a position in Electrochaea, a bio-methanation company, and also entered into an exclusive license with SRI for the mixed-salt process. In hydrogen, we made an investment in Ekona, a growth stage company developing novel turquoise hydrogen production technology as well as Nemesis, a technology company focused on a range of early-stage hydrogen technologies.

While 2021 saw many positive achievements, the year was also not without its challenges. We saw continued disruptions from the COVID-19 pandemic, which continued to impact our operations. Supply chain and inflationary pressures also drove higher costs and delivery issues, primarily across our OFS and DS product companies. Our teams have continued to work to offset some of these pressures. But we expect to continue to see some level of tension and disruption in these areas potentially through the first half of the year.

As we look ahead to 2022, we expect the pace of global economic growth to remain strong. However, growth rates are likely to moderate from 2021 levels as central banks are expected to begin tightening monetary policy in order to reduce COVID-related stimulus plans and quell growing inflationary pressures.

Despite the expected slowdown in the pace of growth, we believe the continuing broader macro recovery would translate into rising energy demand in 2022 with oil demand likely recovering to pre-pandemic levels by the end of the year. Pairing this demand scenario with continued OPEC-plus, IOC, and EMP spending discipline, we expect the oil markets to remain tight for some time. We believe that this will provide an attractive investment environment for our customers and a strong tailwind for many of our product companies.

We also expect continued momentum in the global gas markets in 2022, building on a strong 2021. A combination of demand and supply factors converged in 2021, pushing natural gas and LNG prices to record-breaking levels in both Europe and in Asia. The gas price spikes also highlighted the fragility of the global energy system as the world transitions to net-zero.

Looking ahead, we expect a number of additional LNG FIDs in 2022 and beyond, supported by the growing appetite for longer-term LNG purchase agreements. As we have previously mentioned, we see significant structural demand growth for LNG in the coming decades. Our positive long-term view is also supported by the recent improvement in policy sentiments in certain parts of the world towards natural gases role within the energy transition.

Against this constructive macro backdrop, Baker Hughes remains focused on executing our strategy across the three pillars of transform the core, invest for growth, and position

OFS team is working extremely hard to offset these headwinds with successful pricing increases across multiple product lines and continued progress in mitigating some of the logistics constraints. Based on the actions being taken by our OFS team and assuming the gradual normalization of the current state of supply chain disorder, we remain focused on achieving 20% EBITDA levels in OFS by the end of 2022.

Moving to TPS, the outlook remains constructive driven by opportunities in LNG, onshore, offshore production, and new energy initiatives. I'd like to thank Rod and the TPS team for an exceptional year in 2021, which exemplified the strength of the TPS business. TPS booked almost $7.7 billion of orders, which included 22 MTPA of LNG orders across four projects, and nine FPSOs and offshore top side project awards.

On the execution side, TPS generated over $1 billion of operating income, representing over 16% in operating margin rate, despite revenue growth and equipment, significantly outpacing services. We are excited about what the future holds for TPS across multiple fronts. In LNG, we were pleased to book two awards in the fourth quarter. We announced a major LNG award for the five MTPA Pluto Train 2 project in Western Australia, which is operated by Woodside and also received a large-scale LNG equipment award in the Eastern Hemisphere.

Additionally, we were awarded an order to deliver power-generation equipment for a major LNG project in North America. We continue to be optimistic on the outlook for LNG and remain confident on the potential for 100 to 150 MTPA of awards over the next two to three years. Based on the continued pace of discussions with multiple customers and the positive fundamentals in the global gas markets, we have a general bias towards the upper end of this range.

For the non-LNG segments of our TPS portfolio, we see multiple opportunities for continued growth, and we were pleased to book a number of awards in new energy during the quarter. In hydrogen, we booked an award for advanced compression technology for the NEOM carbon-free hydrogen project in the Kingdom of Saudi Arabia, building on the announcement we made with Air Products in the second quarter of 2021. We will be providing our HPRC solutions to the NEOM project, which will enable a lower cost of production and accelerate the adoption of hydrogen as a zero-carbon fuel.

Our collaboration with Air Products will be critical for a net-zero future. And the award is a good example of how Baker Hughes' proven technology is helping to accelerate the hydrogen economy. In CCUS, we received an order from Santos to supply turbomachinery equipment for the Moomba Carbon Capture and Storage project in South Australia. Baker Hughes will provide gas turbine compressor and heat recovery steam generator technologies to compress the carbon dioxide. The project will serve as a gas processing plant and permanently store 1.7 million tons of carbon dioxide annually in the depleted natural gas reservoirs in the onshore Cooper Basin. Even though, 2021 order activity came in well ahead of our expectations, we still expect to see a similar level of orders for TPS in 2022, driven primarily by LNG.

our presence to non-critical assets, and developing software capabilities to allow us to cover the entire balance of plant.

As the world strives towards the net-zero target in the coming decades, enterprise-level industrial asset management capabilities will be a key driver by enabling better operating efficiency, lowering energy consumption, and reducing emissions across multiple industries.

Overall, I'm pleased with the progress we made in 2021 in navigating the many challenges presented during the year while also executing on the commercial opportunities across our portfolio. At the same time, we were able to convert almost 70% of our 2021 adjusted EBITDA into free cash flow. We returned almost two-thirds of this free cash flow back to shareholders and made good progress on transforming our company into an energy transition leader.

As we enter 2022, we expect to benefit from solid macro tailwinds across both of our major business areas with cyclical recovery in OFSE and a longer-term structural growth trends in LNG, new energy, and industrial asset management. We look forward to further developing our corporate strategy, building on our commercial success and focusing on a range of capital allocation opportunities.

I want to conclude by thanking all of our Baker Hughes employees for their hard work in overcoming another year of challenges surrounding the pandemic. And I look forward to their continued commitment to our success in 2022 and beyond.

With that, I'll turn the call over to Brian.

Brian Worrell {BIO 16231736 <GO>}

Thanks, Lorenzo. I will begin with the total company results and then move into the segment details. Orders for the quarter were $6.7 billion, up 24% sequentially driven by TPS, Digital Solutions, and OFS, partially offset by a decrease in OFE. Year-over-year, orders were up 28% driven by increases in TPS, Digital Solutions, and OFS, and a decrease in OFE.

Remaining performance obligation was $23.6 billion, up 1% sequentially. Equipment RPO ended at $8.2 billion, up 9% sequentially and services RPO ended at $15.3 billion, down 4% sequentially. We are pleased with our strong orders performance in the quarter, particularly in TPS, which provides a good level of revenue visibility into 2022 and beyond.

Our total company book-to-bill ratio in the quarter was 1.2 and our equipment book-to-bill in the quarter was 1.4. Revenue for the quarter was $5.5 billion, up 8% sequentially, driven by increases across all four segments. Year-over-year, revenue was flat driven by an increase in OFS, and offset by decreases in TPS and OFE.

As we said last year, as the energy markets evolve, we think operating around these two broad focus areas makes sense in terms of investment strategy, et cetera. And we also said that aligning across the two broad business areas will actually help us give the most optionality longer-term. So the work we've done only just reinforces our view. Again, the company is strong together at this stage, and we'll continue to align across the two business areas, continue the work and continue to update us on our progress and decisions. But it goes without saying, we continue to operate the company for the best returns to shareholders.

Q - James West {BIO 19758684 <GO>}

Of course. Absolutely. And then maybe an unrelated follow-up, Lorenzo, on TPS, and you gave some good guidance on kind of expected orders over the next several years. I'm just curious how we should think about 2022, the cadence of the orders and then what that means for growth in TPS as we get into 2023.

A - Lorenzo Simonelli {BIO 15243700 <GO>}

Sure, James. And I think importantly, I believe the order momentum we saw at the end of 2021 is likely to continue into 2022. We've indicated over the past quarters that we're seeing an LNG cycle beginning to accelerate. And generally speaking, LNG projects are beginning to be pull forward versus previous expectations due to the strong long-term LNG fundamentals and also the improving environment to secure long-term offtake agreements.

So we also believe the recent policy movement out of Europe, that's encouraging to see what would be FIDs in 2023, maybe potentially be pulled forward into 2022 as well. So there a couple of large awards this year in 2022 and also some small and mid-sized awards that should be coming through. And I think although we're calling the TPS orders in 2022 really flat to 2021, we believe that orders could potentially increase as we go through the year.

So the specific areas are U.S., Middle East and Russia. And for 2023, it's a little early. But I think, again, the outlook is positive, and we still see a lot of projects that we're discussing with our customers. As you know, we're very close on the LNG side. I also think it's important to remember that LNG is a headline for TPS orders. We also see a solid pipeline in our onshore/offshore production segment along with opportunities in pumps, valves, and we continue to see positive traction in the new energy front on the back of a strong order intake in 2021.

Q - James West {BIO 19758684 <GO>}

Okay, got it. Thanks, Lorenzo.

Operator

Our next question comes from Chase Mulvehill with Bank of America.

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

Posted 11am on July 14, 2021

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

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

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

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

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

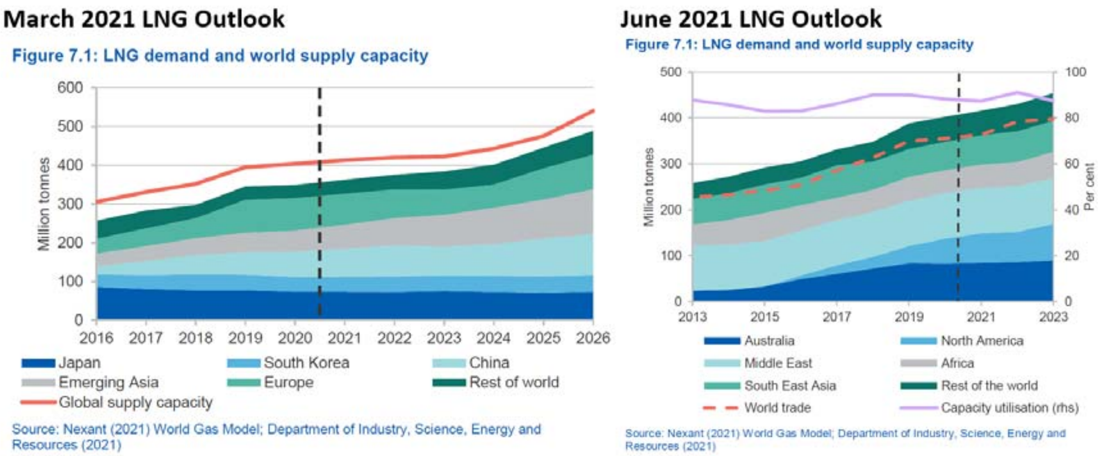
<u>There are other LNG supply delays/interruptions beyond Mozambique.</u> There have been a number of other smaller LNG delay or existing supply interruptions that add to Asian LNG buyers feeling less secure about the reliability of mid to long term LNG supply. Here are just a few examples. (i) Total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

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

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

But we still see major LNG suppliers like Australia hinting but not outright saying that LNG supply gap is coming sooner. We have to believe Australia will be unveiling a sooner LNG supply gap in their September forecast. On June 28, we tweeted [LINK] on Australia's Resources and Energy Quarterly released on Monday [LINK] because there was a major change to their LNG outlook versus their March forecast. We tweeted "*#LNGSupplyGap. AU June fcast now sees #LNG mkt tighten post 2023 vs Mar fcast excess supply thru 2026. Why? $TOT Mozambique delays. See below SAF Apr 28 blog. Means brownfield LNG FID needed ie. like #LNGCanada Phase 2. #OOTT #NatGas".* Australia no longer sees supply exceeding demand thru 2026. In their March forecast, Australia said "*Nonetheless, given the large scale expansion of global LNG capacity in recent years, demand is expected to remain short of total supply throughout the projection period."* Note this is thru 2026 ie. a LNG supply surplus thru 2026. But on June 28, Australia changed that LNG outlook and now says the LNG market may tighten beyond 2023. Interestingly, the June forecast only goes to 2023 and not to 2026 as in March. Hmmm! On Monday, they said "*Given the large scale expansion of global LNG capacity in recent years, import demand is expected to remain short of export capacity throughout the outlook period. Beyond 2023, the global LNG market may tighten, due to the April 2021 decision to indefinitely suspend the Mozambique LNG project, in response to rising security issues. This project has an annual nameplate capacity of 13 million tonnes, and was previously expected to start exporting LNG in 2024*." 13 million tonnes is 1.7 bcf/d so they are only referring to Total Mozambique LNG Phase 1. So no surprise the change is Mozambique LNG driven but we have to believe the reason why they cut their forecast off this time at 2023 is that they are looking at trying to figure out what to forecast beyond 2023 in addition to Total Phase 1. And, importantly, we believe they will be changing their LNG forecast for more than Mozambique ie. India demand that we highlight later in the blog. They didn't say anything else specific on Mozambique but, surely they have to also be delaying the follow on Total Phase 2 of 1.3 bcf/d and Exxon Rozuma Phase 1 of 2.0 bcf/d.

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

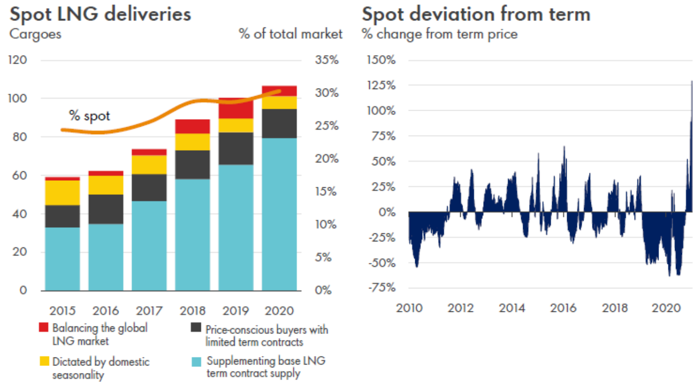


Source: Australia Resources and Energy Quarterly

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

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

Spot LNG deliveries and Spot deviation from term price



Source: Shell LNG Outlook 2021 on Feb 25, 2021

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

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

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

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

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

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

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

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

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

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

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

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

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

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

Baker Hughes Company Announces Fourth Quarter and Total Year 2021 Results

January 20, 2022 at 7:00 AM EST
PDF Version

- *Orders of $6.7 billion for the quarter, up 24% sequentially and up 28% year-over-year*
- *Revenue of $5.5 billion for the quarter, up 8% sequentially and flat year-over-year*
- *GAAP operating income of $574 million for the quarter, up 52% sequentially and favorable year-over-year*
- *Adjusted operating income (a non-GAAP measure) of $571 million for the quarter, up 42% sequentially and up 23% year-over-year*
- *Adjusted EBITDA* (a non-GAAP measure) of $844 million for the quarter was up 27% sequentially and up 10% year-over-year*
- *GAAP diluted earnings per share of $0.32 for the quarter which included $(0.08) per share of adjusting items. Adjusted diluted earnings per share (a non-GAAP measure) were $0.25.*
- *Cash flows generated from operating activities were $773 million for the quarter. Free cash flow (a non-GAAP measure) for the quarter was $645 million.*

The Company presents its financial results in accordance with GAAP. However, management believes that using additional non-GAAP measures will enhance the evaluation of the profitability of the Company and its ongoing operations. Please see reconciliations in the section entitled "Reconciliation of GAAP to non-GAAP Financial Measures." Certain columns and rows in our tables and financial statements may not sum up due to the use of rounded numbers.

**Adjusted EBITDA (a non-GAAP measure) is defined as operating income (loss) excluding depreciation & amortization and operating income adjustments.*

LONDON & HOUSTON--(BUSINESS WIRE)--Jan. 20, 2022-- Baker Hughes Company (Nasdaq: BKR) ("Baker Hughes" or the "Company") announced results today for the fourth quarter and total year 2021.

	Thr
(in millions except per share amounts)	**December 31, 2021**
Orders	$ 6,656
Revenue	5,519
Operating income	574
Adjusted operating income (non-GAAP)	571
Adjusted EBITDA (non-GAAP)	844
Net income attributable to Baker Hughes	294
Adjusted net income (loss) (non-GAAP) attributable to Baker Hughes	224
Diluted EPS attributable to Class A shareholders	0.32
Adjusted diluted EPS (non-GAAP) attributable to Class A shareholders	0.25
Cash flow from operating activities	773
Free cash flow (non-GAAP)	645

"F" is used in most instances when variance is above 100%. Additionally, "U" is used in most instances when variance

“We are pleased with our fourth quarter results as we generated another quarter of strong free cash flow, solid margin rate improvement, and strong orders from TPS. For the full year, we were pleased with our performance and took several important steps to accelerate our strategy and help position the Company for the future. Overall, 2021 proved to be successful on many fronts for Baker Hughes, with key commercial successes and developments in the LNG and new energy markets, as well as record cash flow from operations and free cash flow, and peer-leading capital allocation. I would like to thank our employees for their hard work and commitment to achieve our goals, deliver for our customers and move the Company forward,” said Lorenzo Simonelli, Baker Hughes chairman and chief executive officer.

“As we look ahead to 2022, we expect the pace of global economic growth to remain strong although slightly moderate compared to 2021. We believe the broader macro recovery should translate into rising energy demand for 2022 and relatively tight supplies for oil and natural gas, providing an attractive investment environment for our customers and a strong tailwind for many of our product companies.”

“We are very excited with the strategic direction of Baker Hughes and believe the Company is well-positioned to capitalize on near-term cyclical recovery and for long-term change in the energy and industrial markets. We look forward to another year of supporting our customers, continuing to advance our strategy, and delivering for shareholders in 2022,” concluded Simonelli.

Quarter Highlights

Supporting our Customers

OFS secured a contract with LUKOIL to begin developing 14 offshore wells in the Baltic Sea’s D33 field. The contract will feature the first-ever combined deployment of Baker Hughes’ electrical submersible pumps (ESP) and LUKOIL’s Permanent Magnet Motors (PMM) since the two companies announced a collaboration on energy efficient technologies in June 2021. Baker Hughes’ ESP technology has unsurpassed levels of efficiency, reliability, and performance, while LUKOIL’s PMM technology enables a 15-20% reduction in energy consumption compared to current artificial lift processes.

OFS also secured a two-year contract for technology and services for a major operator in the Permian Basin. The contract combines best-in-class technology and services from the Artificial Lift, Oilfield & Industrial Chemicals, and Reservoir Technical Services product lines, including the CENesis PHASE Artificial Lift system, which optimizes production, extends asset life, increases personnel safety, lowers lifting costs and reduces environmental footprint.

The TPS segment continued to maintain its LNG leadership. TPS secured a major contract from Bechtel to provide high-efficiency gas turbines and centrifugal compressors to support the expansion of the Pluto LNG onshore processing facility in Australia, which is operated by Woodside. The contract will provide six LM6000PF+ aeroderivative gas turbines, 14 centrifugal compressors and additional equipment for Pluto LNG’s second train, leading to an additional expected capacity of approximately 5 million tons per annum (MTPA) and helping to maximize efficiency and flexibility while lowering greenhouse gas emissions.

TPS secured a contract with NOVATEK PAO to provide advanced turbomachinery equipment for a feed gas boosting station in Russia. TPS will provide five turbo-compressors, driven by Frame 5/2D gas turbines, to support the facility, stabilizing the pressure and flow rate of feed gas to maintain maximum carrying capacity. Baker Hughes and NOVATEK have a long history of collaboration, and TPS’ gas turbines have operated successfully at NOVATEK's projects since 2017.

OFE secured a major 10-year contract from Abu Dhabi National Oil Company (ADNOC) for the Surface Pressure Control (SPC) product line to manufacture, supply, store, and service surface wellheads and tree systems. The contract includes ADNOC’s onshore and offshore fields in the UAE as well as a long-term service contract to cover repair, maintenance and spares for the project’s equipment.

The DS segment continued to gain traction in multiple industrial end markets, particularly in the automotive and electronics sectors. The Waygate Technologies product line continued to lead in market share for industrial computed tomography (CT) systems, achieving record revenue in the fourth quarter for battery inspection and securing contracts with major electric vehicle manufacturers and battery suppliers in Europe and Asia.

Executing on Priorities

Baker Hughes and Shell signed a broad strategic collaboration agreement to accelerate the global energy transition. Shell will provide select Baker Hughes sites in the U.S. with power and renewable energy credits, as well as negotiate renewable power for Baker Hughes sites in Europe and Singapore. The two companies will also identify opportunities to accelerate each other’s transition to net-zero carbon emissions by 2050, such as Baker Hughes providing low-carbon solutions for Shell’s LNG fleet through technology upgrades and compressor re-bundles. Baker Hughes will also help Shell develop digital solutions to accelerate decarbonization across Shell’s global assets and operations. The two companies will also explore potential opportunities to co-invest and participate in new models to decarbonize the energy and industrial sectors.

Baker Hughes saw continued customer interest in carbon capture, utilization and storage (CCUS) applications. TPS secured a contract with Santos, a leading natural gas producer in Australia, to supply turbomachinery equipment for the Moomba CCS project, which will serve a gas processing plant and permanently store 1.7 million tons of carbon dioxide (CO2) annually. The equipment scope includes PGT25+G4 aeroderivative gas turbine, MCL compressor, and PCL compressor technologies to compress CO2 captured at Moomba CCS for transportation and subsequent injection for storage.

TPS continued to support the growth of the hydrogen economy, securing a contract with Air Products to supply advanced compression technology for the NEOM carbon-free hydrogen project in the Kingdom of Saudi Arabia. The contract follows the two companies' hydrogen collaboration agreement announced in mid-2021.

Baker Hughes announced an approximately 20% investment in Ekona Power Inc, a growth stage company developing novel hydrogen production technology. The two companies have joined efforts to accelerate the scale up and industrialization of the technology by identifying suitable pilot projects and leveraging Baker Hughes' leading turbomachinery portfolio as well as established technical expertise in providing modular and scalable solutions for global hydrogen and natural gas projects. Baker Hughes has also assumed a seat on Ekona's Board of Directors.

DS continued to secure important contracts with key energy and industrial customers for condition monitoring and industrial asset management solutions. The Bently Nevada product line secured a contract with a major oil company to deploy System 1 asset management software as a standardized platform for enterprise-wide condition monitoring across 28 facilities worldwide. In addition, Bently Nevada secured a five-year service agreement for a major customer in the mining segment to provide asset strategy consulting services and support the customer's digital transformation to help increase production and improve equipment reliability.

Bently Nevada also secured a contract with Yara, one of the world's leading fertilizer companies, to enable digital transformation and improve asset reliability and efficiency. The enterprise-wide contract will enable data availability between Yara's plant operations and the cloud across 23 sites using Bently Nevada's latest System 1 asset management software, accompanied by a maintenance, support and services agreement.

Baker Hughes continued to invest in industrial asset management capabilities, announcing an investment and multi-year commercial alliance with Augury, a machine health solution provider, to deliver an expanded integrated asset performance management solution through Bently Nevada. Through the alliance, customers will benefit from end-to-end visibility into the health and performance of critical assets and the entire balance of plant, leading to reduced downtime, increased availability and lower maintenance costs.

Leading with Innovation

The BakerHughesC3.ai joint venture alliance (BHC3) secured several key contracts with oil & gas customers to deploy AI-based applications and accelerate digital transformation. In the Middle East, BHC3 and TPS secured a contract to deploy the BHC3™ Reliability application for LNG facilities and will deliver predictive insights at scale. The application will be deployed on the Microsoft Azure cloud platform and integrate with the Baker Hughes iCenter software to improve maintenance planning of critical industrial equipment and expand on the customer's current monitoring services across its installed turbomachinery equipment.

The Druck product line in DS also saw increased demand for its pressure measurement technologies for the electronic component and semiconductor manufacturing sectors, including a significant contract with a major Asian semiconductor supplier. To support the sector's rapid growth, Druck has also commercialized and improved the world's fastest pressure controller, the PACE CM3, allowing customers to have greater flexibility, accuracy, speed and stability in pressure measurement.

https://www.shell.nl/media/venster/jaar-van-verandering.html

Year of change

A conversation with Shell CEO Ben van Beurden about the challenges the company faces and why the energy transition needs to be accelerated.

By Rob van 't Wel, Joanna Wrighton on 20 Jan. 2022

Last year was a special year for Shell. What were the highlights of 2021 for you?

“The presentation of our Powering Progress strategy was an important moment. It is the most complete and clear Shell strategy in recent history. It includes ambitious goals for shareholders and actions when it comes to CO_2 emissions, for people and the environment. Powering Progress also sets the industry's most ambitious targets to reduce those emissions.

The simplification of our share structure and the relocation of our headquarters from The Hague to London was also an important moment in our history.”

What were the lows of 2021?

“An attack in Nigeria that killed seven people. It was a deliberate attack on the people who work for us. That hits me hard.

The other low point pales in comparison to the fatalities, but was the ruling in the Climate Case that Shell must reduce its CO_2 emissions faster than planned. I listened at home as the judge gave her verdict. It felt like a blow.

I found it deeply disturbing that Shell as an individual company is being held accountable for how the world produces and uses energy. That goes against everything I believe in when it comes to climate change, which is that this is a social problem and not a problem that a company can solve on its own. It is also worrying that the ruling has received so much acclaim, as if this is indeed the solution society needs.”

Despite your concerns, you mentioned that Shell is taking on the challenge of saying that Shell must reduce its global net CO_2 emissions by 45% by 2030, compared to 2019 levels. What could progress look like in 2022?

“We have already set a target to halve the emissions from our own activities and the energy we purchase to operate our activities by 2030 compared to 2016. I am talking about our so-called scope 1 and 2 emissions. . That is an even greater reduction than the court has requested and it is an important signal that we are up to the challenge.

To achieve that goal, we continue to convert our refineries and chemical plants into low-carbon energy and chemical parks. And we continue to improve our energy efficiency, for example. In 2022 we plan to invest significantly more in CO_2 capture and storage.

We also need to figure out how to design liquefied natural gas and petrochemical plants so that they can be carbon neutral from the start. These are huge technical and technological innovations that Shell will have to deliver. That's what I mean by taking on the challenge.

On the basis of a best-efforts obligation, the court's ruling also applies to our scope 3 emissions, the emissions from customers who use our products. Here we work together with our customers to reduce emissions. We focus on decarbonising various sectors. For example, we are building our first large-scale, sustainable aviation fuel plant in the Netherlands for aviation, and we are looking at alternative energy for industry, such as hydrogen or more electrification.

But no matter how hard we work to reduce our customers' emissions when they use our products, ultimately our progress depends on society's pace in the energy transition. We can't go faster than all our customers, otherwise we wouldn't have customers to buy our new products. Then we would go bankrupt."

You have been considering simplifying Shell's share structure and moving the head office from the Netherlands to the United Kingdom for some time. Why did you decide to do that now?

"Our company must be able to move quickly and do new things to accelerate the energy transition. The existing dual share structure was a real handicap. We were a British plc headquartered in the Netherlands. This meant that legally we had to follow the company rules in the United Kingdom. While we had to comply with tax legislation in the Netherlands from a fiscal point of view. We had restrictions on issuing and buying shares, restructuring and acquiring other companies.

Under the dual stock structure, for example, we would not be able to return to our shareholders as much as we wanted from the sale of our US shale oil and gas holdings.

In my eight years as CEO, I personally worked on finding a solution with the Dutch government. There was no other solution in sight, other than moving the headquarters to the UK.

It was a sad moment when I made the decision to bring the simplification to the shareholders and to the *Board* . When I joined Shell as an engineer 38 years ago, I thought Koninklijke/Shell was the most iconic company in the Netherlands and even in Europe. I could never have imagined that I would be the CEO who would move the headquarters from the Netherlands. But there was no other choice if you wanted to speed up the energy transition. It was the right thing for the company to do."

What is Shell's long-term relationship with the Netherlands?

" We still have a significant presence in the Netherlands and we have no plans to change that. The Netherlands remains an important energy transition country for us. Over the past two years, we have allocated €4 billion to low-carbon projects such as wind farms, chargers for electric cars and a biofuel factory. That is more than we have invested in the energy transition in any other country and it places us among the top investors in the Netherlands."

What is the outcome of the COP26 climate summit in Glasgow and what does this mean for Shell's strategy?

"The world has made progress at COP26 and that makes me optimistic. It may not be moving fast enough, but six years ago - at the time of the Paris Agreement - the world was nowhere near the trajectory we are on now. Governments are also beginning to understand that different sectors of the economy require different policies and that cutting carbon emissions goes beyond generating more solar and wind energy, which only produces electricity. Today, only 20% of the energy system consists of electricity. The rest must also become less dependent on hydrocarbons.

That is exactly what we are advocating and it is at the heart of Shell's strategy. We help customers achieve net-zero emissions by providing them with low-carbon energy products and solutions; they will be different for motorists, airlines or shipping companies.

Progress has also been made on Article 6, which lays down the rules for cooperation between countries, mainly in the form of cross-border carbon trading. The world cannot come close to net-zero emissions without a functioning global CO_2 market. There was a breakthrough at COP26 in that governments agreed on the rules that would allow the implementation of Article 6. Now we need to see how they put these trading mechanisms into practice."

Since you took office as CEO in 2014, the necessary changes have been made. How do you view Shell's transformation so far?

"Shell is a much more financially resilient company than when I took over. Even during the COVID pandemic, we are delivering better results with a smaller portfolio. We have a forward-looking strategy and we have made some hard decisions.
But that's still not enough. We need to move faster in the energy transition, especially in the current environment where society always wants us to accelerate. We cannot say 'When society has decided to accelerate the energy transition, we will be a fast follower'. We have to be a pacesetter. We need to find ways to be ahead of society where we can, to be willing to build new low-carbon markets where it makes sense, while still creating value. That means more daring.

Our challenge is to see what some of the new business models might look like. How do we monetize large-scale aviation biofuel facilities if aircraft biofuels are not competitive with petroleum products? Can we make money from charging electric cars if there aren't enough electric cars on the road?

We need to create a culture where people are willing to take more risks by supplying low-carbon products in the expectation that we can sell them. I think it's fine to invest in the first hydrogen factory in the Netherlands before, for example, the first hydrogen trucks hit the road. Because it is a springboard to creating future value."

Why was the $9.5 billion proceeds from the sale of the US shale oil and gas business not invested in new energy? Surely that could have been a logical step for any company that wants to take the energy transition seriously?

" On balance, I thought it was reasonable to return $7 billion to shareholders. First, in my opinion, our stocks are deeply undervalued, so share buybacks make a lot of sense. Second, the share buyback reduces the dividend burden we have and we also sold a stake that helped pay dividends.

We have kept the remaining $2.5 billion for other purposes. We have been clear that in 2022 we will increase investment in our renewable energy and energy solutions business."

Some of the criticism that Shell is not moving fast enough to reduce CO_2 emissions has been directed at you personally over the past year. How do you deal with that criticism?

" I work every day to bring greater strategic clarity and deliver on our strategy. When people attack Shell because it's not going fast enough, it feels very personal. But I have no choice but to deal with the criticism. I can't run from it or hide under my desk.

If anything, I use my feelings as a source to redouble my efforts and accelerate the pace of change. We make a difference to the world and we make a real and practical contribution to advancing the energy transition.
Working from home and spending more time with my family also had a huge stabilizing effect on me last year."

Shell wants to sell most of the oil and gas fields that NAM, Shell's joint venture in the Netherlands, currently operates. The company has also withdrawn from developing the Cambo oil field in the North Sea. At the same time, it continues to invest in oil and gas elsewhere in the world. Is Shell's oil and gas production

shifting from places where social pressures are high to countries where oil and gas production is easier?

“ Many countries no longer want oil and gas extraction. However, they tend to be among the countries with the highest oil and gas consumption. There is dissonance. We can point out to governments that if they produce less, they need to import more oil and gas. Is that better economically or better for the planet? I do not think so. But we can do nothing about social sentiment. What we can do is choose to operate in places where Shell can compete and where we can still supply the oil and gas people need.”

Supply problems have led to unprecedentedly high prices for natural gas in some parts of the world. Should consumers in Europe get used to paying more for energy?

“ The natural gas prices we see in northwestern Europe today are extreme. I hope that market conditions will improve and bring more stability and relief. But it will take intelligent policies and intelligent application of these policies to get it better. Some governments in northwestern Europe have significantly reduced domestic production of natural gas, but demand remains high. That cannot be solved in the short term by increasing domestic production; it is impossible to increase it quickly. More imports and higher prices to achieve this will be necessary to narrow the gap between supply and demand.

I hope that countries with increasing imports will not unnecessarily complicate supply in the future. Governments must learn to deal with the demand for hydrocarbons, just as they have hitherto wanted to deal with the supply of hydrocarbons. Motorists still need fuel, just as many homeowners need natural gas for cooking and heating, for example. Even if Shell were to stop supplying these products, people would still need them. Then they will buy those oil and gas products from other companies.”

Does the integrated model mean that Shell is still too big and complicated?

“ The companies that make the energy transition possible are companies such as Shell. With the scale, scope, financial clout and ability to operate in an integrated manner. It won't just be the small, start-up businesses.

As an integrated energy company, Shell has two major advantages. One of these is the interdependence of our activities. For example, in the sustainable aviation fuel (SAF) market, we have refineries to house biofuel facilities, an existing distribution network, access to 1,000 airports around the world and an advanced trading company. This interplay makes our SAF strategy work.

The second benefit is our oil and gas producing Upstream business. It is the largest source of cash today and will be for many years to come. This business unit will continue to produce the energy the world needs, provide strong returns for investors and – vitally – help us fund the transition.”

Looking at these benefits, is Shell still undervalued?

“ Investors value companies that generate a lot of cash for the dividends they can pay and Shell has traditionally been in that category. They also value companies that do not generate *surplus cash* but that do hold great promises for the future, such as makers of electric cars.

We try to combine both models. We have traditional activities that bring in a lot of money. We share some of that money with investors, but we also use some of it to build business for the future. These have the potential to be even more valuable than our traditional activities. We believe that investors should take this into account.

Our integrated activities provide cash, at both high and low raw material prices. We need to continue to make progress on our strategy and be more transparent about how we expect to monetize our new energy transition business.”

Where is the motivation and what are the goals for 2022?

“The scale of the challenge to tackle climate change and Shell's role in realizing the energy transition excite me every day. We are working on the greatest social and technological changes of modern times, greater even than during the industrial revolution.

In 2022 I hope to see good progress in reducing our emissions and in making important new investment decisions for hydrogen production. I want to gain ground with activities in renewable energy.

Today we are known for our oil and gas projects and for the gas stations that sell our fuels around the world. In time, we want to be known for our new business models and new energy products. This will be another pivotal year in our transformation.”

https://www.theeastafrican.co.ke/tea/news/east-africa/tanzania-lng-project-talks-drag-on-3690272

Tanzania LNG project talks drag on

SUNDAY JANUARY 23 2022

Summary

- Fresh discussions on the HGA over the multibillion-dollar project are being held in Arusha, northern Tanzania, after the negotiating teams finalised preliminary talks last November.
- After being in limbo for nearly two years, preliminary discussions on the HGA resumed in November 2021 with assurances from the new Minister of Energy January Makamba.
- Mozambique has the potential to produce more than 30 million metric tonnes of LNG a year, but four years of insecurity causing disruption and unrest, stalled the project.

By BEATRICE MATERU

Tanzania is moving cautiously in its lucrative natural gas deals with no end in sight of the Host Government Agreement (HGA) negotiations, which resumed recently but are set to take longer than expected.

Fresh discussions on the HGA over the multibillion-dollar project are being held in Arusha, northern Tanzania, after the negotiating teams finalised preliminary talks last November.

After being in limbo for nearly two years, preliminary discussions on the HGA resumed in November 2021 with assurances from the new Minister of Energy January Makamba.

In November 2021, while opening a fresh HGA discussions, Mr Makamba told stakeholders that the government was committed to having the Liquefied Natural Gas (LNG) project implemented.

The negotiations are expected to proceed by discussing every stage of the project. The discussions will also address the nature of Tanzania Petroleum Development Corporation participation, fiscal framework, including tax exemptions, stability of terms and local content.

"The discussions with the government are vital in co-creating a stable fiscal, legal and regulatory framework to enable a global competitive project and further investments by the LNG investors," said Ola Morten Aanestad, spokesperson of International Upstream.

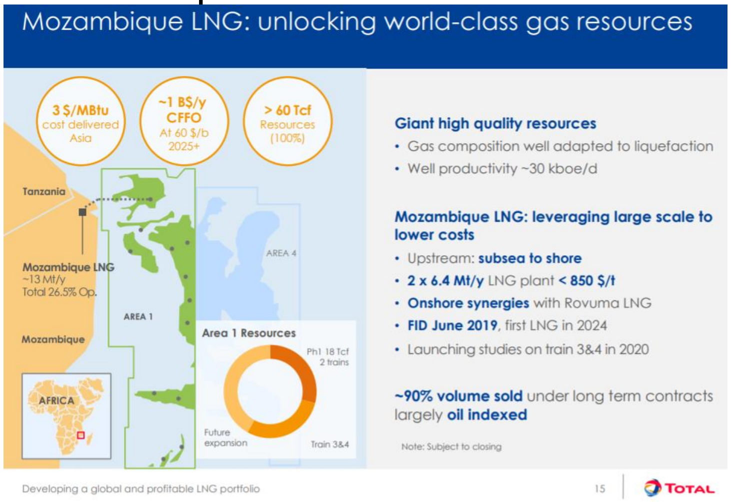
Multiple Brownfield LNG FIDs Now Needed To Fill New LNG Supply Gap From Mozambique Chaos? How About LNG Canada Phase 2?

Posted Wednesday April 28, 2021. 9:00 MT

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

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

Total Mozambique Phase 1 and 2



Source: Total Investor Day September 24, 2019

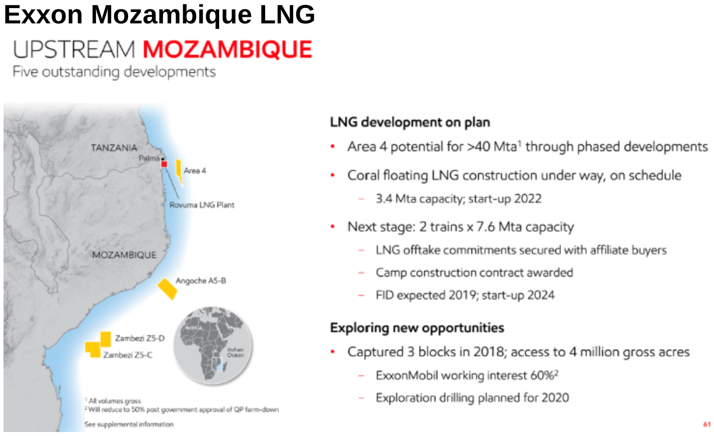
<u>Total's Mozambique force majeure is no surprise, especially the need to the restoration of security and stability "in a sustained manner"</u>. Yesterday, Total announced [LINK] "*Considering the evolution of the security".* No one should be surprised by the force majeure or the sustained manner caveat.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

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

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

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

Exxon Mozambique LNG



Source: Exxon Investor Day March 6, 2019

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

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

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

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

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

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

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

Source: IEA

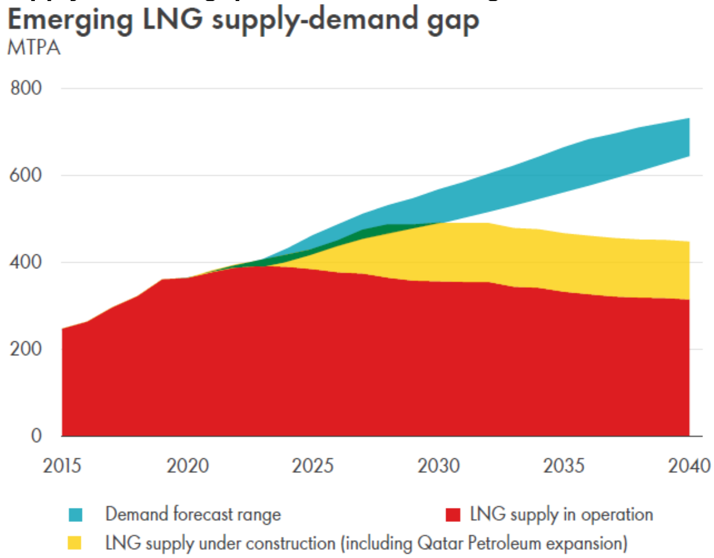
🟢 On Track 🟡 More Efforts Needed 🔴 Not on Track

Source: IEA Tracking Clean Energy Progress, June 2020

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

Shell's March 2021 long term outlook for LNG demand was basically unchanged vs 2020 and leads to a LNG supply gap in mid 2020s Shell does not provide the detailed numbers in their Feb 25, 2021 LNG forecast. We would assume they would have reflected some delay, perhaps 1 year, at Mozambique but would be surprised if they put a 2-3 year delay in for the 5 bcf/d from Total Phase 1 +2 and Exxon Rozuma Phase 1. Compared to their LNG Outlook 2020, it looks like there was no change for their estimate of global natural gas demand growth to 2040, which looked relatively unchanged at approx. 5,000 bcm/yr or 484 bcf/d. Similarly, long term LNG demand looked unchanged to 2040 of ~700 mm tonnes (92 bcf/d) vs 360 mm tonnes (47 bcf/d) in 2020. In the 2021 outlook, Shell highlighted that the pandemic delayed project construction timelines and that the "*lasting impact expected on LNG supply not demand*". And that Shell sees a LNG "*supply-demand gap estimated to emerge in the middle of the current decade as demand rebounds*". Comparing to 2020, it looks like the supply-demand gap is sooner.

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



Source: Shell LNG Outlook 2021, Feb 25, 2021

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

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

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

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

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

https://www.spglobal.com/platts/en/market-insights/latest-news/lng/011722-japan-to-explore-14-tcf-of-recoverable-gas-reserves-for-467-bcfyear-output

- 17 Jan 2022 | 10:00 UTC

Japan to explore 1.4 Tcf of recoverable gas reserves for 46.7 Bcf/year output

HIGHLIGHTS

Gas shows indicate more than Japan's total 1 Tcf recoverable gas reserves

Estimated gas production equates to 1.2% of country's consumption

Gas self-sufficiency rate seen rising to 3.4%, from 2.2% currently

- Author Takeo Kumagai

Japan intends to explore 1.4 Tcf of estimated recoverable natural gas reserves offshore Shimane and Yamaguchi prefectures in the west that could produce 46.7 Bcf/year of gas after starting output in 2032, an official at the Ministry of Economy, Trade and Industry told S&P Global Platts Jan. 17.

The move follows "considerable gas shows" in a series of Japan's funded drilling operations conducted by INPEX until the fiscal year 2019-20 (April-March), marking the first domestic project, which enters an exploration phase with the government's support from initial geological structure surveys, the official said.

INPEX, which has obtained prospecting rights, will start exploratory drilling works in March offshore Shimane and Yamaguchi prefectures at a block at a water depth of about 240 meters, about 130 km from Hamada city in the Shimane prefecture and around 150 km from Hagi city in the Yamaguchi prefecture, the official said.

INPEX separately said Jan. 17 that its exploratory drilling works offshore Shimane and Yamaguchi prefectures will last over March-July.

Initial findings show that the exploration block is estimated to hold about 1.4 Tcf of recoverable gas reserves, which could potentially boost Japan's recoverable gas reserves from the current 1 Tcf, the METI official said.

The exploration project, which is operated 100% by INPEX, will last until FY 2027-28, when the state-owned Japan Oil, Gas and Metals National Corp. will provide a total of Yen 16.5 billion ($144.2 million) equity investment, the official said, adding that production is expected to start in 2032 if the project begins the development phase as planned around 2027.

After entering the development phase, this will be Japan's first project since its only offshore field -- the Iwafune oil and gas field in the Niigata prefecture in the northwest -- started production in 1990, the official said.

Enhancing energy security

The gas production, which will be piped to the Honshu island, is expected at 46.7 Bcf/year, accounting for 1.2% of Japan's current natural gas consumption volumes, according to the official. It is also estimated to boost Japan's domestic gas self-sufficiency rate to 3.4%, from 2.2% currently.

Japan's latest exploration works come at a time when it expects natural gas to play "a significantly important role" as the country aims for carbon neutrality by 2050 as outlined in its Strategic Energy Plan approved by the cabinet in October, the official said.

"This domestic upstream project is among our top priority for the energy security," said the official, referring to the offshore exploration project, while citing Japan's natural gas needs in 2050, with implemented decarbonization measures, in the cabinet approved plan.

"Considering stable energy security and energy security, this is the project we hope to see it succeed most by all means," the official said.

Japan aims to boost its equity liftings in its total oil and gas imports to more than 50% in 2030 and over 60% in 2040 under its new Strategic Energy Plan, up from a prior target of more than 40% in 2030.

The country's equity liftings in its total oil and gas imports stood at 40.6% in FY 2020-21, up from 34.7% in the previous fiscal year, according to the latest METI data.

Google Translate of Bloomberg terminal posting of Le Figaro https://www.lefigaro.fr/societes/shell-pret-a-investir-4-milliards-en-france-20220121

Ben van Beurden: "Reducing dependence on gas and oil is infeasible from day to day"

INTERVIEW - The managing director of Shell, the British oil giant, reveals to Le Figaro its group strategy for the energy transition.

By Guillaume Guichard, Ivan Letessier

Le Figaro. - You came to Paris despite the cancellation of Choose France. Why?
Ben VAN VEURDEN. - Choose France has been cancelled, but not our projects. The France is one of the key countries in which to invest in the energy transition. For a hundred years, we have been selling gasoline in France. From now on, we want develop the energies of the future there. We are investing 100 million euros per year in France, and we can do much more: we have identified for four billion euros of investment opportunities in France: offshore wind tenders, the production of green hydrogen, the commissioning of installation of electric charging stations, or even the manufacture of biofuel for aviation. To realize our projects, we need support from public authorities. They must establish obligations use of the energies of tomorrow and put in place incentive rules for producers.

Do governments seem to you to be too cautious when it comes to supporting the energy transition?
It is up to them to create the energy markets of the future, not to groups private. Oil and gas have an incredible success, it is very difficult to get away from it. to pass. Biofuel for aviation pollutes much less, but it costs two to three times more than fossil kerosene. It is not competitive, but can become so with public support, as for wind and solar power, who have seen their costs fall drastically in 25 years.
The French government is at the forefront, forcing companies airlines to include 1% biofuel from 2022. The European Union is aiming for 5% in 2030, but it would take twice that.

How to get out of the energy crisis that Europe is going through?
Don't think this crisis is good for groups like ours.
On the contrary, price volatility undermines the will of committed companies in the energy transition. Reduce the dependence of our economies on gas and oil is infeasible overnight. Governments can take emergency action, but if they neglect the market, the exit of crisis will take longer. In the short and long term, we must increase energy supply. Europe produces 20% less gas than before the pandemic and we consume as much. There are only long-term solutions for out of this crisis, such as facilitating the construction of gas terminals liquefied natural to increase imports. The lack of contracts long-term gas supply is also a problem.

Until when will Shell produce oil?

The energy transition is going fast, but the world will need oil
and gas for a very long time. That said, the future is not in these
historical activities. He is into green electricity and CO_2 capture.
The French see us as an oil group, but we sell
already as much gas as oil and have been engaged for years in
offshore wind, hydrogen and biofuels. In fact, Shell is a
global energy company committed to the energy transition.

What is the optimal pace for a successful energy transition?
The energy transition can never go too fast for Shell. Some
think we want to slow down the process and would like us to
stop oil and gas production. That's not the point. It's not
we are not the ones setting the pace of the energy transition, it is our
customers, consumers and political leaders. The drop in the
demand for fossil fuels will never be as rapid as the depletion of
our reserves if we do not invest to maintain our capacity to
production.
If we stand idly by, we will produce no more gas or
oil in ten years, when the demand will still be there. The issue is not
not to stop producing oil and gas, but to stop consuming it.
If governments want to speed up the process, we can help them
switch more quickly to green energies. This is the meaning of my encounters with the
ministers Clement Beaune and Barbara Pompili this week, before
meet, soon I hope, President Emmanuel Macron.

**Does Shell's Future Depend On Profits From Its Business?
oil?**
Our added value is now more in services to
customers than in our historical activity. Before, to succeed in the
fossil fuels, you had to have the best geologists, the best
relations with producing countries and the lowest production costs.
That's not how it works anymore. Have the best resources in
wind and the best wind turbines is not the priority. It's not these
criteria that will make it possible to prevail in the new energy world, but
our relationship with consumers and related services. Shell at the
better position to offer services integrating the entire chain of
value: for example, proposing to a large company to build a park
wind farm in the North Sea and sell it green electricity 100% of the time at a
guaranteed rate. We take the risk of price variation on the markets and
can baptize the offshore park with the name of our client. This scheme works
for biofuels and hydrogen. The product is not only
the electron or the hydrogen molecule, it is the service that counts.

**The two business models are radically different. A split
renewable activities, demanded by certain shareholders, would it be
relevant for Shell?**
Financial markets are binary. They agree to finance
on the one hand, profitable companies thanks to their carbon activities, and
on the other, companies having to bring them only promises, but no
benefit. At Shell, we want to combine promise and profit.
Some investors find it difficult to assess the value of such a mix.

But it is much easier to rely on our activities

history, our know-how and our infrastructures to develop in
green energies than reinventing everything from scratch. The very strong growth of renewable energies requires a lot of resources. Use profits from oil and gas makes it possible to go much faster and much further away. The shareholders will have to accept that, for ten years, we invest more money in renewable energy than we do
will win.

Between investors who dream of unchanged dividends and green activists who demand the stop of oil, you are drowning under the contradictory injunctions. How do you cope?
It is useless to look for a common point between their claims. Yes we had to please everyone, we would close up shop. The best reaction is to decide on the best strategy for the group and all its stakeholders, and stick to it. Over the past two years, we have set four objectives: to generate sustainable returns on investment ; achieving net zero CO2 emissions by 2050, which means decarbonizing our products; provide energy to our customers; while respecting the environment.

The fields of wind turbines and solar panels are highly criticized. that do you respond to their detractors?
Onshore wind and solar were the best way to launch these channels. They face societal oppositions that I understand. The future is in solar panels attached to existing buildings and offshore wind. We especially push floating wind turbines. This is why we acquired the French company Eolfi in 2019.

Will Shell also invest in nuclear?
We may be interested in it, but the priority is the energies renewables, where there is so much to do. Nuclear has a role to play in the energy transition: the world needs it to decarbonize. Electricity represents 20% of the energy consumed. To achieve net zero emissions of CO2, its share must increase to 70% by 2050. As energy demand will increase, the production of electricity will have to be multiplied by four or five. We will need solar and wind, but also a reliable basic production, therefore nuclear.

Click here to read the article published on the Le Figaro website

-0- Jan/21/2022 20:18 GMT

To view this story in Bloomberg click here:
https://blinks.bloomberg.com/news/stories/R62TRE5F8XS0

https://www.argusmedia.com/en/news/2293376-colombias-oil-flow-poised-for-recovery-minister?backToResults=true

Colombia’s oil flow poised for recovery: Minister

Published date: 19 January 2022

Share:

Colombia is targeting a 5.4pc increase in oil production to 780,000 b/d -800,000 b/d in 2022, the same goal it missed last year.

Oil output averaged 740,000 b/d in January-November, Colombia's mines and energy minister Diego Mesa told *Argus*. Aside from the Covid-19 pandemic, last year's output was thwarted by a national strike and unrest that blocked roads and forced companies to shut in wells.

Natural gas output climbed to pre-pandemic levels of around 1.08bn cf/d through November, and output is expected to hit 1.1bn cf/d in 2022.

Colombia is pinning gas hopes on offshore blocks, where more exploration will get underway this year at Shell-operated Col-5 and Tayrona operated by Brazilian state-controlled Petrobras.

"We currently have 10 active contracts with pending investment of up to $3bn to execute. These contracts focus on the search for both new gas and oil reserves," said Mesa.

Since taking office in 2018, president Ivan Duque's administration has awarded 69 exploration and production contracts, including 30 blocks awarded late last year, surpassing a target of 50 contracts, Mesa said.

The ministry hopes 60 exploration wells will be drilled in 2022, up from 34 in January-November 2021.

A total of 112 upstream contracts will be in the exploration phase with agreed investments close to $4.11bn in 2022.

Election uncertainty

The oil industry is cautiously watching Colombia's presidential election campaign in which leftist frontrunner Gustavo Petro is advocating a halt on exploration contracts.

Mesa said investors should take solace in Colombia's stable legal conditions despite "some populist and irresponsible proposals from certain candidates."

Petro, a former Bogota mayor, is the favorite in a broad field of candidates for May 2022 elections to replace conservative incumbent Duque in August.

Centrist and rightwing candidates will be selected in March primary elections.

Oil is the main source of government revenue, bringing in about 20 trillion pesos per year ($5.3bn/yr). The oil sector, which represents 2.1pc of total GDP, accounts for 32pc of export revenue, Mesa says.

Referring to Petro's proposals, he said Colombia would struggle to "replace one third of direct foreign investment, 40pc of exports and 80pc of the collection of the general royalty system."

By Diana Delgado

https://www.npd.no/en/facts/news/Production-figures/2022/production-figures-december-2021/

Production figures December 2021

20/01/2022 Preliminary production figures for December 2021 show an average daily production of 2 108 000 barrels of oil, NGL and condensate

Total gas sales were 10.9 billion Sm³ (GSm³), which is an increase of 0.5 GSm³ from the previous month.

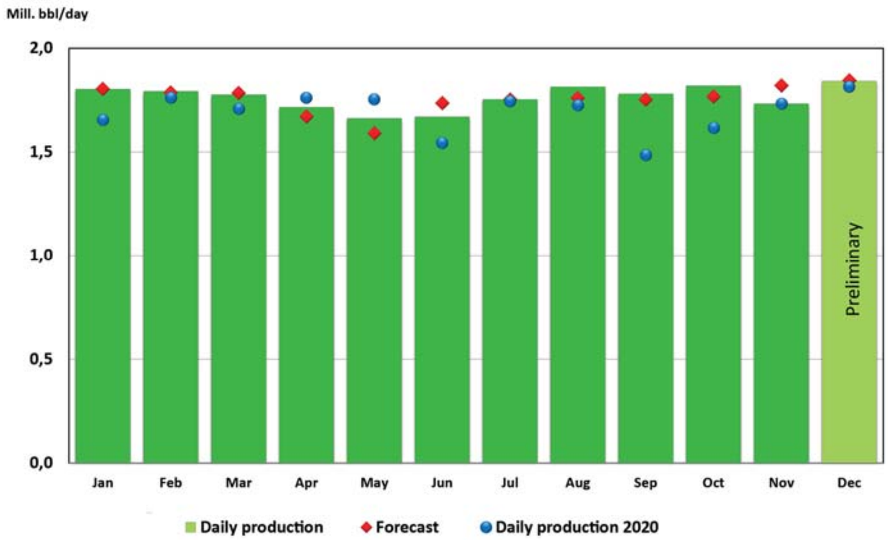
Average daily liquids production in December was: 1 841 000 barrels of oil, 258 000 barrels of NGL and 9 000 barrels of condensate.

Oil production in December is 0.2 percent lower than the NPD’s forecast, and 0.4 percent higher than the forecast so far this year.

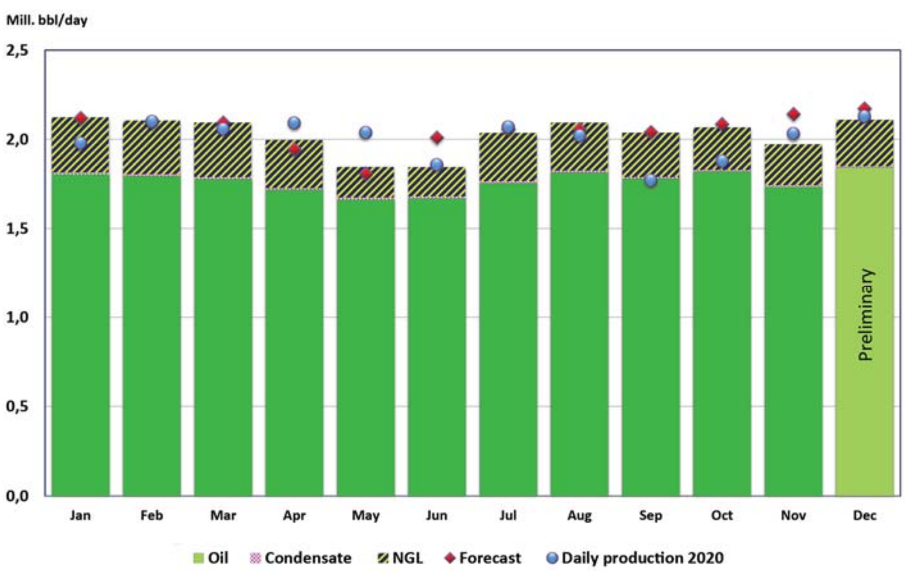
Production December 2021

		Oil	Sum liquid	Gas	Total
		mill bbl/d	mill bbl/d	MSm³/d	MSm³ o.e/d
Production	December 2021	1.841	2.108	353.1	0.688
Forecast for	December 2021	1.845	2.172	334.2	0.680
Deviation from forecast	December 2021	-0.004	-0.064	18.9	0.008
Deviation from forecast in %	Deecember 2021	-0.2%	-2.9%	5.7%	1.2%
Production	November 2021	1.732	1.972	346.3	0.660
Deviation from	November 2021	0.109	0.136	6.8	0.028
Deviation in % from	November 2021	6.3%	6.9%	2.0%	4.2%
Production	December 2020	1.814	2.129	332.0	0.670
Deviation from	December 2020	0.027	-0.021	21.1	0.018
Deviation in % from	December 2020	1.5%	-1.0%	6.4%	2.7%

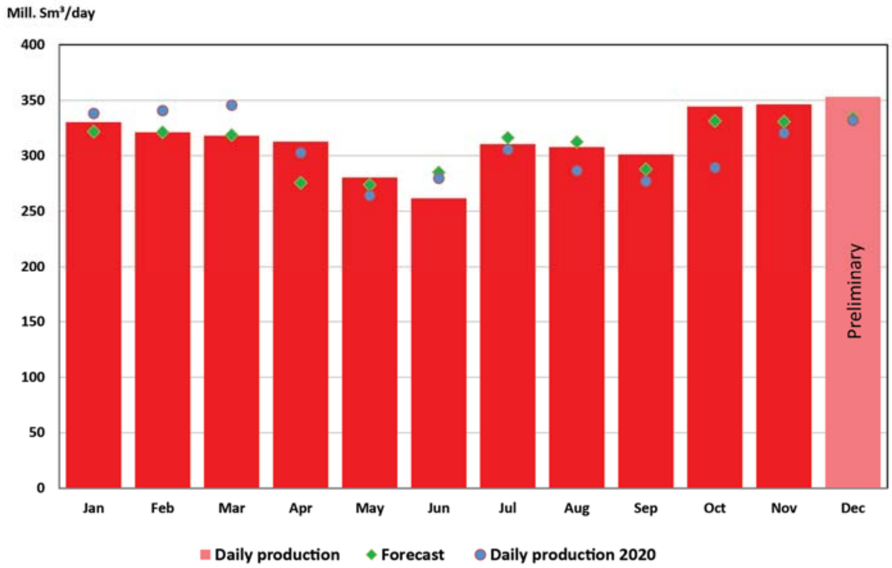
Oil production 2021



Liquid production 2021



Gas production 2021



The total petroleum production in 2021 is about 232,8 million Sm^3 oil equivalents (MSm^3 o.e.), broken down as follows: about 102.3 MSm^3 o.e. of oil, about 15.2 MSm^3 o.e. of NGL and condensate and about 115.2 MSm^3 o.e. of gas for sale.

The total volume is 4.0 higher than the 2020-figures.

Updated: 20/01/2022

https://tass.ru/ekonomika/13226795
DEC 17, 02:19Updated by Dec 17, 03:18

Fedun: oil production in Russia will decrease due to underfunding of the industry

According to the vice president of Lukoil, the world needs up to $ 1 trillion annually in exploration and production of oil, but "no one invests that kind of money."

MOSCOW, December 17. / TASS /. Oil production in Russia may begin to decline due to underfunding of the industry, Lukoil vice president Leonid Fedun told reporters.
"Oil production in Russia will first stagnate, and then even decline naturally," he said, without specifying the timeframe. Fedun also believes that Russia will not be able to restore oil production under OPEC + by April, although there are geological reserves. "Financial and tax instruments are needed to develop them," he explained.
According to Fedun, the world needs investments of up to $ 1 trillion in oil exploration and production annually, but "no one invests that kind of money."
According to the forecasts of the vice-president of Lukoil, the growth of liquid fuel consumption in the world is expected at least until 2030-2035.

https://tass.ru/ekonomika/13226347
DEC 17, 01:46Updated by Dec 17, 01:59

Alekperov said that Lukoil will reach the pre-crisis level of oil production by April

The head of Lukoil said that this will happen if OPEC + continues to increase production by 400 thousand bpd every month

MOSCOW, December 17. / TASS /. Lukoil plans to use all of its free production capacities by April 2022 and reach pre-crisis oil production figures. This will happen if OPEC + continues to increase production by 400 thousand barrels per day (b / d) monthly, Vagit Alekperov, head of Lukoil, told reporters.
"I think, somewhere, if at the same rate of 400 thousand b / d, then by April we will reach almost pre-crisis levels," he said, adding that by April the company will also use all free capacities.
At the end of November, Lukoil's vice president, Alexander Matytsin, said that the company had almost completely restored the operation of wells as part of the mitigation of restrictions in OPEC +.
Lukoil produced 59.59 million tons of oil in January-September 2021 (including the West Qurna-2 project in Iraq), which is 2% less than in the same period in 2020. At the same time, in general, the production of hydrocarbons in the company amounted to 2.116 million barrels of oil equivalent (toe) per day against 2.065 million barrels of oil equivalent. e. a year earlier (excluding the West Qurna-2 project).

https://tass.ru/ekonomika/13225739
DEC 17, 00:33Updated by Dec 17, 01:25

Lukoil predicts oil price of $ 380 per barrel by 2050

Lukoil Vice President Leonid Fedun believes that hydrocarbon consumption will be stable until 2030

MOSCOW, December 17. / TASS /. High inflation reduces the availability of energy for the world's population, the world may face a "dramatic rise in oil prices by 2050". This was stated by the vice-president of Lukoil Leonid Fedun at the presentation of the report "Prospects for the development of world energy until 2050".
According to the presentation, according to all three scenarios of energy development, the cost of oil by 2050 will exceed $ 100 per barrel. According to the evolutionary scenario, it will reach $ 128 per barrel, taking into account the inflationary factor and the introduction of emission quotas for producers. Under the equilibrium scenario, it will be $ 197 per barrel, and under the Transformation scenario - $ 380 per barrel. In all three scenarios, inflation takes the lion's share of the price increase.
At the same time, the onset of the maximum option may occur until 2050, if the problem of underinvestment in the development and production of reserves continues, Fedun said. He believes that the consumption of hydrocarbons will be stable until 2030, and only from 2035 in such large markets as the United States and China, the consumption of liquid fuels will begin to decline.

At the same time, Russia can become the world leader in the export of hydrocarbons with a canceled carbon footprint by 2050. But the price of products in the oil and gas sector with a carbon footprint extinguished will strongly depend on the costs required for the implementation of climate projects

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Oil Market Highlights

Crude Oil Price Movements

Both crude oil spot and futures prices fell for the second-consecutive month in December. Major physical crude benchmarks decreased about 9%, m-o-m, on growing concerns that the rapid spread of the Omicron COVID-19 variant may have an impact on the global economy and oil demand. The OPEC Reference Basket fell $5.99, or 7.5%, to settle at a three-month low of $74.38/b. Crude oil futures prices extended losses in December, declining on both sides of the Atlantic, with the ICE Brent front month down $6.05, or 7.5%, to average $74.80/b and NYMEX WTI declining by $6.96, or 8.8%, to average $71.69/b. Consequently, the Brent/WTI futures spread widened 91¢ to average $3.11/b. The market structure of all three crude benchmarks – ICE Brent, NYMEX WTI and DME Oman – weakened in December, m-o-m. Hedge funds and other money managers extended sharp sell-offs in the first half of December, cutting combined futures and options net long positions related to ICE Brent and NYMEX WTI by about 30% between early November and mid-December.

World Economy

The global GDP growth forecasts for 2021 and 2022 remain unchanged at 5.5% and 4.2%, respectively. The US is estimated to grow by 5.5% in 2021, while growth for 2022 is slightly lowered to 4%. Euro-zone economic growth for 2021 is revised up to 5.2%, while growth for 2022 remains unchanged at 3.9%. Japan's economic growth forecast for 2021 is revised down to 1.8%, while growth for 2022 remains unchanged at 2.2%. Growth forecasts in emerging economies remain largely unchanged, with China's forecast at 8% for 2021 and 5.6% for 2022. India's forecast for 2021 stands at 8.8%, and is forecast at 7% in 2022. Russia's GDP growth forecast remains unchanged at 4% for 2021 and 2.7% for 2022. Brazil's economic growth forecast for 2021 is unchanged at 4.7%, while growth for 2022 was revised down to 1.5%. The spread of COVID-19 variants and the effectiveness of vaccines, as well as the pace of vaccine rollouts worldwide, remain key uncertainties. Moreover, supply chain bottlenecks and sovereign debt levels in many regions, together with rising inflationary pressures and the responses of central banks, remain key factors that require close monitoring.

World Oil Demand

World oil demand growth in 2021 is unchanged from last month's assessment at 5.7 mb/d to average 96.6 mb/d. An upward revision in 4Q21, amid better-than-anticipated transportation fuel consumption in the OECD, was offset by a downward revision in 3Q21 given the latest actual data. Oil demand growth in the OECD is estimated to have averaged 2.5 mb/d and, in the non-OECD region, oil demand growth is estimated at 3.1 mb/d for the year. In 2022, the forecast for world oil demand growth also remains unchanged at 4.2 mb/d, with total global consumption at 100.8 mb/d. In the OECD, oil demand is forecast to grow by 1.8 mb/d, while in the non-OECD oil demand is projected to increase by 2.3 mb/d. While the impact of the Omicron variant is projected to be mild and short-lived, uncertainties remain regarding new variants and renewed mobility restrictions, amid an otherwise steady global economic recovery.

World Oil Supply

Non-OPEC liquids supply growth in 2021 remains unchanged at around 0.7 mb/d, y-o-y, to average 63.6 mb/d. Upward revisions in the US and Kazakhstan were offset by downward adjustments to Brazil, Canada, Ecuador and Norway. The 2021 oil supply estimate primarily sees growth in Canada, Russia, China, the US, Guyana, Norway, Argentina and Qatar, while output is expected to have declined in the UK, Brazil, Colombia and Indonesia. Similarly, the non-OPEC supply growth forecast for 2022 is also unchanged at around 3.0 mb/d, to average 66.7 mb/d. The main drivers of liquids supply growth are expected to be the US and Russia, followed by Brazil, Canada, Kazakhstan, Norway and Guyana. OPEC NGLs are forecast to grow by 0.1 mb/d both in 2021 and 2022 to average 5.1 mb/d and 5.3 mb/d, respectively. In December, OPEC crude oil production increased by 0.2 mb/d m-o-m, to average 27.9 mb/d, according to available secondary sources.

Product Markets and Refining Operations

Refinery margins in all main trading hubs rebounded in December from the downturn seen in the previous month. Margins reached their second highest levels since May 2020 and inched closer to the record highs seen in October 2021. An increasingly tighter product balance in all regions and a pick-up in fuel consumption levels, amid the end-of-the-year holidays, combined to provide positive stimulus to product markets and ultimately led to a robust performance by jet fuel, kerosene and fuel oil, despite a significant rise in global product output levels and rising COVID-19 cases. In addition, strong heating fuel demand, as well as prevailing high gas prices, particularly in Europe, lent further backing to middle distillate markets. In contrast, temporary lockdowns in December exacerbated the seasonal gasoline weakness in the Atlantic Basin, thus limiting further gains in refining economics.

Tanker Market

The long-expected year-end recovery in dirty tanker spot freight rates failed to materialize in December, as lockdowns at the end of the year and softer Chinese buying limited tonnage demand. On average, VLCCs and Aframax slipped 5% and 3%, respectively, m-o-m in December. Suezmax managed a 7% gain over the month before, but remained well below pre-COVID-19 levels. For the year 2021, average VLCC and Suezmax spot freight rates witnessed their worst performance going back more than a decade. Clean rates enjoyed a better performance in December, particularly West of Suez, supported by demand on the Mediterranean routes.

Crude and Refined Products Trade

Preliminary data shows US crude imports edged lower in the final month of the year, but managed to end 4% higher, y-o-y, in 2021, averaging 6.1 mb/d. US crude exports remained below 3.0 mb/d in December and averaged 2.9 mb/d in 2021, representing a 9% decline. The latest data for China shows the country's crude imports recovered from the low level seen in October to average 10.2 mb/d in November, as state-owned refiners returned to the market. Preliminary data for December shows crude imports increasing further to 10.9 mb/d in the final month of the year. This would result in China's crude imports in 2021 averaging 10.3 mb/d, down around 5% from the inflated levels seen in 2020 when Chinese buyers snapped up excess volumes in the market. In India, crude imports jumped to a 10-month high in November to average 4.5 mb/d as refiners sought to replenish inventories in preparation for higher runs in 1Q22, following holidays in October and early November. Product exports from India remained steady, averaging 1.3 mb/d in November, as diesel outflows remained strong and jet fuel exports increased, reflecting tightness in the Asian market due to constrained exports from China. Japan's crude imports jumped in November to the highest since March 2020, averaging 2.8 mb/d, amid higher refinery runs to meet winter heating demand. The latest data shows crude imports into OECD Europe slipped in September, although tanker tracking data shows inflows picking up through November and then easing in December amid lockdown measures.

Commercial Stock Movements

Preliminary November data sees total OECD commercial oil stocks down by 16.0 mb, m-o-m. At 2,721 mb, OECD commercial oil stocks were 389 mb lower than the same period in 2020, 247 mb lower than the latest five-year average, and 221 mb below the 2015-2019 average. Within the components, crude and products stocks fell, m-o-m, by 12.7 mb and 3.3 mb, respectively. At 1,317 mb, crude stocks in the OECD were 143 mb less than the latest five-year average and 137 mb below the 2015-2019 average. OECD product stocks stood at 1,405 mb, representing a deficit of 104 mb compared with the latest five-year average and 84 mb below the 2015-2019 average. In terms of days of forward cover, OECD commercial stocks fell, m-o-m, in November by 0.2 day to stand at 60.7 days. This is 13.2 days below November 2020 levels, 3.6 days less than the latest five-year average and 1.5 days lower than the 2015-2019 average.

Balance of Supply and Demand

Demand for OPEC crude in 2021 remains unchanged from the previous month to stand at 27.8 mb/d, around 4.9 mb/d higher than in 2020. Demand for OPEC crude in 2022 also remains unchanged from the previous month to stand at 28.9 mb/d, around 1.0 mb/d higher than in 2021.

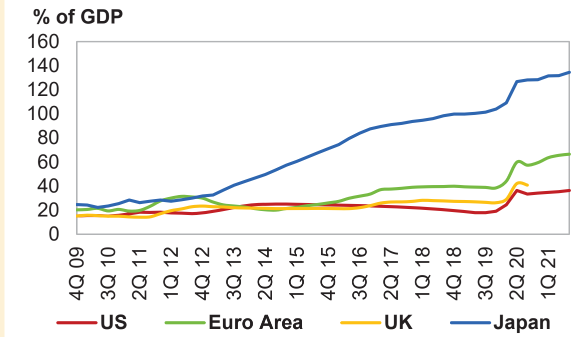
Feature Article

Monetary policies and their impact on the oil market

In 2021, the world economy rebounded considerably from the outbreak of COVID-19 pandemic in 2020. However, the pandemic continued to be a major challenge throughout 2021, particularly with the emergence of new variants such as Delta in 2Q21 and Omicron in 4Q21. At the same time, major central banks, including the US Federal Reserve (Fed), the European Central Bank (ECB), the Bank of England (BoE) and the Bank of Japan (BoJ), carried over their respective efforts of extraordinary quantitative easing (QE) programmes into 2021. In parallel, the global oil market continued its impressive recovery in 2021, driven by strong global oil demand, given worldwide lockdowns gradually easing and mobility increasing, and supported by the relentless efforts of the Declaration of Cooperation (DoC), which continued to rebalance oil markets.

The massive monetary stimulus programmes launched by the major central banks led their balance sheets to expand significantly in 2020 and 2021 ***(Graph 1)***. However, these QE efforts, in combination with strong underlying global demand and supply-chain bottlenecks, have resulted in higher inflation levels, which are now persisting in major economies. To curtail the potentially long-lasting impact of inflation, the major central banks have announced that they would adjust their QE programmes and consider reducing their very accommodative monetary policies.

Graph 1: Major central bank balance sheets as % of GDP

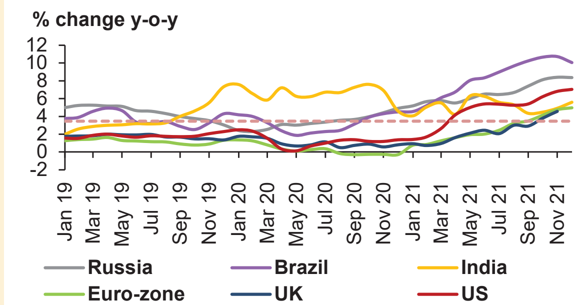


*Note: * UK data ia available until 3Q 20.*
Sources: BEA, BOE, Fed, ECB, BoJ, CAO and Haver Analytics.

Meanwhile, higher inflation levels have impacted economies to varying degrees. In developed, economies, US inflation has picked up strongly. In the emerging economies, particularly Russia and Brazil, inflation has been significant and led to rate hikes***.*** In key Asian economies, including China and Japan, inflation has remained relatively low ***(Graph 2)***.

In the US, the Fed announced a faster tapering of already ongoing reductions in QE measures and is likely to raise key policy rates in 2022 multiple times. On the other hand, the ECB announced that it would only gradually start reducing its QE measures in March 2022 and does not plan to hike interest rates before 2023. The BoE is pursuing the fastest path, having already announced a rate increase in its December meeting, front-running the other major central banks, while ending QE measures in 2021. The BoJ, with the relatively largest monetary stimulus and an extensive history of QE policies, has announced a reduction in pandemic-related QE, but will continue with general ultra-loose monetary policy and non-pandemic-related QE.

Graph 2: High inflation economies (CPI)



Sources: Federal State Statistics Service, Instituto Brasileiro de Geografia e Estatística, Office for National Statistics, Ministry of Statistics & Programme Implementation, European Central Bank, Bureau of Labor Statistics, Haver Analytics and OPEC.

Higher interest rates, compounded by the ongoing US economic growth recovery, will most likely appreciate the value of the US dollar relative to other currencies. This may have a few implications on the oil market. Historically, a strong dollar would cause non-US-dollar denominated net-importing economies to require more of their local currency to import crude oil. However, in the past, a gradually strengthening US dollar had a limiting effect on oil price. Moreover, significant key US interest rate hikes are expected for 2Q22, which coincides with the run-up to northern hemisphere's driving season. Therefore, any demand decrease in the oil market as a result of tighter monetary policies will likely be offset by an increase in demand associated with the driving season at a time of slowing of COVID-19 infections in the northern hemisphere should support an acceleration in oil demand.

In summary, monetary actions are not expected to hinder underlying global economic growth momentum, but rather serve to recalibrate otherwise overheating economies. With an ongoing robust oil demand forecast, and the continuing efforts of OPEC Member Countries and non-OPEC countries participating in the DoC, the oil market is expected to remain well-supported throughout 2022.

World Oil Demand

For 2021, world oil demand growth remains unchanged at 5.7 mb/d. Within the year, growth was adjusted higher in 4Q21 amid better than anticipated OECD transportation fuel consumption, while adjusted downward in 3Q21, due to the implementation of the latest actual data. The 4Q21 OECD oil demand was adjusted higher mainly to account for stronger-than-expected demand in Americas and the Asia Pacific and despite the emergence of the new COVID -19 variant (Omicron). During the same quarter, firm oil demand in China also led to slight upward revisions, while slower transportation fuel demand in India, amid heavy rainfall, called for downward revisions. Weaker actual demand data for October and November 2021, saw slight downward revisions in the Middle East, Latin America and Africa. Total world oil demand is anticipated to reach 96.6 mb/d on an annualized basis in 2021.

In 2022, world oil demand growth has been kept unchanged at 4.2 mb/d with total global consumption at 100.8 mb/d. While the new Omicron variant may have an impact in 1H22, which is dependent on any further lockdown measures and rising hospitalizations levels impacting the workforce, projections for economic growth remain robust. This is despite the current inflation levels, which are being addressed through monetary policy by key central banks. Moreover, supply chain bottlenecks, ongoing trade issues and their impact on industrial and transportation fuel requirements remain key factors of uncertainty. In terms of fuels, light distillates, mainly for the petrochemical industry, are expected to continue to drive oil demand, while gasoline and diesel, particularly for road transportation, are forecast to continue to recover and reach pre-pandemic levels during the year. With regard to jet fuel, while the private travel sector has seen some considerable gains, business travel continues to lag and may not see a full recovery in 2022.

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

World oil demand	2020	1Q21	2Q21	3Q21	4Q21	2021	*Change 2021/20* Growth	%
Americas	22.44	22.73	24.33	24.71	24.84	24.16	1.72	7.66
of which US	*18.35*	*18.65*	*20.21*	*20.39*	*20.51*	*19.95*	*1.60*	*8.73*
Europe	12.44	11.91	12.63	13.85	13.49	12.98	0.54	4.37
Asia Pacific	7.14	7.67	7.04	7.12	7.73	7.39	0.25	3.46
Total OECD	**42.02**	**42.31**	**44.00**	**45.67**	**46.06**	**44.53**	**2.51**	**5.98**
China	13.52	13.79	14.55	14.52	15.16	14.50	0.99	7.29
India	4.51	4.94	4.50	4.59	5.32	4.84	0.33	7.30
Other Asia	8.13	8.56	8.98	8.34	8.62	8.63	0.50	6.10
Latin America	6.01	6.25	6.16	6.46	6.35	6.30	0.29	4.88
Middle East	7.55	7.95	7.77	8.24	8.00	7.99	0.45	5.95
Africa	4.08	4.37	4.08	4.15	4.43	4.26	0.17	4.28
Russia	3.39	3.65	3.42	3.63	3.74	3.61	0.22	6.55
Other Eurasia	1.07	1.23	1.24	1.09	1.28	1.21	0.14	12.70
Other Europe	0.70	0.78	0.72	0.73	0.79	0.75	0.06	8.29
Total Non-OECD	**48.96**	**51.52**	**51.43**	**51.74**	**53.69**	**52.10**	**3.14**	**6.42**
Total World	**90.98**	**93.83**	**95.43**	**97.41**	**99.75**	**96.63**	**5.66**	**6.22**
Previous Estimate	90.98	93.83	95.45	97.66	99.49	96.63	5.65	6.22
Revision	0.00	0.00	-0.02	-0.24	0.26	0.00	0.00	0.00

*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	24.16	24.04	25.42	25.73	25.65	25.22	1.06	4.37
of which US	*19.95*	*19.69*	*21.07*	*21.36*	*21.23*	*20.85*	*0.90*	*4.50*
Europe	12.98	12.63	13.21	14.49	14.01	13.59	0.61	4.73
Asia Pacific	7.39	7.91	7.22	7.25	7.83	7.55	0.17	2.26
Total OECD	**44.53**	**44.58**	**45.86**	**47.47**	**47.49**	**46.37**	**1.84**	**4.13**
China	14.50	14.64	15.44	15.00	15.60	15.17	0.66	4.58
India	4.84	5.48	4.82	4.97	5.64	5.23	0.39	8.07
Other Asia	8.63	9.25	9.59	8.93	8.95	9.18	0.55	6.38
Latin America	6.30	6.49	6.33	6.61	6.51	6.48	0.18	2.85
Middle East	7.99	8.30	8.01	8.49	8.24	8.26	0.27	3.34
Africa	4.26	4.54	4.21	4.27	4.56	4.40	0.14	3.22
Russia	3.61	3.75	3.47	3.68	3.79	3.67	0.07	1.81
Other Eurasia	1.21	1.30	1.29	1.12	1.32	1.26	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	**52.10**	**54.55**	**53.90**	**53.82**	**55.40**	**54.42**	**2.32**	**4.45**
Total World	**96.63**	**99.13**	**99.75**	**101.28**	**102.90**	**100.79**	**4.15**	**4.30**
Previous Estimate	96.63	99.13	99.77	101.53	102.64	100.79	4.15	4.30
Revision	0.00	0.00	-0.02	-0.25	0.26	0.00	0.00	0.00

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

OECD

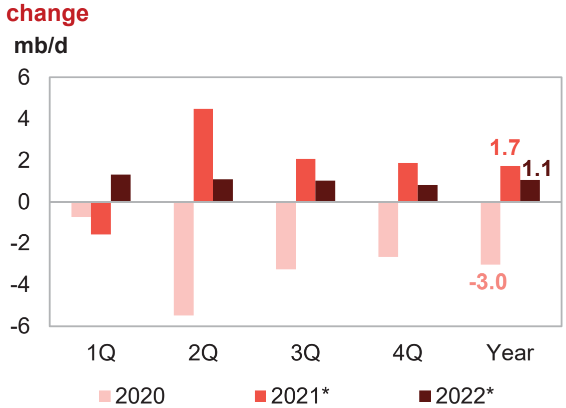
OECD Americas

Update on the latest developments

The latest available **OECD Americas** oil demand data shows an increase of 1.7 mb/d y-o-y in **October,** following a rise of 2.1 mb/d y-o-y in September. Gasoline demand in the region rose for the eighth month in a row, accounting for 0.8 mb/d, or around 50% of the overall increase, despite rising retail prices. Jet/kerosene demand rose by 0.5 mb/d, accounting for a 31% growth share.

October 2021 oil demand gains made up for around 95% of the demand seen during the same month in 2020. However, oil demand was still lower by 1.3 mb/d from October 2019 levels. All countries in the region posted demand gains, and this was on top of a lower baseline in 2020.

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 **October** implies a strong y-o-y increase of approximately 1.3 mb/d. This makes up around 60% of the losses incurred during October 2020, but remains lower than the October 2019 level by 0.8 mb/d. Gasoline, jet kerosene and residual fuel oil requirements contributed to the bulk of the increases, with gasoline and jet/kerosene gained 0.6 mb/d and 0.4 mb/d, respectively, y-o-y, while LPG and diesel demand each fell y-o-y by 0.1 mb/d. According to the Federal Highway Administration (FHA), vehicle miles travelled in the US increased y-o-y by 7.9% in October after rising by 7.7% y-o-y in September. In October 2020, the indicator was down by 8.8% y-o-y. Light vehicle retail sales, as reported by Autodata and Haver Analytics, were at 13.2 million units in October according to seasonally adjusted annual rates (SAAR), compared with 12.4 million units in September. In October 2020, total sales were 16.4 million units, while 16.8 million units were sold in October 2019. Industrial production was higher by 4.9% y-o-y in October 2021 after increasing by 4.6% y-o-y in September. Preliminary figures for November 2021, based on weekly data, indicate a continuation of the recovery in transportation fuel performance, with gasoline and jet/kerosene demand increasing by a combined 1.5 mb/d y-o-y.

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

By product	Oct 20	Oct 21	Change Oct 21/Oct 20 Growth	%
LPG	2.99	2.91	-0.08	-2.8
Naphtha	0.19	0.15	-0.04	-22.1
Gasoline	8.32	8.95	0.63	7.6
Jet/kerosene	1.01	1.45	0.44	43.8
Diesel	4.04	3.89	-0.15	-3.6
Fuel oil	0.26	0.38	0.12	47.8
Other products	2.11	2.46	0.35	16.7
Total	**18.90**	**20.18**	**1.28**	**6.8**

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

Near-term expectations

Despite the surge in COVID-19 cases and hospitalization rates in the US due to the Omicron variant, the overall picture for oil demand in the short term remains healthy, as the country has become more experienced in handling the challenges associated with the pandemic. Recent announcements by the US Federal Reserve to manage monetary policy to curb inflation, in combination with key economic indicators holding steady at robust levels, lend optimism to the ongoing oil demand recovery, despite business travel not expected to recover to pre-pandemic levels any time soon.

In **2022**, OECD Americas oil demand is forecast to rise y-o-y by around 1.1 mb/d, with US oil demand accounting for 0.9 mb/d. The petrochemical and transportation sectors will continue to be the main drivers of oil demand in 2022 on the back of expansions in the petrochemical industry, as well as continued robust increases in vehicle sales and strong economic growth. The main downside risks continue to relate to the COVID-19 pandemic, albeit to a much lesser degree than at the beginning of 2021, as well as inflationary and supply chain challenges.

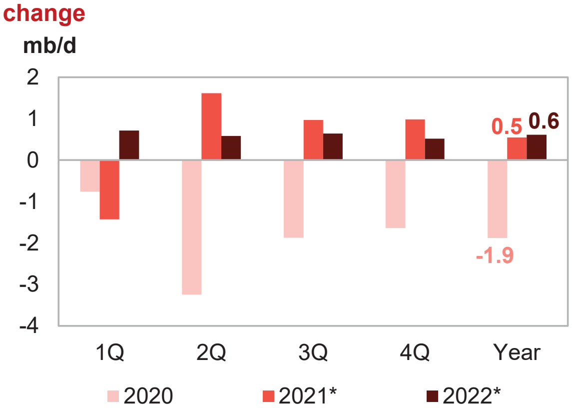
OECD Europe

Update on the latest developments

Oil demand in **OECD Europe** rose by 1.0 mb/d y-o-y in **October,** driven by a steady recovery in transportation fuel consumption, and follows slightly higher growth in September of 1.1 mb/d y-o-y. However, oil demand in OECD Europe remained below October 2019 levels by more than 0.6 mb/d. This was mainly due to the lag in jet fuel recovery in light of reduced travel, notably business related, within and outside the continent.

Demand for jet fuel rose by around 0.4 mb/d y-o-y in October. This was mainly due to a large distortion in the baseline as demand for the product had fallen y-o-y by around 1.0 mb/d in October 2020. This implies a recovery of only around 26%. Other transportation fuels, gasoline and on road diesel, again performed relatively better in October, as driving activities, both locally and across borders continued to improve.

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



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

Gasoline saw growth of around 0.1 mb/d y-o-y, slightly up from September growth levels. This petroleum product category has practically recovered to October 2019 levels. Petrochemical feedstock demand, led by naphtha, also recorded healthy y-o-y gains in October of 0.1 mb/d after y-o-y rising by 0.2 mb/d in September. Naphtha has benefited from high LPG prices and healthy petrochemical margins, with demand for the product now above October 2019 levels by around 0.2 mb/d. Petrochemical demand is supported by stable plastics requirements in the health sector, packaging, construction and end-user demand.

October's initial oil demand data suggests a softening, but still positive, momentum in oil requirements in the big four consuming countries, Germany, France, Italy and the UK. Demand is assumed to have increased by 0.3 mb/d y-o-y in October compared to an increase of around 0.6 mb/d y-o-y in September.

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

By product	Oct 20	Oct 21	*Change Oct 21/Oct 20* Growth	%
LPG	0.39	0.37	-0.02	-5.4
Naphtha	0.59	0.57	-0.02	-4.1
Gasoline	1.13	1.19	0.07	5.9
Jet/kerosene	0.38	0.55	0.17	44.4
Diesel	3.21	3.42	0.21	6.4
Fuel oil	0.18	0.16	-0.02	-10.8
Other products	0.52	0.47	-0.06	-10.9
Total	**6.40**	**6.72**	**0.32**	**5.0**

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

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

Near-term expectations

Looking ahead, mobility has been trending down again recently in Europe on account of the rapid spread of the Omicron variant and the resulting re-imposition of government restrictions and lockdown measures, potentially exerting further downward pressure on oil demand during 1Q22. The seasonal easing of transportation fuel demand in winter could be expected to extend further due to measures to contain the virus. However, it should be noted that other countries in the region may opt not to impose restrictions to avoid further negative impacts on their economies.

Uncertainties remain high and tilted rather to the downside as the region moves through the winter season. Nevertheless, **2022** projections continue to be supported by a steady rebound in OECD Europe macroeconomic indices, including industrial production and the ongoing resolution of supply chain issues, with momentum expected to gather strength particularly in 2H22. Additionally, the ECB appears willing to continue its considerable monetary support, despite signs of higher inflation. As a result, oil demand is anticipated to rise in 2022, mostly supported by transportation and industrial fuels.

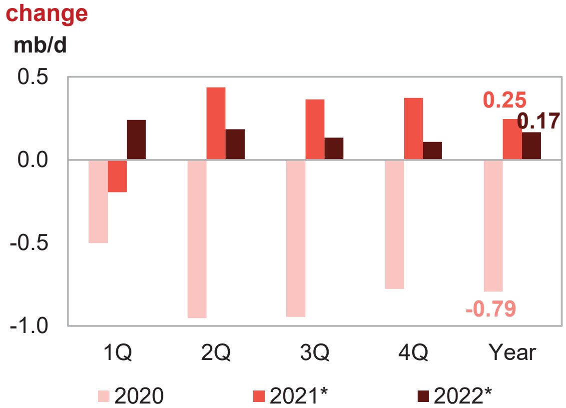
OECD Asia Pacific

Update on the latest developments

Asia-Pacific oil demand in **October** rose y-o-y by more than 0.5 mb/d, after posting an increase of 0.4 mb/d in September. This was mostly on the back of another solid increase in demand for naphtha, which saw a second consecutive monthly rise of 0.3 mb/d y-o-y. Despite this solid y-o-y rise, demand remained slightly lower than October 2019 levels due to a lagging transportation fuel recovery, jet fuel, in particular.

The strength for naphtha was on the back of its demand as a feedstock for steam cracker operators in light of high LPG prices and continued healthy petrochemical margins. Naphtha stood above pre-pandemic levels, higher by nearly 0.2 mb/d compared to October 2019. At the same time, LPG demand dropped y-o-y in October due to the preference to consume naphtha in the petrochemical sector.

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



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

For transportation fuels, gasoline consumption declined marginally in October, while jet fuel was higher y-o-y by around 50 tb/d. Gasoline continues to be pressured by increased efficiency in new vehicles, particularly in Japan, where total demand for gasoline has dropped from around 1.0 mb/d in 2010 to around 0.7 mb/d in 2021. However, demand for jet fuel increased in October backed by a continued recovery in the aviation sector, although it remains below the levels seen in October 2019.

Preliminary data from Japan's Ministry of Economy, Trade and Industry (METI) indicates a slight y-o-y oil demand drop of around 50 tb/d in November, mainly driven by weaker gasoline, jet kerosene and diesel demand.

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

By product	Nov 20	Nov 21	*Change Nov 21/Nov 20* Growth	%
LPG	0.42	0.42	0.00	-0.4
Naphtha	0.75	0.78	0.04	4.8
Gasoline	0.76	0.72	-0.04	-5.1
Jet/kerosene	0.39	0.34	-0.04	-10.9
Diesel	0.73	0.70	-0.03	-4.0
Fuel oil	0.24	0.26	0.02	9.3
Other products	0.19	0.20	0.00	2.3
Total	**3.48**	**3.43**	**-0.05**	**-1.4**

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

Near-term expectations

With the negative developments in 3Q21, particularly in Japan, now left behind, 4Q21 promises to see some upside, with high vaccination rates, improving consumer confidence and business sentiment indicators lending support. Moreover, improving exports are expected to boost demand for industrial fuels and petrochemical feedstock in the coming months.

Ongoing strong support by the Bank of Japan, as well as the ongoing recovery in external trade, are expected to see the positive momentum projected for 4Q21 carry over into **2022**. Most oil product categories are anticipated to return to pre-pandemic levels, with LPG assumed to be the main contributor to oil demand growth. However, jet kerosene demand is projected to continue to lag 2019 levels, as international business travel remains under pressure.

Non-OECD

China

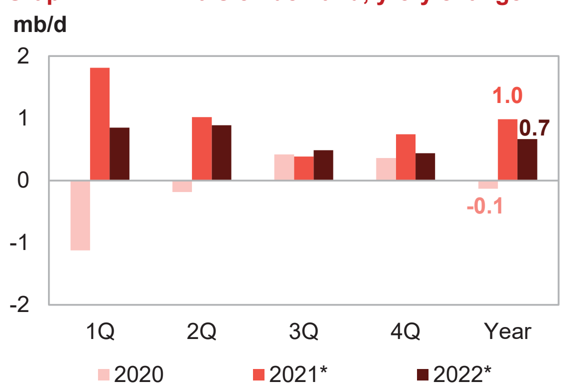
Update on the latest developments

China's oil demand saw another strong y-o-y rise in **November**, increasing by more than 0.5 mb/d on the back of continued healthy petrochemical feedstock demand and rebounding mobility. Demand exceeded the November 2019 level by almost 1.3 mb/d, driven by strong naphtha and LPG requirements.

In November, naphtha demand rose y-o-y by only 0.1 mb/d following a 0.3 mb/d y-o-y increase in October, while LPG demand grew y-o-y by 0.3 mb/ in November following a 0.2 mb/d y-o-y rise a month earlier. Solid consumption over the past few months has raised combined naphtha and LPG demand above pre-pandemic levels by around 0.8 mb/d.

Transportation fuels saw gasoline post strong gains supported by increasing mobility, while jet fuel continued to lag. Gasoline grew y-o-y by 0.2 mb/d in November and diesel increased by 0.2 mb/d too. Gasoline has surpassed pre-pandemic November 2019 levels by around 0.3 mb/d and diesel by almost 0.4 mb/d.

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



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

Jet fuel continues to be impacted by the reduction in local and international flights to counter the spread of COVID-19, as the country holds fast to its zero-COVID policy. According to China's National Bureau of Statistics and Haver Analytics, passenger turnover in civil aviation declined further y-o-y in November, dropping by 51.5% after posting declines of 22.6% in October.

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

By product	Nov 20	Nov 21	Change Nov 21/Nov 20 Growth	%
LPG	1.97	2.30	0.33	16.5
Naphtha	1.57	1.65	0.08	5.2
Gasoline	3.10	3.30	0.20	6.5
Jet/kerosene	0.82	0.65	-0.17	-20.9
Diesel	3.48	3.70	0.22	6.4
Fuel oil	0.55	0.50	-0.05	-9.6
Other products	1.81	1.75	-0.06	-3.3
Total	**13.30**	**13.85**	**0.55**	**4.1**

*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

While macroeconomic indicators, such as manufacturing and services PMIs indicate an expansion trend, the recent emergence of the Omicron variant in select Chinese cities and the ensuing strict government measures to curb a potential spread could pose some downside risks to oil demand in early 2022.

The development of the spread of the virus variant in China is also likely to have an impact on the impending Winter Olympic Games and upcoming Chinese New Year festivities, which otherwise should provide support to oil demand in 1Q22, particularly transportation fuels. Petrochemical feedstock, especially naphtha and LPG, are assumed to be supported by strong end-user demand and by capacity additions in recent years. Gasoline and diesel are forecast to surpass pre-pandemic levels, while jet fuel demand is expected to recover more slowly to just about reach 2019 levels, albeit this is dependent on travel restrictions.

India

Update on the latest developments

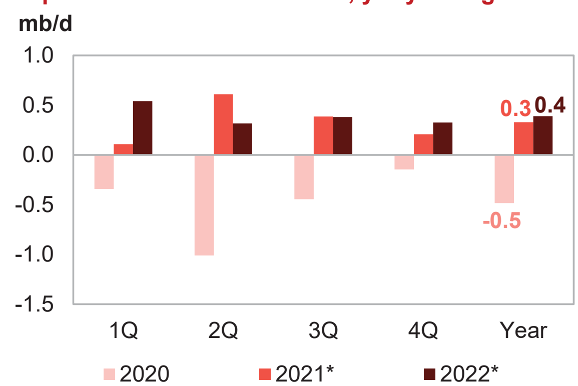
Oil demand in India declined by around 0.4 mb/ in **November** impacted by extreme and particularly heavy rainfall, following a marginal 0.04 mb/d y-o-y rise in October. In comparison with November 2019 levels, oil demand is lower by around 0.5 mb/d. In November, diesel oil saw the largest drop of 0.1 mb/d, while gasoline also declined marginally. Jet fuel saw a small y-o-y increase of 20 tb/d on the back of a pickup in domestic flights.

However, jet fuel demand remained nearly 0.1 mb/d lower than November 2019 levels, still affected by a slower recovery in international flights. At the same time, kerosene continues to be substituted by LPG in the residential sector.

The other product category, which includes bitumen for road construction, declined by around 0.2 mb/d y-o-y, as construction activities were impacted by the extreme weather during November.

LPG fell only marginally and benefited primarily from usage for household cooking in line with past trends. Diesel dropped by around 0.1 mb/d y-o-y after a similar decrease in October. The weather phenomenon in November outweighed other improvements seen in macroeconomic indicators.

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



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

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

By product	Nov 20	Nov 21	Change Nov 21/Nov 20 Growth	%
LPG	1.02	1.01	0.00	-0.3
Naphtha	0.36	0.28	-0.08	-21.6
Gasoline	0.68	0.68	-0.01	-0.8
Jet/kerosene	0.18	0.20	0.02	12.9
Diesel	1.93	1.80	-0.13	-6.7
Fuel oil	0.28	0.28	0.00	1.5
Other products	0.80	0.63	-0.16	-20.3
Total	**5.24**	**4.89**	**-0.35**	**-6.7**

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

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

Near-term expectations

India's oil demand is poised to recover considerably in 2021, almost returning to the level seen in 2019. Over the short term, demand is assumed to be supported by steady macroeconomic indicators, despite some inflation concerns, which are in part being addressed by the government.

For **2022**, total oil demand is projected to exceed 2019 levels by more than 0.2 mb/d on average for the year. This is due to the ongoing healthy economic outlook and the continued improvement in demand for transportation and industrial fuels, with the exception of jet fuel, which is still projected to lag. While ongoing stimulus packages, as well as better management of COVID-19, are projected to offer further support in the year, uncertainties related to COVID-19 developments and possible further extreme weather conditions pose a downward risk.

Latin America

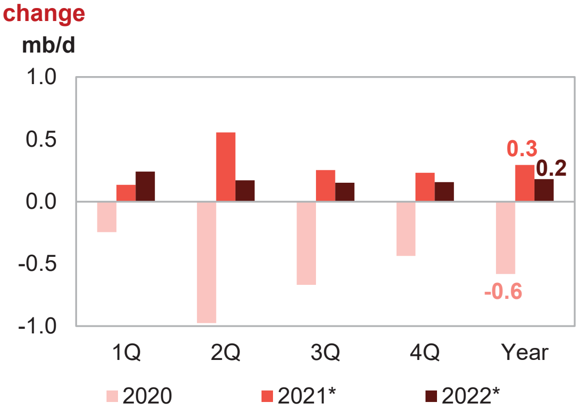
Update on the latest developments

Oil demand in Latin America showed a y-o-y increase of 0.1 mb/d in **October**, compared to more than 0.2 mb/d y-o-y in September.

Despite showing y-o-y growth for the eighth consecutive month, Latin America's October 2021 oil demand remained marginally lower than October 2019.

Gasoline and diesel demand led the increases in October, rising y-o-y by 0.1 mb/d each, driven by rising mobility across the region's main economies. Jet fuel also saw a 0.04 mb/d y-o-y rise in October, however, the overall level remains around 0.1 mb/d below October 2019.

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



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

Brazil led the positive recovery in mobility with an increase from 112% in September to 118% in October, compared with January 2020, as reported by Google Maps and Apple's mobility indicator. Despite a slowdown in industrial production and disappointing numbers from manufacturing and services sectors in November, diesel continued to show growth in Brazil and increased by around 0.04 mb/d y-o-y. Demand for diesel in Brazil has already exceeded pre-pandemic levels in November.

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

			Change	*Nov 21/Nov 20*
By product	**Nov 20**	**Nov 21**	**Growth**	**%**
LPG	0.23	0.22	0.00	-1.9
Naphtha	0.14	0.14	0.00	2.9
Gasoline	0.68	0.72	0.05	6.8
Jet/kerosene	0.07	0.09	0.03	39.6
Diesel	1.03	1.07	0.04	4.2
Fuel oil	0.10	0.11	0.01	11.1
Other products	0.44	0.31	-0.13	-30.1
Total	**2.67**	**2.67**	**0.00**	**-0.2**

*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

Going forward, oil demand expectations for the region show a continued recovery for most fuels from the historical decline in 2020, led mostly by diesel and gasoline. Demand for fuel oil is assumed to benefit from shortages in hydropower generation due to expected droughts.

Despite the recent pressures from soaring inflation and slowing economic activity, particularly in 4Q21, and a possible spill-over to 1Q22, Brazil is assumed to lead 2022 oil demand growth in the region. Y-o-y growth is expected in all product categories led by transportation fuels followed by industrial fuels, namely diesel, gasoline and jet fuel. Uncertainties, however, have shifted to the downside and specifically related to economies. This includes inflation, unemployment and currency challenges, all of which could potentially weigh on oil demand projections going forward.

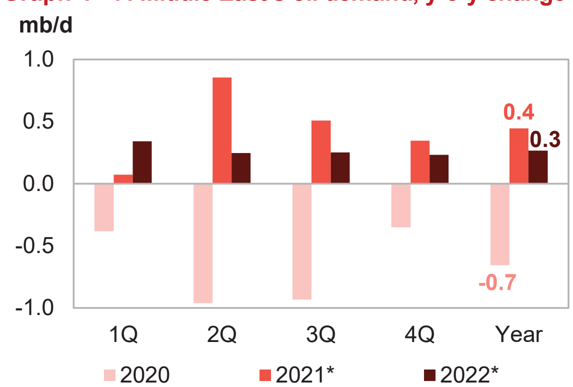
Middle East

Update on the latest developments

Middle Eastern oil demand rose y-o-y by 0.2 mb/d in **October** following an increase of around 0.5 mb/d y-o-y in September. The mobility index reached 104% when compared to January 2020, according to Google Maps and the Apple mobility index.

Gasoline demand increased by more than 0.1 mb/d in October after rising by more than 0.2 mb/d in September. Increases in gasoline demand in some countries of the region, point to a more relaxed or a lifting of mobility restrictions.

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 November showed a decline of 0.1 mb/d, despite a y-o-y rise in some products, such as diesel and jet/kerosene. Residual fuel oil demand dropped by 0.1 mb/d y-o-y, while crude oil for power generation rose slightly y-o-y. Diesel expanded by around 0.1 mb/d, supported by a pick-up in industrial activities, while jet fuel posted marginal gains supported by increases in domestic and international flights. Compared with November 2019, total oil demand levels were slightly higher.

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

By product	Nov 20	Nov 21	Change Nov 21/Nov 20 Growth	%
LPG	0.05	0.05	0.00	1.0
Gasoline	0.51	0.48	-0.03	-5.9
Jet/kerosene	0.04	0.04	0.01	16.2
Diesel	0.41	0.50	0.09	20.9
Fuel oil	0.76	0.64	-0.12	-15.9
Other products	0.41	0.42	0.01	1.9
Total	**2.19**	**2.13**	**-0.06**	**-2.8**

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

Sources: JODI and OPEC.

The latest available data for November 2021 in **Iraq** shows a y-o-y oil demand increase of 0.1 mb/d. Fuel oil saw the largest y-o-y increase of 0.1 mb/d, followed by gasoline with 0.04 mb/d and diesel at 0.03 mb/d. At the same time, jet fuel saw a y-o-y decline of 65 tb/d. Fuel oil and diesel demand was mostly supported by industrial sector demand improvements, while the decline in jet fuel was due to ongoing travel restrictions.

Near-term expectations

Going forward, oil demand in the Middle East is projected to continue to recover in the final months of 2021. Industrial fuels, on the back of steady economic developments, are forecast to drive growth in 2022, with feedstock requirements for the petrochemical industry further supporting the recovery.

The further easing of COVID-19 measures are projected to provide support for transportation fuel, with jet fuel expected to gain support from the resumption of international flights in the region's main travel hubs. However, jet fuel demand is not anticipated to reach pre-pandemic levels in 2022, amid lagging intercontinental business travel.

World Oil Supply

Non-OPEC liquids supply growth in 2021 (including processing gains of 0.13 mb/d) is kept unchanged at around 0.7 mb/d y-o-y, to average of 63.6 mb/d. Upward revisions mainly to the US were offset by downward revisions in the supply forecasts of other countries such as Brazil, Canada, Ecuador and Norway, due to unexpected lower output in 4Q21. Following an upward revision to production estimates in 4Q21, due to a faster-than-expected production recovery in the Gulf of Mexico (GoM) and steady monthly growth in the main shale plays, particularly in the Permian, the US liquids supply forecast was revised up to show growth of 0.13 mb/d y-o-y. The 2021 oil supply forecast primarily sees growth in Canada, Russia, China, the US, Guyana, Norway and Argentina, while output is projected to decline in the UK, Brazil, Colombia and Indonesia.

Non-OPEC supply growth for 2022 also remains broadly unchanged at 3.0 mb/d y-o-y, to average 66.7 mb/d. Upward revisions to the supply forecast of Other Asia were offset by downward revisions in Other Eurasia. The main drivers of liquids supply growth are expected to be the US, Russia, Brazil, Canada, Kazakhstan, Norway and Guyana.

OPEC NGLs and non-conventional liquids production in 2021 is unchanged from the previous assessment to show growth of 0.1 mb/d y-o-y for an average of 5.1 mb/d. Growth of 0.1 mb/d y-o-y is forecast in 2022 for an average of 5.3 mb/d. OPEC-13 crude oil production in December increased by 0.17 mb/d m-o-m to average 27.88 mb/d, according to available secondary sources.

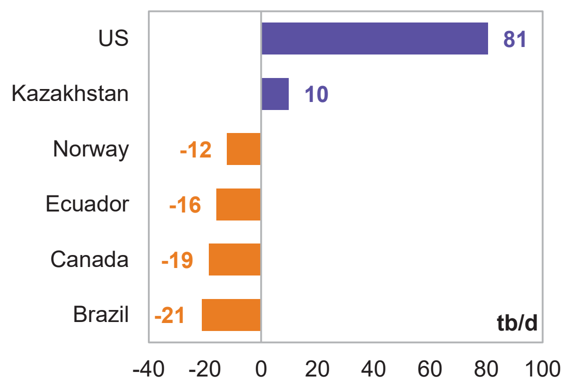
Preliminary non-OPEC liquids production in December, including OPEC NGLs, is estimated to have grown by 0.48 mb/d m-o-m to average 70.63 mb/d, up by 2.99 mb/d y-o-y. As a result, preliminary data indicates that global oil supply in December grew by 0.65 mb/d m-o-m to average 98.51 mb/d, up by 5.58 mb/d y-o-y.

Non-OPEC liquids production growth in 2021 was revised down by a minor 5 tb/d from the previous month's assessment to average 0.67 mb/d.

In the OECD, a downward revision of 24 tb/d in 3Q21 was more than offset by an upward revision of 211 tb/d in 4Q21, which led to an upward revision of 47 tb/d for the year in the region. The driver for the upward revision was the US with 81 tb/d for the year, while Canada and Norway saw the main downward revisions with 19 tb/d and 12 tb/d, respectively.

The non-OECD supply forecast for 2021 was revised down by 52 tb/d, mainly due to downward revisions in Brazil and Ecuador by 21 tb/d and 16 tb/d, respectively, as well as several other countries in Latin America and other regions.

Graph 5 - 1: Major revisions to annual supply change forecast in 2021*, MOMR Jan 22/Dec 21



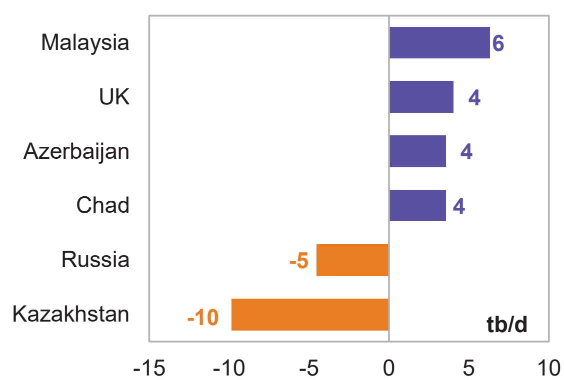
*Note: * 2021 = Forecast. Source: OPEC.*

The **non-OPEC supply growth forecast for 2022,** despite showing a few very minor upward and downward revisions, remained unchanged to average 3.02 mb/d.

The main upward revision was seen in Other Asia, of which Malaysia saw the largest adjustment.

This month's upward revisions were slightly more than offset by downward adjustments, mainly in Kazakhstan. With the revisions, mainly to 4Q21, the non-OPEC absolute liquids supply forecast for 2022 was revised down by 5 tb/d to average 66.66 mb/d, but in terms of growth, it remains unchanged at 3.02 mb/d.

Graph 5 - 2: Major revisions to annual supply change forecast in 2022*, MOMR Jan 22/Dec 21

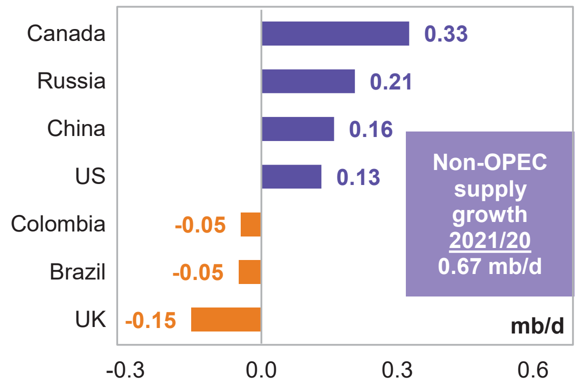


*Note: * 2022 = Forecast. Source: OPEC.*

Key drivers of growth and decline

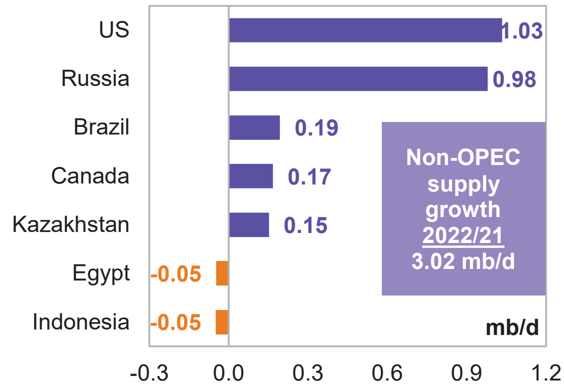
The **key drivers of non-OPEC liquids supply growth in 2021** are estimated to have been Canada, Russia, China, the US, Guyana, Norway and Argentina, while output is projected to have declined in the UK, Brazil, Colombia and Indonesia.

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 the US, Russia, Brazil, Canada, Kazakhstan, Norway, Guyana and other non-OPEC countries participating in the Declaration of Cooperation (DoC), while oil production is projected to decline, mainly in Indonesia, Egypt, Thailand and Colombia.

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	25.17	25.19	26.21	25.17	0.47	1.91
of which US	*17.61*	*16.63*	*17.93*	*17.84*	*18.53*	*17.74*	*0.13*	*0.75*
Europe	3.90	3.96	3.52	3.81	3.86	3.79	-0.11	-2.90
Asia Pacific	0.52	0.50	0.45	0.53	0.52	0.50	-0.02	-3.47
Total OECD	**29.12**	**28.56**	**29.13**	**29.53**	**30.58**	**29.46**	**0.34**	**1.17**
China	4.16	4.30	4.34	4.33	4.32	4.32	0.16	3.86
India	0.77	0.76	0.75	0.75	0.74	0.75	-0.01	-1.78
Other Asia	2.51	2.52	2.46	2.34	2.37	2.42	-0.08	-3.39
Latin America	6.04	5.96	5.99	6.11	5.90	5.99	-0.05	-0.79
Middle East	3.19	3.22	3.23	3.24	3.28	3.24	0.05	1.53
Africa	1.41	1.37	1.35	1.32	1.32	1.34	-0.07	-5.21
Russia	10.59	10.47	10.74	10.81	11.17	10.80	0.21	1.95
Other Eurasia	2.91	2.96	2.89	2.79	3.06	2.93	0.01	0.38
Other Europe	0.12	0.12	0.11	0.11	0.11	0.11	-0.01	-4.66
Total Non-OECD	**31.71**	**31.67**	**31.86**	**31.80**	**32.29**	**31.91**	**0.20**	**0.64**
Total Non-OPEC production	60.82	60.23	61.00	61.34	62.87	61.37	0.54	0.89
Processing gains	2.15	2.28	2.28	2.28	2.28	2.28	0.13	6.03
Total Non-OPEC liquids production	**62.97**	**62.51**	**63.28**	**63.62**	**65.15**	**63.65**	**0.67**	**1.07**
Previous estimate	62.97	62.51	63.28	63.64	65.15	63.65	0.68	1.08
Revision	0.00	0.00	0.00	-0.02	0.01	0.00	0.00	-0.01

*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

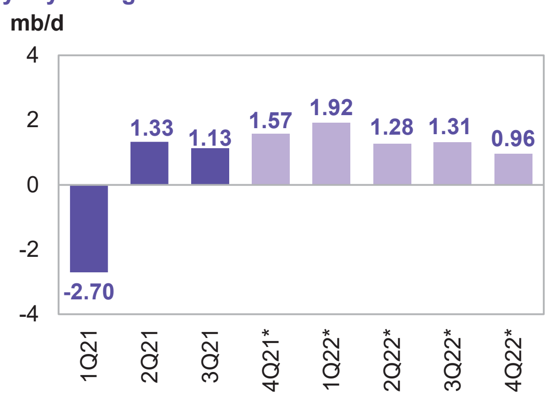
Non-OPEC liquids production	2021	1Q22	2Q22	3Q22	4Q22	2022	*Change 2022/21* Growth	%
Americas	25.17	26.08	26.13	26.50	26.88	26.40	1.23	4.89
of which US	*17.74*	*18.43*	*18.68*	*18.83*	*19.14*	*18.77*	*1.03*	*5.83*
Europe	3.79	3.86	3.75	3.81	4.13	3.89	0.10	2.69
Asia Pacific	0.50	0.54	0.54	0.53	0.53	0.53	0.03	6.08
Total OECD	**29.46**	**30.48**	**30.41**	**30.84**	**31.55**	**30.82**	**1.36**	**4.63**
China	4.32	4.33	4.33	4.37	4.45	4.37	0.04	1.02
India	0.75	0.73	0.75	0.78	0.80	0.77	0.01	1.59
Other Asia	2.42	2.44	2.41	2.39	2.38	2.41	-0.01	-0.56
Latin America	5.99	6.30	6.24	6.18	6.39	6.27	0.28	4.71
Middle East	3.24	3.34	3.34	3.36	3.36	3.35	0.11	3.33
Africa	1.34	1.29	1.27	1.25	1.22	1.25	-0.09	-6.38
Russia	10.80	11.51	11.83	11.88	11.88	11.78	0.98	9.08
Other Eurasia	2.93	3.10	3.12	3.16	3.22	3.15	0.22	7.63
Other Europe	0.11	0.11	0.11	0.10	0.10	0.10	-0.01	-6.90
Total Non-OECD	**31.91**	**33.14**	**33.39**	**33.46**	**33.80**	**33.45**	**1.54**	**4.83**
Total Non-OPEC production	61.37	63.62	63.80	64.31	65.35	64.27	2.91	4.74
Processing gains	2.28	2.39	2.39	2.39	2.39	2.39	0.11	4.91
Total Non-OPEC liquids production	**63.65**	**66.01**	**66.19**	**66.70**	**67.74**	**66.66**	**3.02**	**4.74**
Previous estimate	63.65	66.02	66.20	66.70	67.74	66.67	3.02	4.74
Revision	0.00	0.00	0.00	-0.01	0.00	0.00	0.00	0.00

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

OECD

OECD liquids production in 2021 is estimated to increase by 0.34 mb/d y-o-y to average 29.46 mb/d, revised up by 0.05 mb/d m-o-m owing to an upward revision of 0.06 mb/d in the production forecast for OECD Americas, which is now projected to grow by 0.47 mb/d to average 25.17 mb/d. OECD Europe is forecast to decline by 0.11 mb/d, with an average supply of 3.79 mb/d. The supply forecast in OECD Asia Pacific is also forecast to decline by 0.02 mb/d y-o-y, to average 0.50 mb/d.

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



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

For **2022**, oil production in the OECD is forecast to increase by 1.36 mb/d y-o-y to average 30.82 mb/d, revised up by 0.05 mb/d compared to a month earlier, amid upward revisions in OECD Americas by 64 tb/d, which are offset by a downward adjustment in the supply forecast of OECD Europe by 12 tb/d. Based on these revisions, OECD Americas is forecast to grow by 1.23 mb/d to average 26.40 mb/d. Oil production in OECD Europe and OECD Asia Pacific is anticipated to grow respectively by 0.10 mb/d and 0.03 mb/d y-o-y to average 3.89 mb/d and 0.53 mb/d.

OECD Americas

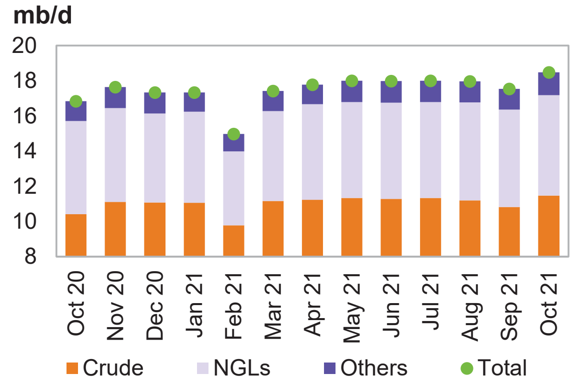
US

US liquids production rose in October 2021 by 0.94 mb/d m-o-m to average 18.49 mb/d, up by 1.64 mb/d compared with October 2020.

Crude oil and condensate production increased in October 2021 by 651 tb/d m-o-m to average 11.47 mb/d, up by 1.06 mb/d y-o-y. Regarding the crude and condensate production breakdown by region (PADDs), production rose the most on the US Gulf Coast (USGC) by 629 tb/d to average 8.12 mb/d, and also increased slightly in the Midwest, Rocky Mountains and West Coast. Production on the East Coast declined by 7 tb/d m-o-m in October.

NGL production was up by 173 tb/d m-o-m to average 5.71 mb/d in October, higher by 0.42 mb/d y-o-y. Meanwhile, production of **non-conventional liquids** (mainly ethanol) in September decreased by 9 tb/d m-o-m to average 1.18 mb/d, according to the Department of Energy (DOE). According to a preliminary estimate, non-conventional liquids are estimated to average 1.3 mb/d in October.

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



Source: OPEC.

Production in the Gulf of Mexico (GoM) rose by 680 tb/d m-o-m in October to average 1,744 tb/d, showing a rebound from the impact of Hurricane Ida.

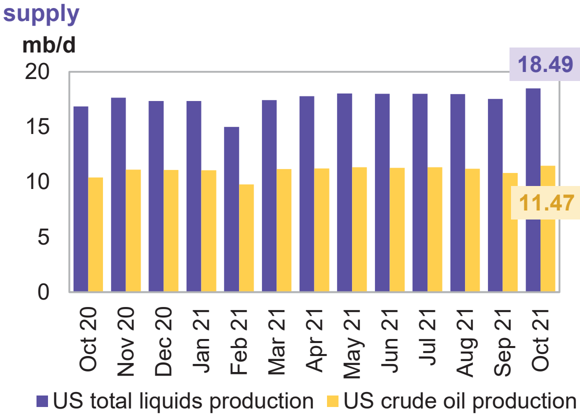
Looking at states, oil production in New Mexico declined by 23 tb/d m-o-m to average 1.33 mb/d, and production in Texas decreased by 44 tb/d to average 4.91 mb/d, 260 tb/d higher than a year ago. Production in North Dakota decreased by a marginal 1 tb/d m-o-m to average 1.1 mb/d, but was lower by 130 tb/d y-o-y. Production in Alaska was up by 7 tb/d at an average of 0.44 mb/d. Oil output in Oklahoma and Colorado showed an increase m-o-m by 5 tb/d and 15 tb/d, respectively. In the onshore lower 48, September production decreased by 36 tb/d m-o-m to average 9.3 mb/d.

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

State	Sep 21	Oct 21	*Change Oct 21/Sep 21*
Oklahoma	397	402	*5*
Colorado	396	411	*15*
Alaska	430	437	*7*
North Dakota	1,102	1,101	*-1*
New Mexico	1,356	1,333	*-23*
Gulf of Mexico (GoM)	1,064	1,744	*680*
Texas	4,950	4,906	*-44*
Total	**10,822**	**11,473**	***651***

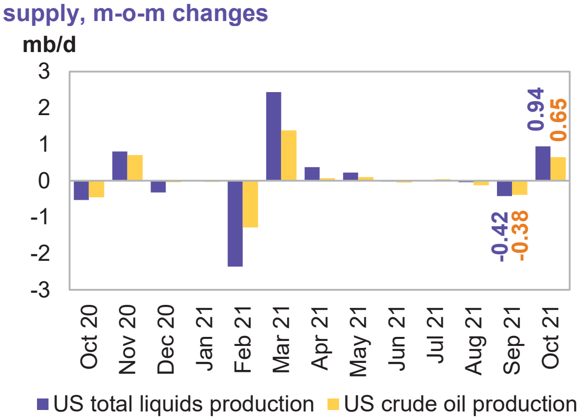
Sources: EIA and OPEC.

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.

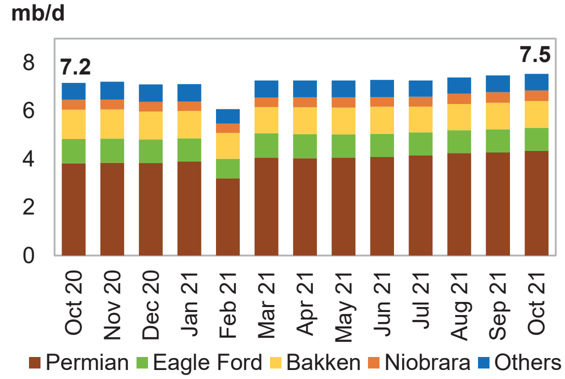
US tight crude output in October increased by 66 tb/d m-o-m to average 7.54 mb/d, which was 376 tb/d higher than the same month a year earlier, according to Energy Information Administration (EIA) estimates.

The m-o-m increase from shale and tight formations through horizontal wells came mostly from the Permian, which increased by 56 tb/d to average 4.37 mb/d, and was up by 0.51 mb/d y-o-y.

In the Williston Basin, production in the Bakken shale rose by 11 tb/d to average 1.1 mb/d, down by 103 tb/d y-o-y. Tight crude output at Eagle Ford in Texas declined by a minor 1 tb/d to average 0.96 mb/d, while production in Niobrara-Codell in Colorado and Wyoming was up by 7 tb/d, to average 0.44 mb/d.

Average tight crude output in the first ten months of the year was estimated at 7.19 mb/d.

Graph 5 - 9: US tight crude output breakdown

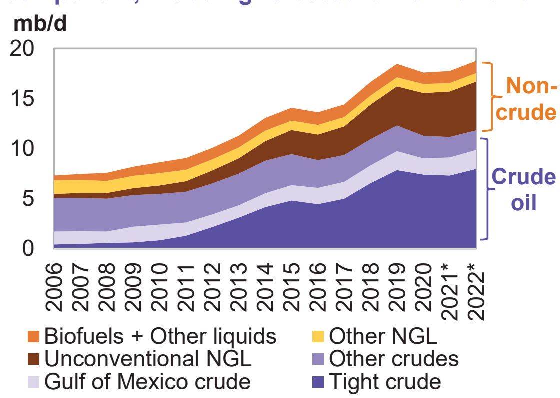


Sources: EIA, Rystad Energy and OPEC.

The **US liquids production growth forecast for 2021** was revised up by 81 tb/d and now stands to grow by 0.13 mb/d y-o-y to average 17.74 mb/d. The US liquids supply 2021 exit rate has been adjusted higher due to an upward revision to 4Q21 by 305 tb/d, compared to a previously projected growth of 0.05 mb/d. 3Q21 was also revised upward by a minor 15 tb/d.

Regarding the liquids breakdown, US crude and condensate production for 2021 is expected to decline by 0.12 mb/d to average 11.17 mb/d. Growth of NGLs and non-conventional liquids is forecast at 0.22 mb/d and 0.03 mb/d to average 5.39 mb/d and 1.18 mb/d, respectively.

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



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

US crude oil production is expected to exit December 2021 at 11.70 mb/d. US tight and conventional crude oil production are forecast to see contractions of 0.08 mb/d and 0.19 mb/d in 2021, to average 7.31 mb/d and 2.06 mb/d, respectively.

US liquids production in 2022, excluding processing gains, is anticipated to grow by 1.03 mb/d y-o-y to average 18.77 mb/d, revised up by 0.08 mb/d. The 2022 gains are due primarily to forecast tight crude production growth of 0.7 mb/d and projected growth of 0.08 mb/d in the GoM. However, the expected growth from shale and tight formations as well as from the GoM will be partially offset by natural declines in onshore conventional fields by 0.10 mb/d y-o-y.

Given the current pace of drilling and well completion in oil fields, **production of crude oil** is forecast to grow by 0.65 mb/d y-o-y to average 11.82 mb/d. This forecast assumes ongoing capital discipline, limited active drilling rigs, completion crews and labour shortages.

Production of NGLs, mainly from unconventional shale sources, is forecast to increase by 0.34 mb/d to average 5.7 mb/d, and non-conventional liquids are projected to grow by 0.04 mb/d.

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	7.39	-0.45	7.31	-0.08	7.98	0.67
Gulf of Mexico crude	1.64	-0.25	1.80	0.16	1.88	0.08
Conventional crude oil	2.25	-0.30	2.06	-0.19	1.96	-0.10
Total crude	11.28	-1.01	11.17	-0.11	11.82	0.65
Unconventional NGLs	4.27	0.35	4.53	0.26	4.89	0.36
Conventional NGLs	0.91	0.00	0.86	-0.05	0.84	-0.02
Total NGLs	5.17	0.35	5.39	0.22	5.73	0.34
Biofuels + Other liquids	1.15	-0.20	1.18	0.03	1.22	0.04
US total supply	**17.61**	**-0.86**	**17.74**	**0.13**	**18.77**	**1.03**

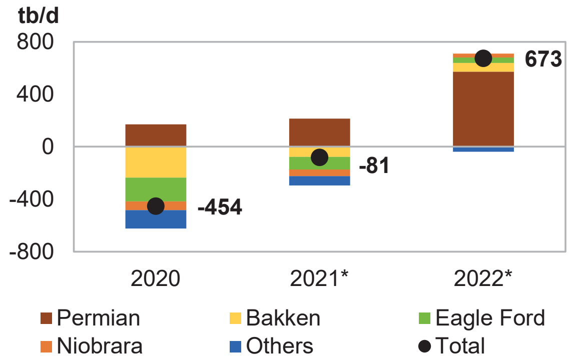
*Note: * 2021-2022 = Forecast. Sources: EIA, OPEC and Rystad Energy.*

US tight crude production in 2021 and 2022 is expected to show continuous y-o-y growth in the Permian Basin by 219 tb/d and 572 tb/d to average 4.14 mb/d and 4.71 mb/d, respectively.

The decline rate in Bakken shale production slowed in 2021 compared to 2020, from a contraction of 235 tb/d to a decline of 71 tb/d, and is now expected to stand at an average of 1.1 mb/d in 2021. For 2022, tight crude production from the Bakken shale is forecast to grow by 66 tb/d on the back of increased drilling activities in North Dakota.

The Eagle Ford in Texas is expected to decline this year by 0.08 mb/d to average 0.96 mb/d, but is forecast to grow next year by 0.04 mb/d to average 1.0 mb/d. According to the EIA-DPR (Drilling Productivity Report) forecast for January 2022, production is forecast to decrease by 7 tb/d in January m-o-m.

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



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

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

US tight oil	2020	Change 2020/19	2021*	Change 2021/20	2022*	Change 2022/21
Permian tight	3.92	0.17	4.14	0.21	4.71	0.57
Bakken shale	1.18	-0.23	1.10	-0.08	1.17	0.07
Eagle Ford shale	1.05	-0.18	0.96	-0.10	1.00	0.04
Niobrara shale	0.47	-0.07	0.42	-0.05	0.45	0.03
Other tight plays	0.76	-0.14	0.69	-0.07	0.65	-0.04
Total	**7.39**	**-0.45**	**7.31**	**-0.08**	**7.98**	**0.67**

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

Production in the Niobrara, following an expected decline of 51 tb/d this year, is likely to grow by 31 tb/d y-o-y in 2022, to average 0.45 mb/d. Other shale plays are not expected to show growth in 2021 or 2022, given current drilling and completion activities.

US tight crude saw a contraction of 453 tb/d in 2020 and is expected to decline by 72 tb/d y-o-y this year. In 2022, production is forecast to grow by 673 tb/d to average 7.98 mb/d.

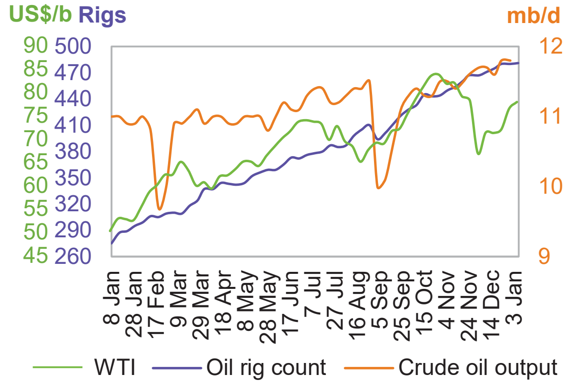
US rig count, spudded, completed, DUC wells and fracking activity

Total **US active drilling rigs** remained unchanged w-o-w at 586 rigs in the week ended 31 December. The number of active offshore rigs was steady w-o-w at 15, two rigs down from 2020. Moreover, 570 rigs (oil and gas) were active onshore and one in inland waters.

The US horizontal rig count rose by two rigs w-o-w to 530 rigs, compared to 313 horizontal rigs in 2020 a year ago.

While the rig count in the Permian dropped by one w-o-w to 293 rigs, the number of active rigs increased by one to 28 rigs in Cana Woodford and remains unchanged at 27 in the Williston, 44 in the Eagle Ford, and 11 rigs in the DJ-Niobrara basins.

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



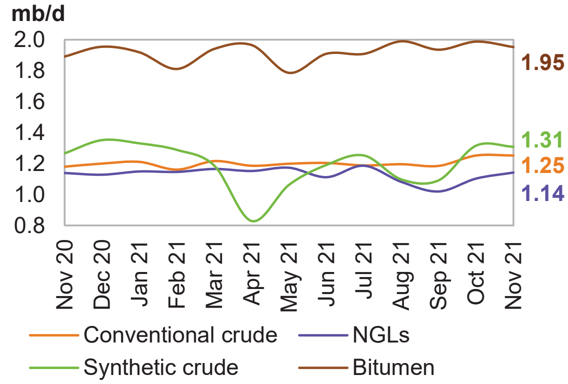
Sources: Baker Hughes, EIA and OPEC.

Canada

Canada's liquids production in November is estimated to have remained flat m-o-m, to average 5.69 mb/d.

Crude bitumen and synthetic crude output decreased slightly, by 42 tb/d, while production of conventional crude was unchanged at an average of 1.25 mb/d. At the same time, production of and NGLs was up by 39 tb/d m-o-m to average 1.14 mb/d.

Graph 5 - 13: Canada's monthly liquids production development by type

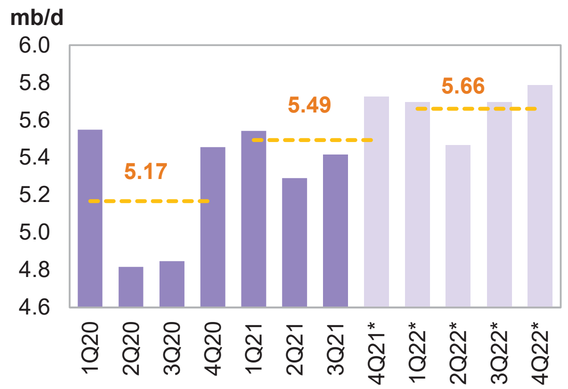


Sources: National Energy Board and OPEC.

Lower-than-forecast monthly liquids output in both October and November have necessitated a slight downward revision to Canadian liquids supply for **2021** by 19 tb/d, to show growth of 0.33 mb/d and average 5.49 mb/d.

For **2022**, Canada's liquids 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, revised down by 0.02 mb/d from the previous month's assessment.

Graph 5 - 14: Canada's quarterly liquids production and forecast



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

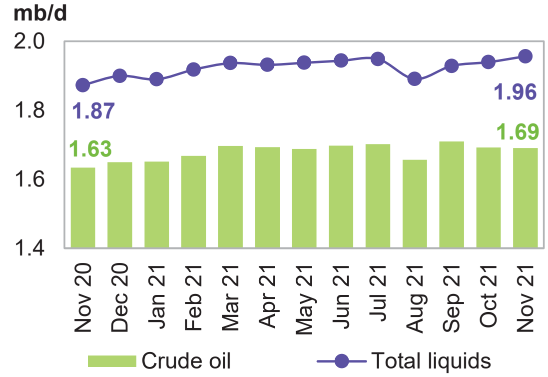
Mexico

Mexico's crude output was broadly flat in **November** to average 1.69 mb/d. However, NGL output rose by 18 tb/d. Therefore, Mexico's total liquids output in November increased by 17 tb/d m-o-m to average 1.96 mb/d.

For **2021**, liquids production in Mexico is forecast to grow by 0.01 mb/d to average 1.93 mb/d, unchanged from the previous assessment.

For **2022**, growth is forecast at 0.03 mb/d to average 1.96 mb/d.

Graph 5 - 15: Mexico's monthly liquids and crude production development



Sources: PEMEX and OPEC.

OECD Europe

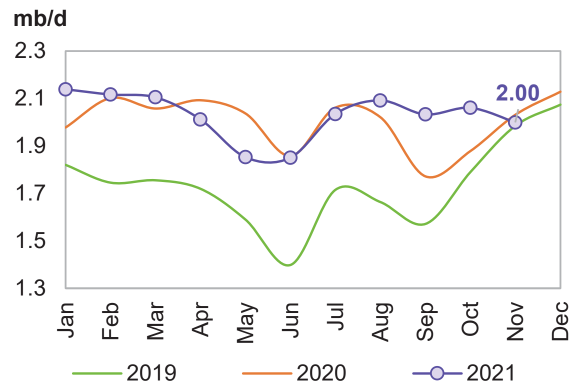
Norway

Norwegian crude production declined by 89 tb/d m-o-m in **November** to average 1.73 mb/d, and was flat y-o-y. Production of NGLs and condensates rose by 27 tb/d m-o-m, to average 0.27 mb/d.

For **2021**, Norway's liquids supply growth forecast has been revised down by 12 tb/d m-o-m due to lower-than-expected output in 4Q21, which saw a downward revision of 48 tb/d. Production is now expected to average 2.03 mb/d, with growth of 0.03 mb/d y-o-y.

For **2022**, Norwegian liquids production is expected to grow by 0.12 mb/d to average 2.16 mb/d, a downward revision of 0.01 mb/d from last month's assessment. It is worth noting that the second phase of the Johan Sverdrup facility is planned to start up in 4Q22. Thereby, oil production capacity of the field will increase by 0.22 mb/d to 0.76 mb/d at the peak.

Graph 5 - 16: Norway's monthly liquids production development



Sources: NPD and OPEC.

UK

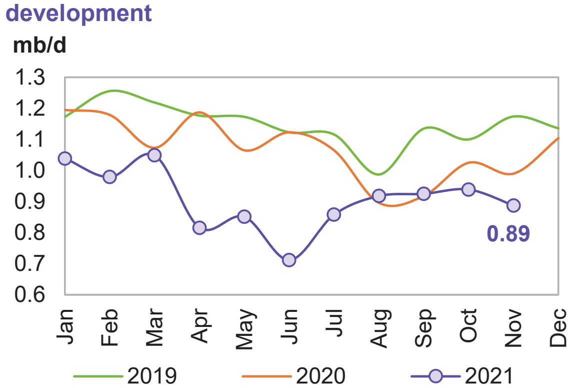
UK liquids production declined in November, by 52 tb/d m-om, to average 0.89 mb/d.

Crude oil output fell by 52 tb/d m-o-m to average 0.76 mb/d, according to official data, and was down by 91 tb/d y-o-y. NGL output held steady m-o-m in November, to average 93 tb/d.

For **2021**, UK liquids production is forecast to contract by 0.15 mb/d to average 0.91 mb/d.

For **2022**, UK liquids production is forecast to grow by a minor 0.01 mb/d to average 0.93 mb/d, following two consecutive years of heavy declines.

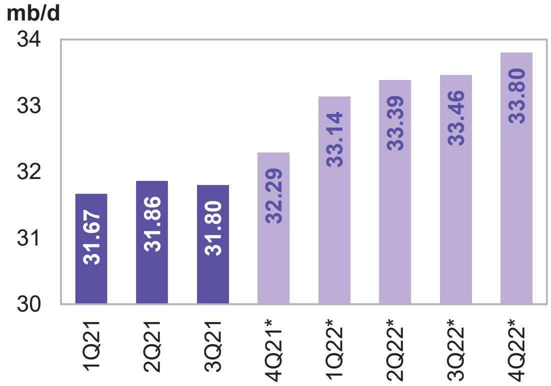
Graph 5 - 17: UK monthly liquids production development



Sources: Department of Energy & Climate Change and OPEC.

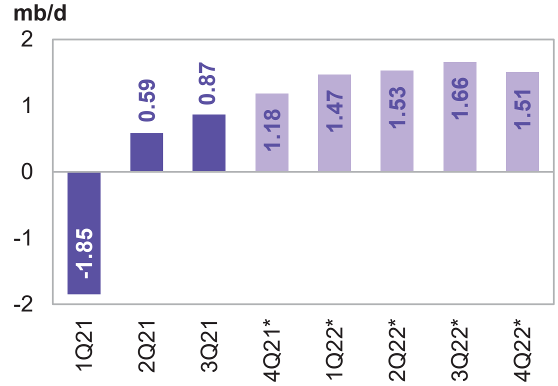
Non-OECD

Graph 5 - 18: Non-OECD quarterly liquids production and forecast



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

Graph 5 - 19: Non-OECD quarterly liquids supply, y-o-y changes

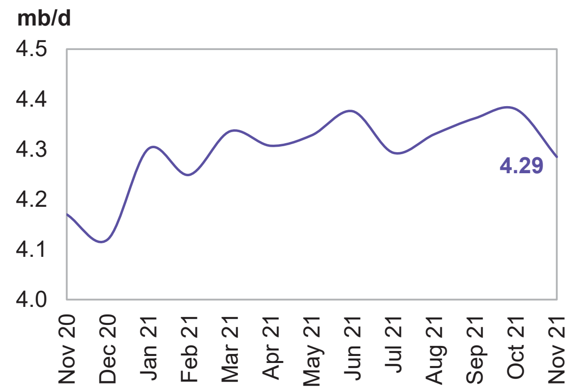


*Note: * 4Q21-4Q22 = Forecast. Source: OPEC.*

China

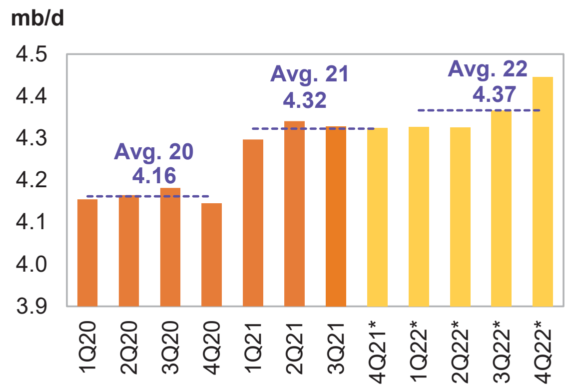
China's liquids production declined by 0.9 mb/d m-o-m in November to average 4.29 mb/d, but showed a y-o-y increase of 0.12 mb/d, according to official data. Crude oil output in November dropped up by 91 tb/d to average 3.97 mb/d and was higher by 85 tb/d y-o-y. Crude oil output in January-November averaged 4.0 mb/d, up by 117 tb/d from the same period in 2020.

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



Sources: CNPC and OPEC.

Graph 5 - 21: China's quarterly liquids production and forecast



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

For **2021**, China's liquids supply is projected to see growth of 0.16 mb/d to average 4.32 mb/d, unchanged from the previous assessment.

For **2022**, growth of 0.04 mb/d is anticipated for an average of 4.37 mb/d.

Latin America

Brazil

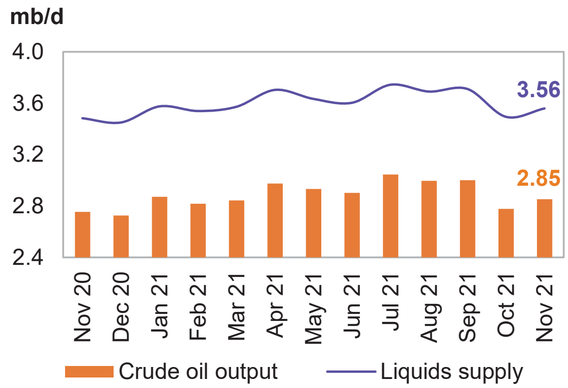
Brazil's crude output in November increased by 74 tb/d m-o-m to average 2.85 mb/d. NGLs declined by 9 tb/d to average 84 tb/d, and biofuel output remained steady at 623 tb/d. Therefore, in November, total liquids production rose by 65 tb/d to average 3.56 mb/d, which was higher by 76 tb/d y-o-y.

Average crude production in Brazil during January-November 2021 shows a decline of 48 tb/d compared with the same period in 2020, despite the production ramp-up in the Sepia and Buzios fields. This is far from the initial expected growth for 2021. Maintenance impacted crude production in 2021, and this is expected to continue until the end of 2021. Moreover, COVID-19-related health and safety measures at production platforms, delays in project start-ups and heavy natural declines at offshore mature fields, particularly in the Campos Basin, have also contributed to under-performance in production.

Hence, the initial liquids supply forecast for **2021** has been revised down by 21 tb/d m-o-m to average 3.62 m/d, a decline of 0.05 mb/d y-o-y, including non-crude, mainly biofuels.

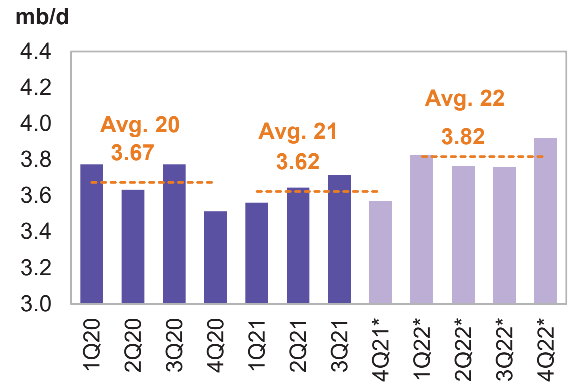
For **2022**, Brazil's liquids supply forecast, including biofuels, is forecast to increase by 0.19 mb/d y-o-y to average 3.82 mb/d, revised down by 0.02 mb/d. Crude oil production is expected to rise through two new project start-ups: Mero-1 (Guanabara), which was initially planned to start in 2021, and Peregrino-Phase 2. Moreover, in Buzios, a fifth unit, the Almirante Barroso FPSO — to be supplied by Japan's Modec — is due to begin operation in 2022.

Graph 5 - 22: Brazil's monthly liquids production development by type



Sources: ANP, Petrobras and OPEC.

Graph 5 - 23: Brazil's quarterly liquids production



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

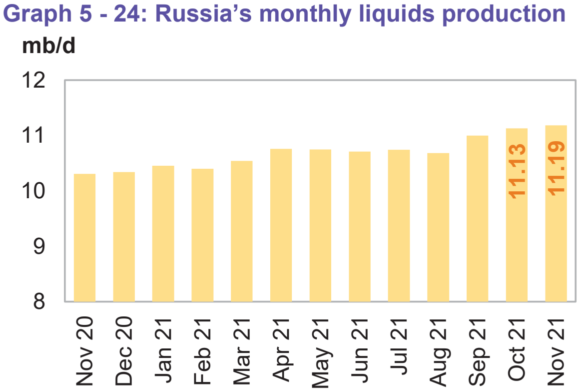
Russia

Russia's liquids production in November increased by 54 tb/d m-o-m to average 11.19 mb/d. This includes 9.96 mb/d of crude oil and 1.23 mb/d of condensate and NGLs. A preliminary estimate for Russia's crude and condensates production in December based on the Ministry of Energy's production data shows an increase of 0.01 mb/d m-o-m.

Annual liquids production in **2021** is forecast to increase by 0.21 mb/d y-o-y to average 10.80 mb/d, revised up marginally m-o-m.

For **2022**, Russian liquids output is expected to increase by 0.98 mb/d to average 11.78 mb/d, with 3Q22 and 4Q22 both expected to reach 11.88 mb/d, unchanged from the previous assessment.

Graph 5 - 24: Russia's monthly liquids production



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

Graph 5 - 25: Russia's quarterly liquids production

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

Caspian

Kazakhstan & Azerbaijan

Liquids output in Kazakhstan increased by 74 tb/d m-o-m to average 2.0 mb/d in **November**. Oil output from Tengiz, the country's largest oil field, averaged 0.6 mb/d prior to maintenance in August and September. Kazakh crude production inched up by 14 tb/d m-o-m in November to average 1.62 mb/d, the highest output since April 2020, and up by 0.2 mb/d y-o-y. At the same time, production of condensate and

NGLs was up by 60 tb/d m-o-m to average 381 tb/d in November. This was broadly in line with the 373 tb/d average seen in 1Q21.

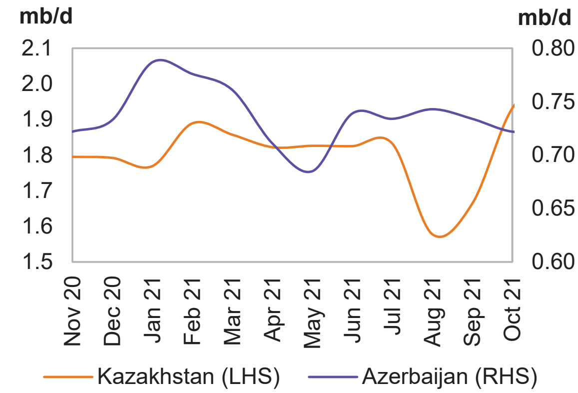
Kazakhstan's liquids supply estimate for **2021** was revised up by 10 tb/d from the previous assessment and is now estimated to average 1.83 mb/d, unchanged y-o-y, while for **2022**, liquids supply is forecast to grow by 0.15 mb/d to average 1.98 mb/d.

Azerbaijan's liquids production in November held steady at a m-o-m average of 0.72 mb/d and broadly unchanged y-o-y. Crude production inched up by a minor 2 tb/d m-o-m to average 584 tb/d as maintenance continued on the Chirag platform. Condensate output held steady at 140 tb/d, according to official sources.

Oil production is expected to increase in December to average 0.79 mb/d, following the completion of maintenance.

Azerbaijan's liquids supply is expected to show growth of 0.01 mb/d y-o-y to average 0.74 mb/d in **2021**, while for **2022**, growth of 0.08 mb/d y-o-y is anticipated for an average of 0.82 mb/d.

Graph 5 - 26: Caspian monthly liquids production development by selected country



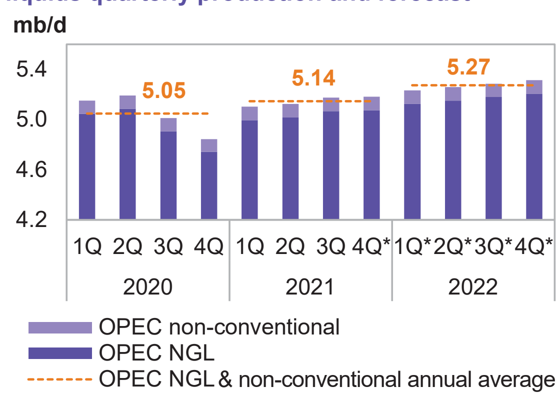
Sources: Nefte Compass and OPEC.

OPEC NGLs and non-conventional oils

OPEC NGLs and non-conventional liquids in 2021 are estimated to have grown by 0.10 mb/d, following a decline of 0.17 mb/d in 2020, to average 5.14 mb/d, unchanged from last month's assessment.

For **2022**, OPEC NGLs and non-conventional liquids production is expected to grow by 0.13 mb/d to average 5.27 mb/d.

Graph 5 - 27: OPEC NGLs and non-conventional liquids quarterly production and forecast



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

Table 5 - 6: 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*	**5.04**	*0.09*	5.12	5.15	5.18	5.20	**5.16**	*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***	**5.14**	***0.10***	**5.23**	**5.26**	**5.29**	**5.31**	**5.27**	***0.13***

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

OPEC crude oil production

According to secondary sources, total **OPEC-13 crude oil production** averaged 27.88 mb/d in December 2021, higher by 0.17 mb/d m-o-m. Crude oil output increased mainly in Angola, Saudi Arabia, Iraq and the UAE, while production in Libya and Nigeria declined.

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

Secondary sources	2020	2021	2Q21	3Q21	4Q21	Oct 21	Nov 21	Dec 21	*Change Dec/Nov*
Algeria	897	908	886	922	954	945	954	964	*10*
Angola	1,255	1,120	1,109	1,106	1,123	1,120	1,082	1,166	*85*
Congo	288	265	261	258	269	275	262	270	*7*
Equatorial Guinea	115	101	106	99	93	86	89	103	*14*
Gabon	195	186	186	186	186	177	185	196	*11*
IR Iran	1,988	2,404	2,440	2,479	2,476	2,480	2,470	2,478	*8*
Iraq	4,049	4,024	3,940	4,053	4,218	4,144	4,242	4,270	*28*
Kuwait	2,430	2,415	2,356	2,445	2,528	2,502	2,531	2,552	*21*
Libya	367	1,149	1,151	1,154	1,115	1,155	1,137	1,053	*-84*
Nigeria	1,579	1,381	1,424	1,349	1,342	1,308	1,381	1,338	*-43*
Saudi Arabia	9,182	9,090	8,502	9,536	9,856	9,766	9,871	9,932	*61*
UAE	2,802	2,718	2,644	2,762	2,853	2,829	2,852	2,880	*28*
Venezuela	500	554	513	538	652	614	661	681	*20*
Total OPEC	**25,648**	**26,315**	**25,520**	**26,885**	**27,665**	**27,400**	**27,715**	**27,882**	***166***

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

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

Direct communication	2020	2021	2Q21	3Q21	4Q21	Oct 21	Nov 21	Dec 21	*Change Dec/Nov*
Algeria	899	911	886	924	958	949	959	966	*7*
Angola	1,271	1,124	1,125	1,114	1,122	1,106	1,110	1,150	*40*
Congo	300	267	265	266	260	269	253	257	*4*
Equatorial Guinea	114	94	99	94	79	81	71	85	*14*
Gabon	207	181	179	180	183	171	188	189	*1*
IR Iran	..	..	..	..	..	..	..	..	*..*
Iraq	3,997	3,971	3,890	3,979	4,167	4,070	4,208	4,225	*17*
Kuwait	2,438	2,415	2,355	2,447	2,528	2,503	2,532	2,549	*17*
Libya	389	1,207	1,213	1,220	1,182	1,244	1,211	1,092	*-119*
Nigeria	1,493	1,312	1,343	1,270	1,233	1,228	1,275	1,197	*-78*
Saudi Arabia	9,213	9,125	8,535	9,565	9,905	9,780	9,912	10,022	*110*
UAE	2,779	2,718	2,645	2,758	2,854	2,833	2,852	2,878	*26*
Venezuela	569	636	556	635	817	756	824	871	*47*
Total OPEC	..	..	..	..	..	..	..	..	*..*

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

Commercial Stock Movements

Preliminary November data sees total OECD commercial oil stocks down by 16.0 mb m-o-m. At 2,721 mb, they were 389 mb lower than the same month in 2020, 247 mb lower than the latest five-year average and 221 mb below the 2015-2019 average. Within the components, crude and products stocks fell m-o-m by 12.7 mb and 3.3 mb, respectively.

At 1,317 mb, crude stocks in the OECD were 143 mb lower than the latest five-year average and 137 mb below the 2015-2019 average. OECD product stocks stood at 1,405 mb, representing a deficit of 104 mb compared with the latest five-year average and 84 mb below the 2015-2019 average.

In terms of days of forward cover, OECD commercial stocks fell m-o-m by 0.2 days in November to stand at 60.7 days. This is 13.2 days below November 2020 levels, 3.6 days less than the latest five-year average and 1.5 days lower than the 2015-2019 average.

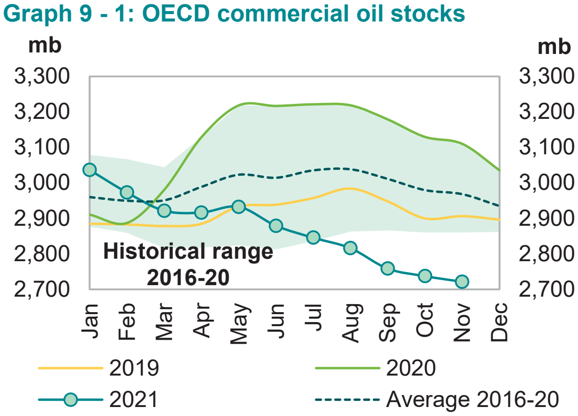
Preliminary data for December showed that total US commercial oil stocks fell m-o-m by 24.4 mb to stand at 1,195 mb. This is 148.6 mb lower than the same month a year earlier and 93.9 mb below the latest five-year average. Crude and product stocks fell m-o-m by 15.3 mb and 12.1 mb, respectively.

OECD

Preliminary November data sees **total OECD commercial oil stocks** down by 16.0 mb m-o-m. At 2,721 mb, they were 389 mb lower than the same time one year ago, 247 mb lower than the latest five-year average and 221 mb below the 2015-2019 average.

Within the components, crude and products stocks fell m-o-m by 12.7 mb and 3.3 mb, respectively. Total commercial oil stocks in November fell in OECD Americas and OECD Europe, while they rose slightly 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 November by 12.7 mb to stand at 1,317 mb. This is 185 mb lower than the same time a year ago and 143 mb below the latest five-year average. Compared with the previous month, OECD Americas saw a stock draw of 3.5 mb, OECD Europe fell by 12.0 mb, and OECD Asia Pacific had a stock build of 2.8 mb.

Total product inventories fell m-o-m in November by 3.3 mb to stand at 1,405 mb. This is 204 mb less than the same time a year ago, and 104 mb lower than the latest five-year average. Product stocks in OECD Asia Pacific and OECD Europe fell m-o-m by 2.7 mb and 3.0 mb, respectively, while OECD Americas rose by 2.4 mb.

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

OECD stocks	Nov 20	Sep 21	Oct 21	Nov 21	*Change* Nov 21/Oct 21
Crude oil	1,502	1,308	1,329	1,317	*-12.7*
Products	1,608	1,450	1,408	1,405	*-3.3*
Total	**3,110**	**2,758**	**2,737**	**2,721**	***-16.0***
Days of forward cover	**73.9**	**60.5**	**60.9**	**60.7**	***-0.2***

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 fell m-o-m by 0.2 days in November to stand at 60.7 days. This is 13.2 days below November 2020 levels, 3.6 days less than the latest five-year average and 1.5 days lower than the 2015-2019 average. All three OECD regions were below the latest five-year average: the Americas by 1.9 days at 62.6 days, Asia Pacific by 4.2 days at 45.0 days and Europe by 7.0 days at 66.3 days.

OECD Americas

OECD Americas total commercial stocks fell by 1.1 mb m-o-m in November to settle at 1,513 mb. This is 144 mb less than the same month in 2020 and 59 mb lower than the latest five-year average.

Commercial crude oil stocks in OECD Americas fell m-o-m by 3.5 mb in November to stand at 772 mb, which is 67 mb lower than in November 2020 and 24 mb less than the latest five-year average. The stock drawn came on the back of higher November crude runs.

In contrast, **total product stocks** in OECD Americas rose m-o-m by 2.4 mb in November to stand at 741 mb. This was 77 mb lower than the same month of the previous year and 35 mb below the latest five-year average. Lower total consumption in the region was behind the stock draw.

OECD Europe

OECD Europe total commercial stocks fell m-o-m by 14.9 mb in November to settle at 863 mb. This is 194 mb less than the same month in 2020 and 120 mb below the latest five-year average.

OECD Europe's **commercial crude stocks** in November fell m-o-m by 12.0 mb to end the month at 381 mb, which is 64 mb lower than one year ago and 48 mb below the latest five-year average. The fall in crude oil inventories came on the back of higher m-o-m refinery crude runs in the EU-14, plus the UK and Norway.

OECD Europe's **commercial product stocks also** fell m-o-m by 3.0 mb to end November at 481 mb. This is 131 mb lower than a year ago and 72 mb below the latest five-year average.

OECD Asia Pacific

OECD Asia Pacific's total commercial oil stocks rose m-o-m by 0.1 mb in November to stand at 346 mb. This is 50 mb lower than a year ago and 68 mb below the latest five-year average.

OECD Asia Pacific's **crude inventories** rose by 2.8 mb m-o-m to end November at 164 mb, which is 54 mb lower than one year ago and 71 mb below the latest five-year average.

In contrast, OECD Asia Pacific's **total product inventories** fell by 2.7 mb m-o-m to end November at 182 mb. This is 4.0 mb higher than the same time a year ago and 2.9 mb above the latest five-year average.

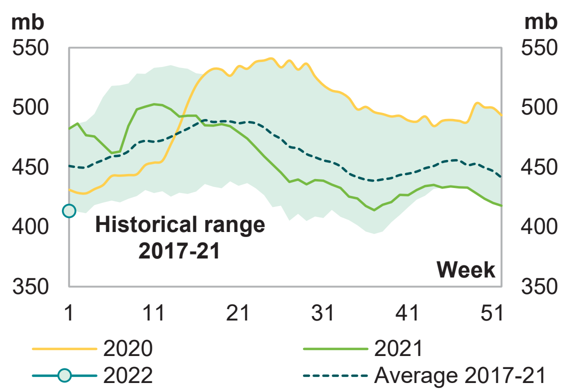
US

Preliminary data for December showed that **total US commercial oil stocks** fell m-o-m by 27.4 mb to stand at 1,195 mb. This is 148.6 mb, or 11.1%, lower than the same month in 2020 and 93.9 mb, or 7.3%, below the latest five-year average. Crude and product stocks fell m-o-m by 15.3 mb and 12.1 mb, respectively.

US **commercial crude stocks** in December fell m-o-m by 15.3 mb to stand at 417.9 mb. This is 67.6 mb, or 13.9%, lower than the same month of the previous year, and 35.6 mb, or 7.8%, below the latest five-year average. The stock draw came on the back of higher crude runs.

Total product stocks in December fell m-o-m by 12.1 mb to stand at 776.9 mb. This is 81.0 mb, or 9.4%, below December 2020 levels, and 58.3 mb, or 7.0%, lower than the latest five-year average. The stock draw was mainly driven by higher overall US consumption.

Graph 9 - 2: US weekly commercial crude oil inventories



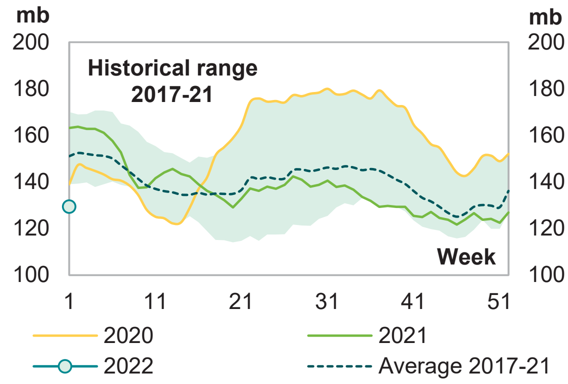
Sources: EIA and OPEC.

Gasoline stocks in December, however, rose m-o-m by 17.4 mb to settle at 232.8 mb. This is 10.6 mb, or 4.4%, below the same month in 2020, and 11.1 mb, or 4.5%, lower than the latest five-year average. The monthly stock build came mainly on the back of lower gasoline consumption, which dropped considerably in the last week of the month.

Distillate stocks also rose m-o-m in December by 3.0 mb to stand at 126.8 mb. This is 34.3 mb, or 21.3%, lower than the same month of the previous year, and 23.8 mb, or 15.8%, below the latest five-year average.

In contrast, **jet fuel stocks** fell m-o-m by 1.1 mb, ending December at 35.0 mb. This is 3.7 mb, or 9.5%, lower than the same month of the previous year, and 6.0 mb, or 14.7%, below the latest five-year average.

Graph 9 - 3: US weekly distillate inventories



Sources: EIA and OPEC.

Residual fuel oil stocks also fell m-o-m in December, decreasing by 2.0 mb. At 25.9 mb, this was 4.3 mb, or 14.1%, lower than a year earlier, and 6.1 mb, or 18.9%, below the latest five-year average.

Table 9 - 2: US commercial petroleum stocks, mb

US stocks	Dec 20	Oct 21	Nov 21	Dec 21	*Change* Dec 21/Nov 21
Crude oil	**485.5**	**436.6**	**433.1**	**417.9**	***-15.3***
Gasoline	243.4	216.7	215.4	232.8	*17.4*
Distillate fuel	161.2	132.6	123.9	126.8	*3.0*
Residual fuel oil	30.2	28.4	27.9	25.9	*-2.0*
Jet fuel	38.6	40.3	36.1	35.0	*-1.1*
Total products	**857.9**	**810.8**	**789.0**	**776.9**	***-12.1***
Total	**1,343.3**	**1,247.4**	**1,222.2**	**1,194.8**	***-27.4***
SPR	**638.1**	**610.6**	**602.6**	**593.7**	***-8.9***

Sources: EIA and OPEC.

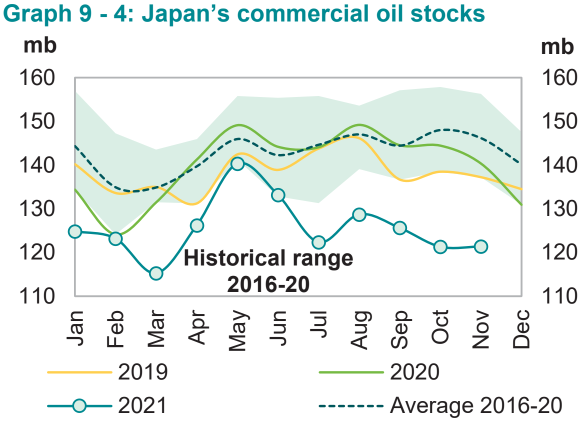
Japan

In **Japan**, **total commercial oil stocks** in November rose slightly m-o-m by 0.1 mb to settle at 121.4 mb. This is 19.0 mb, or 13.5%, lower than the same month in 2020, and 24.8 mb, or 17.0%, below the latest five-year average. Crude stocks rose by 2.8 mb, while products stocks fell m-o-m by 2.7 mb.

Japanese **commercial crude oil stocks** rose in November to stand at 58.7 mb. This is 13.7 mb, or 18.9%, below the same month of the previous year, and 21.7 mb, or 27.0%, lower than the latest five-year average. The build came on the back of lower crude runs, which decreased by 0.2%.

In contrast, Japan's **total product inventories** fell m-o-m by 2.7 mb to end November at 62.7 mb. This is 5.3 mb, or 7.8%, lower than the same month in 2020, and 3.1 mb, or 4.7%, below the latest five-year average.

Graph 9 - 4: Japan's commercial oil stocks



Sources: METI and OPEC.

Gasoline stocks fell m-o-m by 1.2 mb to stand at 10.5 mb. This was 2.1 mb, or 17.0%, lower than a year earlier, and 0.5 mb, or 4.3%, below the latest five-year average. Higher exports, which rose by 23.4%, were behind the gasoline stock draw.

Total residual fuel oil stocks fell m-o-m by 0.4 mb to end November at 11.7 mb. This is 0.7 mb, or 5.6%, lower than in the same month of the previous year, and 1.7 mb, or 12.4%, below the latest five-year average. Within the components, fuel oil A stocks rose by 2.7%, while fuel oil B.C stocks fell by 56.8%.

In contrast, **distillate stocks** rose m-o-m by 0.2 mb to end November at 32.1 mb. This is 1.5 mb, or 4.6%, lower than the same month in 2020, and 0.1 mb, or 0.2%, below the latest five-year average. Within the distillate components, **jet fuel and kerosene** rose m-o-m by 3.1% and 1.8%, respectively, while **gasoil** stocks fell by 2.3%.

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

Japan's stocks	Nov 20	Sep 21	Oct 21	Nov 21	*Change* Nov 21/Oct 21
Crude oil	**72.4**	**62.0**	**55.9**	**58.7**	***2.8***
Gasoline	12.6	10.3	11.7	10.5	*-1.2*
Naphtha	9.4	9.4	9.8	8.5	*-1.4*
Middle distillates	33.6	31.4	31.9	32.1	*0.2*
Residual fuel oil	12.4	12.5	12.0	11.7	*-0.4*
Total products	**68.0**	**63.6**	**65.4**	**62.7**	***-2.7***
Total**	**140.4**	**125.6**	**121.3**	**121.4**	***0.1***

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

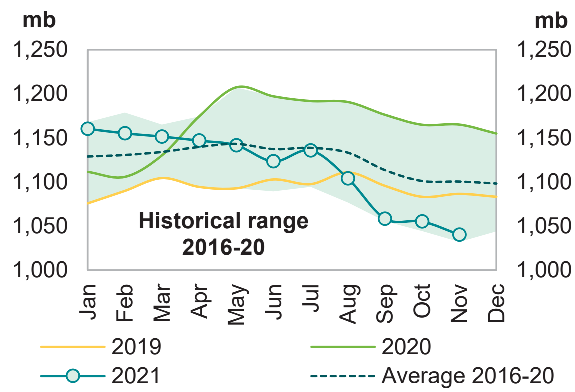
Sources: METI and OPEC.

EU-14 plus UK and Norway

Preliminary data for November showed that **total European commercial oil stocks** fell m-o-m by 14.9 mb to stand at 1,040.3 mb. At this level, they were 124.8 mb, or 10.7%, below the same month a year earlier, and 60.4 mb, or 5.5%, lower than the latest five-year average. Crude and product stocks fell m-o-m by 12.0 mb and 3.0 mb, respectively.

European **crude inventories** fell in November to stand at 426.8 mb. This is 56.0 mb, or 11.6%, lower than the same month in 2020 and 52.0 mb, or 10.9%, lower than the latest five-year average. The fall in crude oil inventories came on the back of higher m-o-m refinery throughputs in the EU-14, plus the UK and Norway, which rose by around 280 tb/d to 9.62 mb/d in November.

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



Sources: Argus, Euroilstock and OPEC.

Total European product stocks fell m-o-m by 3.0 mb to end November at 613.5 mb. This is 68.8 mb, or 10.1%, lower than the same month of the previous year, and 8.4 mb, or 1.4%, below the latest five-year average.

Gasoline stocks fell m-o-m by 4.7 mb in November to stand at 104.0 mb. At this level, they were 19.2 mb, or 15.6%, lower than the same time a year earlier and 10.4 mb/d, or 9.1%, less than the latest five-year average.

Residual fuel stocks also fell m-o-m by 0.6 mb in November to 62.0 mb. This is 3.4 mb, or 5.2%, lower than the same month in 2020, and 3.6 mb, or 5.5%, below the latest five-year average.

Naphtha stocks fell by 0.3 mb in November, ending the month at 25.1 mb. This is 6.3 mb, or 20.1%, below November 2020 levels, and 2.1 mb, or 7.7%, below the latest five-year average.

In contrast, **distillate stocks** increased m-o-m by 2.5 mb in November to stand at 422.4 mb. This is 40.0 mb, or 8.6%, below the same month in 2020, but 7.6 mb, or 1.8%, above the latest five-year average.

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

EU stocks	Nov 20	Sep 21	Oct 21	Nov 21	*Change Nov 21/Oct 21*
Crude oil	**482.8**	**441.4**	**438.8**	**426.8**	***-12.0***
Gasoline	123.1	99.9	108.6	104.0	*-4.7*
Naphtha	31.4	26.2	25.3	25.1	*-0.3*
Middle distillates	462.4	428.3	419.9	422.4	*2.5*
Fuel oils	65.4	62.6	62.6	62.0	*-0.6*
Total products	**682.3**	**617.0**	**616.4**	**613.5**	***-3.0***
Total	**1,165.1**	**1,058.4**	**1,055.2**	**1,040.3**	***-14.9***

Sources: Argus, Euroilstock and OPEC.

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

Singapore

In November, **total product stocks in Singapore** fell m-o-m by 2.7 mb to 40.4 mb. This is 12.9 mb, or 24.2%, lower than the same month in 2020.

Light distillate stocks rose m-o-m by 1.1 mb in November to stand at 12.1 mb. This is 0.2 mb, or 1.7%, lower than the same month of the previous year.

In contrast, **middle distillate stocks** fell m-o-m by 1.9 mb in November to stand at 8.1 mb. This is 7.7 mb, or 48.7%, lower than a year earlier.

Residual fuel oil stocks also fell m-o-m by 1.9 mb, ending November at 20.3 mb, which is 5.0 mb, or 19.8%, lower than in November 2020.

ARA

Total product stocks in ARA fell for the ninth consecutive month in November, down by 1.0 mb m-o-m to 37.1 mb. This is 11.5 mb, or 23.7%, lower than the same month in 2020.

Gasoline stocks in November fell m-o-m by 0.3 mb to stand at 7.2 mb, which is 3.9 mb, or 35.0%, lower than the same month of the previous year.

Gasoil stocks also fell by 1.7 mb to end November at 13.3 mb. This is 5.1 mb, or 27.7%, lower than the level seen in November 2020.

Jet oil stocks fell m-o-m by 0.6 mb to end November at 6.4 mb. This is 1.1 mb, or 15.2%, below the level registered one year earlier.

In contrast**, fuel oil stocks** rose m-o-m by 1.4 mb in November to stand at 7.9 mb, which is 0.9 mb, or 10.5%, lower than in November 2020.

Fujairah

During the week ending 3 January 2022, **total oil product stocks in Fujairah** rose w-o-w by 0.53 mb to stand at 16.52 mb, according to data from Fed Com and S&P Global Platts. At this level, total oil stocks were 6.85 mb lower than the same time a year ago. While middle distillates witnessed a stock draw w-o-w, light and heavy distillate stocks saw a stock build.

Light distillate stocks rose by 0.41 mb w-o-w to stand at 4.75 mb in the week to 3 January 2022, which is 2.55 mb lower than the same period a year ago. **Heavy distillate stocks** increased by 0.61 mb to stand at 10.12 mb, which is 1.48 mb lower than the same time last year. In contrast, **middle distillate stocks** fell by 0.49 mb to stand at 1.65 mb, which is 2.82 mb lower than a year ago.

Balance of Supply and Demand

Demand for OPEC crude in 2021 remained unchanged from the previous MOMR to stand at 27.8 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, 1.1 mb/d lower than demand for OPEC crude in the same period. In 2Q21, OPEC crude production averaged 25.5 mb/d, which was 1.5 mb/d lower than demand for OPEC crude. In 3Q21, OPEC crude oil production averaged 26.9 mb/d, 1.7 mb/d lower than demand for OPEC crude.

Demand for OPEC crude in 2022 remained also unchanged from the previous month to stand at 28.9 mb/d, around 1.0 mb/d higher than in 2021.

Balance of supply and demand in 2021

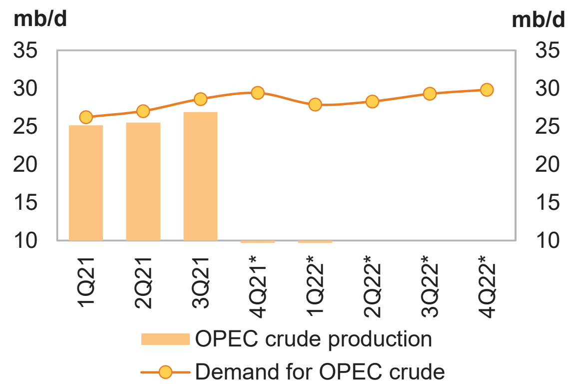
Demand for OPEC crude in 2021 remained unchanged from the previous MOMR to stand at 27.8 mb/d, around 4.9 mb/d higher than in 2020.

Compared with the previous assessment, 1Q21 and 2Q21 remained unchanged, while 3Q21 was revised down by 0.2 mb/d. Meanwhile, 4Q21 was revised up by 0.3 mb/d.

When compared with the same quarters in 2020, demand for OPEC crude in 1Q21 and 2Q21 were higher by 3.8 mb/d and 9.6 mb/d, respectively. 3Q21 and 4Q21 are estimated to show an increase of 3.7 mb/d and 2.3 mb/d, respectively.

According to secondary sources, OPEC crude production averaged 25.2 mb/d in 1Q21, 1.1 mb/d lower than demand for OPEC crude in the same period. In 2Q21, OPEC crude production averaged 25.5 mb/d, which was 1.5 mb/d lower than demand for OPEC crude. In 3Q21, OPEC crude oil production averaged 26.9 mb/d, 1.7 mb/d lower than demand for OPEC crude.

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



*Note: * 4Q21-4Q22 = 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	**90.98**	**93.83**	**95.43**	**97.41**	**99.75**	**96.63**	***5.66***
Non-OPEC liquids production	62.97	62.51	63.28	63.62	65.15	63.65	*0.67*
OPEC NGL and non-conventionals	5.05	5.10	5.12	5.17	5.18	5.14	*0.10*
(b) Total non-OPEC liquids production and OPEC NGLs	**68.02**	**67.61**	**68.40**	**68.79**	**70.34**	**68.79**	***0.77***
Difference (a-b)	**22.96**	**26.22**	**27.03**	**28.62**	**29.42**	**27.84**	***4.88***
OPEC crude oil production	**25.65**	**25.15**	**25.52**	**26.88**			
Balance	**2.69**	**-1.06**	**-1.51**	**-1.74**			

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

https://www.iea.org/reports/oil-market-report-january-2022?mode=overview

Oil Market Report - January 2022

Report extract

Overview

Highlights

- While the number of Omicron cases is surging worldwide, oil demand defied expectations in 4Q21, rising by 1.1 mb/d to 99 mb/d. In 1Q22, demand is set for a seasonal decline, exacerbated by more teleworking and less air travel. We have raised our global demand estimates by 200 kb/d for 2021 and 2022 – resulting in growth of 5.5 mb/d and 3.3 mb/d, respectively – due to softer Covid restrictions.

- World oil supply in 2022 has the potential for a Saudi-driven gain of 6.2 mb/d if OPEC+ fully unwinds its cuts. Oil output from OPEC+ could rise this year by 4.4 mb/d, resulting in reduced effective spare capacity in 2H22 of 2.6 mb/d, held primarily by Saudi Arabia and the United Arab Emirates. Non-OPEC+ growth of 1.8 mb/d in 2022 will be led by the United States.

- The global refining industry ended 2021 on a high note, with both runs and margins improving. Refinery throughputs averaged 79.8 mb/d in 4Q21, up 4.6 mb/d on a year ago. In 2021, global refining capacity fell for the first time in 30 years, by 730 kb/d, as new capacity was outweight by closures. In 2022, net additions are expected to amount to 1.2 mb/d, with runs forecast to gain 3.7 mb/d.

- OECD total industry stocks declined by 6.1 mb in November, as rising crude and gasoline stocks were more than offset by draws in other products. At 2 756 mb, stocks were down 354 mb on a year ago and at their lowest level in seven years. Preliminary data for December show OECD industry stocks falling by another 45 mb while volumes of oil on the water rose.

- Crude prices struggled under demand uncertainties in December before a vigorous post-holiday rebound. North Sea Dated rose from an average $74.01/bbl last month to $87.30/bbl on 18 January, its highest level since 2014. ICE Brent backwardation doubled, reflecting tight oil stocks.

IEA World Oil Supply and Demand Forecasts: Summary (Table)
2022-01-19 09:00:00.3 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	100.8	100.9	99.3	97.8	99.0	97.8	95.4	93.3	99.7	96.4
Total OECD	46.7	46.9	45.8	45.3	46.1	45.7	44.0	42.3	46.2	44.5
Americas	25.1	25.5	25.1	24.2	24.7	24.7	24.3	22.7	25.0	24.1
Europe	13.7	14.0	13.5	13.1	13.7	13.8	12.6	11.9	13.6	13.0
Asia Oceania	7.9	7.4	7.2	7.9	7.7	7.1	7.0	7.7	7.6	7.4
Non-OECD countries	54.1	54.0	53.5	52.6	52.8	52.1	51.4	51.0	53.5	51.8
FSU	5.1	5.1	4.8	4.7	5.0	4.9	4.7	4.6	4.9	4.8
Europe	0.8	0.8	0.8	0.7	0.8	0.8	0.7	0.7	0.8	0.8
China	15.8	15.8	15.8	15.2	15.4	15.3	15.3	14.6	15.6	15.2
Other Asia	14.2	13.5	14.0	14.1	13.8	12.5	12.8	13.5	13.9	13.2
Americas	6.1	6.2	6.0	5.9	6.1	6.2	5.8	5.8	6.0	6.0
Middle East	8.0	8.5	8.0	7.9	7.8	8.4	8.0	7.7	8.1	8.0
Africa	4.2	4.0	4.1	4.1	4.0	3.9	4.0	4.1	4.1	4.0
	Supply									
Total Supply	n/a	n/a	n/a	n/a	98.2	96.4	94.1	92.3	n/a	95.3
Non-OPEC	67.3	67.1	66.3	65.4	65.3	64.3	63.5	61.9	66.5	63.7
Total OECD	30.0	29.6	29.3	29.4	29.4	28.3	27.8	27.4	29.6	28.2
Americas	26.0	25.7	25.4	25.3	25.4	24.3	24.2	23.3	25.6	24.3
Europe	3.5	3.4	3.4	3.5	3.4	3.4	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	31.9	31.7	31.5	31.3	30.9	30.5	30.5	30.2	31.6	30.5
FSU	14.8	14.6	14.5	14.4	14.3	13.7	13.7	13.4	14.6	13.8
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	2.7	2.8	2.8	2.8	2.8	2.8	2.9	3.0	2.8	2.9
Americas	5.6	5.6	5.5	5.4	5.2	5.4	5.3	5.3	5.5	5.3
Middle East	3.3	3.3	3.2	3.2	3.1	3.1	3.1	3.1	3.2	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	33.0	32.1	30.7	30.4	n/a	31.6
Crude	n/a	n/a	n/a	n/a	27.7	26.9	25.5	25.3	n/a	26.4
Natural gas liquids NGLs	5.4	5.4	5.4	5.3	5.2	5.2	5.2	5.1	5.4	5.2
Call on OPEC crude and stock change *	28.0	28.3	27.6	27.1	28.5	28.3	26.7	26.3	27.8	27.5

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: December Crude Oil Production in OPEC Countries (Table)
2022-01-19 09:00:00.2 GMT

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

	Dec. 2021	Nov. 2021	Dec. MoM
Total OPEC	27.99	27.80	0.19
Total OPEC10	23.64	23.41	0.23
Algeria	0.97	0.96	0.01
Angola	1.15	1.11	0.04
Congo	0.28	0.26	0.02
Equatorial Guinea	0.10	0.07	0.03
Gabon	0.21	0.19	0.02
Iraq	4.28	4.25	0.03
Kuwait	2.55	2.53	0.02
Nigeria	1.21	1.29	-0.08
Saudi Arabia	10.01	9.89	0.12
UAE	2.88	2.86	0.02
Iran	2.50	2.47	0.03
Libya	1.05	1.14	-0.09
Venezuela	0.80	0.78	0.02

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: Oil Demand Defies Omicron, Balance Gets Tighter
2022-01-19 09:14:40.7 GMT

By Stephen Voss
(Bloomberg) -- Summary including stories from IEA's monthly
Oil Market Report on Wednesday:
* IEA sees tighter oil market as demand withstands omicron wave
** Oil demand estimates slightly raised for both 2021, 2022
** Demand defied expectations with 4Q gain despite virus
* Click here for summary of key IEA supply/demand forecasts
* OPEC output rose 190k b/d in December, led by Saudi gains: IEA
** OPEC-10 stayed below target due to Nigeria, Angola
undersupply
** See full table
* Compliance with pledged target cutbacks in December:
** OPEC 128%; non-OPEC 110%; combined OPEC+ 19 nations 121%
** Saudi Arabia 101%, Russia 107%
* Russia may struggle to bring crude-only output to 11m b/d
* China's slowing refinery run growth may benefit India

* Supply growth to come from U.S., Saudis, Russia in 2022
* U.S. to lead non-OPEC+ oil supply growth this year
* Jet fuel demand growth in OECD Europe to speed up after 1Q
* Global oil inventories plunge below pre-pandemic levels
* Refiners may struggle to sustain gains in margins
* TABLE: IEA's quarterly supply/demand forecasts
* NOTE: OPEC issued its own monthly report Jan. 18, saying demand remains robust
* NOTE: The OPEC+ alliance is continuing with its plan to revive oil output halted during the pandemic, in monthly increments, with the next tranche coming in February

--With assistance from Alex Longley, Rachel Graham, Olga Tanas, Dina Khrennikova, Sherry Su, John Deane, Kristian Siedenburg, Amanda Jordan, Brian Wingfield and Grant Smith.

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IEA Sees Tighter Oil Market as Demand Withstands Omicron Wave
2022-01-19 09:00:00.29 GMT

By Grant Smith
(Bloomberg) -- Global oil markets look tighter than previously thought as demand suffers surprisingly little impact from the latest coronavirus strain while supplies are curbed by disruptions, the International Energy Agency said.
The surplus facing world markets this year is shrinking, with oil demand -- slightly upgraded from last month -- on track to hit pre-pandemic levels of 99.7 million barrels a day, the IEA said in its monthly report. At the same time, supplies have been restricted as the OPEC+ coalition struggles to revive halted output and producers elsewhere suffer a range of disruptions, thinning the margin of spare capacity.
The more bullish outlook from the Paris-based agency comes just hours after crude prices climbed to a seven-year high above $89 a barrel in London. The rally is proving a challenge for consuming nations and central banks as they try to stimulate the economic recovery while fending off an inflationary spike and cost-of-living crisis.
The IEA, which advises most major economies, raised projections for global oil demand by 200,000 barrels a day for both 2021 and 2022. Consumption will increase by 5.5 million barrels a day and 3.3 barrels million a day, respectively.
"Covid-19 is once again causing record infections. But this time around, the surge is having a more muted impact on oil

use," the IEA said.
As demand recovers, the supply situation grows more tenuous. The 23-nation OPEC+ coalition led by Saudi Arabia and Russia, which has been restoring production halted during the pandemic, managed only 60% of its planned increase in December, the agency said. Nigeria, Angola, Malaysia and even Russia are struggling with capacity constraints.
As OPEC+ tries to restore its remaining offline output, the coalition's spare production capacity -- a shock absorber in case of disruptions -- could diminish to 3 million barrels a day, from about 5 million a day currently, the IEA said. That could leave the market vulnerable to price volatility, even as output grows sharply in the U.S., Canada and Brazil, it said.
READ: Dwindling OPEC+ Spare Capacity Sets Oil Up for Sizzling Summer
The cartel's outages intensified on Tuesday, as a crucial pipeline from Iraq to Turkey was briefly halted by an explosion -- a reminder of how critical spare production capacity can be to maintaining steady oil flows.
Other sources of cover in emergencies are also reduced, with fuel inventories in developed nations sinking by 6.1 million barrels in November to a seven-year low, the agency said.

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IEA World Oil Supply/Demand Key Forecasts
2022-01-19 09:00:00.5 GMT

By Kristian Siedenburg
(Bloomberg) -- World oil demand 2022 fcast was revised to 99.7m b/d from 99.5m b/d in Paris-based Intl Energy Agency's latest monthly report.
* 2021 world demand was revised to 96.4 from 96.2m b/d
* Demand change in 2022 est. 3.4% y/y or 3.3m b/d
* Non-OPEC supply 2022 was revised to 66.5m b/d from 66.7m b/d
* Call on OPEC crude 2022 was revised to 27.8m b/d from 27.5m b/d
* Call on OPEC crude 2021 was revised to 27.5 m b/d from 27.3m b/d
** OPEC crude production in Dec. rose by 190k b/d on the month to 27.99m b/d
* Detailed table: FIFW NSN R5Y35AGQD79C <GO>
* NOTE: Fcasts based off IEA's table providing one decimal point

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OPEC Output Rose 190k B/D in December, Led by Saudi Gains: IEA
2022-01-19 09:00:00.6 GMT

By Amanda Jordan
(Bloomberg) -- OPEC's December crude production increased by 190k b/d from a month earlier to 27.99m b/d, the IEA said in its monthly report.
* Saudi Arabia produced 10.01m b/d, up 120k b/d, just below its quota
** The kingdom's crude output this year could rise to an annual record of 10.7m b/d, reducing spare capacity
* Iraqi supply rose by 30k b/d to 4.28m b/d, above its quota
* Elsewhere in the Gulf, Kuwaiti output edged up to 2.55m b/d; UAE production rose slightly to 2.88m b/d; Iranian supply, exempt from cuts, inched up to 2.5m b/d
* Nigerian production fell 80k b/d to 1.21m b/d amid force majeure on some exports; Angolan output expanded 40k b/d to 1.15m b/d
* Libya, exempt from cuts, posted the biggest decline, losing 90k b/d to 1.05m b/d, after a blockade by armed groups shut fields and disrupted exports
* Venezuela pumped 800k b/d, up 20k b/d
* OPEC's compliance with the OPEC+ output-cuts deal was 128% in December

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Russia May Struggle to Bring Crude-Only Output to 11m B/d: IEA
2022-01-19 09:00:00.19 GMT

By Olga Tanas and Dina Khrennikova
(Bloomberg) -- "Market consensus is that Russia will struggle to reach its OPEC+ crude oil target of 11m b/d given its previous pre-pandemic best was 10.6m b/d," the IEA said in its monthly report.

* Last year Russia pumped 260k b/d above prior year levels,
bringing total oil output, including condensate, to 10.9m b/d
** Output gains could more than double in 2022, “provided
there’s a full phase-out”
*** “That would push Russia close to an all-time high in 2022
but will require more capital, potential easing of fiscal terms
and front loaded drilling schedules”
* Russia’s crude-only December production eased 10k b/d to 9.95m
b/d vs nation’s quota of 10.02m b/d,
* NOTE: Total crude and condensate production reached 10.903m
b/d last month, according to Bloomberg calculations based on
data from the Russian Energy Ministry’s CDU-TEK unit
** CDU-TEK doesn’t provide a breakdown between crude and
condensate, which is excluded from the OPEC+ agreement
* Russia’s December compliance with the OPEC+ deal was at 107%
** “A sharp decline at Rosneft’s fields, the country’s largest
producer, was the main factor behind the dip in December that
saw Russia pump below quota for the first time since record
OPEC+ cuts were enforced in May 2020”
* IEA estimates Russia’s spare capacity at 280k b/d vs December
* The nation is expected to pump virtually flat out from May
onwards
* IEA expects Russian oil demand to increase by 110k b/d this
year to 3.8m b/d and exceed pre-pandemic levels by 200k b/d
* READ (Jan. 18): Russia Seen Struggling to Keep Pace With OPEC+
Supply Hikes

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China’s Slowing Oil Refinery Run Growth May Benefit India: IEA
2022-01-19 09:00:00.30 GMT

By Rachel Graham
(Bloomberg) -- Growth in China’s refinery runs will slow
this year, potentially benefiting other refiners in Asia such as
India, the IEA said in its monthly Oil Market Report.
* Growth in China’s throughput is forecast to drop to under 300k
b/d in 2022, vs avg of 630k b/d in recent years
* “Lower Chinese throughput growth and a reduction in transport
fuels exports, if combined with a steady demand recovery, will
provide a boost to Asian refiners that have been exposed to

intense competition from China for several years"
* India, which has structural excess of refining capacity, is possibly already benefiting from China's slowdown
* November runs in India surged by 300k b/d to 5.2m, up almost 1m b/d from a low point in August. Overall, in 2021, Indian refining activity increased more than demand

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Oil Supply Growth to Come From U.S., Saudis, Russia in 2022
2022-01-19 09:00:00.7 GMT

By Alex Longley
(Bloomberg) -- "The global oil supply growth story this year looks markedly different from 2021," the IEA said in its monthly oil market report.
* The world's big three producers -- the U.S., Saudi Arabia and Russia -- are looking at volumes at or near annual records
* Canada and Brazil will also be aiming for record levels
* Last year's growth was led by Libya and Iran, while Nigeria the U.K. and Angola posted the biggest losses
* If OPEC+ cuts get fully unwound, global oil supply could soar by 6.2m b/d this year, up from an increase 1.5m b/d in 2021

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U.S. to Lead Non-OPEC+ Oil Supply Growth This Year, IEA Says
2022-01-19 09:00:00.31 GMT

By Brian Wingfield
(Bloomberg) -- Oil supply in non-OPEC+ countries is set to grow by 1.8m b/d this year, led by production in the U.S., the IEA said in its monthly Oil Market Report.
* U.S. oil supplies to rise by 1m b/d y/y in 2022
** "A strong market in 2021 encouraged U.S. energy firms to boost activity, return capital to shareholders, and pay down debt"; these trends should continue this year
** The nation's total liquids production was 17.8m b/d in December
* U.S., Canada and Brazil combined "will account for 75% of non-OPEC+ gains in 2022"

* This year, the world's big three producers -- the U.S., Saudi Arabia and Russia -- are "eyeing volumes at or near annual records"

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Jet Demand Growth in OECD Europe to Accelerate After 1Q22: IEA
2022-01-19 09:00:00.11 GMT

By Sherry Su
(Bloomberg) -- Demand for jet fuel and kerosene in OECD Europe is expected to grow by 300k b/d this year, despite a slow recovery in 1Q due to the omicron variant of Covid-19, the IEA said its monthly Oil Market Report.
* "The omicron variant is expected to slow the ongoing recovery in jet/kerosene demand during 1Q22, but growth should gather pace in 2Q22 and return to close to the five-year average throughout the remainder of the year," the IEA said
* Overall OECD Europe demand growth is pegged at 590k b/d in 2021 and forecast to rise by a further 560k b/d in 2022
* IEA expects some renewed growth from fuel switching in Europe after recent slowdown, concentrated in other gasoil excluding diesel and fuel oil, in December and January as gas prices remained volatile through end-2021, spiking in late-December
* Naphtha demand in Europe has been particularly strong in recent months, reflecting the general strength of petrochemical demand, and the very competitive naphtha costs versus LPG as a feedstock for olefins production
** With prices re-balancing, this margin advantage began to fade late in the year, suggesting that naphtha demand will begin to soften in 2022, IEA said

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Global Oil Inventories Plunge to Below Pandemic Levels, IEA Says
2022-01-19 09:00:00.20 GMT

By Rachel Graham

(Bloomberg) -- Global observed oil inventories plunged last
year, more than reversing the build in 2020, the IEA said in its
monthly Oil Market Report.
* At about 7.4b bbl, oil stocks at end-December 2021 were just
over 1b bbl lower than their peak in May 2020 peak and well
below pre-pandemic levels
* The draw was a “massive” 1.66m b/d on average in 2021,
preliminary data show
* The changes were mostly reflected in OECD industry and
government stocks
* Stock changes don’t fully correspond with the IEA’s supply and
demand estimates, suggesting supply could be overstated and
demand understated

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Oil Refiners May Struggle to Sustain Gains in Margins, IEA Says
2022-01-19 09:00:00.21 GMT

By Rachel Graham
(Bloomberg) -- Global refinery runs are set to rise this
year, which could cap recent increases in margins, the IEA said
in its monthly report.
* “Product markets may switch to a product stock-build mode,
possibly leading to an unwinding of some of the refinery margin
gains from late last year”
* Crude throughput is forecast at 81.2m b/d in 2022, up 3.7m
from last year
** About 1.2m b/d of new capacity due to start operating in 2022
* A drop in capacity last year had helped to push refining
margins in Singapore and Europe to multiyear highs
* Last year, almost 1.6m b/d of capacity shut, while 850k b/d
came online, marking the first net decline in global capacity
for years
* Some of the closed capacity was for conversion to biofuels
production

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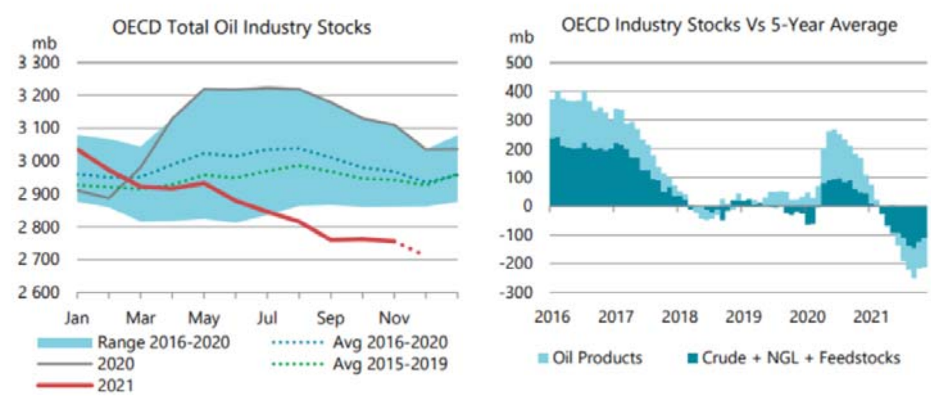
Apparent IEA OMR Jan graphics on twitter this morning

From Bloomberg's Javier Blas

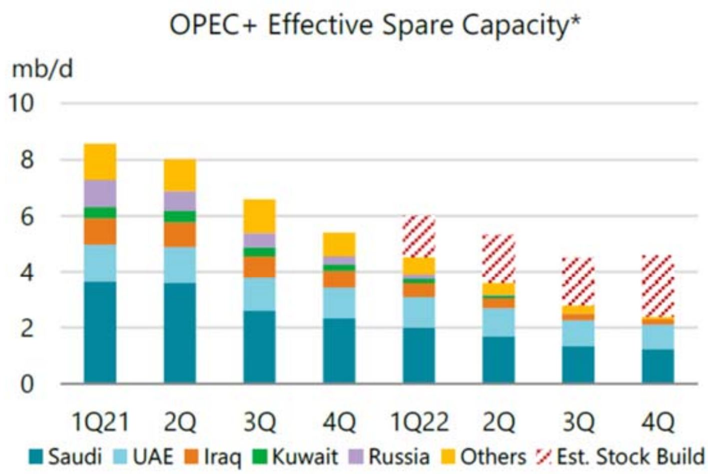
Javier Blas @JavierBlas · 3h

OIL MARKET: @IEA turning bullish, flagging OECD oil inventories hit a 7-year low in Nov. "If demand continues to grow strongly or supply disappoints, the low level of stocks and shrinking spare capacity mean that oil markets could be in for another volatile year in 2022" #OOTT

Show this thread

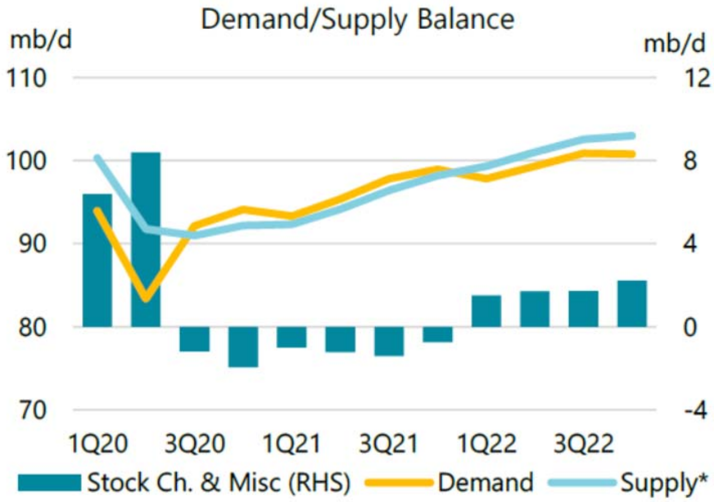


https://twitter.com/Jamie__Ingram/status/1483730619045720069/photo/1



*Assumes Iran under sanctions, excludes shut in crude. OPEC+ cut phased out by Sept 2022.

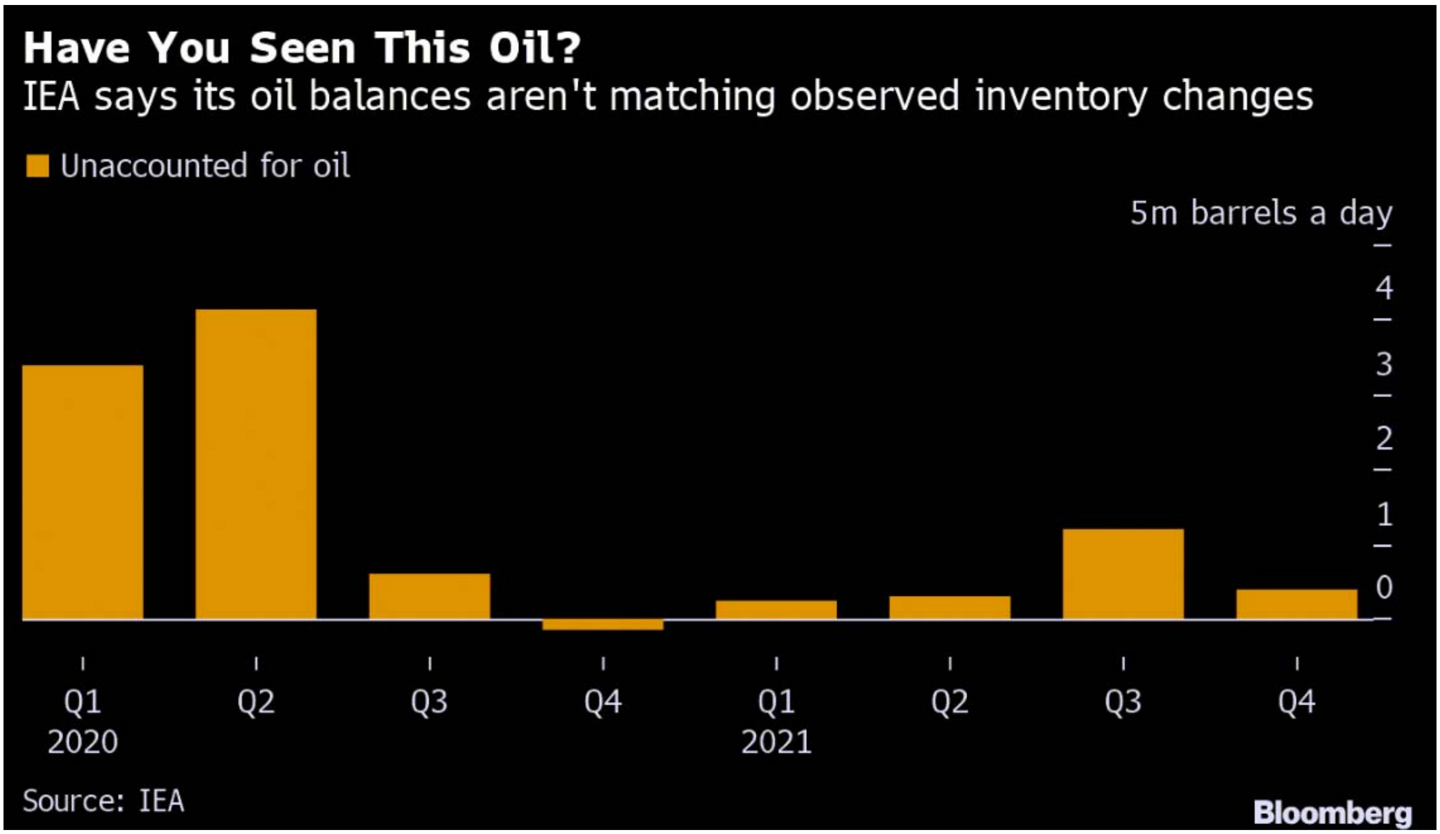
https://twitter.com/Jamie__Ingram/status/1483729895066935298/photo/1



* Assumes OPEC+ unwinds cuts. Iran remains under sanctions.

The IEA Goes Hunting for 200 Million Missing Barrels of Oil
2022-01-20 15:49:07.354 GMT

By Alex Longley and Julian Lee
(Bloomberg) -- The International Energy Agency is trying to figure out where 200 million barrels of oil went.
The adviser to energy-consuming nations said on Wednesday that observable global oil inventories plunged by more than 600 million barrels last year. That would be fine were it not for the fact -- based on its estimates of supply and demand -- that the decrease should only have been 400 million.



There is always a gap between the two, but the 200 million barrel discrepancy means the oil market could be tighter than previously thought. The gap could be a result of underreporting of demand or over-reporting production, the IEA said. Its monthly report is a benchmark for traders trying to evaluate the balance between supply and demand the world over.
"A retrospective view shows the difficulty over the past two years of reliably analyzing and forecasting supply and demand," the agency said on Wednesday. "Lessons learned will improve the work in 2022 and allow us to better understand our market."
While the balance of supply and demand may be one cause of the mismatch, there could be others too. The agency uses satellite data to track oil stockpiles, for example -- but that doesn't extend to the barrels used to fill pipes or those stored in huge underground caverns.

Read: Oil Markets May Be Even Tighter Than Forecasters Say
There are also issues with reporting. While huge emphasis is placed on stockpiles in OECD nations -- the IEA's core reporting area -- there are burgeoning volumes outside the region that go unreported, particularly in China.
Throw in a global pandemic that has transformed the dynamics behind oil consumption, and tracking demand has become significantly more difficult.

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Mon 17-01-2022 13:30 PM

Abu Dhabi Police confirms explosion of three petroleum tankers in Mussafah

A-AA+

ABU DHABI, 17th January, 2022 (WAM) -- Abu Dhabi Police confirmed that a fire broke out this morning, which led to the explosion of three petroleum tankers in ICAD 3, Mussafah, near ADNOC's storage tanks.

A minor fire also broke out in the new construction area of Abu Dhabi International Airport.

Preliminary investigations suggest that the cause of the fires are small flying objects, possibly belonging to drones, that fell in the two areas. Teams from the competent authorities have been dispatched and the fire is currently being put out.

The competent authorities have launched an extensive investigation into the cause of the fire and the circumstances surrounding it. However, there are no significant damages resulting from the two accidents.

WAM/Amjad Saleh

https://apnews.com/article/houthis-middle-east-abu-dhabi-united-arab-emirates-dubai-7279ab674dbe3183af751dcd5f01c5a2?utm_source=Twitter&utm_medium=AP&utm_campaign=SocialFlow

UAE envoy: Yemen's Houthis used missiles in Abu Dhabi attack

By AYA BATRAWY and MALAK HARByesterday

1 of 4

this satellite image provided by Planet Labs PBC, white fire suppressing foam is seen after an attack on an Abu Dhabi National Oil Co. fuel depot in the Mussafah neighborhood of Abu Dhabi, United Arab Emirates, Monday, Jan. 17, 2022. A drone attack claimed by Yemen's Houthi rebels targeting a key oil facility in Abu Dhabi killed three people on Monday and sparked a fire at Abu Dhabi's international airport. (Planet Labs PBC via AP)

2 of 4

In this satellite image provided by Planet Labs PBC, smoke rises over an Abu Dhabi National Oil Co. fuel depot in the Mussafah neighborhood of Abu Dhabi, United Arab Emirates, Monday, Jan. 17, 2022. A drone attack claimed by Yemen's Houthi rebels targeting a key oil facility in Abu Dhabi killed three people on Monday and sparked a fire at Abu Dhabi's international airport. (Planet Labs PBC via AP)

3 of 4

In this satellite image provided by Planet Labs PBC, an Abu Dhabi National Oil Co. fuel depot in the Mussafah neighborhood of Abu Dhabi, United Arab Emirates, is seen Saturday, Jan. 15, 2022, before being targeted in an attack days later. A drone attack claimed by Yemen's Houthi rebels targeting a key oil facility in Abu Dhabi killed three people on Monday, Jan. 17, 2022, and sparked a fire at Abu Dhabi's international airport. (Planet Labs PBC via AP)

4 of 4

In a satellite photo by Planet Labs PBC, Abu Dhabi International Airport is seen Dec. 8, 2021. A suspected drone attack by Yemen's Houthi rebels targeting a key oil facility in Abu Dhabi killed three people and sparked a separate fire at Abu Dhabi's international airport on Monday, Jan. 17, 2022, police said. (Planet Labs PBC via AP)

DUBAI, United Arab Emirates (AP) — Yemen's Houthi rebels used cruise and ballistic missiles, in addition to drones, in an attack on Abu Dhabi this week that killed three people and set off fires at a fuel depot and an international airport, the Emirati ambassador to the United States said Wednesday.

The remarks by Ambassador Yousef Al-Otaiba marked an official acknowledgement that missiles — and not just drones — were used in Monday's attack, claimed by the Iran-backed Houthis.

"Several attacks — a combination of cruise missiles, ballistic missiles, and drones — targeted civilian sites" in the United Arab Emirates, Al-Otaiba said.

"Several were intercepted, a few of them didn't and three innocent civilians unfortunately lost their lives," he added in remarks at a virtual event hosted by the Jewish Institute for National Security of America. The event was held to discuss U.S. policies and Israeli relations with the UAE and Bahrain.

Al-Otaiba did not respond to further questions from The Associated Press about how many missiles targeted the UAE and how many were intercepted.

Gulf Arab states, as well as the U.S., U.N. experts and others have previously accused Iran of supplying arms to the Houthis, a charge that Tehran denies.

The missiles and drones with bombs attached — if they were fired from the Houthis' stronghold in northern Yemen — would have needed to travel some 1,800 kilometers (1,100 miles) to reach targets in Abu Dhabi.

Monday's attack targeted an Abu Dhabi National Oil Co. fuel depot in an industrial zone outside the city center of the Emirati capital, as well as an area of Abu Dhabi International Airport still under construction.

The attack killed two Indian nationals and one Pakistani. Six people also were wounded at the oil and gas facility when a fire caused an explosion of fuel tankers. Police in Abu Dhabi said preliminary investigations suggested the possibility of drones sparking the fires.

The Houthis said they fired five ballistic missiles and a number of explosive-laden drones in their attack. They said they targeted the airports of Abu Dhabi and Dubai, the world's busiest for international transits, as well as an oil refinery and other sensitive Emirati facilities. There was no indication Dubai was hit in Monday's attack.

The UAE was a key member of the Saudi-led coalition that entered Yemen's civil war in 2015, after the Houthis had overrun the capital of Sanaa the previous year and ousted the country's president from power. Although the UAE has largely withdrawn its forces from the conflict, it remains heavily involved in the war and supports local militias on the ground in Yemen.

Earlier this month, Yemeni government forces, aided by Saudi airstrikes and Emirati-backed fighters known as the Giants Brigades, took back the province of Shabwa from the Houthis. The loss of this key province was a blow to Houthi efforts to complete their control of the entire northern half of Yemen.

In a statement after the attack, the Houthis warned they would target other vital facilities in the UAE if it continued escalations against the group.

The Houthis have used drones and missiles to attack Saudi Arabia and oil targets in the Persian Gulf over the course of Yemen's war, now in its eighth year. Monday's attack was the UAE's first acknowledgement of being hit by the Houthis. There have been several civilian deaths in Saudi Arabia from cross-border Houthi attacks.

The Saudi-led coalition intensified airstrikes on the Houthis across Yemen late Monday, including in Sanaa. At least 14 people, including a senior Houthi military official, were killed in one airstrike in Saana, the group said. The office of U.N. High Commissioner for Human Rights said that there were five civilians among the dead.

The U.S., meanwhile, condemned the attack against the UAE. The Biden administration vowed to work with the UAE and international partners to hold the Houthis accountable, though it has also repeatedly criticized civilian deaths caused by coalition airstrikes in Yemen.

Al-Otaiba said the UAE is pressing Washington to designate once again the Houthis as a terrorist organization. The ambassador and the UAE's Director of National Intelligence Ali Al-Shamsi are holding meetings in Washington on Wednesday with officials from the White House and Congress to press for this.

President Joe Biden's administration revoked the designation of Yemen's Houthis as a terrorist group in February, undoing a decision by the Trump administration to brand the group as a terrorist organization.

A U.S. designation of the Houthis as a terrorist group would limit aid to Yemen. The war has killed 130,000 people in Yemen — both civilians and fighters — and has exacerbated hunger and famine across the impoverished country.

Later Wednesday, a ballistic missile fired by the Houthis hit a fuel station in Marib province's district of Harib, killing at least four civilians and wounding five, according to Moammar al-Iryani, information minister in the internationally recognized government.

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Associated Press writer Samy Magdy in Cairo contributed to this report.

https://www.defensenews.com/land/2022/01/21/thaad-in-first-operational-use-destroys-midrange-ballistic-missile-in-houthi-attack/

THAAD, in first operational use, destroys midrange ballistic missile in Houthi attack

By Jen Judson and Joe Gould

Jan 21, 12:35 PM

The deployment of a THAAD System to Israel in 2019 was an exercise involving U.S. Army, U.S. Air Force and Israeli forces, under the Dynamic Force Employment concept. (Staff Sgt. Cory D. Payne/U.S. Air Force)

WASHINGTON — A multibillion-dollar missile defense system owned by the United Arab Emirates and developed by the U.S. military intercepted a ballistic missile on Monday during a deadly attack by Houthi militants in Abu Dhabi, marking the system's first known use in a military operation, Defense News has learned.

The Terminal High Altitude Area Defense System, made by Lockheed Martin, took out the midrange ballistic missile used to attack an Emirati oil facility near Al-Dhafra Air Base, according to two sources granted anonymity because they are not authorized to speak about the UAE's activities. The Emirati base hosts U.S. and French forces.

The attack, which used cruise missiles, ballistic missiles and drones, killed three civilians and wounded six others, UAE's ambassador to the United States, Yousef Al Otaiba, said earlier in the week.

"Several attacks, a combination of cruise missiles, ballistic missiles and drones, targeted civilian sites in the UAE. Several were intercepted, a few of them [weren't], and three innocent civilians unfortunately lost their lives," Al Otaiba said at a virtual event sponsored by the Jewish Institute for National Security of America.

The Emirati Embassy in Washington did not immediately respond to a request for comment.

The UAE was a key member of the Saudi-led coalition that entered Yemen's civil war in 2015, after the Houthis had overrun Yemen's capital of Sanaa the previous year and ousted the country's president from power. Although the UAE has largely withdrawn forces from the conflict, it remains heavily involved in the war and supports local militias on the ground in Yemen.

U.S. Central Command on Friday confirmed “a potential inbound threat” had forced U.S. service members at Al-Dhafra into their bunkers, in a “heightened alert posture” for about 30 minutes Sunday night. Airmen were directed to keep their protective gear close for 24 hours afterwards.

“Everything was professional and disciplined. The ‘all clear’ was called at 9:27 p.m. local time,” said Capt. Bill Urban, a spokesman for the command. “There was no mission impact.”

Lockheed Martin declined to comment.

THAAD, which is designed to counter short-, medium- and long-range ballistic missiles, was initially developed in the 1990s. It struggled in early testing, but has had a consistent reliability track record in flight tests since Lockheed Martin in 2000 won the development contract to turn THAAD into a mobile tactical army fire unit.

By 2019, the Missile Defense Agency had demonstrated the capability for the THAAD system to remotely fire an interceptor following 16 consecutive successful intercept tests.

The U.S. has deployed THAAD throughout the world, including to Guam, Israel, South Korea and Japan. In 2017, Saudi Arabia agreed to buy THAAD in a deal thought to be worth up to $15 billion. The UAE was the first foreign customer for the system and trained its first units in 2015 and 2016.

The Army operates seven THAAD batteries, but has long had a requirement to field nine total. The MDA has lacked the funding to build the final two, but U.S. lawmakers added funding in the fiscal 2021 budget to build an eighth THAAD battery.

The Houthis have used drones and missiles to attack Saudi Arabia and oil targets in the Persian Gulf over the course of Yemen’s war, now in its eighth year. Monday’s attack was the UAE’s first acknowledgement of being hit by the Houthis. Several civilians have died in Saudi Arabia from cross-border Houthi attacks.

This week, Abu Dhabi asked the U.S. for help bolstering its defenses against missiles and drones and halting weapons from being transported to the Houthis, according to a statement the UAE’s Embassy in Washington posted to Twitter.

In a call Wednesday between Abu Dhabi Crown Prince Mohamed bin Zayed Al Nahyan and U.S. Defense Secretary Lloyd Austin, Austin “underscored his unwavering support for the security and defense of UAE territory against all threats.” The Pentagon has since declined to provide specifics about the UAE’s request.

Abu Dhabi was also consulting with congressional gatekeepers on U.S. arms sales this week. The embassy said Al Otaiba met Wednesday with House Foreign Affairs Committee Chairman Gregory Meeks, D-N.Y.

Ahead of Senate Foreign Relations Committee Chairman Robert Menendez’s meeting with Al Otaiba, Menendez said, “We’ll see what their request is. I certainly recognize some of the challenges they’re having.”

Congressional aides said lawmakers have generally been open to Abu Dhabi’s requests for weapons to defend against Houthi attacks, but Emirati officials are likely to face questions over the country’s growing ties to China and accusations its forces have intervened in Libya’s ongoing war.

U.S. officials would also have to consider the suitability and production schedules for the equipment Abu Dhabi is requesting, according to a Senate aide granted anonymity to talk about diplomatically sensitive arms sale talks. If the UAE is seeking Patriot missiles, there's reportedly an interceptor shortage fueled by Houthi drone and rocket attacks against Saudi Arabia.

"The Saudis are using up their Patriots at a good clip, and these things, you don't just pick them up at Walmart," the aide said. "The Emiratis could be asking for things very appropriately, but before anything comes from it and arrives in country, it could be years."

Gulf Arab states, as well as the U.S., U.N. experts and others, have previously accused Iran of supplying arms to the Houthis, a charge Tehran denies.

Bilal Saab, a former Pentagon official now at the Middle East Institute, said the Houthis' use of missiles suggests Iranian involvement, even after diplomatic talks in December between Iranian and Emirati officials in Tehran.

"Clearly those talks were ineffective," Saab said. "The very use of ballistic missiles signals to me that the Iranians knew about it, were on board or at least had a role."

President Joe Biden said Wednesday his administration, following the strikes, is considering restoring the Houthis to the U.S. list of international terrorist organizations.

Al Otaiba had urged the move, and the Emirati Embassy welcomed it in a statement that said, "Case is clear — launching ballistic and cruise missiles against civilian targets, sustaining aggression, diverting aid from Yemeni people."

Agnes Helou in Beirut and The Associated Press contributed to this report.
About Jen Judson and Joe Gould

Jen Judson is an award-winning journalist covering land warfare for Defense News. She has also worked for Politico and Inside Defense. She holds a Master of Science in journalism from Boston University and a Bachelor of Arts from Kenyon College.

Joe Gould is senior Pentagon reporter for Defense News, covering the intersection of national security policy, politics and the defense industry.

Global Oil Inventories Plunge to Below Pandemic Levels, IEA Says
2022-01-19 09:00:00.20 GMT

By Rachel Graham
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Jan 19, 2022 11:05:46

OIL DEMAND MONITOR: Weak International Flying Curbs Jet Fuel (1)

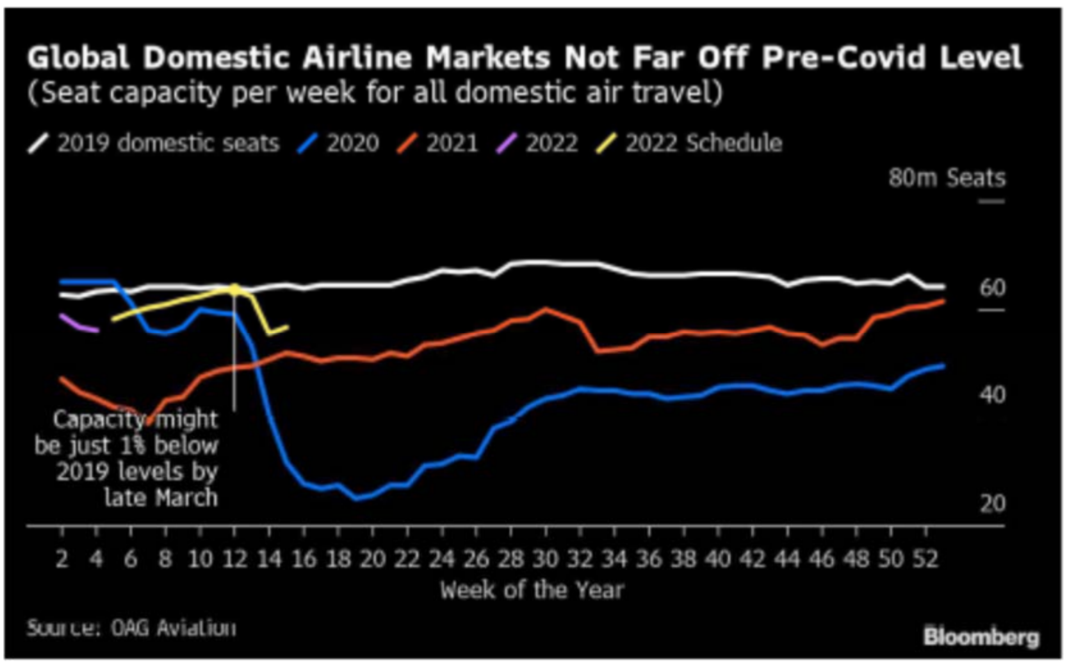
- Domestic air travel near pre-Covid levels, international lags
- London road congestion Monday morning exceeded the 2019 norm

By Stephen Voss

(Bloomberg) -- Airline traffic has weakened in Europe so far this month and broader international air travel is still a long way below pre-pandemic levels as countries around the world approach, or pass through, peak infection levels caused by the fast-spreading omicron variant.

Flights have dwindled in Europe since Christmas and, moreover, the gap versus 2019 widened to 34% on Jan. 17, from between about 20% and 25% during November and early December, according to Eurocontrol, an intergovernmental agency involved in air-traffic management.

Comparing seats offered by airlines for domestic versus international travel provides another way to view the outlook for jet fuel demand. The number of domestic-travel seats is close to reaching pre-pandemic levels on a global basis. The capacity estimate from DAG Aviation includes airline schedules running several weeks into the future.

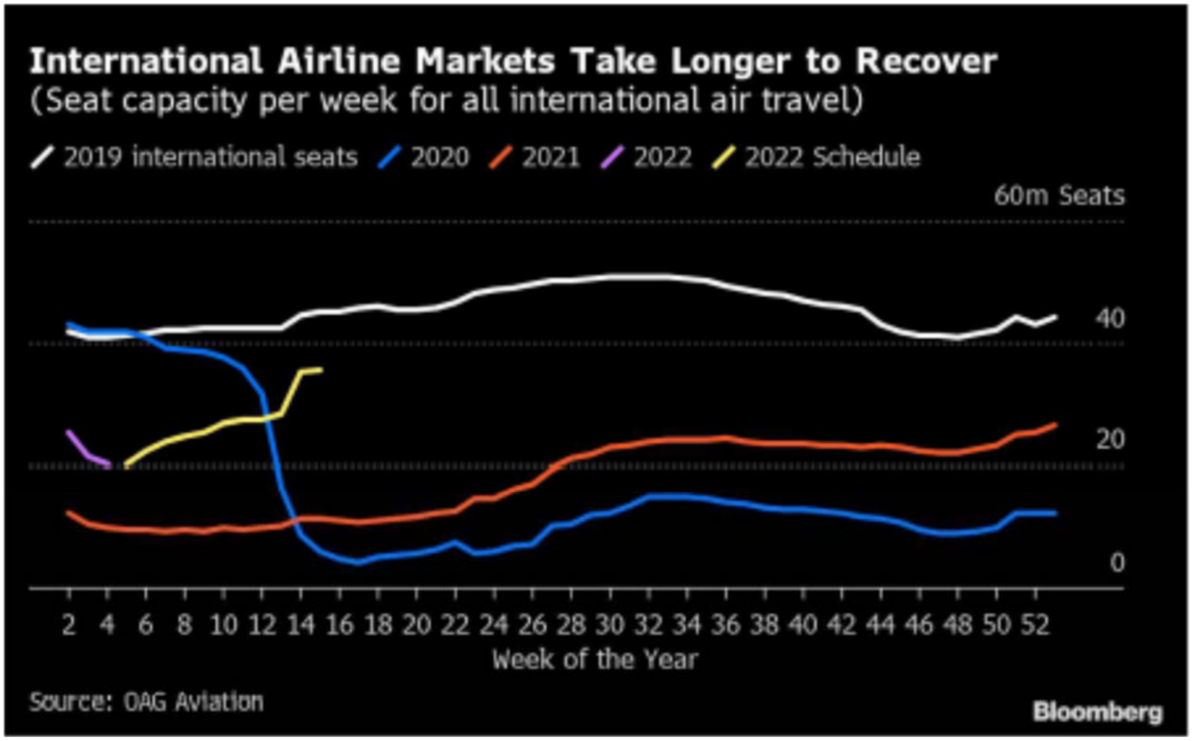


"On current plans, airlines expect scheduled capacity to reach just 1% below 2019 levels by the week of March 21," DAG said in a note on its website, referring to domestic seats.

Over the entire course of this year, demand for jet fuel and kerosene in OECD-member nations in Europe is expected to grow by 300,000 barrels a day this year, the International Energy Agency said Wednesday in its latest monthly report.

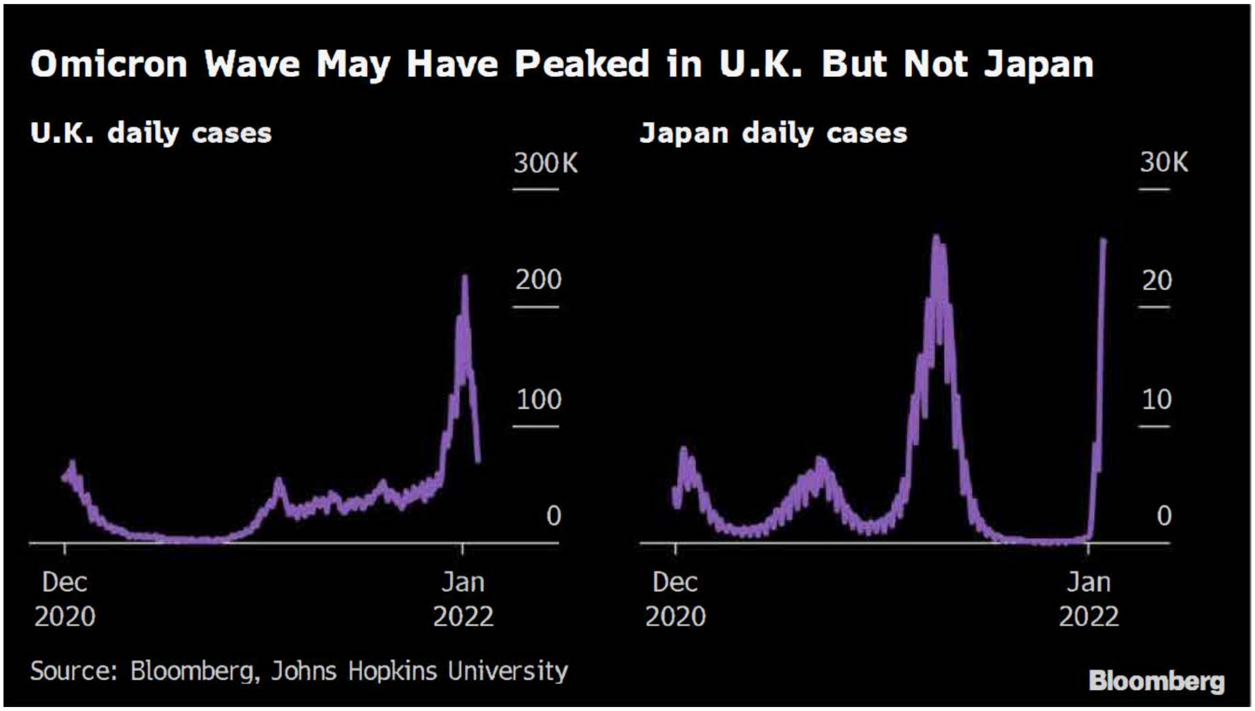
"The omicron variant is expected to slow the ongoing recovery in jet/kerosene demand during 1Q22, but growth should gather pace in 2Q22 and return to close to the five-year average throughout the remainder of the year," the Paris-based agency said.

While domestic flights are poised to recover, international air travel is currently much lower than normal and will take longer to revive because it's prone to virus-led immigration restrictions, DAG estimates show.



Regional breakdowns of the data show that the North American market, including domestic and international travel, is far closer to pre-Covid levels than Western Europe. They lag the equivalent week of 2019 by 12% and 43%, respectively.

Seat capacity is 22% below the equivalent period of 2019 in North East Asia, where reasonably buoyant domestic markets are offset by minimal amounts of international travel. That's particularly true for China and Japan, which remain largely cut off for foreign visitors, and infections may yet rise further in Japan.



Separate tracking data from FlightRadar24 shows that total worldwide flights exceeded 2019 levels in recent days. However, once smaller items including helicopters, drones, military and government flights are stripped out of the tally, the main segment of commercial passenger and cargo flights remains 18% lower, stuck midway between the levels seen last January and January 2019.

Gasoline Demand

Turning to road traffic, out of 13 world cities regularly tracked in this monitor, only London showed congestion levels at 8 a.m. on Monday morning that were higher than typical levels seen in 2019. Compared with a week earlier, city traffic strengthened in Tokyo, Jakarta and London, while weakening again in New York and Los Angeles because of a public holiday on Monday.

The latest U.K. data for road fuel sales and vehicle use both show a strengthening from the prior week, with gasoline sales now down 21% from a baseline of early 2020 versus a deficit of 28% in the prior week that straddled the New Year. That's still some way off the stronger readings seen in early December when U.K. gasoline sales across Britain were only 5% below the equivalent week of 2019.

U.S. gasoline demand dipped in the week ended Jan. 7, Energy Information Administration data showed. Comparisons with prior years appear somewhat erratic though, perhaps due to large swings at the start of the year as refiners adjust stockpiles for tax purposes, and especially since EIA estimates are based on the volume of product supplied by refineries, rather than end-user consumption. The data is likely to settle down later this month. The EIA will release new weekly data on Thursday.

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

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

Demand Measure	Location	% y/y	% vs 2019	% m/m	Freq	Latest Date	Latest Value	Source
Gasoline	U.S.	+5	-9.5	-17	w	Jan. 7	7.91m b/d	EIA
Distillates	U.S.	+3.9	+27	-23	w	Jan. 7	3.75m b/d	EIA
Jet fuel	U.S.	+9.4	-11	unch	w	Jan. 7	1.61m b/d	EIA
Total oil products	U.S.	+6.2	+5.4	-10	w	Jan. 7	20.8m b/d	EIA
All vehicles miles traveled	U.S.		-3.9		w	Jan. 9	13.6b miles	DoT
Passenger car VMT	U.S.		-4.3		w	Jan. 9	n/a	DoT
Truck VMT	U.S.		+1.8		w	Jan. 9	n/a	DoT
All motor vehicle use index	U.K.	+38	-13	-9.4	w	Jan. 10	87	DfT
Car use	U.K.	+46	-18	-9.9	w	Jan. 10	82	DfT
Heavy goods vehicle use	U.K.	+5.2	+2	-8.9	w	Jan. 10	102	DfT
Gasoline (petrol) avg sales per filling station	U.K.	+41	-21	-15	w	Jan. 9	5,786 liters/d	BEIS
Diesel avg sales per station	U.K.	+8.9	-25	-20	w	Jan. 9	7,795 liters/d	BEIS
Total road fuels sales per station	U.K.	+21	-24	-18	w	Jan. 9	13,580 liters/d	BEIS
Gasoline	India	-2.8		-14	2/m	Jan. 1-15	964k tons	Bberg
Diesel	India	-5		-14	2/m	Jan. 1-15	2.47m tons	Bberg
LPG	India	+9.5		+4.8	2/m	Jan. 1-15	1.3m tons	Bberg
Jet fuel	India	+7.3		-13	2/m	Jan. 1-15	209k tons	Bberg
Total Products	India	+0.4	-5.4	+7.7	m	December	18.4m tons	PPAC
Toll roads volume	Italy	+102	+3.7		w	Dec. 20-26	n/a	Atlantia
Toll roads volume	Spain	+39	-9		w	Dec. 20-26	n/a	Atlantia
Toll roads volume	France	+28	-5.3		w	Dec. 20-26	n/a	Atlantia
Toll roads volume	Brazil	+7.9	+0.5		w	Dec. 20-26	n/a	Atlantia
Toll roads volume	Chile	+51	+27		w	Dec. 20-26	n/a	Atlantia
Toll roads volume	Mexico	+20	+11		w	Dec. 20-26	n/a	Atlantia
Gasoline	Spain	+23	+1.4	+6.3	m	December	477k m3	Exolum
Diesel	Spain	+7.6	-0.7	+2.7	m	December	2466k m3	Exolum

All petroleum products	France	+14	-0.3		m	December	4.83m m3	UFIP
Total fuel sales	Italy	+15	-0.2	-4.7	m	November	4.25m tons	Ministry
Gasoline	Italy	+47	+6.5	-6.7	m	November	586k tons	Ministry
Diesel /gasoil	Italy	+18	+2.8	-5.9	m	November	2.23m tons	Ministry
Jet fuel	Italy	+72	-34	-8.6	m	November	222k tons	Ministry
All vehicles traffic	Italy	+35		-2	m	December	n/a	Anas
Heavy vehicle traffic	Italy	+9		-10	m	December	n/a	Anas
Gasoline	Portugal	+17	-2.5	+8	m	December	87k tons	ENSE
Diesel	Portugal	+10	-3.4	+0.8	m	December	405k tons	ENSE
Jet fuel	Portugal	+77	-23	-14	m	December	91k tons	ENSE
Gasoline	Brazil	+6.7	+6.7	-0.9	m	November	720k b/d	ANP
Diesel	Brazil	+4.2	+6.2	-6.2	m	November	1.07m b/d	ANP
Jet fuel	Brazil	+40	-21	+10	m	November	94k b/d	ANP

Note: Click here for a PDF with more information on sources, methods. The frequency column shows w for data updated weekly, 2/m for twice a month and m for monthly.
* In DtT 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.
** 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 avg 2019	% chg m/m	Jan. 17	Jan. 10	Jan. 3	Dec. 27	Dec. 20	Dec. 13	Dec 6	Nov 29	Nov 22
		(Jan. 17)		Congestion minutes added to 1 hr trip at 8am local time								
Congestion	Tokyo	-6	-8	35	5	1	31	38	37	33	35	30
Congestion	Taipei	-7	+6	33	32	32	43	31	42	41		
Congestion	Jakarta	-5	+35	37	32	26	20	28	30	28		
Congestion	Mumbai	-98	-86	1	1	2	2	4	5	6	6	8
Congestion	New York	-87	-79	4	19	11	5	20	26	32	28	34
Congestion	Los Angeles	-78	-50	8	13	10	6	16	27	29	29	18
Congestion	London	+10	+229	41	37	1	1	13	36	41	43	43
Congestion	Rome	-54	-49	22	28	7	10	44	50	46	53	49
Congestion	Madrid	-66	-5	12	12	2	3	13	23	0	24	41
Congestion	Paris	-22	+93	35	36	19	10	18	46	52	46	53
Congestion	Berlin	-14	+30	29	29	20	9	22	37	32	31	32
Congestion	Mexico City	-70	-24	15	20	13	11	20	31	34	31	32
Congestion	Sao Paulo	-64	-30	16	18	10	10	22	28	28	29	27

Source: TomTom. Click here for a PDF with more information on sources, methods.
NOTE: m/m comparisons are Jan. 17 vs Dec. 20. TomTom has been unable to provide Chinese data since late April. Taipei and Jakarta were added to the table in early December. It was a public holiday in New York and Los Angeles on Jan. 17.

Air Travel:

Measure	Location	y/y	vs 2 yrs ago	vs 2019	m/m	w/w	Freq.	Latest Date	Latest Value	Source
		changes shown as %								
Airline passenger throughput	U.S.	+94	-5.7	-9.9	-19	+17	d	Jan. 17	1.70m	TSA
Commercial flights	Worldwide	+29	-23	-18	-8.5	-4.4	d	Jan. 17	85,085	FlightRadar24
Air traffic (flights)	Europe			-34	-24	-6.8	d	Jan. 17	17,131	Eurocontrol
Seat capacity	Worldwide	+43	-29	-27		-2.1	w	Jan. 17-23	76.2m	OAG
Seat cap.	North America			-12		+0.3	w	Jan. 17-23	n/a	OAG
Seat cap.	North East Asia			-22		+0.7	w	Jan. 17-23	n/a	OAG
Seat cap.	South East Asia			-50		-0.3	w	Jan. 17-23	n/a	OAG
Seat cap.	South Asia			-21		-10	w	Jan. 17-23	n/a	OAG
Seat cap.	Western Europe			-43		-4.9	w	Jan. 17-23	n/a	OAG

NOTE: Comparisons versus 2019 or versus the early weeks of 2020 are a better measure of a return to normal for most nations, rather than y/y comparisons.
FlightRadar24 data shown above, and comparisons thereof, all use 7-day moving averages, except for w/w which uses single day data.

Refineries:

Measure	Location/area	y/y	chg vs 2019	m/m chg	Latest as of Date	Latest Value	Source
		Changes are in ppt unless noted					
Crude intake	U.S.	+6.3%	-11%	-0.6%	Jan. 7	15.6m b/d	EIA
Apparent Oil Demand	China	+2.5%		-3.8%	December 2021	13.65m b/d	NBS
Utilization	U.S.	+6.4	-7.7	-1.4	Jan. 7	88.4 %	EIA
Utilization	U.S. Gulf	+6.8	-8	-0.3	Jan. 7	89.7 %	EIA
Utilization	U.S. East	+20	-0.9	-2.8	Jan. 7	87 %	EIA
Utilization	U.S. Midwest	+5.8	-3.8	-0.9	Jan. 7	93.3 %	EIA

NOTE: All of the refinery data is weekly, except NBS apparent demand, which is usually monthly. Changes are shown in percentages for the rows on crude intake and Chinese apparent oil demand, while refinery utilization changes are shown in percentage points. SCI99 data on Chinese refinery run rates was discontinued in late 2021 https://www.trucking.org/news-insights/ata-truck-tonnage-index-increased-1-december

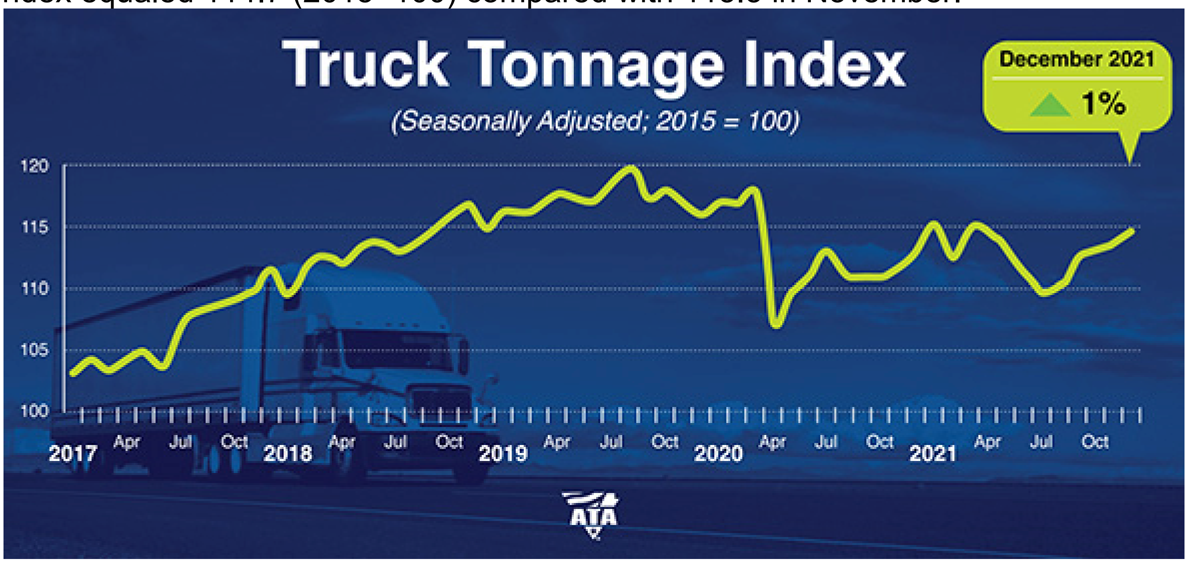
ATA Truck Tonnage Index Increased 1% in December

JAN18

Media Contact: Sean McNally

Tonnage Rose 0.3% in 2021 over 2020

Arlington, Virginia — American Trucking Associations' advanced seasonally adjusted (SA) For-Hire Truck Tonnage Index increased 1% in December after rising 0.5% in November. In December, the index equaled 114.7 (2015=100) compared with 113.5 in November.



"December's gain was the fifth straight totaling 4.4%," said **ATA Chief Economist Bob Costello**. "In December, tonnage reached the highest level since March, but it was still 2.7% below the pre-pandemic high. This is likely due to the fact ATA's data is dominated by contract freight. Contractor truckload carriers operated fewer trucks in 2021 compared with 2020 and it is difficult to haul significantly more tonnage with fewer trucks. But overall, we have seen a nice trend up that is reflective of a still growing goods-economy."

November's reading was revised down from our December 21 press release.

Compared with December 2020, the SA index rose 1.4%, which was the fourth straight year-over-year gain. In November, the index was up 1.6% from a year earlier. In 2021, compared with the average in 2020, tonnage was up 0.3%. In 2020, tonnage was off 4% compared with 2019.

The not seasonally adjusted index, which represents the change in tonnage actually hauled by the fleets before any seasonal adjustment, equaled 113.9 in December, 0.2% above the November level (113.8). In calculating the index, 100 represents 2015. ATA's For-Hire Truck Tonnage Index is dominated by contract freight as opposed to spot market freight.

Trucking serves as a barometer of the U.S. economy, representing 72.5% of tonnage carried by all modes of domestic freight transportation, including manufactured and retail goods. Trucks hauled 10.23 billion tons of freight in 2020. Motor carriers collected $732.3 billion, or 80.4% of total revenue earned by all transport modes.

ATA calculates the tonnage index based on surveys from its membership and has been doing so since the 1970s. This is a preliminary figure and subject to change in the final report issued around the 5th day of each month. The report includes month-to-month and year-over-year results, relevant economic comparisons, and key financial indicators.

HTTPS://WWW.TIPRO.ORG/NEWSROOM/TIPRO-NEWS/TEXAS-UPSTREAM-SECTOR-CONTINUES-TO-EXPAND-WITH-EIGHTH-CONSECUTIVE-MONTH-OF-JOB-GAINS

JANUARY 21, 2022

TEXAS UPSTREAM SECTOR CONTINUES TO EXPAND WITH EIGHTH CONSECUTIVE MONTH OF JOB GAINS

Austin, Texas - Today, the Texas Independent Producers and Royalty Owners Association (TIPRO) highlighted updated employment figures for the Texas upstream sector. Citing the latest Current Employment Statistics (CES) report from the U.S. Bureau of Labor Statistics (BLS), TIPRO reported that Texas upstream employment for December 2021 totaled 188,700, an increase of 3,000 jobs from revised November numbers, and the eighth consecutive month of job growth for the industry since last April. Texas upstream employment in December 2021 represented an increase of 27,800 positions compared to December 2020, reflecting a rise of 26,500 jobs in the services sector and increase of 1,300 jobs in oil and natural gas extraction.

According to TIPRO's analysis, once the direct, indirect and induced impact of these upstream positions are incorporated, the organization calculated a multiplier effect of 6.8 percent per job for Crude Petroleum Extraction, 5.2 percent for Natural Gas Extraction, 2.4 percent for Drilling Oil and Gas Wells and 2 percent for the Support Activities for Oil and Gas Operations sector, further capturing the significant economic impact of the Texas oil and natural gas industry.

TIPRO also once again noted strong job posting data for upstream, midstream and downstream sectors for the month of December in line with rising employment, showing a continued demand for talent in the Texas oil and natural gas industry. According to TIPRO's workforce analysis released today, there were 8,484 active unique job postings for the Texas oil and natural gas industry in December of 2021, including 2,612 new job postings added for the month.

Among the 14 specific industry sectors TIPRO uses to define the Texas oil and natural gas industry, Support Activities for Oil and Gas Operations ranked the highest in December with 2,144 unique job postings, followed by Crude Petroleum Extraction (1,506) and Petroleum Refineries (874). The leading three cities by total unique oil and natural gas job postings were Houston (3,041), Midland (939) and Dallas (531). The top three companies ranked by unique job postings in December were National Oilwell Varco, Inc. (477), Baker Hughes (468) and Halliburton (407). Top posted occupations for December included heavy tractor-trailer truck drivers (334), personal service managers (303) and computer occupations (230).

"Oil and natural gas employment continues to rebound, providing quality, high-paying jobs to Texans throughout the state, and we expect that trend to continue. These employment opportunities also span across a spectrum of occupations, from laborers and roustabouts to software developers and electrical engineers," said Ed Longanecker, president of TIPRO. "We believe increasing global demand will outpace production as economic conditions improve, and oil inventories could hit their lowest level in over two decades this summer, likely driving commodity prices higher and accelerating exploration and production activity in the state, if the market demands it," concluded Longanecker.

https://www.capp.ca/news-releases/capp-projects-investment-in-canadas-natural-gas-and-oil-sector-will-rise-to-32-8-billion-in-2022/

CAPP projects investment in Canada’s natural gas and oil sector will rise to $32.8 billion in 2022

January 20, 2022, Calgary, Alberta

The Canadian Association of Petroleum Producers (CAPP) is forecasting a 22 per cent increase in natural gas and oil investment in 2022. Capital spending in the sector is expected to grow by $6.0 billion to reach $32.8 billion, compared to an estimated total investment of $26.9 billion in 2021. (All figures in Canadian dollars.)

The expected growth in spending for 2022 would mark the second straight year of significant increases in investment as Canadian producers look to capitalize on stronger commodity prices due to rapidly growing global demand for natural gas and oil.

Conventional oil and natural gas capital investment for 2022 is forecast at $21.2 billion, up from an estimated $18.1 billion last year, while growth in oil sands investment is expected to increase 33 per cent to $11.6 billion compared to $8.7 billion last year.

While this is great news for the struggling Canadian economy, within the context of total global investment Canada is continuing to lose market share to other jurisdictions. In 2014, Canada was viewed as a top tier international investment jurisdiction for resource development and attracted $81 billion or more than 10 per cent of total global upstream natural gas and oil investment. International energy research firm Wood Mackenzie is forecasting global spending on upstream natural gas and oil production will reach $525 billion in 2022. Based on that forecast Canada has fallen to just six per cent of total market share, a four per centage point drop which represents over $21 billion in potential investment.

Regional Review

Alberta

Alberta is expected to lead all provinces with upstream investment expected to increase 24 per cent to total $24.5 billion in 2022. Over 80 per cent of the new spending this year is focused in Alberta, representing an additional $4.8 billion of investment into the province compared to 2021. The growth in investment is being driven both in the conventional and oil sands sectors.

British Columbia

With rapidly growing global demand for natural gas translating into multi-year highs in natural gas prices, producers in British Columbia are showing interest in growing their investment in the province. However, the ongoing review on royalties paired with the current moratorium on issuing development permits stalled investment in 2021. Investment in the province fell approximately $600 million short of last year's anticipated $3.9 billion, only reaching $3.4 billion in 2021. In 2022, upstream investment in B.C. is forecast to grow to $4.1 billion. Rig counts in B.C. currently sit at half of the historical average for mid-January indicating producers are potentially holding off some investment until later in 2022.

Saskatchewan

In 2022, producers expect to invest $2.7 billion in the province, a 16 per cent increase over 2021. Similar to British Columbia, Saskatchewan's 2021 upstream investment was forecast to reach $2.8 billion but updated estimates show producers spent $2.3 billion last year, a shortfall of approximately $500 million. Increasing municipal costs in some rural jurisdictions have significantly raised concerns which are likely contributing to a slowing of investment in the province.

Offshore

In Newfoundland and Labrador, offshore investment is expected to remain relatively flat at $1.6 billion in 2022 compared to $1.5 billion last year. Globally, the offshore sector is attracting significant new investment with expected spending in the sector to grow by seven per cent to approximately $195 billion in 2022. For comparison, the Gulf of Mexico is expected to grow investment by 21 per cent to $13.1 billion this year. Canada's offshore development offers some of the world's lowest emission oil. The natural gas and oil industry along with the provincial government are seeking to work with the federal government to improve the region's global competitiveness to help realize the value in Canada's offshore sector.

CAPP quotes Tim McMillan, President and CEO:

- "Canada's natural gas and oil industry is continuing its path towards recovery. The growth in upstream investment will support jobs across the country and provide a positive boost to Canada's economic recovery. Improving commodity prices and increased investment in natural gas and oil production will also deliver billions more dollars of much-needed government revenues to support Canadians as we work our way through the ongoing Covid-19 pandemic."
- "Rapid demand growth for oil and natural gas globally and strengthening commodity prices mean there is opportunity for Canada's industry for decades to come. To ensure a true recovery takes hold in Canada, government at all levels along with the industry must work together to create an environment where the natural gas and oil industry can thrive and attract investment back to Canada."
- "Demand for oil and natural gas is expected to rise and remain strong for decades. Every barrel of oil and molecule of natural gas not produced in Canada will be produced by other countries that likely do not match our high environmental and social standards. As one of the most innovative and responsible energy producers

in the world, Canada needs to take on a larger role in meeting the growing global demand for energy."

Supporting information:

- Credible projections from the International Energy Agency (IEA), OPEC and IHS Markit indicate oil demand will top 100 million barrels per day within the next two to three years and remain at or above that level until 2040 and beyond.
- Natural gas is expected to be one of the fastest growing sources of energy in the world, with demand projected to increase 14% by 2030, and 28% by 2050 (IEA World Energy Outlook 2021).
- The natural gas and oil industry is one of the largest employers of Indigenous people in Canada with a supply chain that includes approximately 275 Indigenous-owned businesses from which producing companies procure about $2.5 billion annually in products and services.

The Canadian Association of Petroleum Producers (CAPP) represents companies, large and small, that explore for, develop and produce natural gas and oil throughout Canada. CAPP's member companies produce about 80 per cent of Canada's natural gas and oil. CAPP's associate members provide a wide range of services that support the upstream oil and natural gas industry. Together CAPP's members and associate members are an important part of a national industry with revenues from oil and natural gas production of about $116 billion a year. CAPP's mission, on behalf of the Canadian upstream oil and natural gas industry, is to advocate for and enable economic competitiveness and safe, environmentally and socially responsible performance.

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https://www.newswire.ca/news-releases/petroshale-inc-announces-appointment-of-new-management-team-board-appointment-oversubscribed-54-5-million-equity-financing-2022-capital-budget-and-production-guidance-and-proposed-name-change-to-lucero-energy-corp--882400000.html

PetroShale Inc. Announces Appointment of New Management Team, Board Appointment, Oversubscribed $54.5 Million Equity Financing, 2022 Capital Budget and Production Guidance and Proposed Name Change to Lucero Energy Corp.

NEWS PROVIDED BY
PetroShale Inc.
Jan 13, 2022, 18:12 ET

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CALGARY, AB, Jan. 13, 2022 /CNW/ - PetroShale Inc. ("**PetroShale**" or the "**Company**") (TSXV: PSH) (OTCQB: PSHIF) is pleased to announce the appointment of a new management team (the "**New Management Team**") led by Brett Herman as President & Chief Executive Officer, Jason Skehar as Chief Operating Officer, Marvin Tang as Vice President, Finance & Chief Financial Officer, Sandy Brown as Vice President, Geosciences, Kristine Lavergne as Vice President, Engineering, and Shane Manchester as Vice President, Operations.

The New Management Team has a successful track record of creating shareholder value through a disciplined and long term integrated strategy of acquiring and developing assets, most recently at TORC Oil & Gas Ltd. ("**TORC**"). TORC grew from nil production to more than 28,000 Boepd through the successful execution of several strategic acquisitions, combined with a low risk development drilling and exploitation program that advanced the prolific Bakken resource play in the southeast Saskatchewan region of the Williston Basin.

In addition to the New Management Team, one new independent director, Dale O. Shwed has been appointed to the board of directors of PetroShale (the "**PetroShale Board**"), which continues to include M. Bruce Chernoff, David Rain, Gary Reaves, Jacob Roorda and Brett Herman. The expanded PetroShale Board has a solid track record of building, financing and directing oil and gas companies and brings a wide range of experience, knowledge and innovation to the recapitalized entity. It is anticipated that additional directors will be appointed at the next shareholder meeting of the Company. Syd Abougoush, a partner with Burnet, Duckworth and Palmer LLP, will continue to act as Corporate Secretary.

In connection with the appointment of the New Management Team, PetroShale intends to complete (i) a non-brokered private placement of units of PetroShale (the "**Units**") with the New Management Team for gross proceeds of $9.5 million (the "**Non-Brokered Private Placement**"), and (ii) a brokered commercially reasonable efforts private placement of common shares of PetroShale ("**Common Shares**") for gross proceeds of up to $45.0 million (the "**Brokered Private Placement**"), and combined with the Non-Brokered Private Placement (the "**Private Placements**"), gross proceeds of up to $54.5 million will be raised. Due to strong demand, PetroShale agreed to increase the size of the Brokered Private Placement from its initial target of $30 million.

It is anticipated that the shareholders of PetroShale will be asked to approve a change of the Company's name to "Lucero Energy Corp." at the next annual general meeting of shareholders.

NEW MANAGEMENT TEAM AND BOARD MEMBER

Brett Herman President & CEO	Mr. Herman has extensive oil and gas experience in leadership roles at public oil and gas companies. Most recently, Mr. Herman was the President & CEO of TORC Oil & Gas Ltd., and previously, President & CEO of Result Energy Inc. and TriStar Oil & Gas Ltd. Prior thereto, Mr. Herman was the Vice President, Finance & CFO of StarPoint Energy Ltd. and StarPoint Energy Trust.
Jason Skehar COO	Mr. Skehar has extensive oil and gas experience in leadership and operational roles, most recently as the President & CEO of Bonavista Energy Corporation ("Bonavista"). Prior thereto, Mr. Skehar was the President & Chief Operating Officer of Bonavista and its predecessor, Bonavista Energy Trust.
Marvin Tang VP Finance & CFO	Mr. Tang has over 17 years of oil and gas experience in various financial and compliance related roles, most recently as the VP & Controller of TORC Oil & Gas Ltd. Prior thereto, Mr. Tang was the Manager of Financial Reporting of Result Energy Inc. and TriStar Oil & Gas Ltd.
Sandy Brown VP Geosciences	Mr. Brown has significant geological oil and gas experience, particularly in the Williston Basin, and most recently was the VP Geosciences at TORC Oil & Gas Ltd. Previously, Mr. Brown was the New Ventures Manager/Senior Geological Advisor of Apache Canada, and prior thereto, the Vice President, Exploration of Rock Energy.
Kristine Lavergne VP Engineering	Ms. Lavergne has over 18 years of oil and gas engineering experience, particularly in the Williston Basin, and most recently was the Engineering Manager of TORC Oil & Gas Ltd. Prior thereto, Ms. Lavergne specialized in various engineering roles at Legacy Oil + Gas Inc., TriStar Oil & Gas Ltd., and Harvest Energy Trust.
Shane Manchester VP Operations	Mr. Manchester has significant oil and gas engineering and operations experience, particularly in the Williston Basin, and most recently was the VP Operations of TORC Oil & Gas Ltd. Previously, Mr. Manchester was the Vice President, Operations of Vero Energy Inc., and prior thereto, the Production & Engineering Manager of True Energy Inc.
Dale O. Shwed	Mr. Shwed is currently the President and Chief Executive Officer of Crew Energy Inc. Mr. Shwed graduated from the University of Alberta with a Bachelor of Science degree in Geology in 1980, and has held positions of increasing responsibility with various exploration and production companies before founding Baytex Energy Ltd. ("Baytex") in 1993. He was the President and Chief Executive Officer overseeing the operations of Baytex, growing production to over 40,000 boe/d. In 2003, Baytex was reorganized into Baytex Energy Corp. and Crew Energy Inc. Mr. Shwed served on the Board of Directors of TORC Oil & Gas Ltd. from 2012 to 2021, and is currently on the Board of Directors of Inplay Oil Corp.

CORPORATE STRATEGY

The New Management Team has a strong track record of disciplined operating and consolidating success in the Williston Basin, where PetroShale's existing asset base is located (within the prolific North Dakota Bakken). The New Management Team believes PetroShale's assets, currently producing in excess of 10,000 boe/d (approximately 85% light oil and natural gas liquids) offer compelling economic returns. With the resulting financial returns enhanced by increasingly positive market conditions, the New Management Team is excited to implement a proven disciplined strategy of acquiring and exploiting assets. This entry point, combined with the New Management Team's experience in consolidating and integrating acquisitions, as well as exploiting and exploring for resource-in-place assets in the Williston Basin, will provide a platform for focused growth through strategic acquisitions and internally generated prospects.

PRIVATE PLACEMENTS

Pursuant to the Non-Brokered Private Placement, the New Management Team, together with additional subscribers identified by the New Management Team, will subscribe for 23,750,000 Units at a price of $0.40 per Unit for total proceeds of $9.5 million. Each Unit will be comprised of one Common Share and one warrant ("**Warrant**") entitling the holder to purchase one Common Share at a price of $0.475 per Common Share for a period of 5 years from the issuance date. The Warrants will vest and become exercisable as to one-third upon the 20-day volume weighted average trading price of the Common Shares (the "**Trading Price**") equalling or exceeding $0.67 per Common Share, an additional one-third upon the Trading Price equalling or exceeding $0.83 per Common Share and the final one-third upon the Trading Price equalling or exceeding $0.95 per share.

Concurrent with the appointment of the New Management Team and the Non-Brokered Private Placement, PetroShale has entered into an agreement, on a commercially reasonable efforts private placement basis, with a syndicate of agents led by Peters & Co. Limited for 112,500,000 Common Shares at a price of $0.40 per Common Share for gross proceeds of up to $45 million. Closing of the Brokered Private Placement is expected to occur on or about February 2, 2022. Proceeds from the Private Placements will be used to reduce debt and for general corporate purposes, positioning the Company to execute on a disciplined corporate strategy.

All securities issued in connection with the Private Placements will be subject to a Canadian statutory hold period of four months plus one day from the respective date of closing.

The Company's two largest shareholders, FR XIII PetroShale Holdings L.P. and M Bruce Chernoff, have waived their respective rights to participate in each of the Non-Brokered Private Placement and the Brokered Private Placement in order to maintain their current pro-rata ownership positions and are not expected to acquire any Common Shares as part of the Company's Private Placements.

2022 CAPITAL BUDGET AND PRODUCTION GUIDANCE

PetroShale is pleased to announce the Company's Board of Directors has approved a 2022 capital budget of US$45 million (CDN$57 million), subject to completing the Private Placements. PetroShale's strategic objectives associated with the 2022 capital budget are consistent with the New Management Team's long term objectives of delivering disciplined per share growth in combination with maintaining financial flexibility.

PetroShale's 2022 capital budget is specifically focused on:

- Investing in higher rate of return, lower risk light oil opportunities across the Company's high quality, low risk development drilling inventory;
- Maximizing free cash flow through an efficient capital program focused on high graded development drilling opportunities;
- Moderating the Company's production decline profile;
- Directing the pace of the capital program to maintain spending flexibility throughout the year; and
- Maintaining PetroShale's strong financial position and flexibility to take advantage of additional growth opportunities as they arise.

PetroShale's capital program in 2022 is focused on light oil development projects, with the majority of the capital directed to drilling, completions and tie-ins (greater than 85%) with the remainder allocated to operational and facility optimization to maximize production efficiency.

With the strong performance of the Company's underlying production base, PetroShale anticipates that the US$45 million (CDN$57 million) 2022 capital budget will result in 2022 average production between 10,500-11,000 boepd (85% light oil & natural gas liquids) and exit guidance of 11,000 boepd (85% light oil and natural gas liquids) while improving the production decline profile below 25% by year end.

At current commodity prices, the recapitalized entity is expected to generate greater than $130 million of cash flow in 2022, and combined with the Private Placement proceeds, net debt is expected to be less than $82 million (or 0.6 times net debt/cash flow) at the end of 2022.

STOCK EXCHANGE APPROVALS

Completion of the Private Placements, is subject to certain conditions, including the approval of the TSXV, and is expected to occur on or about February 2, 2022 assuming all conditions have been met by such day. The Private Placements are not expected to materially affect control of PetroShale nor create a new control person of the Company.

ADVISORS

Peters & Co. Limited is acting as exclusive financial advisor to the New Management Team. Burnet, Duckworth and Palmer LLP is acting as counsel to PetroShale, and McCarthy Tétrault LLP is acting as counsel to the syndicate of agents led by Peters & Co. Limited in respect of the Brokered Private Placement.

OUTLOOK

PetroShale has built a sustainable growth platform of light oil focused assets. The stability of the high quality, lower decline, light oil assets in the Bakken resource play in North Dakota positions PetroShale to provide value creation through a disciplined long term focused growth strategy.

PetroShale has the following key operational and financial attributes:

Production Guidance	2022E Average: 10,500 – 11,000 boepd (85% light oil and liquids) 2022E Exit: 11,000 boepd (85% light oil and liquids)
Total Proved plus Probable Reserves (1)	Approximately 72 MMboe (87% light oil and liquids)
Sustainability Assumptions	Corporate production decline: 30% (2022E) Capital Efficiency(2),(3): $17,000/boepd (IP 365)
2022 Capital Program(3)	US$45 million (CDN$57 million)
Year-end net debt (2022E)(4)	$134 million ($82 million pro forma the Private Placements)
Common Shares Outstanding (basic)	521 million (657 million pro forma the Private Placements)

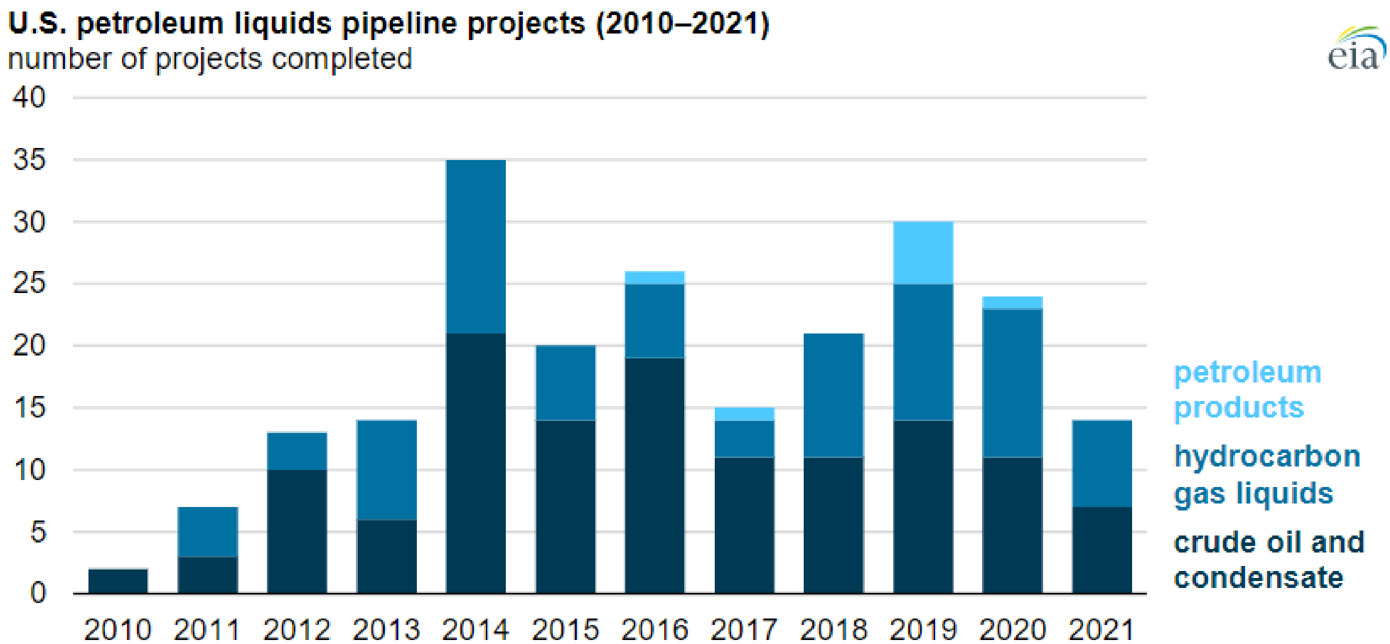
Notes:
(1) All reserves information in this press release are gross reserves. The reserve information for PetroShale in the foregoing table is derived from the independent engineering report effective December 31, 2020 prepared by Netherland Sewell & Associates evaluating the oil, NGL and natural gas reserves attributable to all of the Company's properties.
(2) Capital efficiency is a measure of forecast capital expenditures divided by forecast production additions.
(3) Assumes a foreign exchange rate of US$1.00 = CDN$1.2529.
(4) Year-end net debt (2022E) does not include proceeds from the exercise of any Warrants.

This press release is not an offer of the securities for sale in the United States. The securities have not been registered under the U.S. Securities Act of 1933, as amended, and may not be offered or sold in the United States absent registration or an exemption from registration. This press release shall not constitute an offer to sell or the solicitation of an offer to buy nor shall there be any sale of the securities in any state in which such offer, solicitation or sale would be unlawful.

https://www.linkedin.com/pulse/yakutiya-gas-lng-project-ben-seligman

JANUARY 19, 2022

In 2021, 14 petroleum liquids pipeline projects were completed in the United States



Source: U.S. Energy Information Administration, Liquids Pipeline Projects Database

In 2021, pipeline companies completed 14 petroleum liquids pipelines projects in the United States, according to our recently updated Liquids Pipeline Projects Database. This total includes seven crude oil pipeline projects and seven hydrocarbon gas liquids pipeline projects; no petroleum product pipeline projects were completed last year.

Of the 14 completed projects:

- Six projects were new pipelines.
- Five projects were expansions of existing systems.
- Two projects reversed the direction that the commodity flowed on the pipeline.
- One project was a change in the commodity carried by the pipeline.

Our Liquids Pipeline Projects Database contains information about projects at various stages of construction. During 2021, 11 projects were announced and 2 projects were listed as under construction. An additional 10 projects were permanently canceled, and 5 projects were put on temporary hold as of the end of 2021.

Notable completions in 2021:

- **Enbridge—Line 3 and Line 61** are two expansion projects that transport crude oil from Alberta, Canada, to Illinois. Line 3 goes from Alberta, Canada, to Superior, Wisconsin. Line 61 goes from Superior, Wisconsin, to Pontiac, Illinois.
- **Marathon Pipe Line—Capline Reversal** project reversed the direction of the pipeline to a south-flowing pipeline that originates in Patoka, Illinois and flows down to various terminals in St. James, Louisiana.
- **Energy Transfer—Dakota Access Pipeline (DAPL) Expansion** project increased capacity by 180,000 barrels per day along the DAPL system by adding horsepower and a few modifications and upgrades at pump stations. The DAPL system runs from North Dakota, through South Dakota and Iowa, and ends near Patoka, Illinois.

Our Liquids Pipeline Projects Database compiles information on more than 250 future, ongoing, and past liquids pipeline projects in the United States. These pipelines carry crude oil, hydrocarbon gas liquids, and petroleum products—which include gasoline, diesel, jet fuel, and other refinery products. This database includes projects that date back to 2010. Our database contains project types, start dates, capacity, mileage, geographic information, and project status. We track expanded, reversed, converted, and new pipeline projects.

Some projects are related to each other and may carry the same fuels to their final destination. As a result, adding together the capacity of all projects would result in overestimating or double-counting some pipeline capacity.

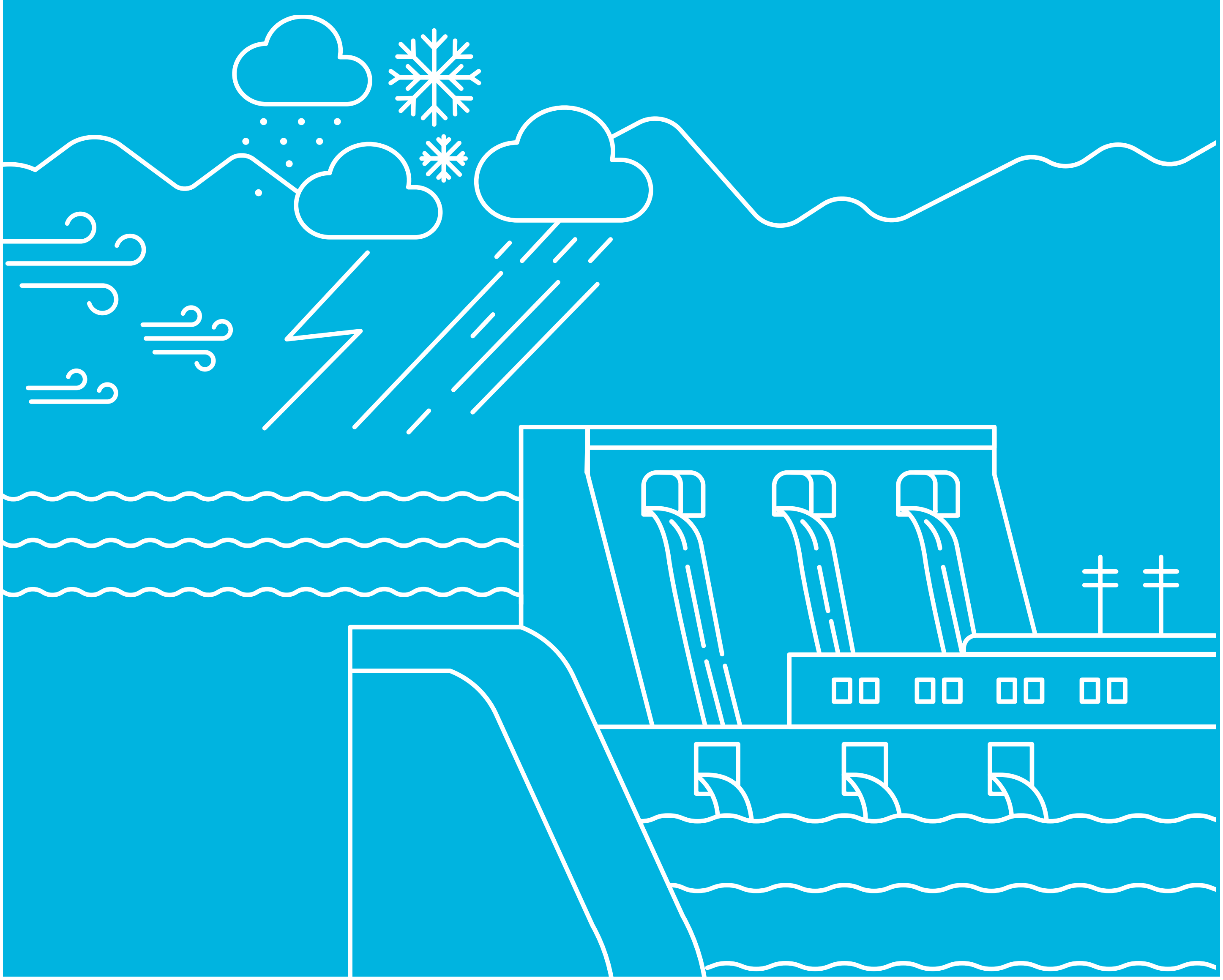
The Liquids Pipeline Projects Database complements our natural gas pipeline projects table. We update our Liquids Pipeline Projects Database based on the best available information from pipeline company websites, trade press reports, and government documents, such as U.S. State Department permits for border crossings. We update the database twice each year. The data reflect reported plans and do not reflect our assumptions on the likelihood or timing of project completion.

Principal contributor: Jim O'Sullivan

Tags: pipelines, liquid fuels, crude oil, oil/petroleum, petroleum products, HGL (hydrocarbon gas liquid)

2021:

A record-breaking year for electricity demand and extreme weather



Report

January 2022

BC Hydro
Power smart

2021: A record-breaking year for electricity demand and extreme weather

From extreme heat and cold, to unprecedented rainfall, British Columbia experienced wild and devastating weather in 2021. BC Hydro's hydroelectric system is directly impacted by variations in weather, and in 2021 more electricity demand records were broken than any other year prior, largely because of the back-to-back extreme temperatures lasting for days and weeks on end. Although BC Hydro research[1] shows 76 per cent of British Columbians are more concerned than ever about grid reliability due to extreme weather and climate change, BC Hydro is well positioned because of its flexible hydroelectric system to provide safe, clean and reliable electricity to its customers through extreme weather events and increases in demand.

Highlights

- New data shows BC Hydro experienced more record system peak loads – the hour in a day that customers use the most electricity–in 2021 than ever before.
- While BC Hydro remains a winter-peaking utility, extreme weather caused by climate change is driving higher summer consumption.
- In fact, BC Hydro experienced record-breaking demand for electricity in both summer and winter 2021, a trend that is expected to continue.
- In summer 2021, some places in B.C. broke temperature records, and BC Hydro experienced 19 of its top 25 all-time summer daily peak records.
  - O This includes breaking its all-time summer peak hourly demand record.
- Similarly, the 2021 holiday season saw extremely cold temperatures and heavy snow throughout B.C. that resulted in the highest and longest sustained load levels ever experienced on the BC Hydro system.
  - Overall, this winter so far, BC Hydro has experienced 11 of its top 25 all-time daily peak records.
  - BC Hydro has broken the peak record five times in the past five years.
- Peak demand patterns have also changed since the first year of the COVID-19 pandemic.
  - When the previous peak hourly load record was broken in January 2020, load displayed sharper increases and decreases throughout the day, suggesting more typical weather and behaviour.
  - In contrast, the 2021 peak load built up more gradually throughout the day, suggesting more British Columbians were likely working from home, or home for the holidays — waking up later and home earlier in the evening — as well as colder weather than average.
- The record-breaking electricity demand can be tied to B.C. experiencing extreme temperatures in both summer and winter that lasted for extended periods of time.
- Current climate models suggest a warming trend continuing in years to come which could increase demand year-round, and fortunately, BC Hydro's flexible hydroelectric system can meet changes in demand quickly.
- To meet increased demand, including from electrification, BC Hydro is preparing its system for increasingly challenging and unpredictable weather brought on by climate change. While the exact nature of British Columbia's future climate remains uncertain, BC Hydro is working to ensure that it is ready.

Solutions

BC Hydro's goal is to have the adaptive capacity to continue to safely provide its customers with reliable, affordable, clean electricity. BC Hydro is well positioned to meet increases in demand and can also help people reduce their carbon footprint:

1 Online survey by Majid Khoury of 801 British Columbians from Sept 24 to Sept 27, 2021. Margin of error: 3.46%.

- BC Hydro has a surplus of electricity and expects to have more than it needs until about 2030. BC Hydro's 20- year **Integrated Resource Plan** maps out how it will meet future demand for electricity through a combination of energy conservation and the development of generation resources.
- BC Hydro is encouraging electrification. British Columbians can reduce greenhouse gas emissions and help mitigate the effects of climate change by switching to hydroelectricity from fossil fuels: an electric heat pump can cool in the summer and heat in the winter, while electric vehicles significantly reduce greenhouse gas emissions.

Wild weather, changing patterns

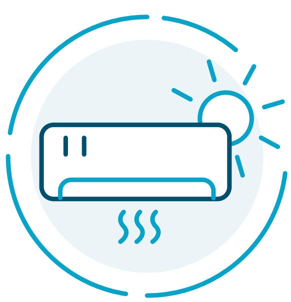
Extreme weather hit British Columbia hard in 2021, with temperature records broken in both the summer and winter in some parts of the province, and unprecedented levels of rainfall from multiple atmospheric rivers. In fact, B.C.'s June heat dome and November flooding topped Environment Canada's list of worst weather events of 2021.[2] Research conducted on behalf of BC Hydro found British Columbians are experiencing increasing anxiety over these weather events – with 76 per cent saying they are more concerned than ever about grid reliability due to extreme weather and climate change.

Unlike utilities in Ontario and Quebec, BC Hydro normally experiences peak electricity demand in the winter months, when British Columbians turn up their heating systems and leave lights and appliances on longer. However, extreme weather in recent years is slowly changing this pattern. Although winter peaks remain higher than summer peaks, new data shows BC Hydro experienced more daily system peak loads in 2021 than ever before, in both summer and winter. This report will explore the record-breaking year in demand and how BC Hydro is fully prepared to provide safe, reliable power as the province faces more challenging weather in the years to come.

Cruel summer

In summer 2021, several places in B.C. broke temperature records, most notably Lytton, B.C. which reached a high of 49.6°C – the highest temperature ever recorded anywhere in Canada. That same week, 90 per cent of the village of Lytton burned in a tragic wildfire. The unprecedented heat also caused record-breaking demand for electricity, as British Columbians turned to using air conditioning more than ever before.

With traditionally cooler summers compared to other parts of the country, especially in the Lower Mainland and on Vancouver Island, B.C. has always fallen far below the national average when it comes to air conditioning use. However, with extreme temperatures becoming the norm, air conditioning use has grown - increasing by about 50 per cent over the past decade from a quarter of British Columbians using it at home to nearly 40 per cent.[3]



On June 28, 2021 BC Hydro broke its all-time summer peak demand record at 8,568 megawatts – breaking the previous record by 600 megawatts - the equivalent of turning on 600,000 portable air conditioners.

In 2021, record-breaking temperatures and an increased number of air conditioning users drove summer peak hourly demand – the time of day British Columbians use the most power – to all-time highs. In fact, this summer BC Hydro experienced 19 of its top 25 all-time summer daily peak hours for system load. This includes breaking its all-time summer peak hourly demand record on June 28, 2021 when demand reached 8,568 megawatts, shattering the record that was set before the heat wave began by more than 600 megawatts – the equivalent of turning on 600,000 portable air conditioners.

2 Environment and Climate Change Canada
3 BC Hydro Residential End Use Survey 2020

Winter wonderland demand

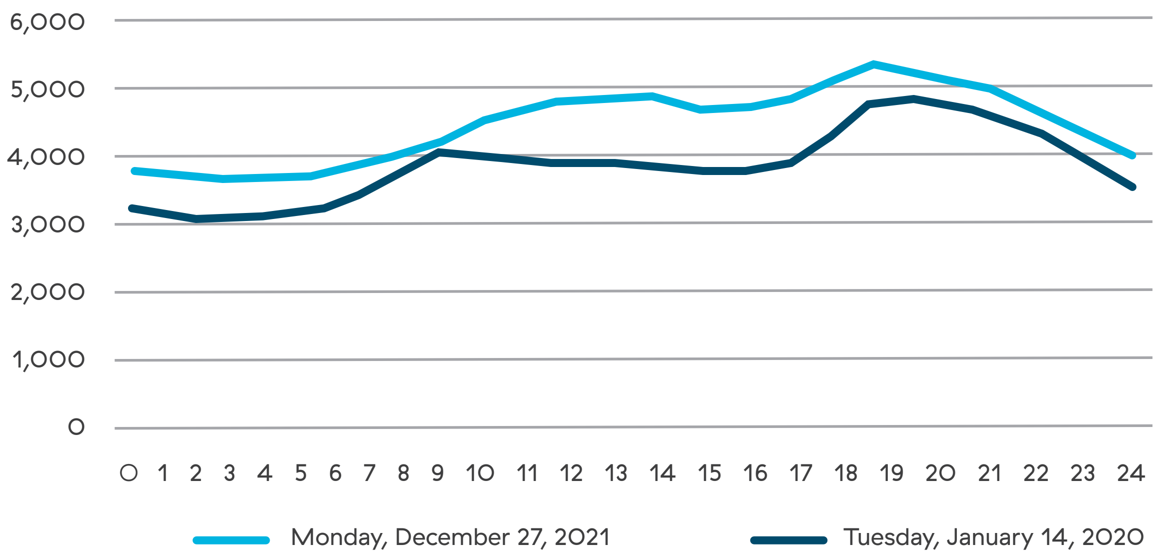
Much like the extreme heat experienced this past summer, the 2021 holiday season saw extremely cold temperatures and heavy snow throughout B.C. that resulted in the highest and longest sustained load levels ever experienced on the BC Hydro system.

Overall, this winter so far, BC Hydro has experienced 11 of its top 25 all-time daily system peak load hours ever. In fact, on December 27, BC Hydro broke its all-time peak hourly demand record at 10,787 megawatts.[4] To put things in further perspective, BC Hydro has broken the peak record five times in the past five years.

Peak demand patterns have also changed since the first year of the COVID-19 pandemic.

When the previous peak hourly load record was broken in January 2020, load displayed sharper increases and decreases throughout the day. In contrast, the 2021 peak load built up more gradually throughout the day, suggesting more British Columbians were likely working from home, or home for the holidays — waking up later and home earlier in the evening — as well as colder weather than average.

Residential hourly load peak record: 2020 vs. 2021



Typically, BC Hydro records the highest demand for electricity on weekday evenings when British Columbians come home, turn up the heat, and switch on lighting and appliances. However, while residential electricity use can increase, on average, by 88 per cent in the colder, darker, winter months, the increase has been even more pronounced in recent years as climate change creates stronger storms and cold snaps that last for days — and sometimes weeks- on end.

How BC hydro is preparing

The record-breaking electricity demand that BC Hydro saw in 2021 is tied to B.C. experiencing extreme temperatures in both summer and winter that lasted for extended periods of time. Fortunately, BC Hydro's flexible hydroelectric system can meet changes in demand quickly and BC Hydro's asset management and emergency management processes have continuously evolved to prepare for and effectively respond to increasingly severe weather-related events and changes in electricity demand.

4 The original load number of 10,902 listed in a previous media release has been adjusted based on new data.

BC Hydro has a surplus of electricity and expects to have more than it needs until about 2030. BC Hydro's 20-year **Integrated Resource Plan** maps out how it will meet future demand for electricity through a combination of energy conservation and the development of additional generation resources.

BC Hydro has the tools and expertise to continue to manage the unpredictable weather and climate change. This includes in-house weather forecasting and ensemble runoff forecasting, operations planning optimization methods, and its own climate, water and snow monitoring network. It is also a contributing partner in complementary networks in B.C. for water, climate, snow and glacier monitoring.

Electrification and climate change

Mitigating the effects of climate change can be done by significantly reducing greenhouse gas emissions through electrification. Here in British Columbia, we are in a unique position for electrification given the abundance of clean electricity available. About 98 per cent of the power BC Hydro generates already comes from clean or renewable resources, mostly from its hydroelectric resources that are powered by water.

BC Hydro's Electrification Plan aims to reduce greenhouse gas emissions in the province by 900,000 tonnes per year by April 2026 – that is around the same as taking 200,000 gas-powered cars off the road for one year. While British Columbia has more than enough power to keep up with changes in demand, British Columbians are encouraged to do the following to help reduce greenhouse gas emissions:

- Purchase a heat pump: Installing an electric heat pump in place of a gas furnace will significantly reduce home heating emissions, and provides the added benefit of not only heating, but cooling in the hotter months. Rebates up to $11,000 are available for installation when switching from a gas furnace.
- Switch to an EV: driving an EV pays off in many ways including saving 80 per cent on fuel costs and lowering your carbon footprint. Rebates up to $3,000 on the purchase of an EV are available, with another $5,000 available through federal rebates.

CS–1677

BC Hydro
Power smart

https://www.blackrock.com/corporate/investor-relations/larry-fink-ceo-letter

LARRY FINK'S 2022 LETTER TO CEOS:

The Power of Capitalism

Dear CEO,

Each year I make it a priority to write to you on behalf of BlackRock's clients, who are shareholders in your company. The majority of our clients are investing to finance retirement. Their time horizons can span decades.

The financial security we seek to help our clients achieve is not created overnight. It is a long-term endeavor, and we take a long-term approach. That is why, for the past decade, I have written to you, as CEOs and Chairs of the companies our clients are invested in. I write these letters as a fiduciary for our clients who entrust us to manage their assets – to highlight the themes that I believe are vital to driving durable long-term returns and to helping them reach their goals.

When my partners and I founded BlackRock as a startup 34 years ago, I had no experience running a company. Over the past three decades, I've had the opportunity to talk with countless CEOs and to learn what distinguishes truly great companies. Time and again, what they all share is that they have a clear sense of purpose; consistent values; and, crucially, they recognize the importance of engaging with and delivering for their key stakeholders. This is the foundation of stakeholder capitalism.

Stakeholder capitalism is not about politics. It is not a social or ideological agenda. It is not "woke." *It is capitalism*, driven by mutually beneficial relationships between you and the employees, customers, suppliers, and communities your company relies on to *prosper*. This is the power of capitalism.

In today's globally interconnected world, a company must create value for and be valued by its full range of stakeholders in order to deliver long-term value for its shareholders. It is through effective stakeholder capitalism that capital is efficiently allocated, companies achieve durable profitability, and value is created and sustained over the long-term. Make no mistake, the fair pursuit of profit is still what animates markets; and long-term profitability is the measure by which markets will ultimately determine your company's success.

At the foundation of capitalism is the process of constant reinvention – how companies must continually evolve as the world around them changes or risk being replaced by new competitors. The pandemic has turbocharged an evolution in the operating environment for virtually every company. It's changing how people work and how consumers buy. It's creating new businesses and destroying others. Most notably, it's dramatically accelerating how technology is reshaping life and business. Innovative companies looking to adapt to this environment have easier access to capital to realize their visions than ever before. And the relationship between a company, its employees, and society is being redefined.

COVID-19 has also deepened the erosion of trust in traditional institutions and exacerbated polarization in many Western societies. This polarization presents a host of new challenges for CEOs.

Political activists, or the media, may politicize things your company does. They may hijack your brand to advance their own agendas. In this environment, facts themselves are frequently in dispute, but businesses have an opportunity to lead. Employees are increasingly looking to their employer as the most trusted, competent, and ethical source of information – more so than government, the media, and NGOs.

That is why your voice is more important than ever. It's never been more essential for CEOs to have a consistent voice, a clear purpose, a coherent strategy, and a long-term view. Your company's purpose is its north star in this tumultuous environment. The stakeholders your company relies upon to deliver profits for shareholders need to hear directly from you – to be engaged and inspired by you. They don't want to hear us, as CEOs, opine on every issue of the day, but they do need to know where we stand on the societal issues intrinsic to our companies' long-term success.

Putting your company's purpose at the foundation of your relationships with your stakeholders is critical to long-term success.

Putting your company's purpose at the foundation of your relationships with your stakeholders is critical to long-term success. Employees need to understand and connect with your purpose; and when they do, they can be your staunchest advocates. Customers want to see and hear what you stand for as they increasingly look to do business with companies that share their values. And shareholders need to understand the guiding principle driving your vision and mission. They will be more likely to support you in difficult moments if they have a clear understanding of your strategy and what is behind it.

A new world of work

No relationship has been changed more by the pandemic than the one between employers and employees. The quit rate in the US and the UK is at historic highs. And in the US, we are seeing some of the highest wage growth in decades. Workers seizing new opportunities is a good thing: It demonstrates their confidence in a growing economy.

While turnover and rising pay are not a feature of every region or sector, employees across the globe are looking for more from their employer – including more flexibility and more meaningful work. As companies rebuild themselves coming out of the pandemic, CEOs face a profoundly different paradigm than we are used to. Companies expected workers to come to the office five days a week. Mental health was rarely discussed in the workplace. And wages for those on low and middle incomes barely grew.

That world is gone.

Workers demanding more from their employers is an essential feature of effective capitalism. It drives prosperity and creates a more competitive landscape for talent, pushing companies to create better, more innovative environments for their employees – actions that will help them achieve greater profits for their shareholders. Companies that deliver are reaping the rewards. Our research shows that companies who forged strong bonds with their employees have seen lower levels of turnover and higher returns through the pandemic.[1]

Companies not adjusting to this new reality and responding to their workers do so at their own peril. Turnover drives up expenses, drives down productivity, and erodes culture and corporate memory. CEOs need to be asking themselves whether they are creating an environment that helps them compete for talent. At BlackRock we are doing the same: working with our own employees to navigate this new world of work.

Creating that environment is more complex than ever and reaches beyond issues of pay and flexibility. In addition to upending our relationship with where we physically work, the pandemic also shone a light on issues like racial equity, childcare, and mental health – and revealed the gap between generational expectations at work. These themes are now center stage for CEOs, who must be thoughtful about how they use their voice and connect on social issues important to their employees. Those who show humility and stay grounded in their purpose are more likely to build the kind of bond that endures the span of someone's career.

At BlackRock, we want to understand how this trend is impacting your industry and your company. What are you doing to deepen the bond with your employees? How are you ensuring that employees of all backgrounds feel safe enough to maximize their creativity, innovation, and productivity? How are you ensuring your board has the right oversight of these critical issues? Where and how we work will never be the same as it was. How is your company's culture adapting to this new world?

New sources of capital fueling market disruption

Over the past four decades, we have seen an explosion in the availability of capital. Today, global financial assets total $400 trillion.[2] This exponential growth brings with it risks and opportunities for investors and companies alike, and it means that banks alone are no longer the gatekeepers to funding.

Young, innovative companies have never had easier access to capital. Never has there been more money available for new ideas to become reality. This is fueling a dynamic landscape of innovation. It means that virtually every sector has an abundance of disruptive startups trying to topple market leaders. CEOs of established companies need to understand this changing landscape and the diversity of available capital if they want to stay competitive in the face of smaller, more nimble businesses.

BlackRock wants to see the companies we invest in for our clients evolve and grow so that they generate attractive returns for decades to come. As long-term investors, we are committed to working with companies from all industries. But we too must be nimble and ensure our clients' assets are invested, consistent with their goals, in the most dynamic companies – whether startups or established players – with the best chances at succeeding over time. As capitalists and as stewards, that's our job.

I believe in capitalism's ability to help individuals achieve better futures, to drive innovation, to build resilient economies, and to solve some of our most intractable challenges. Capital markets have allowed companies and countries to flourish. But access to capital is not a right. It is a privilege. And the duty to attract that capital in a responsible and sustainable way lies with you.

Capitalism and sustainability

Most stakeholders – from shareholders, to employees, to customers, to communities, and regulators – now expect companies to play a role in decarbonizing the global economy. Few things will impact capital allocation decisions – and thereby the long-term value of your company – more than how effectively you navigate the global energy transition in the years ahead.

It's been two years since I wrote that climate risk is investment risk. And in that short period, we have seen a tectonic shift of capital.[3] Sustainable investments have now reached $4 trillion.[4] Actions and ambitions towards decarbonization have also increased. This is just the beginning – the tectonic shift towards sustainable investing is still accelerating. Whether it is capital being deployed into new ventures focused on energy innovation, or capital transferring from traditional indexes into more customized portfolios and products, we will see more money in motion.

Every company and every industry will be transformed by the transition to a net zero world. The question is, will you lead, or will you be led?

In a few short years, we have all watched innovators reimagine the auto industry. And today, every car manufacturer is racing toward an electric future. The auto industry, however, is merely on the leading edge – every sector will be transformed by new, sustainable technology.

Engineers and scientists are working around the clock on how to decarbonize cement, steel, and plastics; shipping, trucking, and aviation; agriculture, energy, and construction. I believe the decarbonizing of the global economy is going to create the greatest investment opportunity of our lifetime. It will also leave behind the companies that don't adapt, regardless of what industry they are in. And just as some companies risk being left behind, so do cities and countries that don't plan for the future. They risk losing jobs, even as other places gain them. The decarbonization of the economy will be accompanied by enormous job creation for those that engage in the necessary long-term planning.

The next 1,000 unicorns won't be search engines or social media companies, they'll be sustainable, scalable innovators – startups that help the world decarbonize and make the energy transition affordable for all consumers. We need to be honest about the fact that green products often come at a higher cost today. Bringing down this green premium will be essential for an orderly and just transition. With the unprecedented amount of capital looking for new ideas, incumbents need to be clear about their pathway succeeding in a net zero economy. And it's not just startups that can and will disrupt industries. Bold incumbents can and must do it too. Indeed, many incumbents have an advantage in capital, market knowledge, and technical expertise on the global scale required for the disruption ahead.

Our question to these companies is: what are you doing to disrupt your business? How are you preparing for and participating in the net zero transition? As your industry gets transformed by the energy transition, will you go the way of the dodo, or will you be a phoenix?

We focus on sustainability not because we're environmentalists, but because we are capitalists and fiduciaries to our clients.

We focus on sustainability not because we're environmentalists, but because we are capitalists and fiduciaries to our clients. That requires understanding how companies are adjusting their businesses for the massive changes the economy is undergoing. As part of that focus, we are asking companies to set short-, medium-, and long-term targets for greenhouse gas reductions. These targets, and the quality of plans to meet them, are critical to the long-term economic interests of your shareholders. It's also why we ask you to issue reports consistent with the Task Force on Climate-related Financial Disclosures (TCFD): because we believe these are essential tools for understanding a company's ability to adapt for the future.

The transition to net zero is already uneven with different parts of the global economy moving at different speeds. It will not happen overnight. We need to pass through shades of brown to shades of green. For example, to ensure continuity of affordable energy supplies during the transition, traditional fossil fuels like natural gas will play an important role both for power generation and heating in certain regions, as well as for the production of hydrogen.

The pace of change will be very different in developing and developed countries. But all markets will require unprecedented investment in decarbonization technology. We need transformative discoveries on a level with the electric light bulb, and we need to foster investment in them so that they are scalable and affordable.

As we pursue these ambitious goals - which will take time - governments and companies must ensure that people continue to have access to reliable and affordable energy sources. This is the only way we will create a green economy that is fair and just and avoid societal discord. And any plan that focuses solely on limiting supply and fails to address demand for hydrocarbons will drive up energy prices for those who can least afford it, resulting in greater polarization around climate change and eroding progress.

Divesting from entire sectors – or simply passing carbon-intensive assets from public markets to private markets – will not get the world to net zero. And BlackRock does not pursue divestment from oil and gas companies as a policy. We do have some clients who choose to divest their assets while other clients reject that approach. Foresighted companies across a wide range of carbon intensive sectors are transforming their businesses, and their actions are a critical part of decarbonization. We believe the companies leading the transition present a vital investment opportunity for our clients and driving capital towards these phoenixes will be essential to achieving a net zero world.

Capitalism has the power to shape society and act as a powerful catalyst for change.

Capitalism has the power to shape society and act as a powerful catalyst for change. But businesses can't do this alone, and they cannot be the climate police. That will not be a good outcome for society. We need governments to provide clear pathways and a consistent taxonomy for sustainability policy, regulation, and disclosure across markets. They must also support communities affected by the transition, help catalyze capital for the emerging markets, and invest in the innovation and technology that will be essential to decarbonizing the global economy.

It was the partnership between government and the private sector that led to the development of COVID-19 vaccines in record time. When we harness the power of both the public and private sectors, we can achieve truly incredible things. This is what we must do to get to net zero.

Empowering clients with choice on ESG votes

Stakeholder capitalism is all about delivering long-term, durable returns for shareholders. And transparency around your company's planning for a net zero world is an important element of that. But it's just one of many disclosures we and other investors ask companies to make. As stewards of our clients' capital, we ask businesses to demonstrate how they're going to deliver on their responsibility to shareholders, including through sound environmental, social, and governance practices and policies.

In 2018, I wrote that we would double the size of our stewardship team and it remains the largest in the industry. We've built this team so we can understand your company's progress throughout the year, not just during proxy season. It's up to you to chart your own course and to tell us how you're moving forward. We seek to understand the full range of issues that you face, not just the ones on the ballot – and that includes your long-term strategy.

Just as other stakeholders are adjusting their relationships with companies, many people are rethinking their relationships with companies as shareholders. We see a growing interest among shareholders – including among our own clients – in the corporate governance of public companies. That is why we are pursuing an initiative to use technology to give more of our clients the option to have a say in how proxy votes are cast at companies their money is invested in. We now offer this option to certain institutional clients, including pension funds that support 60 million people. We are working to expand that universe.

We are committed to a future where every investor – even individual investors – can have the option to participate in the proxy voting process if they choose.

We know there are significant regulatory and logistical hurdles to achieving this today, but we believe this could bring more democracy and more voices to capitalism. Every investor deserves the right to be heard. We will continue to pursue innovation and work with other market participants and regulators to help advance this vision toward reality.

Of course, many corporate leaders are responsible for overseeing equity assets, whether through employee pension funds, corporate treasury accounts, or other investments your company makes. I encourage you to ask that your asset manager gives you the opportunity to participate in the proxy voting process more directly.

BlackRock's Investment Stewardship team remains core to our fiduciary approach, and many of our clients prefer that the team continues to engage and execute voting on their behalf. But fundamentally, clients should at least be given the choice and chance to participate in voting more directly.

Our conviction at BlackRock is that companies perform better when they are deliberate about their role in society and act in the interests of their employees, customers, communities, and their shareholders.

However, we also believe that there is still much to learn about how a company's relationship with stakeholders impacts long-term value. That's why we are launching a Center for Stakeholder Capitalism, to create a forum for research, dialogue, and debate. It will help us to further explore the relationships between companies and their stakeholders and between stakeholder engagement and shareholder value. We will bring together leading CEOs, investors, policy experts, and academics to share their experience and deliver their insights.

Delivering on the competing interests of a company's many divergent stakeholders is not easy. As a CEO, I know this firsthand. In this polarized world, CEOs will invariably have one set of stakeholders demanding that we do one thing, while another set of stakeholders demand that we do just the opposite.

That is why it is more important than ever that your company and its management be guided by its purpose. If you stay true to your company's purpose and focus on the long term, while adapting to this new world around us, you will deliver durable returns for shareholders and help realize the power of capitalism for all.

Sincerely,

Larry Fink

Chairman and Chief Executive Officer

Excerpts from CNBC posted transcript of excerpts from CNBC Squawk Box Andrew Ross-Sorkin interview with BlackRock CEO Larry Fink on Jan 18, 2022.

Excerpt from CNBC posted transcript of the Fink interview [LINK]

SORKIN: So, one of the things that you have been very outspoken about and have singularly perhaps changed the conversation in boardrooms around the country and around the world is about the environment, and really pushing companies to focus more on the environment. But at the same time, you say in this letter this year, you say, "We focus on sustainability not because we're environmentalists, but because we are capitalists and fiduciaries to our clients." And so maybe this is a chicken and the egg kind of thing here. But how much of this is your view that the environment really does matter? And how much of it is your view that the profits matter? And you think it's gonna come because people are focused on the environment?

FINK: I am just as much as a, as focused on environmental issues as I've ever been. And I believe we need to be moving forward. And I'm really pleased to say that $4 trillion of money has moved into more sustainable strategies and it's accelerating. I talked about in my, in my 2020 letter about the tectonic shift that we are seeing, we are going to see it if anything COVID and the way we live and work today has accelerated the investments towards sustainability. But that being said, I had a great deal of frustration in 2021 about the means in which we're moving forward. I wrote over the last few years about to move forward in a more sustainable decarbonized world, it requires a combination of government and private sector and that's just not happening. We are not seeing the totality of society moving forward together. We need to be working with hydrocarbon companies, not against them. We need to be working with the communities that are involved in hydrocarbons, not against them. But we also need to be working with all, with new startup companies to rapidly deploy and create new technologies so we can get to a decarbonized world by 2050. At the present pace, Andrew, we're not going to get there.

SORKIN: How do you distinguish and how should the public and the investor class distinguish between a hydrocarbon company that you think is on the good side of being a hydrocarbon company and a hydrocarbon company that you think is on the bad side? Because right now, it appears but oftentimes these things are thought of in a very binary way. You're either a hydrocarbon company, or you're not.

FINK: Society is dependent on hydrocarbons right now. We are, you know, we will not survive with the society that we are talking to without hydrocarbons right now. We need to rapidly admit that and we need to have fair and just solutions about how do we utilize hydrocarbons as we move more towards a decarbonized way. We need to be advancing ideas about green and blue hydrogen. We need to be advancing new ideas and creating new mechanisms to decarbonize steel and decarbonize cement. We need to find technologies to, to so we can afford the sequestering of carbon. These are all going to be the tools in which we can create a more sustainable world, but it has to be done together. It's not going to happen overnight. If we want to just admonish the hydrocarbon companies today and say stop investing, get out of your business. We're going to have a very unequal outcome.

let's use this competitive advantage. What is your view? Is Europe still upfront in the ESG field, or is there a shift and balance here?

Laurence Fink

First, I would answer, Jörg, to say it's not a race. It's certainly not a competitive race. No question, society in Europe stated that sustainability is a societal risk. In the United States, it took a number of years for society and government to start talking that way. It was harder in the United States to move forward when government was saying climate risk was not a societal risk. I think, globally now, including Asia and China, our conversations, and this began about two years ago, are saying -- more and more societies are saying climate risk is a societal risk.

And once you go over that hurdle, then you have more cooperation. And that's what we're seeing now. And to me, I see a huge movement, very accelerated movement by the Biden administration. I see huge movement by investors now in the United States. I don't think it matters who's first or second on this, because this is not a race. We're all trying to improve society and improve the earth's health. And so I would start there. But I would say -- saying it's a societal risk and actually moving to a true net zero, that's the difficulty. Okay. We can all believe in it, but now getting there we're not seeing what I would say an aggressive stance by many governments yet.

They're talking the talk. Many societies, including Europe, are talking the talk but not walking the talk. Because to really get to a net zero, we don't have the science yet. A great article today about as much as airlines want to move forward on more sustainable, they can't do it yet. Biofuels right now are 50% to 60% more expensive than hydrocarbons. The margins on airlines is so severe. Now, basically, if we want to get every airline to use biofuels, I think within a number of years, we could do it. But are we then really getting back to your inflation story in question? Maybe that it will reduce the cost differential of the green premium. But to do that, are we willing to say to everybody in the world that you're going to be -- your cost of flying is up 30% to offset the cost or whatever the differential is?

Jörg Eigendorf

Should it be up 30%, because it's external costs of environmental damage? Should it be up 30%?

Laurence Fink

With the cost of flying or the biofuel costs?

Jörg Eigendorf

No, the cost for carbon -- for cost for flying in general?

Laurence Fink

Yes, did we create a giant carbon tax is that what you're referring to that offsets it? The problem is it displaces so many jobs. It displaces -- I don't think politically you can do that day one, it displaces jobs. When I write in my CEO letters, a transition has to be fair and just. And so if you can tell me we can increase a carbon tax to X, Y without displacing jobs, without having regional inequalities, without having all these other issues, let's do it. It's just not feasible now. Now, what is feasible that I don't see movement in Europe. If Europe really is about this, and if the U.S. is really going to be about this, to name two parts of the world, we need to develop a continental power grid.

Okay. We all know we're going to move to electric cars. We now have solar and wind having no green premium versus any other source of energy today. Now it's intermittent. We have to have storage and all that. But that's a great example of these issues. It took 30 years to bring the cost of solar and wind back down to the same level of other hydrocarbon costs. We need to do that for every industry. So what I'm trying to suggest is, and this is why I say transition is an opportunity, but it's an opportunity because we have to be investing more and more.

We need to do the R&D. Governments are going to need to do much more R&D in credits on developing new science and technologies. It's not just about the carbon tax. Here's my issue in many of the countries of Europe. If they really want to have a true carbon tax, shouldn't 100% of the revenue from carbon tax go into green? In many countries in Europe, the carbon tax goes to balance a budget. Okay. That's not a good solution. And so what I'm trying to say is, it's not so simple here. And my last thing I would like to say, and I'm saying it loudly to every person who will listen to me, if society believes that all public companies need to now report under TCFD, the IFR standards, whatever standard one wants to use, it can't just ask public companies of doing it and not ask for a society.

Right now, what we are seeing worldwide is a movement by regulators and policymakers moving very rapidly for disclosure of public companies. You see that in Europe right now, some countries have mandated it. But there's no conversation about the rest of society. So the burden is, if Deutsche Bank and BlackRock tomorrow needed to report under TCFD Scope 3, which is all our supply chains, we are then the policeman. We are the organization that is policing the down streaming. I don't think politically that's going to work. They're going to hate us more than ever; big companies, banks, because isn't it the responsibility of government setting policy that policy is good for all of society.

But right now, all I'm seeing is mostly governments and regulators are asking public companies to move forward. BlackRock is too, by the way. We don't manage a lot of private money. But the key of getting this done to really get into net zero, and to doing it effectively, is that asking all the society moving together. And the last thing, if we only ask public companies to disclose and to report, if they don't ask the rest of society, we're going to have some very important companies that are in hydrocarbons or chemicals to go private. And that's not a solution. That doesn't change the net zero of the world.

Two, what we have witnessed in Europe are some of the hydrocarbon companies what they do, they sell some of the worst and dirtiest of their assets. And that's considered good. We as a shareholder like how those companies look now because they have less of a carbon footprint. But the world doesn't change. It just goes from a transparent organization to an opaque organization. That is not going to get us to where we want to go as a society. And so these are issues we need to ask. And so I'm urging everybody to focus on this in a societal way, not just with public companies. And we need regulators.

When you ask Christian about coming together, if we could get one thing done in the G20s, the COP26 is have a one taxonomy, which we don't have at the moment, so we can judge companies worldwide in the same way. But two, we come to terms with the idea that we're trying to get all parts of society moving together, not just public companies, or we're going to have this incredible arbitrage of companies leaving the private -- leaving public domain into the private domain. We're going to see a lot of the worst assets just going into the private domain, then we don't change the world.

Jörg Eigendorf

Thank you, Larry. You touched very important topics here. Effectively, [indiscernible] short is how do we manage this transition? It's not black and white. It's not green or brown. It's how do we get from A to B as quickly as possible? What role for governments to play, what role for banks to play and what role for society?

Christian Sewing

Well, first of all, it's important that we are really not talking about a race, but that we are talking from ambition to impact. We need an impact now and not only the talk, but really impact. By the way, that was the reason why we declared last week or two weeks ago in our sustainability deep dive, that we don't want to even raise our absolute numbers for the time being, but we move it forward by two years in order to have an impact. Number two, the most important, because when we talk about ESG, of course, climate change is super important and it's a societal task. But we have to do it in a way that the S part is not lost on people's mindset. And that's what I'm always saying.

When we talk about the climate change and the transformation, for instance, German corporates have to do, it's our task as the bank to support the transformation integrate, but not to stop in an abrupt way the relationship with corporate. I think that would be the worst thing to do, because you leave something on the table, which is twofold. A, a societal problem in countries like, for instance, Germany or in others and the real issue exactly what Larry is saying is only moved from one country into another because the production will take place but at another part of the world, and it's not addressed.

And in this regard, I really do think that when we talk about the role of banks, the role of regulators; a, we need to take this jointly together with the governments. Secondly, there must be a clear understanding that with a certain ratio to be achieved or implemented by the end of next year, nothing is actually one. We need the understanding that this is a transformation over the next four, five, six years in order to come into the direction of net zero. But if we stop from one day to the other, also what we as public companies are sometimes by some of our shareholders, we do actually nothing good for the long term to the society, to the environment, and it will net zero not help the climate. And therefore, we need the joint understanding that this is a long way of transformation.

In this regard, I think the banks are very much there to support that. This is something where we want to be part of, but we need the understanding that this is a long-term race, that this needs joint understanding of regulators, governments and the private economy. And what Larry is saying is more than true. I can tell you in our M&A activities, in the mandates we are getting, we get so many mandates that we should advise public companies in order to get rid of the so-called bad part of their production facilities. That goes privately. That goes somewhere else where it's not reported. That doesn't help the next generation. That is not the right thing to do. But therefore, we need to change the direction of speech, the direction how people and public companies are measured and we need a different understanding what is really needed.

And getting it right, ESG, getting it right is a 10-year task starting now and it must be a fundamental transformation. For that, the banks are there. And for that, to be honest, we need two other things. You need balance sheet in order to finance it, happy to do this. And in Europe, other than in the U.S., more than ever, we need the Capital Markets Union, because the financing needs in order to transform the economy in Europe cannot only be done by banks. We need a deeper capital market. And therefore, I kept saying and I keep saying the Green Deal in Europe will only come if the Capital Markets will also come -- the Capital Markets Union will come to Europe. The one thing is the necessity for the other and we should jointly work on both.

Jörg Eigendorf

Larry, we see the huge volume targets out and [indiscernible] very clear coming to an end and the final 1.5 minute, we see the huge volume targets out there. What will be the future metrics banks have to follow, companies have to follow? Is it carbon footprint? Is it green asset ratio? What will be the future of what everybody will scrutinize?

Laurence Fink

It has to be more than that. Just to further the conversation that Christian and I just had, Jörg, I don't believe in divestiture of public companies. And so their carbon footprint is going to be larger for a while. But I want to understand how are they evolving into a more green foundational company? How are they moving? How are they creating green hydrogen from regular hydrogen? How are they doing this? Some of the top energy companies are going to be the leaders in the decarbonization component of sequestering carbon.

And so it can't just be done through a metric as saying, and this is some of the risks we have, and we just use carbon footprint, then you have massive divestiture and the world doesn't get anywhere. These are very complex solutions that have to be done. And so to me, it's not about okay, what's your carbon footprint? If they could do it for BlackRock and we could do that, we can measure there. But the companies that are essential in the carbon world, and I'm talking about agricultural companies, because agriculture represents 18% of the footprint of carbon. I'm talking about steel and cement, they represent 10%.

We focus on a lot of other things, but there are many components that create this carbon footprint. It is not about just okay, a numeric number of where's your carbon footprint but I want to understand over this journey, how are you migrating and changing it? How are you creating -- I look at this using a financial term. I use the carbon or let's say energy and oil, that's an iostream. Okay. How are you going to navigate your iostream and create a new stream of revenues? Those are the things that we're going to do this fairly and justly is going to be how we're going to have to do it.

The last thing I just want to say and to link in ESG&E with the question on inflation, let's be clear. If we rush this and if our solution is entirely just to get a green world, we're going to have much higher inflation, because we do not have the technology to do all this yet to have it equivalent to the cheapness of hydrocarbons. And so that's going to be a big policy issue going forward too. Are we going to be willing to accept more inflation if the inflation is to accelerate our green footprint? And that's going to be a big policy question.

Jörg Eigendorf

A final question to both of you and just one word answer before I hand over then to Christian also for the one word answer and his final remarks. But, Larry, with that complex issue, are you an optimist or a pessimist that we get that done fast enough?

Laurence Fink

I've lived my life as being an optimist. Because when we talk about the problems and when we see the problems and the severity of the problems, we solve solutions. That is the beauty of human beings. We proved it with COVID, having a vaccination within 10 months. So if we focus on it, we talk about it, we talk about how severe it is, we'll fix it.

Jörg Eigendorf

Christian, you're an optimist.

Christian Sewing

I couldn't agree more. I think I said in my first answer to one of the question and now it depends on leadership. And if you have the right people around with the right mindset and with the long-term horizon and with the right spirit, to be honest, we will get the stuff. You need now to really get the right people in the world together in order to address it. And we have proven so many things over the last years and decades that I don't think this will stop us.

Question-and-Answer Session

Jörg Eigendorf

Thank you so much for this seventh conversation with Larry Fink on our Global Financial Services and FinTech Conference. I think for everybody who has followed us in the last 40 minutes, Larry, we would like to see an eighth conversation with Larry Fink and Christian next year again. Thank you so much. And thanks to everybody who followed us in the last 40 minutes. Thank you and goodbye.

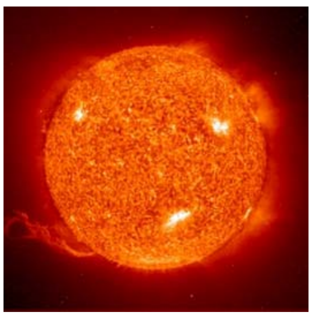
https://www.eia.gov/energyexplained/hydrogen/#:~:text=Hydrogen%20is%20an%20energy%20carrier&text=Hydrogen%2C%20like%20electricity%2C%20is%20an,source%20of%20energy%20or%20fuel.

Independent Statistics & Analysis
U.S. Energy Information Administration

Hydrogen explained
What is hydrogen?

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

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



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

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

Hydrogen is an energy carrier

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

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

Last updated: January 20, 2022

https://www.hydrogenenergysupplychain.com/dawn-of-australias-hydrogen-industry/

Dawn of Australia's Hydrogen Industry

- JANUARY 21, 2022

Today's arrival of the world's first liquefied hydrogen carrier, the Suiso Frontier, in Victoria marks the success of the Hydrogen Energy Supply Chain (HESC) Pilot Project and the dawn of Australia's hydrogen industry.

HESC's vision is to produce carbon neutral hydrogen through extraction from a mix of Latrobe Valley coal and biomass, capturing and storing CO2 via the CarbonNet Project and optimising energy efficiency in the HESC supply chain.

The 225,000 tonnes of carbon neutral liquefied hydrogen (LH2) produced by HESC in a commercial phase will contribute to reducing global CO2 emissions by some 1.8 million tonnes per year (equivalent to the emission of about 350,000 petrol-driven cars), while providing valuable infrastructure for other hydrogen projects in the region.

In a commercial phase, the project will create 30,000 full-time jobs across the Gippsland and Mornington Peninsula regions over the life of the project.

During the Pilot Project, 99.999% pure hydrogen has been produced from Latrobe Valley coal and biomass via gasification, trucked to Hastings, cooled to -253 degrees and subsequently liquified to less than 800 times its gaseous volume to create highly valuable liquefied hydrogen.

The loading of liquefied hydrogen onto the Suiso Frontier for the return journey to Kobe, Japan, makes the HESC Project the most advanced and scalable hydrogen project in Australia and the first project in the world to make, liquefy and transport liquid hydrogen by sea to an international market.

The Australia-Japan HESC partnership is at the cutting edge of creating new technology, cleaner energy, and jobs for both countries.

The learnings from the Pilot will form the basis for further work towards delivering HESC at a commercial scale. Over the next two years, the project partners will undertake extensive research and development of the technical and operational requirements for a commercial-scale project.

Activities that will be undertaken include:

- Continuing to test and demonstrate maritime transport of liquid hydrogen with the Suiso Frontier making further trips between Australia and Japan
- Preparing for regulatory approval processes
- Investigating economics of the commercial scale project and its business model
- Engaging potential 'off-takers' in Australia and Japan
- Further refining and testing of biomass feed stock for hydrogen production (blending with Latrobe Valley coal)
- Improving technologies to reduce costs and carbon intensity across the supply chain. This includes further development of the ortho-para conversion catalyst for creating LH2 in partnership with CSIRO
- Implementing a comprehensive stakeholder engagement program to continue building a social licence in the communities the project would operate in.

The HESC project partners are: Kawasaki Heavy Industries, Ltd (KHI), Electric Power Development Co., Ltd. (J-POWER), Iwatani Corporation (Iwatani), Marubeni Corporation (Marubeni), AGL Energy (AGL) and Sumitomo Corporation (Sumitomo). Royal Dutch Shell (Shell), ENEOS Corporation and Kawasaki Kisen Kaisha, Ltd. (K-Line) are also involved in the Japanese portion of the project.

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https://www.hydrogenenergysupplychain.com/about-hesc/

HOMEABOUT THE PROJECT

About the Project

HESC's Vision

The world-first Hydrogen Energy Supply Chain **(HESC)** Project aims to safely produce and transport clean liquid hydrogen from Australia's Latrobe Valley in Victoria to Kobe in Japan. A key objective of the pilot project is to demonstrate an end-to-end supply chain between both countries.

The Fuel Of The Future

Hydrogen is a clean-burning fuel with a range of uses, from powering vehicles to storing energy. Hydrogen can make a significant contribution to the required transition to clean energy by replacing existing fuels and reducing CO_2 emissions by many gigatonnes and across a broad range of applications.

A Game Changer

The project has the potential to be a game-changer – providing an innovative, economically viable and environmentally conscious solution to producing clean hydrogen safely, through gasification of coal with carbon capture and storage (CCS).

The Pilot Phase

The HESC Project is being developed in two phases, beginning with a pilot, which aims to demonstrate that hydrogen can be produced using Latrobe Valley coal and transported to Japan. Key elements of the **pilot** supply chain include:

- Hydrogen is produced from coal at a newly constructed plant located at AGL's Loy Yang Complex in the Latrobe Valley through a coal gasification and gas-refining Carbon offsets have been purchased to mitigate emissions from the pilot. In the commercial phase, carbon dioxide would be captured during this process and stored deep underground in a process known as carbon capture and storage (CCS).
- The hydrogen gas is transported by truck to a liquefaction and loading terminal at the Port of Hastings, the first of its kind in Australia.
- The hydrogen gas is liquefied and then loaded on to a specially designed marine carrier for shipment to Japan.

The decision to progress to a **commercialisation phase,** which will produce clean hydrogen from coal with CCS, will be made after the pilot project is completed.

Hydrogen has never been shipped in liquid form on this scale before. This is a **world first**.

Why did the HESC Project start?

Climate change is a massive global threat that requires us to pursue a range of clean energy options, now. We are pursuing hydrogen from coal with CCS because **producing hydrogen through electrolysis is currently more expensive**. Additionally, a commercial HESC Project can expand and produce hydrogen at the scale needed to meet growing global hydrogen demand.

Clean hydrogen from HESC will also contribute to emissions reductions, **reducing global CO2 emissions by 1.8 million tonnes per year** (equivalent to the emission of about 350,000 petrol-driven cars), while paving the way for renewable hydrogen projects.

HESC will create jobs for Australians

The current HESC Pilot Project is creating approximately 400 jobs across the Victorian supply chain. It has the potential for thousands more in the commercial phase, including in a region in an economic transition.

Australia could be the first country to create a thriving hydrogen export industry with huge local economic benefits and contribute to global environmental goals. The HESC Project will also help develop critical infrastructure, sustainable jobs, and in-demand skills in Australia. These are crucial ingredients for a clean hydrogen market.

The pioneering pilot project is delivered by a partnership between Japanese and Australian experienced industry partners supported by the Victorian, Australian and Japanese Governments.

When is it happening?

The HESC project has a number of phases. The phase being proposed and discussed now is a small pilot to demonstrate a fully integrated supply chain before starting commercial scale operations.

2018: Approval from local, state, and federal authorities and community engagement for the pilot phase.

2019: **Pilot Phase.** Construction of the pilot facilities began in 2019, following planning approvals. Pilot operations started in 2021 and are expected to run for approximately one year through to 2022.

2020s: The decision to proceed to **commercial phase** will be made in the 2020s with **operations targeted in the 2030s**, depending on the successful completion of the pilot phase, regulatory approvals, social licence to operate and hydrogen demand.

HESC Governance

For funding purposes, the pilot phase is split into different delivery portions – a Japanese funded portion and an Australian funded portion.

Australia

The Australian funded portion is coordinated by Hydrogen Engineering Australia (HEA), a consortium comprised of KHI, J-POWER, Iwatani, Marubeni, AGL and Sumitomo. HEA is a 100 per cent subsidiary of KHI. The Australian and Victorian Governments are providing funds to the Australian portion.

Hydrogen Engineering Australia (HEA) has established an office in Melbourne to administer the project locally.

J-Power Latrobe Valley Pty Ltd (JPLV) is based in Traralgon to manage the Latrobe Valley components of the project. JPLV is a subsidiary of J-Power.

Japan

The Japan funded portion of the HESC pilot phase is coordinated by the CO2-Free Hydrogen Supply Chain Technology Association (HySTRA), acting on behalf of KHI, J-POWER, Iwatani, Shell, Marubeni, ENEOS Corporation and Kawasaki Kisen Kaisha, Ltd. (“K” LINE).

The Japanese funded portion includes converting coal to gas in the Latrobe Valley, transporting liquefied hydrogen by sea and then unloading it in Japan. The Japanese Government is providing funds to the Japanese portion.

HESC Partners

The pioneering project is being delivered by a partnership between Japanese and Australian experienced industry partners and supported by the Victorian, Australian and Japanese Governments.

The consortium of industry partners from Japan and Australia includes Kawasaki Heavy Industries, Ltd (KHI), Electric Power Development Co., Ltd. (J-POWER), Iwatani Corporation (Iwatani), Marubeni Corporation (Marubeni), AGL Energy (AGL) and Sumitomo Corporation (Sumitomo). Royal Dutch Shell (Shell), ENEOS Corporation and Kawasaki Kisen Kaisha, Ltd. (K-Line) are also involved in the Japanese portion of the project.

Supporting Organisations

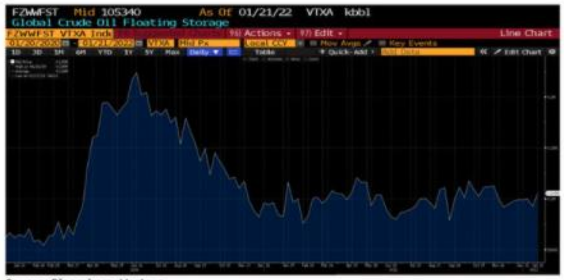
- **CarbonNet** is a joint initiative of the governments of Australia and Victoria aimed at establishing a large-scale commercial Carbon Capture and Storage (CCS) network.

- The **Global CCS Institute** is an international member-led organisation whose mission is to accelerate the deployment of CCS as an imperative technology in tackling climate change and providing energy security.
- **CO2CRC** is Australia's key designer, initiator, and manager of CCS research. The Otway Research Facility is a world-leading project to demonstrate that CCS is a technically and environmentally safe way to make deep cuts into global greenhouse gas emissions. It's Australia's first demonstration of the deep geological storage of CO2 and the world's largest CCS demonstration project. Lessons learned at the Otway facility are shared with partners around the world.

Dan Tsubouchi @Energy_Tidbits · 18h

SAF GROUP

#Vortexa crude #Oil floating storage for 01/21 est 105.34 mmb. No surprise big +19.6 upward revision to 01/14 now at 92.32 mmb (was 72.72 mmb) so no real outliers over past several weeks. Thx @Vortexa @TheTerminal #OOTT



Source: Bloomberg, Vortexa

Jan 22, 2pm MT Estimate

FZWWFST VTXA Inde — 01/20/2020 - 01/21/2022

Date	FZWWFST VT... Mid Px
Fr 01/21/2022	105.34k
Fr 01/14/2022	92319
Fr 01/07/2022	99648
Fr 12/31/2021	99274
Fr 12/24/2021	99329
Fr 12/17/2021	97642
Fr 12/10/2021	94770
Fr 12/03/2021	91781
Fr 11/26/2021	100.434k
Fr 11/19/2021	112.382k
Fr 11/12/2021	111.712k

Jan 15, 1pm MT Estimate

FZWWFST VTXA Inde — 01/13/2020 - 01/14/2022

Date	FZWWFST VT... Mid Px
Fr 01/14/2022	72720
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Fr 12/31/2021	101.377k
Fr 12/24/2021	99808
Fr 12/17/2021	94753
Fr 12/10/2021	93011
Fr 12/03/2021	90672
Fr 11/26/2021	100.755k
Fr 11/19/2021	113.539k
Fr 11/12/2021	110.236k
Fr 11/05/2021	111.433k

Jan 8, 3pm MT Estimate

FZWWFST VTXA Inde — 01/06/2020 - 01/07/2022

Date	FZWWFST VT... Mid Px
Fr 01/07/2022	93780
Fr 12/31/2021	100.715k
Fr 12/24/2021	95632
Fr 12/17/2021	91527
Fr 12/10/2021	85689
Fr 12/03/2021	83841
Fr 11/26/2021	90115
Fr 11/19/2021	100.833k
Fr 11/12/2021	100.522k
Fr 11/05/2021	104.878k
Fr 10/29/2021	91462

Source: Bloomberg, Vortexa

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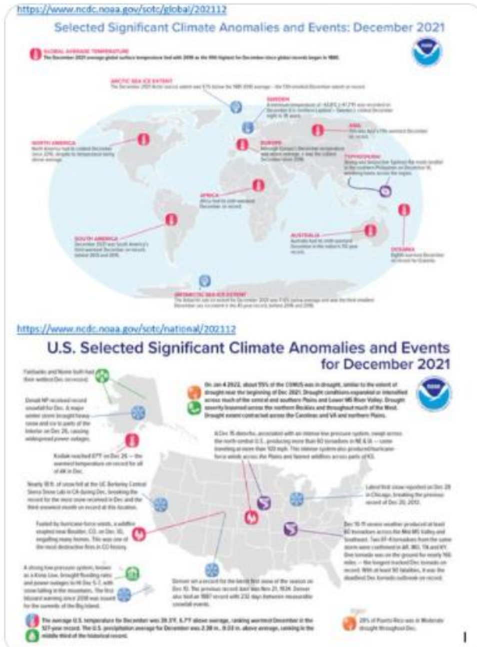
Dan Tsubouchi @Energy_Tidbits · Jan 22

Yes, #LNG prices are off the crazy high prices (EU #Natgas price still really high at ~$25/mcf) but only because Dec was hot in every major #NatGas consuming region. US, hottest Dec ever, Asia 17th hottest ever, EU above average temps. #OOTT



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Dan Tsubouchi @Energy_Tidbits · Jan 22

"europe produces 20% less #NatGas than before thje pandemic & we consume as much. there are only long-term solutions for out of this crisis" ie. #LNG terminals but EU don't do LT supply deals. warns @VanBeurdenShell. lucky Dec was warm. Merci @guillaume_gui @IvanLetessier #OOTT

of excerpt from Le Figaro https://www.lefigaro.fr/societes/shell-pret-a-investir-4-mi

›rêt à investir 4 milliards en France"

:hard, Ivan Letessier

› get out of the energy crisis that Europe is going through?

ırden. *"Don't think this crisis is good for groups like ours. On the contrary, price volati*
:ted companies in the energy transition. Reduce the dependence of our economies on
ht. Governments can take emergency action, but if they neglect the market, the exit
rt and long term, we must increase energy supply. Europe produces 20% less gas thar
consume as much. There are only long-term solutions for out of this crisis, such as fa
ıs terminals liquefied natural to increase imports. The lack of contracts long-term gas

2 5 13

Dan Tsubouchi @Energy_Tidbits · Jan 22

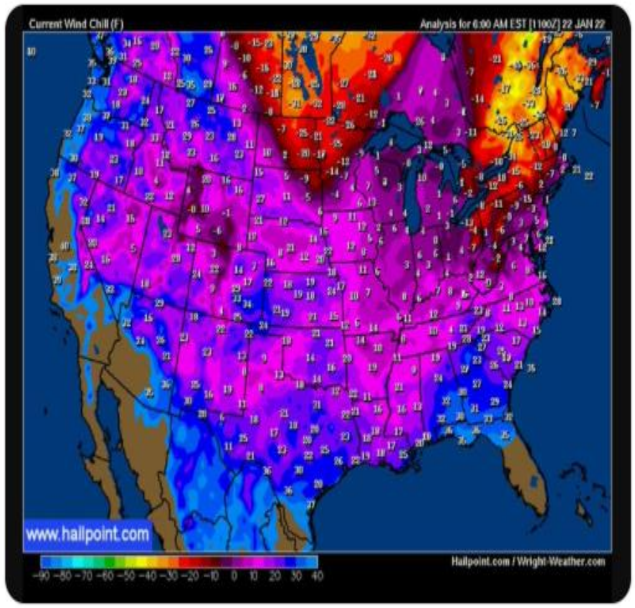
Airfares are going higher for 2020s. "Biofuel for aviation pollutes much less, but it costs 2 to 3 times more than fossil kerosene. It is not competitive, but can become so with public support" @VanBeurdenShell. Big govt subsidies needed. Merci @guillaume_gui @IvanLetessier #OOTT

> Ivan Letessier @IvanLetessier · Jan 22
>
> Ben van Beurden, le patron de Shell est prêt à investir massivement dans les énergies renouvelables en France, et prévient en même temps : «Réduire la dépendance au gaz et au pétrole est infaisable du jour au lendemain» lefigaro.fr/societes/ben-v... via @Le_Figaro

1 5 4

Dan Tsubouchi @Energy_Tidbits · Jan 22

#NatGas furnaces will be working hard across US this am. Supply will be temporarily impacted. Freeze-off hits to production also impact production for #Oil wells that produce associated #NatGas. Plus will delay rig/frac spread moves. Wind chill map from Wright-Weather, LLC. #OOTT

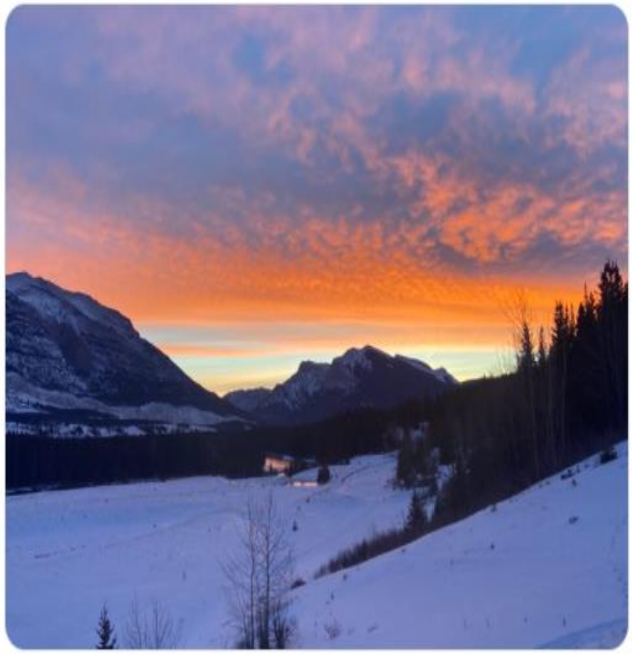


11 33

SAF

Dan Tsubouchi @Energy_Tidbits · Jan 21

another spectacular sunrise in #Canmore in the Cdn Rockies looking east over the Bow River.



20

Dan Tsubouchi @Energy_Tidbits · Jan 21

#Schlumberger Q4, see "material step up in industry capital spending with simaultaneous double-digit growth" in international & NAM. Absent further COVID disruptions, see #Oil demand exceed preCovid by yr end 2022 & further strengthen in 2023. #OOTT

6

Dan Tsouchi Retweeted

Dan Tsubouchi @Energy_Tidbits · Jan 20

Is #Shell FID for #LNGCanada coming soon? @VanBeurdenShell 2022 progress is figure out design to get #LNG plants carbon neutral.Interview w/ Shell staff so must believe is doable & wanted this out there. $BKR announced strategic agreement w/ Shell to reduce emissions. Hmm! #OOTT

Dan Tsubouchi @Energy_Tidbits · Nov 23, 2021

New SAF 11- pg blog just posted "LNG Supply FIDs Starting to Happen, Does Shell Need to Get LNG Canada Phase 2 FID in the Queue To Protect Its Brownfield Advantages?" #LNG #NatGas #OOTT ...

2 1

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Dan Tsubouchi @Energy_Tidbits · Jan 21

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

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

eia U.S. Energy Information Administration

Hydrogen explained
What is hydrogen?

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

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

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

Source: NASA (public domain)

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

Hydrogen is an energy carrier

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

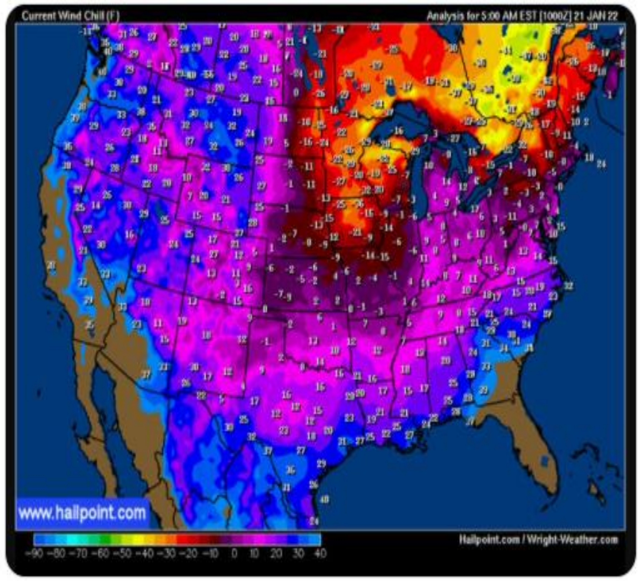
It takes more energy to produce hydrogen (by separating it from other elements in molecules) than hydrogen provides when it is converted to useful energy. However, hydrogen is useful as an energy source/fuel because it has a high energy content per unit of weight, which is why it is used as a rocket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

Last updated: January 20, 2022

3 14 35

Dan Tsubouchi @Energy_Tidbits · Jan 21

#NatGas furnaces will be working hard this morning. Also cause some freeze-offs hits to production that also impact production for #Oil wells that produce associated #NatGas. Current wind chill (not straight temp) map from Wright-Weather, LLC. #OOTT hp2.wright-weather.com/icons/us_chill...



1 3 17

Dan Tsubouchi @Energy_Tidbits · Jan 20

Surprise move, but makes sense. A warm Dec so less winter demand so far. Economy is slowing so reduce burden of high #LNG $ & replace with coal. Less eyes of the world as Olympics end Feb 20 so less worry on clean skies. #Sinopec makes money selling oil linked for spot LNG. #OOTT

> Stephen Stapczynski @SStapczynski · Jan 19
>
> China is trying to sell a lot of LNG into the spot market, indicating the world's top importer is well-stocked 🇨🇳
>
> Sinopec issued a sales tender offering up to 45 cargoes for 2022 delivery (They usually buy)
>
> The surprise move may spur bearish sentiment
>
> bloomberg.com/news/articles/...
>
> Show this thread

2 2

Dan Tsubouchi @Energy_Tidbits · Jan 20

#Houthi long range UAE attack more significant than originally portrayed. @UAEEmbassyUS says not just drones, but also ballistic missiles & cruise missiles, "several were intercepted". reminds THAAD/Patriots effective on ballistic, but not as much so vs cruise/drones. #OOTT

> The Associated Press @AP · Jan 19
>
> Yemen's rebels used cruise missiles, ballistic missiles and drones in an attack on Abu Dhabi this week that killed three people and set off fires at a fuel depot and an international airport, the Emirati ambassador to the United States said. apne.ws/fDssi0c

1 3 6

Dan Tsubouchi @Energy_Tidbits · Jan 20

Looks like #Oil markets tighter than @IEA previously thought. On Wed, IEA said oservable global oil inventories plunged by >600 mmb last year. But based on its estimates of supply and demand - that the decrease should only have been 400 mmb. Thx @alexlongley1 @JLeeEnergy #OOTT

> Alex Longley @alexlongley1 · Jan 20
>
> The International Energy Agency is trying to figure out where 200 million barrels of oil went bloomberg.com/news/articles/... via @markets #OOTT

11 40

Dan Tsubouchi @Energy_Tidbits · Jan 20

Is #Shell FID for #LNGCanada coming soon? @VanBeurdenShell 2022 progress is figure out design to get #LNG plants carbon neutral.Interview w/ Shell staff so must believe is doable & wanted this out there. $BKR announced strategic agreement w/ Shell to reduce emissions. Hmm! #OOTT

Dan Tsubouchi @Energy_Tidbits · Nov 23, 2021

New SAF 11- pg blog just posted "LNG Supply FIDs Starting to Happen, Does Shell Need to Get LNG Canada Phase 2 FID in the Queue To Protect Its Brownfield Advantages?" #LNG #NatGas #OOTT ...

2 1

Dan Tsubouchi @Energy_Tidbits · Jan 20

SAF

1/2. #LNG cycle beginning to accelerate, projects (FIDs) beginning to be pulled forward vs prior expectations w/ strong long term LNG fundamentals & improving environment to secure long term offtake agreements says $BKR @simonelli_l. LT offtake are key to FID #OOTT #NatGas

:rpts from Baker Hughes Q4 call Jan 20

ıs in "italics" are SAF Group created transcript

)am MT. Note that the Q4 call cut out on the specific question on expected orders over the next :ral years and then the rest of the question was cut off. But then Simonelli replies *"sure James, ar k importantly, the order momentum we saw at the end of 2021 is likely to continue into 2022. We :cated over the past quarters that we're seeing an LNG cycle beginning to accelerate. And general ıking, LNG projects are beginning to be pulled forward versus previous expectations due to the str ı term LNG fundamentals and also the improving environment to secure long term offtake :ements. So we also believe the recent policy movement out of Europe, that's encouraging to see ıt would be FIDs in 2023 maybe potentially pulled forward into 2022 as well."*

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

1 5 7

Dan Tsubouchi @Energy_Tidbits · Jan 20

2/2. Asian #LNG buyers abruptly changed to lock in long term supply seeing 2020s supply risk post unplanned delay of 5 bcf/d of Mozambique LNG supply. LT deals are the key for FIDs. A LNG Canada Phase 2 FID would be huge to CAN #NatGas. See Saf 04/28, 07/14, 11/23 blogs. #OOTT

SA

Blog Summary

rownfield LNG FIDs Now Needed To Fill New LNG Sup
ambique Chaos? How About LNG Canada Phase 2?

day April 28, 2021 9:00 MT

nths will determine the size and length of the new LNG supply gap that is hitting harder a
d six months ago. Optimists will say the Mozambique government will bring sustainable s
thern Cabo Delgado province and provide the confidence to Total to quickly get back to L
ch that its LNG in-service delay is a matter of months and not years. We hope so for Moz
on, but will it be that easy for Total's board to quickly look thru what just happened? Total
3 months, restarted development on March 25, but then 3 days of violence led it to susp
28, and announce force majeure on Monday April 26. Even if the optimists are right, Moz
NG supply and the major LNG supply project that are in LNG supply forecasts are now a
cf/d and its follow on Phase 2 of 1.3 bcf/d, and Exxon's Rovuma Phase 1 of 2.0 bcf/d. It
.0 bcf/d of major LNG supply is being counted in LNG supply forecasts and starting in 20
nk the more likely scenario is a delay of at least 2 years in this 5.0 bcf/d from the pre-Co
a much bigger and sooner LNG supply gap starting ~2025 and stronger outlook for LNG
play a role in keeping a lid on LNG prices. But there will be the opportunity for LNG suppl
tial for brownfield LNG projects to fill the growing supply gap. The thought of increasing
rs ago, but there is a much stronger outlook for global oil and gas prices. Oil and gas com
tting capex to small increases in 2021 capex and expecting for higher capex in 2022. We
king at potential FID of brownfield LNG projects before the end of 2021 to be included in
nbique is causing an LNG supply gap that someone will try to fill. And if brownfield LNG
ing at 1.8 bcf/d brownfield LNG Canada Phase 2? Cdn natural gas producers hope so a
natural gas will be tied to Asian LNG markets and not competing in the US against Henr

For Details, Please See The 7 Page Blog
http://www.safgroup.ca/insights/trends-in-the-market/

Blog Summary

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

Blog Summary

LNG Supply FIDs Starting to Happen, Does Shell Need to Get LNG Canada Phase 2 FID in the Queue To Protect Its Brownfield Advantages?

1 4

Dan Tsubouchi @Energy_Tidbits · Jan 20

Japan #LNG imports Dec -8.9% YoY to 10.89 bcf/d. A warm Dec & high LNG inventories (thx @SStapczynski) let Japan redirect some LNG cargos. High LNG prices squeezed out LNG as Dec imports #ThermalCoal +7.0% YoY, #Oil +7.1% YoY, #PetroleumProducts +1.5% YoY #OOTT

Prepared by SAF Group
Japan Monthly LNG Imports

bcf/d	2015	2016	2017	2018	2019	2020	20/19	2021	21/20
Jan	13.06	11.22	12.85	12.79	11.69	11.63	-0.5%	12.48	7.3%
Feb	13.26	12.30	13.36	14.23	12.61	10.99	-12.8%	13.84	25.9%
Mar	12.60	12.62	12.61	12.28	11.30	11.16	-1.2%	11.04	-1.1%
Apr	10.56	10.21	10.52	8.97	9.00	8.31	-7.7%	7.96	-4.3%
May	8.91	8.55	9.66	9.92	8.62	7.09	-17.7%	7.67	8.1%
June	10.61	10.02	9.90	8.88	8.32	8.42	1.2%	9.13	8.5%
July	10.77	10.19	10.19	10.55	10.56	9.35	-11.5%	9.58	2.5%
Aug	10.93	11.96	11.24	11.73	9.45	9.04	-4.3%	9.75	7.8%
Sept	11.06	10.67	9.31	10.04	10.30	10.41	1.0%	8.66	-16.8%
Oct	9.38	9.73	9.50	10.12	9.75	9.20	-5.7%	7.17	-22.1%
Nov	10.71	12.07	10.26	10.15	10.03	9.63	-4.0%	9.38	-2.6%
Dec	12.51	11.69	12.31	11.23	10.54	11.96	13.4%	10.89	-8.9%

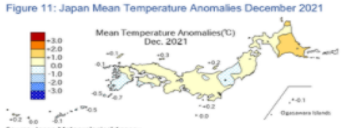
Source: Japan Ministry of Finance

Excerpt SAF Group Jan 16, 2022 Energy Tidbits Memo https://safgroup.ca/news-insights/

Natural Gas – It was a warm December in Japan

We have been noting the warm start to winter and how it has enabled Japan to have high LNG storage levels. Yesterday, the Japan Meteorological Agency posted its recap of December weather [LINK] and their mean temperature anomalies map (below) shows it was above average temperatures month in Japan. Their recap also noted how it got colder in late December "*Strong cold air inflow in late December resulted in heavy snowfall on the sea of Japan side of northern, eastern, and western Japan, and temperature fluctuations were significant over Japan.*"

Figure 11: Japan Mean Temperature Anomalies December 2021



Source: Japan Meteorological Agency

Stephen Stapczynski @SStapczynski · Jan 18

Japan's LNG inventories (held by power utilities) fell to the lowest level since late-May as colder weather boosts demand and Europe hoards shipments of the fuel 🇯🇵

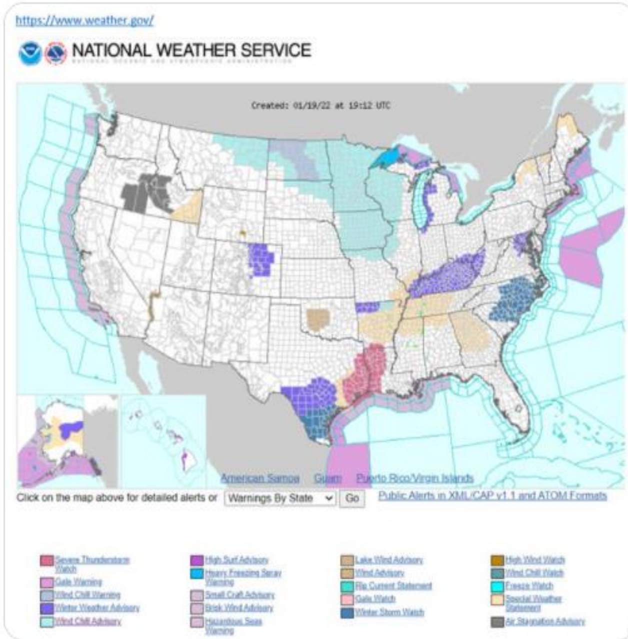
...

Show this thread

2

Dan Tsubouchi @Energy_Tidbits · Jan 19

Expect #Bakken drilling/frac delays and some temporary production shut-ins as its very cold in North Dakota wind chills taking effective temp down to -40F. Also impacts #NatGas as Bakken #Oil all produces associated natural gas. #OOTT



2 16

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Dan Tsubouchi @Energy_Tidbits · Jan 19

...

Remember @ClimateEnvoy reality check in May. Same impression from @BlackRock Fink as need to be advancing new ideas, creating new mechanisms, need to find technologies, & "It's not going to happen overnight." Thx @andrewrsorkin. #Oil #NatGas #LNG needed for a lot longer. #OOTT

:erpts from CNBC posted transcript of excerpts from CNBC Squawk Box Andrew Ross-Sorkin interview with BlackRoc
D Larry Fink on Jan 18, 2022.

:erpt from CNBC posted transcript of the Fink interview [LINK]

RKIN: How do you distinguish and how should the public and the investor class distinguish between a hydrocarbon
npany that you think is on the good side of being a hydrocarbon company and a hydrocarbon company that you thi
on the bad side? Because right now, it appears but oftentimes these things are thought of in a very binary way. You'
her a hydrocarbon company, or you're not.

IK: Society is dependent on hydrocarbons right now. We are, you know, we will not survive with the society that we
talking to without hydrocarbons right now. We need to rapidly admit that and we need to have fair and just
utions about how do we utilize hydrocarbons as we move more towards a decarbonized way. We need to be
vancing ideas about green and blue hydrogen. We need to be advancing new ideas and creating new mechanisms tc
carbonize steel and decarbonize cement. We need to find technologies to, to so we can afford the sequestering of
bon. These are all going to be the tools in which we can create a more sustainable world, but it has to be done
gether. It's not going to happen overnight. If we want to just admonish the hydrocarbon companies today and say
p investing, get out of your business. We're going to have a very unequal outcome.

Dan Tsubouchi @Energy_Tidbits · May 16, 2021

#JohnKerry "I am told by scientists that 50% of the reductions we have to make to get to net zero are going to come from technologies that we don't yet have. That's just a reality". This means other reality is will need #NatGas #Oil for longer. #OTTT

...

2 2

Dan Tsubouchi @Energy_Tidbits · Jan 19

#Oil +$0.75 since @IEA OMR 4am ET "raised our global demand estimates by 200 kb/d for 2021 and 2022 – resulting in growth of 5.5 mb/d and 3.3 mb/d, respectively – due to softer Covid restrictions". Basically what @SullyCNBC got out of @fbirol on Fri. #OOTT iea.org/reports/oil-ma...

> **Dan Tsubouchi** @Energy_Tidbits · Jan 14
>
> 
>
> Asking a direct question works. "when I look at different indicators around the world, I would say that the oil demand dynamics now are significantly stronger than it was a few weeks ago" says @fbirol to @SullyCNBC ask for sneak peak @IEA Jan OMR. See ...

2 8

Dan Tsubouchi @Energy_Tidbits · Jan 18

Positive for #Oil from #OPEC MOMR Jan vs Dec. Yes, no change MoM to demand forecast. But, oil stocks deficit widened below 2015-19 average. "oil + product" at 11/30 now -221 mmb below vs 10/31 -174 mmb below. "oil" stocks at 11/30 now -137 mmb below vs 10/31 -25 mmb below. #OOTT

Commercial Stock Movements

Preliminary November data sees total OECD commercial oil stocks down by 16.0 mb m-o-m. At 2,721 mb, they were 389 mb lower than the same month in 2020, 247 mb lower than the latest five-year average and 221 mb below the 2015-2019 average. Within the components, crude and products stocks fell m-o-m by 12.7 mb and 3.3 mb, respectively.

At 1,317 mb, crude stocks in the OECD were 143 mb lower than the latest five-year average and 137 mb below the 2015-2019 average. OECD product stocks stood at 1,405 mb, representing a deficit of 104 mb compared with the latest five-year average and 84 mb below the 2015-2019 average.

In terms of days of forward cover, OECD commercial stocks fell m-o-m by 0.2 days in November to stand at 60.7 days. This is 13.2 days below November 2020 levels, 3.6 days less than the latest five-year average and 1.5 days lower than the 2015-2019 average.

Preliminary data for December showed that total US commercial oil stocks fell m-o-m by 24.4 mb to stand at 1,195 mb. This is 148.6 mb lower than the same month a year earlier and 93.9 mb below the latest five-year average. Crude and product stocks fell m-o-m by 15.3 mb and 12.1 mb, respectively.

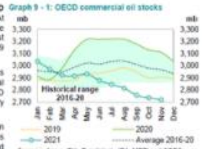
OECD

Preliminary November data sees **total OECD commercial oil stocks** down by 16.0 mb m-o-m. At 2,721 mb, they were 389 mb lower than the same time one year ago, 247 mb lower than the latest five-year average and 221 mb below the 2015-2019 average.

Within the components, crude and products stocks fell m-o-m by 12.7 mb and 3.3 mb, respectively. Total commercial oil stocks in November fell in OECD Americas and OECD Europe, while they rose slightly in OECD Asia Pacific.

OECD **commercial crude stocks** fell m-o-m in November by 12.7 mb to stand at 1,317 mb. This is 185 mb lower than the same time a year ago and 143 mb below the latest five-year average. Compared with the previous month, OECD Americas saw a stock draw of 3.5 mb, OECD Europe fell by 12.0 mb, and OECD Asia Pacific had a stock build of 2.8 mb.

Graph 9 - 1: OECD commercial oil stocks



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

Total product inventories fell m-o-m in November by 3.3 mb to stand at 1,405 mb. This is 204 mb less than the same time a year ago, and 104 mb lower than the latest five-year average. Product stocks in OECD Asia Pacific and OECD Europe fell m-o-m by 2.7 mb and 3.0 mb, respectively, while OECD Americas rose by 2.4 mb.

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

OECD stocks	Nov 20	Sep 21	Oct 21	Nov 21	Change Nov 21/Oct 21
Crude oil	1,502	1,308	1,329	1,317	-12.7
Products	1,608	1,450	1,408	1,405	-3.3
Total	3,110	2,758	2,737	2,721	-16.0
Days of forward cover	73.9	60.5	60.9	60.7	-0.2

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 fell m-o-m by 0.2 days in November to stand at 60.7 days. This is 13.2 days below November 2020 levels, 3.6 days less than the latest five-year average and 1.5 days lower than the 2015-2019 average. All three OECD regions were below the latest five-year average: the Americas by 1.9 days at 62.6 days, Asia Pacific by 4.2 days at 45.0 days and Europe by 7.0 days at 66.3 days.

6 12

Dan Tsubouchi @Energy_Tidbits · Jan 18

Positive #Oil fundamental reminder. "Global crude inventories were at 2.834b bbls as of Jan. 9, near the lowest since October 2019, according to data from analytics firm Kayrros. * That compares with 3.090b bbls a year earlier" reports @iamsharoncho. #OOTT

Global Oil Inventories Hit Lowest Since Before Pandemic: Kayrros
2022-01-18 03:20:22.477 GMT

By Sharon Cho
(Bloomberg) -- Global crude inventories were at 2.834b bbls as of Jan. 9, near the lowest since October 2019, according to data from analytics firm Kayrros.
* That compares with 3.090b bbls a year earlier
** Onshore crude stockpiles have been consistently drawing in the past year, led by declines in China and the U.S.
* In China, inventories were 923m bbls as of Jan. 9 vs 1.006b bbls a year earlier
** That's the smallest volume since 895m bbls on Feb. 23, 2020
** China had stocked up on crude until April 2021, with holdings peaking at 1.037b bbls; since then, the nation has been depleting onshore inventories
* Japan's stockpiles are down to 325m bbls, the lowest since Kayrros started compiling data in May 2016
** That compares with 339m bbls on Jan. 10, 2021 and 352m bbls on July 18, 2021

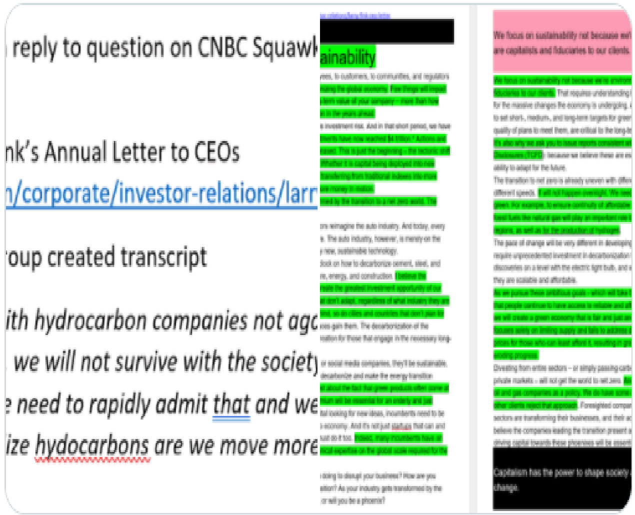
To contact the reporter on this story:
Sharon Cho in Singapore at ccho28@bloomberg.net
To contact the editors responsible for this story:
Serene Cheong at scheong20@bloomberg.net
Jake Lloyd-Smith

To view this story in Bloomberg click here:
https://blinks.bloomberg.com/news/stories/R5VWGST1UM0X

5 9

Dan Tsubouchi @Energy_Tidbits · Jan 18

"we will not survive with the society we are accustomed without hydrocarbons right now, we need to rapidly admit that" @BlackRock CEO Fink to @AndrewSorkin @SquawkCNBC re his annual letter to CEOs. bullish for #Oil #NatGas stocks. #OOTT #MacronMoment blackrock.com/corporate/inve...



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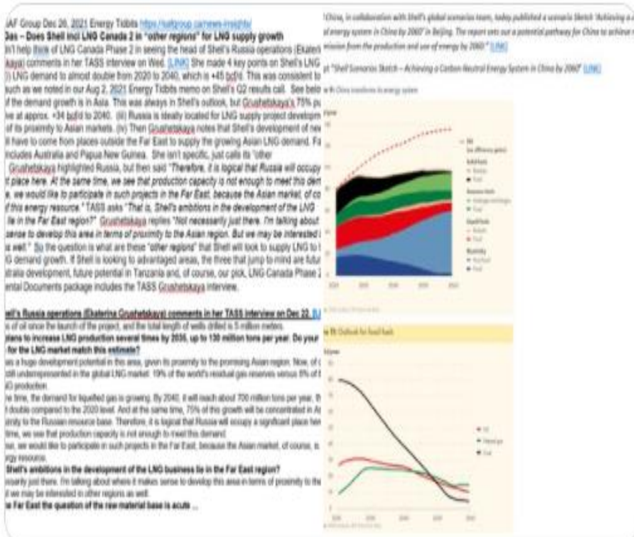
SAF

Dan Tsubouchi @Energy_Tidbits · Jan 17

Will @Shell use "potential pathway for China to achieve #NetZero" by 2060, incl CN #NatGas demand peak in 2030, for capital allocation? Or its Russia head 12/22 fcast global #LNG demand to almost double to 2040 ie. +45 bcf/d, incl 75% in Asia so +34 bcf/d? Think the latter #OOTT



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SAF

Dan Tsubouchi @Energy_Tidbits · Jan 17

#Houthi drone attack vs #UAE. Abu Dhabi police "fire lead to the explosion of three petroleum tankers near ADNOC's storage tanks. also minor fire at Abu Dhabi international airport. #OOTT

wam.ae

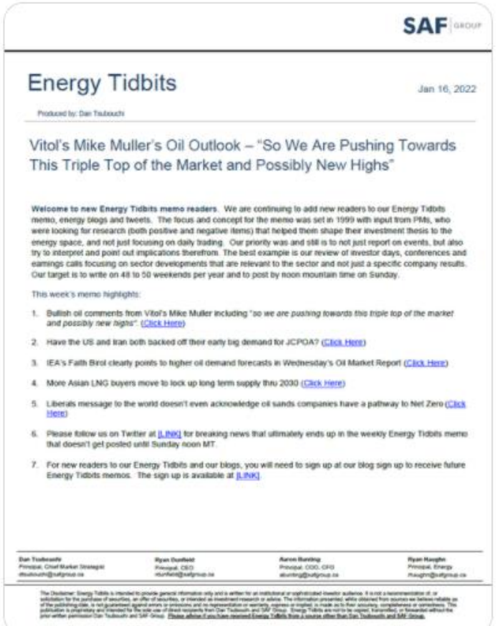
Abu Dhabi Police confirms explosion of three petroleum tankers in Mu...

ABU DHABI, 17th January, 2022 (WAM) -- The Abu Dhabi Police confirmed that a fire broke out this morning, which led to the explosio...

1

Dan Tsubouchi @Energy_Tidbits · Jan 16

Our weekly SAF Jan 16, 2022 Energy Tidbits memo is posted on our SAF Group website. This 54-pg energy research memo expands upon & covers more items than tweeted this week. See news/insights section of SAF website #Oil #OOTT #LNG #NatGas #EnergyTransition safgroup.ca/news-insights/



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Energy Tidbits

Jan 16, 2022

Produced by: Dan Tsubouchi

Vitol's Mike Muller's Oil Outlook – "So We Are Pushing Towards This Triple Top of the Market and Possibly New Highs"

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. Bullish oil comments from Vitol's Mike Muller including *"so we are pushing towards this triple top of the market and possibly new highs"*. (Click Here)
2. Have the US and Iran both backed off their early big demand for JCPOA? (Click Here)
3. IEA's Fatih Birol clearly points to higher oil demand forecasts in Wednesday's Oil Market Report (Click Here)
4. More Asian LNG buyers move to lock up long term supply thru 2030 (Click Here)
5. Liberals message to the world doesn't even acknowledge oil sands companies have a pathway to Net Zero (Click Here)
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