Oil 2021

Analysis and forecast to 2026

INTERNATIONAL ENERGY AGENCY

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Abstract

World oil markets are rebalancing after the Covid-19 crisis spurred an unprecedented collapse in demand in 2020, but they may never return to "normal". Oil 2021, the IEA's latest medium-term outlook, explains why.

Rapid changes in behaviour from the pandemic and a stronger drive by governments towards a low-carbon future have caused a dramatic downward shift in expectations for oil demand over the next six years. This is forcing hard decisions on oil-producing countries and companies, which are reluctant to leave resources untapped or to install new capacity that would only sit idle. Could oil demand peak sooner than expected? Or is the world heading into a supply crunch? What will the implications be for the refining industry and trade flows?

Oil 2021 tackles these questions by analysing oil market data, trends in investment and government policies. The report provides a comprehensive outlook for global supply and demand through 2026 and explores some of the challenges and uncertainties that lie ahead.

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Executive summary

A new normal for oil markets?

The global economy and oil markets are recovering from the historic collapse in demand caused by the coronavirus (Covid-19) pandemic in 2020. The staggering inventory surplus that built up last year is being worked off and global oil stocks, excluding strategic reserves, will return to pre-pandemic levels in 2021. And yet, there may be no return to "normal" for the oil market in the post-Covid era.

The pandemic has forced rapid changes in behaviour: from new working-from-home models to cuts in business and leisure air travel. At the same time, more and more governments are focusing on the potential for a sustainable recovery as a way to accelerate momentum towards a low-carbon future. The outlook for oil demand has shifted lower as a result of these trends, raising the prospect of a peak sooner than previously expected if governments follow through with strong policies to hasten the shift to clean energy.

These forces are creating a dilemma for oil-producing countries and companies that are reluctant to leave resources in the ground or build new capacity that could sit idle. But if this leads to a shortfall in investment, it could also have geopolitical implications and heighten the risk of supply shortages later on.

Demand recovery path uneven

Global oil demand, still reeling from the effects of the pandemic, is unlikely to catch up with its pre-Covid trajectory. In 2020, the start of our forecast period, oil demand was nearly 9 mb/d below the level seen in 2019, and it is not expected to return to that level before 2023. In the absence of more rapid policy intervention and behavioural changes, longer-term drivers of growth will continue to push up oil demand. As a result, by 2026, global oil consumption is projected to reach 104.1 mb/d. This would represent an increase of 4.4 mb/d from 2019 levels. Oil demand in 2025 is set to be 2.5 mb/d lower than was forecast a year ago in our *Oil 2020* report.

All of this demand growth relative to 2019 is expected to come from emerging and developing economies, underpinned by rising populations and incomes. Asian oil demand will continue to rise strongly, albeit at a slower pace than in the recent past. OECD demand, by contrast, is not forecast to return to pre-crisis levels.

The speed and depth of the recovery is likely to be uneven both geographically and in terms of sectors and products. Gasoline demand is unlikely to return to 2019 levels, as efficiency gains and the shift to electric vehicles eclipse robust mobility growth in the developing world. Aviation fuels, the hardest hit by the crisis, are expected to slowly return to 2019 levels by 2024, but the spread of online meetings could permanently alter business travel trends.

The petrochemical industry remains a pillar of growth over the forecast period. Ethane, LPG and naphtha together account for 70% of the projected increase in oil product demand to 2026.

Spending cuts slow world oil supply growth

The Covid-induced demand shock and a shifting momentum towards investment in clean energy are set to slow the expansion of the world's oil production capacity over our six-year forecast period. At the same time, the historic collapse in demand in 2020 resulted in a record 9 mb/d spare production capacity cushion that would be enough to keep global markets comfortable at least for the next several years.

Against this backdrop, it is hardly surprising that upstream investments and expansion plans have been scaled back. In 2020, operators spent one-third less than planned at the start of the year (and 30% less than in 2019). In 2021, total upstream investment is expected to rise only marginally.

Those sharp spending cuts and project delays are already constraining supply growth across the globe, with world oil production capacity now set to increase by 5 mb/d by 2026. In the absence of stronger policy action, global oil production would need to rise 10.2 mb/d by 2026 to meet the expected rebound in demand.

Producers from the Middle East are expected to provide half of the increase, largely from existing shut-in capacity. If Iran remains under sanctions, keeping the world oil market in balance may require Saudi Arabia, Iraq, the UAE and Kuwait – with their surplus capacity – to pump at or near record highs.

That marks a dramatic change from recent years when the United States dominated world supply growth. In the current policy environment, US production growth is set to resume as investment and activity levels pick up in tandem with rising prices. Yet any increase is unlikely to match the lofty levels of the recent past. The outlook for the tight oil industry has been tempered by an apparent shift in the business model towards spending discipline, free cash flow generation, deleveraging and cash returns for investors.

The global market still looks adequately supplied through much of the medium term. But in the absence of fresh upstream investments, the spare capacity cushion will slowly erode. By 2026, global effective spare production capacity (excluding Iran) could fall to 2.4 mb/d, its lowest level since 2016.

Refining sector in the midst of third rationalisation round

While the upstream sector could see its capacity cushion deflate, the refining sector is struggling with excess capacity. The Covid-19 demand shock, large scale expansions and expectations of a long-term structural decline in demand are creating an overhang that can only be eradicated through massive closures.

A third wave of worldwide refinery rationalisation is currently underway. Global shutdowns of 3.6 mb/d have already been announced, but a total of at least 6 mb/d will be required to allow utilisation rates to return to above 80%.

Operations east of Suez are expected account for all the growth in refining activity to 2026 from 2019 levels. As a result, Asian crude oil imports are projected to surge to nearly 27 mb/d by 2026, requiring record levels of both Middle Eastern crude oil exports and Atlantic Basin production to fill the gap. The centre of gravity for refined products trade is also set to shift to Asia, resulting in the region's oil import dependence rising to 82% by 2026.

Stronger policies can lower demand and hasten peak

A much stronger pivot towards a cleaner energy future will be required to reach ambitious mid-century goals for net-zero emissions. This will involve more concrete government policies and legislative action, as well as major behavioural changes.

Further fuel efficiency improvements, increased teleworking and reduced business travel, much stronger electric vehicle penetration and new policies to curb oil use in the power sector and more recycling will all be needed. Taken together, these actions could reduce oil use by as much as 5.6 mb/d by 2026, which would mean that oil demand never gets back to pre-crisis levels.

In our base case – which takes into account current industry plans, government policies and existing energy transition initiatives – global oil demand is forecast to rise by 3.5 mb/d between 2019 and 2025. Aligning with the *World Energy Outlook*'s Sustainable Development Scenario – which maps out a trajectory consistent with the climate goals of the Paris Agreement and other sustainable energy objectives – oil demand would have to decline by 3 mb/d over the same period. A pathway to net-zero emissions globally by 2050 would require an even sharper decrease.

Implications for industry

Fast-evolving government plans to accelerate transitions towards a more sustainable future have created a high degree of uncertainty that is testing the oil industry. It is crucial to invest in the upstream sector even during rapid transitions in which it would still take years to shift global transport fleets away from internal combustion engines to electric vehicles and other low-carbon alternatives. Some sectors – such as aviation, shipping and petrochemicals – will continue to rely on oil for some time.

Whatever the transition pathway, the oil and gas industry has an important role to play, and no energy company will be unaffected. Minimising emissions from their core operations, notably methane, is an urgent priority. In addition, there are technologies vital to energy transitions that can be a match for the industry's capabilities, such as carbon capture, low-carbon hydrogen, biofuels and offshore wind. In many cases, these can help decarbonise sectors where emissions are hardest to tackle. A number of oil and gas companies are already scaling up their commitments in these areas.

An effective and orderly transition will be critical – not only to reach international climate targets but also to prevent serious supply disruptions and destabilising price volatility along the way.

World oil balance

World oil demand and supply (mb/d)

	2019	1Q20	2Q20	3Q20	4Q20	2020	1Q21	2Q21	3Q21	4Q21	2021	2022	2023	2024	2025	2026
DEMAND																
Total OECD	47.7	45.4	37.6	42.3	43.1	42.1	43.3	43.8	45.4	46.5	44.7	45.8	46.2	46.2	46.0	45.8
Total Non-OECD	52.0	48.3	45.3	50.4	51.7	48.9	50.7	51.1	52.3	52.7	51.7	53.7	55.0	56.1	57.2	58.3
Total Demand[1]	99.7	93.8	82.9	92.7	94.7	91.0	93.9	94.9	97.7	99.2	96.5	99.4	101.2	102.3	103.2	104.1
SUPPLY																
Total OECD	28.5	29.9	26.9	27.1	27.8	27.9	27.8	28.1	28.3	28.7	28.2	29.0	29.6	29.9	29.9	29.7
Total Non-OECD	32.0	32.3	30.0	29.7	29.9	30.5	30.3	30.8	30.8	30.7	30.6	31.5	32.0	32.0	32.1	32.1
Processing Gains[2]	2.4	2.3	2.0	2.1	2.1	2.1	2.1	2.2	2.3	2.3	2.2	2.4	2.4	2.4	2.5	2.5
Global Biofuels	2.8	2.2	2.5	3.1	2.6	2.6	2.3	2.9	3.2	2.9	2.8	3.0	3.1	3.2	3.3	3.3
Total Non-OPEC[3]	65.6	66.7	61.3	61.9	62.4	63.1	62.5	63.9	64.5	64.6	63.9	66.0	67.1	67.5	67.7	67.6
OPEC																
Crude	29.5	28.2	25.6	24.1	24.9	25.7										
OPEC NGLs	5.4	5.4	5.2	5.1	5.2	5.2	5.2	5.3	5.3	5.3	5.3	5.5	5.5	5.6	5.6	5.7
Total OPEC[3]	34.9	33.6	30.8	29.2	30.0	30.9										
Total Supply	100.5	100.2	92.1	91.1	92.4	93.9										
Memo items:																
Call on OPEC crude + Stock ch.[4]	28.7	21.7	16.4	25.7	27.2	22.8	26.2	25.7	27.9	29.3	27.3	28.0	28.6	29.2	29.9	30.8

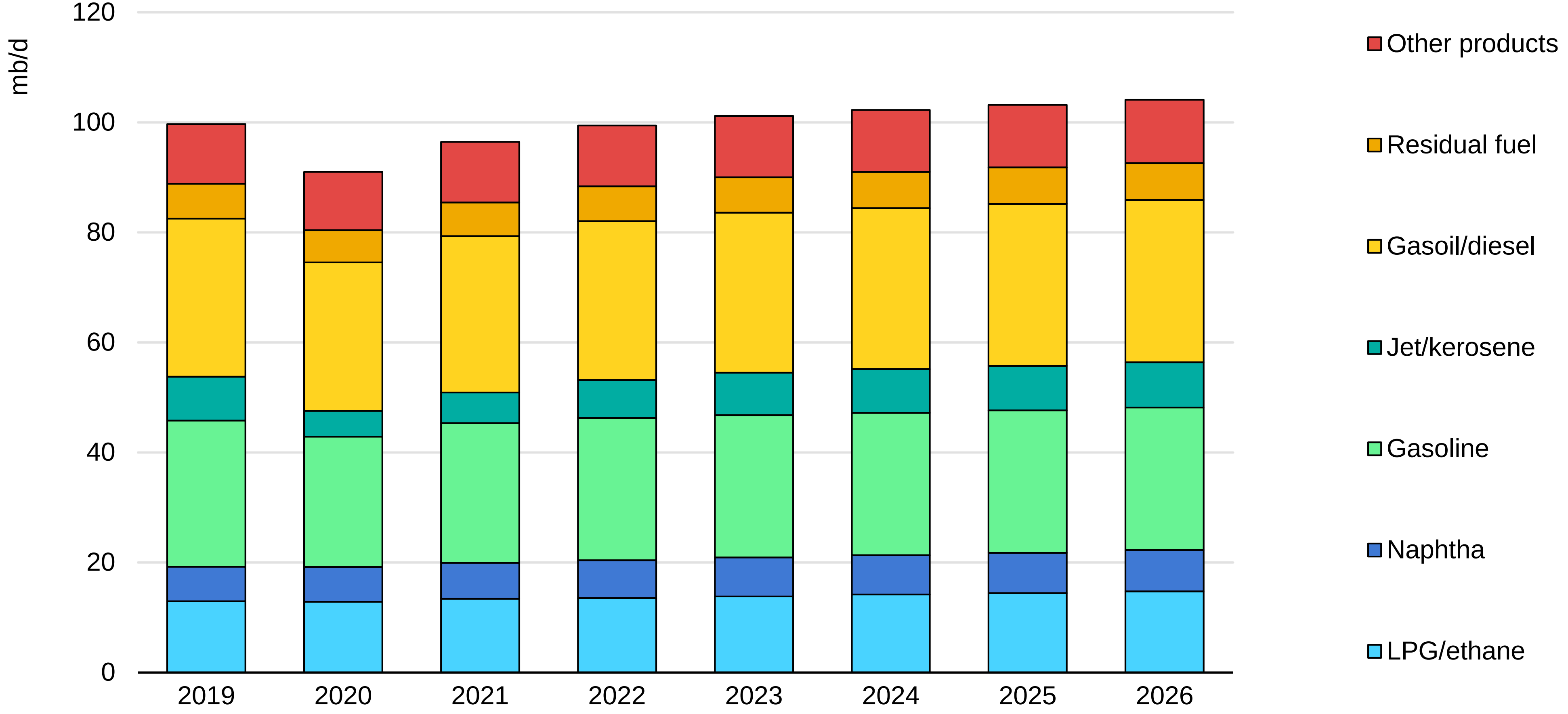
1. Measured as deliveries from refineries and primary stocks, comprises inland deliveries, international marine bunkers, refinery fuel, crude for direct burning, oil from non-conventional sources and other sources of supply.
2. Net volumetric gains and losses in the refining process and marine transportation losses.
3. Total Non-OPEC excludes all countries that are currently members of OPEC. Total OPEC comprises all countries which are current OPEC members.
4. Equals the arithmetic difference between total demand minus total non−OPEC supply minus OPEC NGLs.

Demand

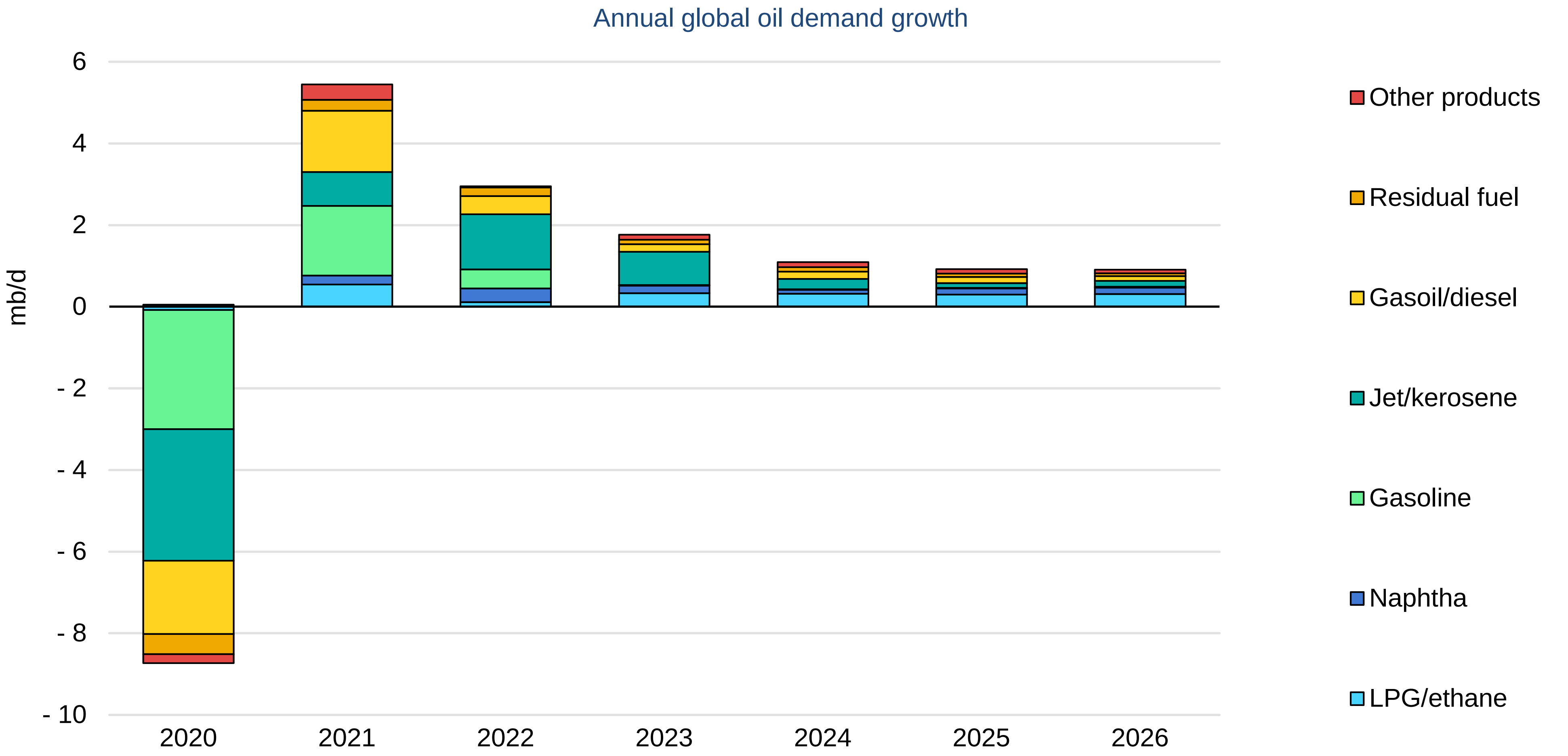
Global demand overview

Global oil demand rebounds from 9-year low of 91 mb/d in 2020 to 104 mb/d in 2026

Global oil demand by product



Following a sharp recovery over 2021-2022, oil demand growth slows markedly



Global oil demand recovery from Covid-19 likely to be protracted

The worldwide pandemic and tumultuous economic downturn triggered an unprecedented collapse in global oil demand of 8.7 mb/d in 2020. Growth will rebound sharply in 2021, and is projected to rise by 13.1 mb/d to 2026. Growth in road transport fuel demand slows to less than 0.5% per year from 2023 onwards, following its recovery from Covid-19. Even so, other sectors such as petrochemicals will boost oil demand, meaning that additional policy measures and drastic behaviour changes would be required for oil demand to peak.

The lingering impacts from the pandemic, coupled with a growing urgency to tackle the low-carbon energy transition, means that oil demand will likely never catch up with its pre-pandemic trajectory. World oil demand in 2026 will be only 4.4 mb/d above 2019 levels, with all of the increase coming from non-OECD countries. The strongest gains will come from the People's Republic of China ("China" hereafter), India and other Asian economies, which together account for more than 90% of the net increase.

In the near term, oil demand in the OECD is set to rebound strongly. Prolonged and repeated lockdowns, stringent social distancing measures including widespread teleworking, and a near halt to international travel caused OECD demand to plunge by 5.6 mb/d in 2020. As a larger share of the population gets vaccinated, restrictions will ease, allowing demand to rebound.

The pathway to recovery will be uneven, reflecting different impacts of the energy transition across regions, sectors, and oil products. World gasoline demand might never return to its 2019 level, while diesel demand growth will slow markedly. Efficiency improvements, the transition to electric vehicles and changes in consumer habits will offset part of the impact of strong economic growth and the demand dynamism from developing countries.

Aviation, the sector the most affected by the pandemic, will continue to struggle. Jet fuel consumption will only return to 2019 levels by 2024 as travel restrictions, changing travel habits, and the relatively slow progress of vaccinations in low-income economies cap its recovery. The proliferation of online meetings and conferences, along with cost cuttings by companies, are likely to permanently dent business travel.

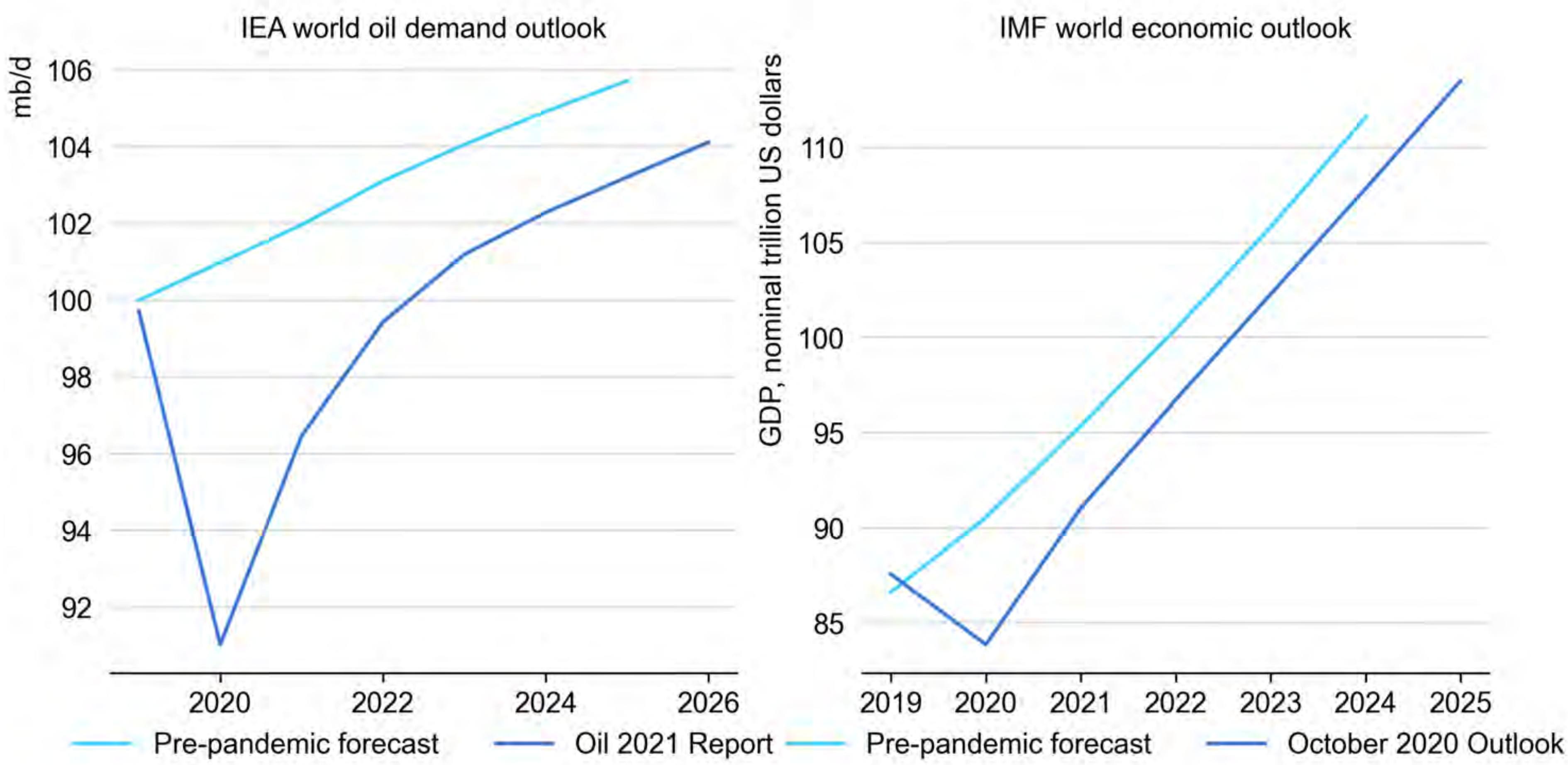
By contrast, the petrochemical industry that accounts for the majority of ethane, LPG and naphtha demand suffered relatively little from the Covid crisis and will continue to post healthy growth. Together, these products will be responsible for 70% of the growth in oil product demand through 2026 compared with the 2019 level.

Globally, after a recovery period lasting until 2023, actions taken to implement the energy transition will slow demand growth. Strong demand growth in developing economies, however, will more than offset a contraction in high-income ones.

Fundamentals

Oil demand, GDP unlikely to ever catch up with their pre-Covid trajectory

World oil demand



Note: The IEA's pre-pandemic forecast line includes figures from the January 2020 Oil Market Report (year 2020) and the Oil 2020 Report (years 2021-25).
Source: IEA, IMF World Economic Outlook.

The return of mobility and economic activity is conditional on vaccine outreach

In 2020, the Covid-19 pandemic triggered the worst global economic downturn since World War II. Global economic growth is expected to rebound sharply in 2021, with GDP forecast up 5% after a decline of 3.5% in 2020.

The most important assumption underpinning this forecast is that Covid-19 vaccines in high income economies are rolled out before the end of summer 2021, which would support a strong recovery in the second half of the year. Vaccine deployment will take longer in middle and low-income economies than in high-income markets, but vaccination programmes will prove supportive, nonetheless. In 2022, global economic growth will remain higher than the recent trend (4.5% vs. 3% in 2015-19), as sectors particularly affected by the Covid-19 crisis continue to recover. Growth then returns to 3.5% per year from 2023 through 2026.

However, some permanent scars will remain from the crisis, including the large number of bankruptcies, lost investments and low growth in parts of the service economy (tourism, entertainment, hospitality). Emerging markets, which were particularly affected by these different shocks, have seen their debt levels and fiscal imbalances rise to dangerous levels which could penalise medium-term growth.

Huge fiscal expenditures have been, and will continue to be, the engine of the expected recovery. China's GDP posted positive growth of 2.3% in 2020, as massive public investment offset a drop in consumer spending, and is forecast to rise by more than 8% in 2021 and just over 5% in 2022.

The new US administration has also committed to supporting the economy, with an additional $1.9 trillion stimulus package, equivalent to roughly 9% of US GDP. The European Union put together a € 750 billion recovery fund. The funds are set to be delivered over the next six years, half as grants and half as loans. The huge fiscal and monetary stimulus deployed in 2020 will continue to have an impact in the medium term.

The main risk to the short-term forecast is the apparition of new virus variants, more transmissible and resistant to vaccines. Virus mutations and the need to adapt vaccines may result in Covid-19 becoming endemic, forcing populations to adapt indefinitely to life with the virus and likely remaining a drag on economic activity. While the repetition of extended episodes of hard lockdowns appears unlikely in the medium term, given their economic cost, social distancing measures and low tourism, entertainment and travel recoveries would significantly slow oil demand over the forecast period.

In this report we used the ICE Brent forward curve as of February 2021 as a price assumption.

Global economic growth roars in 2021-2022 before averaging 3.5% through 2026

GDP forecast real PPP (%)

	2019	2020	2021	2022	2023	2024	2025	2026
United States	2.0%	-3.5%	4.1%	3.5%	1.9%	1.9%	1.4%	1.8%
European Union	1.7%	-6.9%	4.3%	4.7%	2.2%	1.6%	1.6%	1.1%
Asia Pacific	4.5%	-1.8%	6.8%	5.0%	4.6%	4.9%	4.7%	4.6%
Japan	0.3%	-5.3%	2.7%	2.4%	1.4%	1.3%	1.0%	0.8%
China	6.0%	2.3%	8.1%	5.1%	4.9%	5.0%	4.7%	4.5%
India	4.9%	-7.6%	9.0%	5.8%	6.8%	7.5%	7.0%	7.4%
Africa	3.9%	-2.1%	3.5%	4.4%	4.1%	4.0%	4.0%	4.0%
World	**3.2%**	**-3.9%**	**4.9%**	**4.7%**	**3.7%**	**3.6%**	**3.4%**	**3.3%**

Source: IMF / Oxford Economics.

Asia Pacific provides 90% of global oil demand growth

Global oil demand by region (mb/d)

	2019	2020	2021	2022	2023	2024	2025	2026	2019-26 Growth	2019-26 Growth
North America	25.3	22.2	23.8	24.5	24.7	24.7	24.6	24.6	-0.4%	-0.7
Central and South America	6.6	5.9	6.3	6.6	6.7	6.7	6.8	6.9	0.7%	0.3
Europe	15.7	13.8	14.6	14.8	15.0	15.0	14.9	14.9	-0.8%	-0.8
Africa	4.2	3.8	4.0	4.2	4.4	4.5	4.7	4.8	1.7%	0.5
Middle East	8.3	7.6	7.9	8.2	8.4	8.5	8.7	8.9	0.9%	0.6
Eurasia	4.4	4.2	4.3	4.4	4.5	4.6	4.6	4.7	1.1%	0.4
Asia Pacific	35.2	33.4	35.6	36.9	37.7	38.2	38.9	39.3	1.6%	4.1
World	**99.7**	**91.0**	**96.5**	**99.4**	**101.2**	**102.3**	**103.2**	**104.1**	**0.6%**	**4.4**

Energy transitions

Global oil demand must be cut *now* to meet 2050 net-zero targets

A reduction in global oil demand over the medium term is crucial to reaching net-zero emissions ambitions, but formidable challenges lie ahead. For a start, the transport sector, which makes up roughly 60% of total consumption, will have to lower its dependence on oil for overall demand to decline. Buildings and industry as well as the power and petrochemicals sectors must also burn less oil. Efficiency gains and energy substitution will also be critical.

However, current government policies and industry plans show that energy transition initiatives will have only a marginal impact on oil demand over the next six years. This report forecasts a steady rise in liquid fuel demand over the medium term, and by 2025 it will be 3.5 mb/d above the 2019 level. By comparison, in the World Energy Outlook (WEO) 2020 Sustainable Development Scenario (SDS), which maps out a trajectory consistent with global net-zero emissions by 2070, oil demand falls by 3 mb/d over the same period. A pathway to net-zero emissions globally by 2050 would require even sharper falls.

It is encouraging that the world's largest economies are aligning behind a greater collective effort for the energy transition. Some 127 countries covering ~75% of global CO_2 energy-related emissions have stated net-zero carbon emissions ambitions for 2050 or 2060. However, by February 2021 only 12 countries had proposed or enacted legislation.

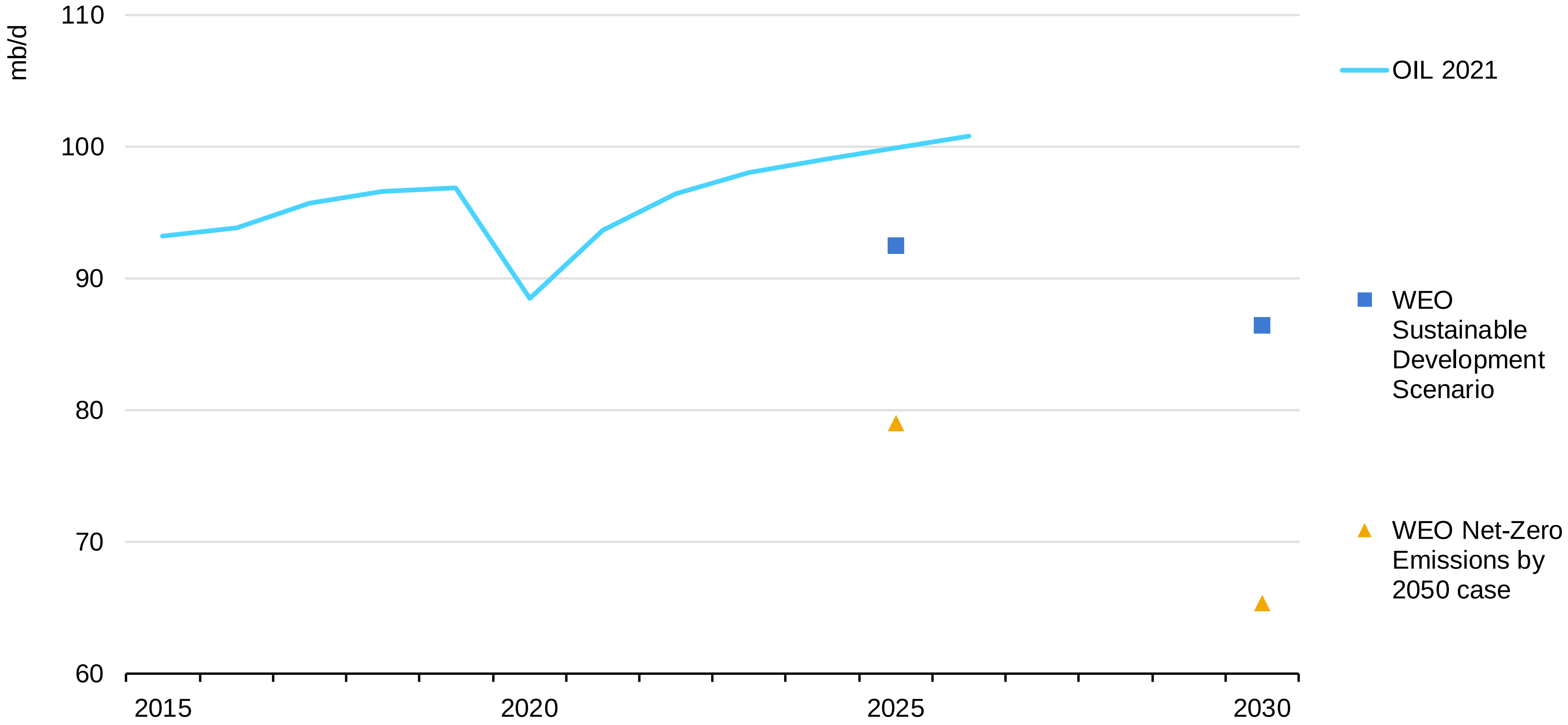
Leading the world on net-zero emissions policy is the European Union, which has a 55% GHG reduction target for 2030 versus 1990. Legislative details, to be revealed in June 2021, will likely focus on power and buildings in the next 10 years as strong legislation of vehicle CO_2 emissions already exists through 2030. Transport and industry decarbonisation will accelerate post-2030. To achieve this transition, the European Union will use higher carbon prices as well as tougher policies supporting renewable development and energy efficiency.

China's President Xi announced last year a goal of carbon neutrality before 2060, and subsequently a target of peak CO_2 emissions before 2030. The government will take this into account in preparing its 14th five-year plan that will be ready later this year. Other Asian nations such as South Korea and Japan have also announced carbon neutrality by 2050.

Importantly, the United States officially re-joined the Paris Agreement in mid-February after a four-year absence and unveiled aggressive measures to tackle climate change. US President Biden has pledged to decarbonise the power grid by 2035 and achieve net-zero greenhouse gas emissions by 2050. Executive Orders have also been signed to halt construction of the Keystone XL pipeline and to temporarily ban oil and gas leasing on federal land.

Oil demand off-course to meet sustainable development and net-zero targets

Global oil demand forecast in Oil 2021, Sustainable Developments Scenario and Net-Zero Emissions by 2050 case



Notes: This report uses Oil Market Report definitions for oil demand, which comprises all liquid fuel deliveries, including biofuels. WEO scenarios separate biofuels from oil liquids. For the purposes of this comparison, biofuel volumes have been removed from Oil 2021 historical and forecast demand (see page 100 for more detail). Increased biofuels deployment is another pathway for lowering oil demand growth, but is not being discussed here due to the specifics of the Oil Market Report definitions.

Source: World Energy Outlook, 2020.

Tough policies and behavioural changes could spur 2026 oil demand peak

For oil demand to peak in coming years, strong policy initiatives and behavioural changes must be pushed - otherwise the use of oil will continue to rise through 2026.

One such action could be an acceleration of fuel efficiency, in particular in the transport sector, which we already expect to lower oil demand by 850 kb/d on average each year over the next few years. If efficiency improvements are brought forward by one year, oil demand could be 900 kb/d below our base case by 2026.

Governments could also encourage citizens to reduce car use by creating incentives for teleworking. In our base case, those who telework undertake one to two days a week of remote work in OECD countries and less in non-OECD countries. This reduces transport fuel demand by around 250 kb/d. If more teleworking is encouraged, this volume could be much higher. With three days a week in OECD countries and two days in major non-OECD economies, we estimate that 800 kb/d per year of combined gasoline and diesel demand could be saved.

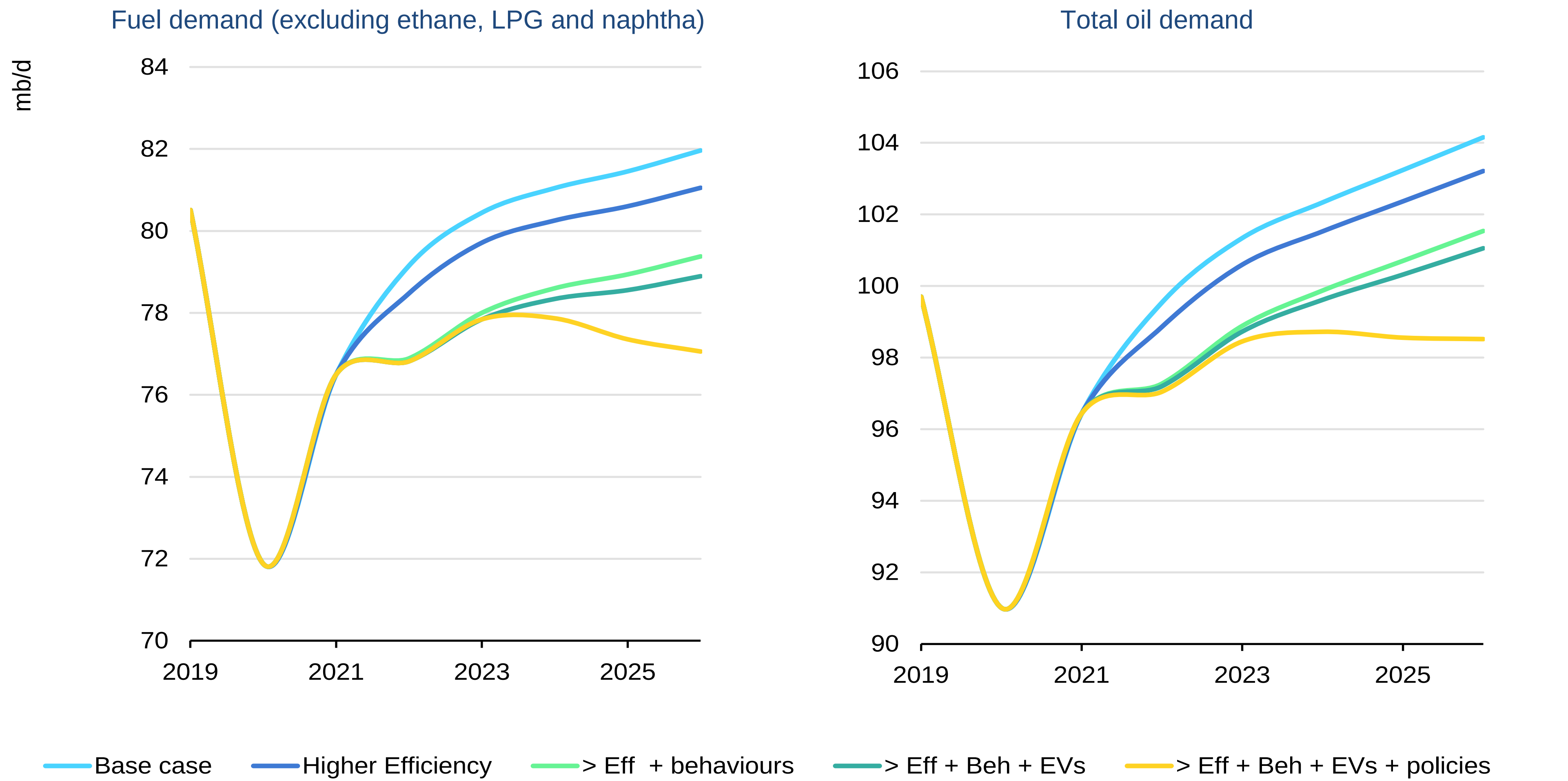
In addition, if companies opt to reduce air business trips by half from pre-pandemic levels and modest reductions are seen in other air travel, jet fuel demand could be reduced by nearly 1 mb/d by 2026. Altogether, more teleworking and a fall in air transport demand could bring a reduction of 1.7 mb/d in total oil demand.

In our base case, the global electric car fleet reaches 60 million by 2026. With stronger incentives from governments and cities, (including improved charging infrastructure) the size of the fleet could be increased by 50% to 90 million. Electric buses and 2-3 wheelers would also lower transport fuel demand. Overall, gasoline and diesel demand would be reduced by a total of 1.6 mb/d at the end of the forecast, or 500 kb/d more than our base case.

Further action would be required for oil demand to peak, however. This would include tougher measures to reduce plastic demand and further cuts to the amount of oil burned in the power sector. Governments would need to take aggressive action to discourage the use of internal combustion engines to reduce transport fuel demand. Increased fuel taxes and the removal of subsidies would also help to reduce oil use. And, finally, governments could take measures to further reduce heating oil use in the northern hemisphere. The combination of these actions, could achieve an additional saving of 2.5 mb/d.

All these policies, it taken now, could save a total of 5.6 mb/d of oil consumption and thus prevent oil demand returning to 2019 levels.

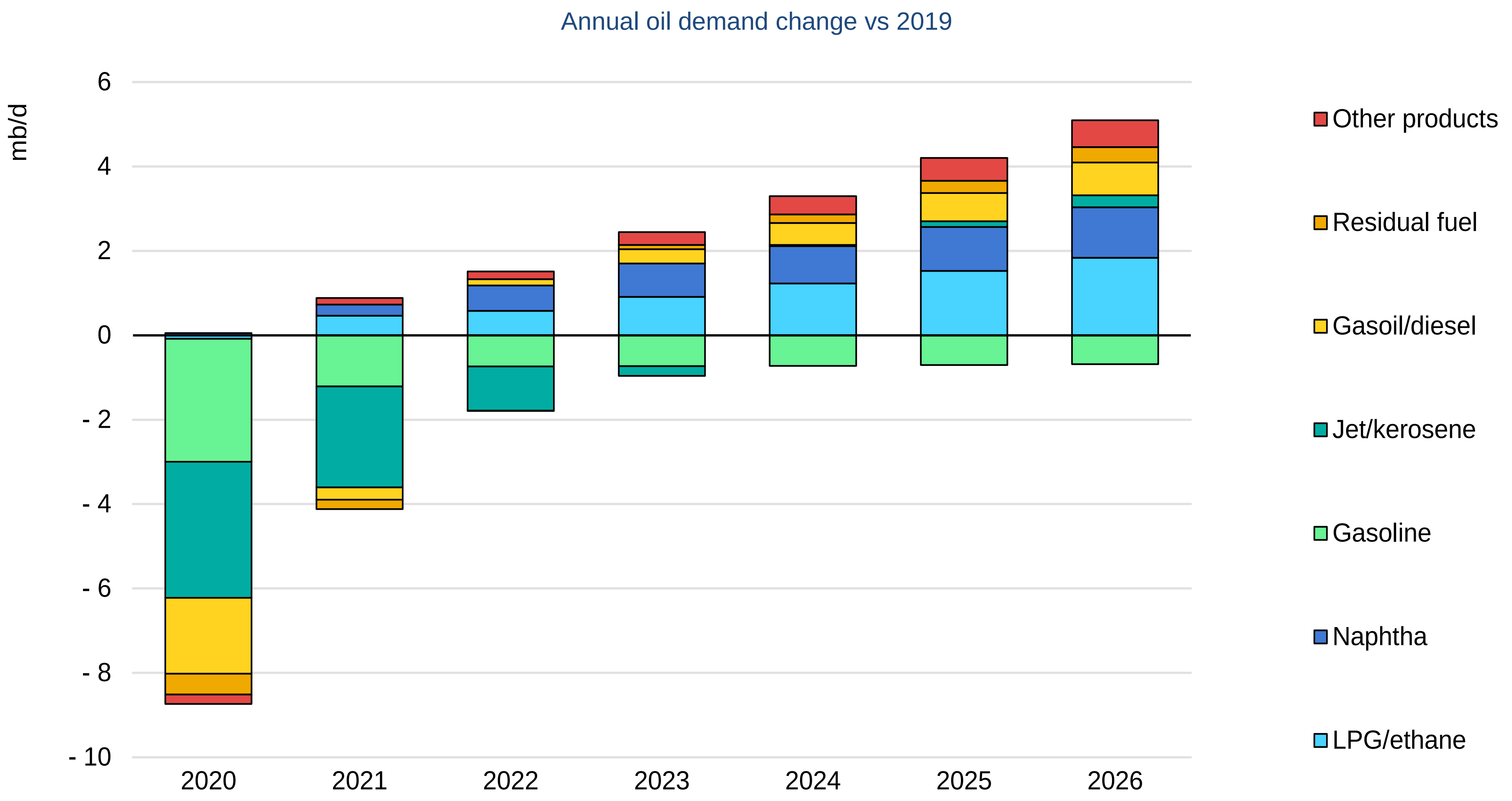
It would take a significant combination of new measures to achieve a peak in oil demand



Notes: Higher Efficiency = efficiency improvements in the transport sector; > Eff + behaviours = higher efficiency and changes in behaviours; > Eff + Beh + EVs = higher efficiency, changes in behaviours and more Electric Vehicles; > Eff + Beh + EVs + policies = higher efficiency, changes in behaviours, more EVs and additional policy changes.

Global oil demand by product

Petrochemical sector drives demand growth in the medium term



The petrochemical industry remains the largest source of oil demand growth

While the near-term recovery in global oil demand will primarily stem from transportation fuels, it is the petrochemical sector that will dominate growth over the medium term. Total ethane, LPG and naphtha demand is expected to grow by 430 kb/d per year on average over 2019-2026, of which more than two-thirds will be for petrochemical feedstocks. With demand growth for all other products slowing overall, LPG and naphtha will account for nearly 70% of gains compared with 2019 levels.

The use of LPG, ethane and naphtha as feedstock for the petrochemical industry will increase in line with global economic growth and rising plastic demand. Even during the Covid-19 pandemic in 2020, petrochemical products demand was relatively sheltered as higher demand for medical protective equipment and packaging partly offset a decline in manufacturing such as for the automobile and construction industries.

The utilisation of petrochemical plants will fluctuate with demand trends. Through the forecast period, we expect a utilisation rate for existing capacity slightly below 85%. New capacity may have a lower utilisation rate (70% to 80%) as capacity additions could experience difficulties and delays. LPG and ethane demand growth will be dominated by the United States and China, where another wave of LPG/ethane cracker capacity additions is expected to come online during the forecast period. LPG and ethane used as petrochemical feedstocks will increase by 900 kb/d, or 130 kb/d per year, over the 2019-2026 period.

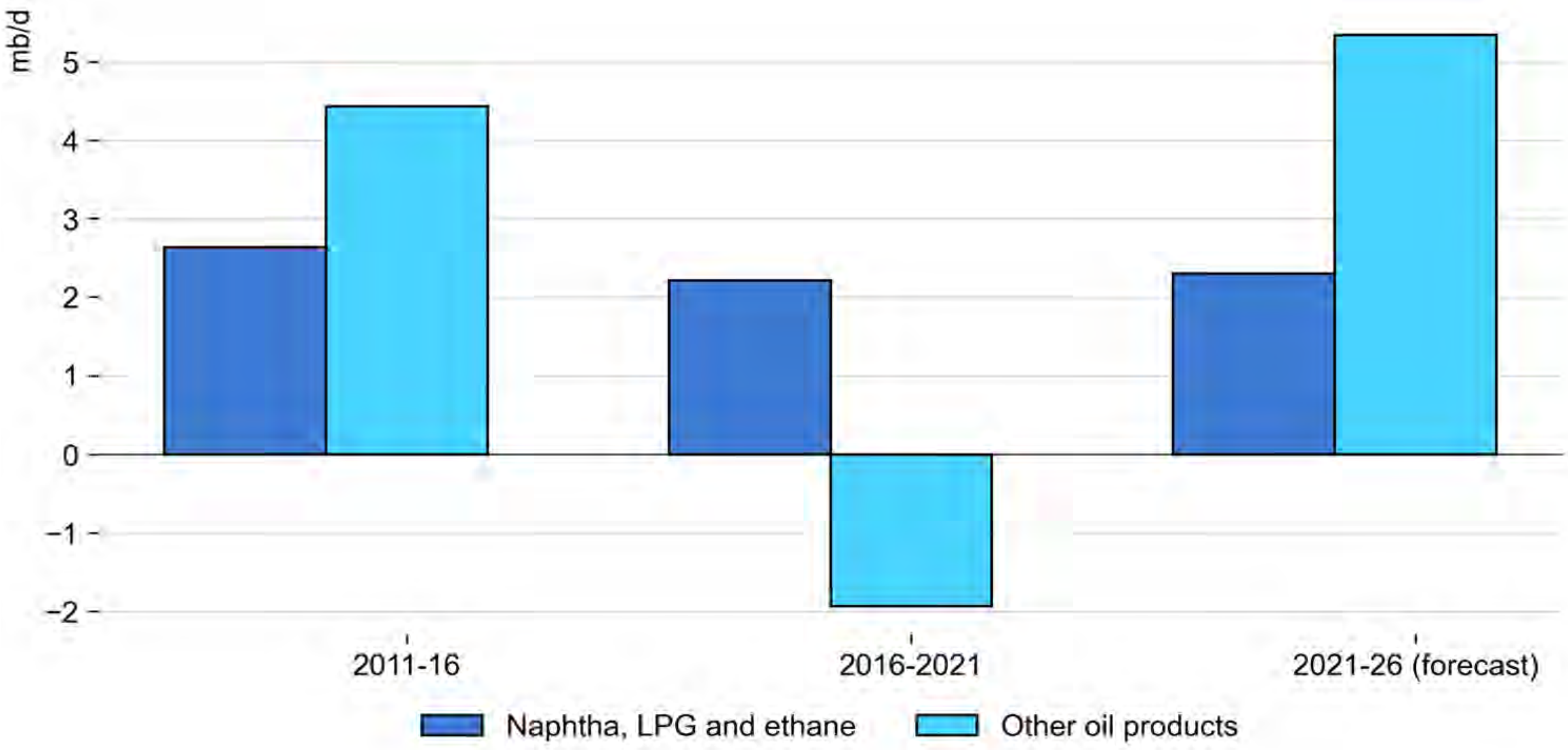
Naphtha demand will increase by 1.2 mb/d in total and 170 kb/d per year on average, as Asian countries continue to expand their capacities. China will increase its naphtha feedstock demand by a total of 475 kb/d in 2019-2026. India and the Russian Federation ("Russia" hereafter) are expected to commission new crackers during the same period and push naphtha demand up by 135 kb/d and 90 kb/d, respectively.

There is a growing momentum for single use plastic bans, recycling targets and other innovative plastic technologies. Governments and institutions are starting to tax single use plastics or non-recycled plastic used in packaging. However, in the medium term, these initiatives are expected to have a moderate impact on overall plastics consumption.

In an alternative scenario, we looked at what it would take to slow global petrochemical demand growth. It could be reduced by a third if governments were to take more stringent measures to ban single-use plastics and, at the same time, nearly double the plastics collection rate from 16% in 2020 to 28% by 2026.Under this scenario, petrochemical feedstock demand could be lowered by around 700 kb/d in 2026 versus our base case.

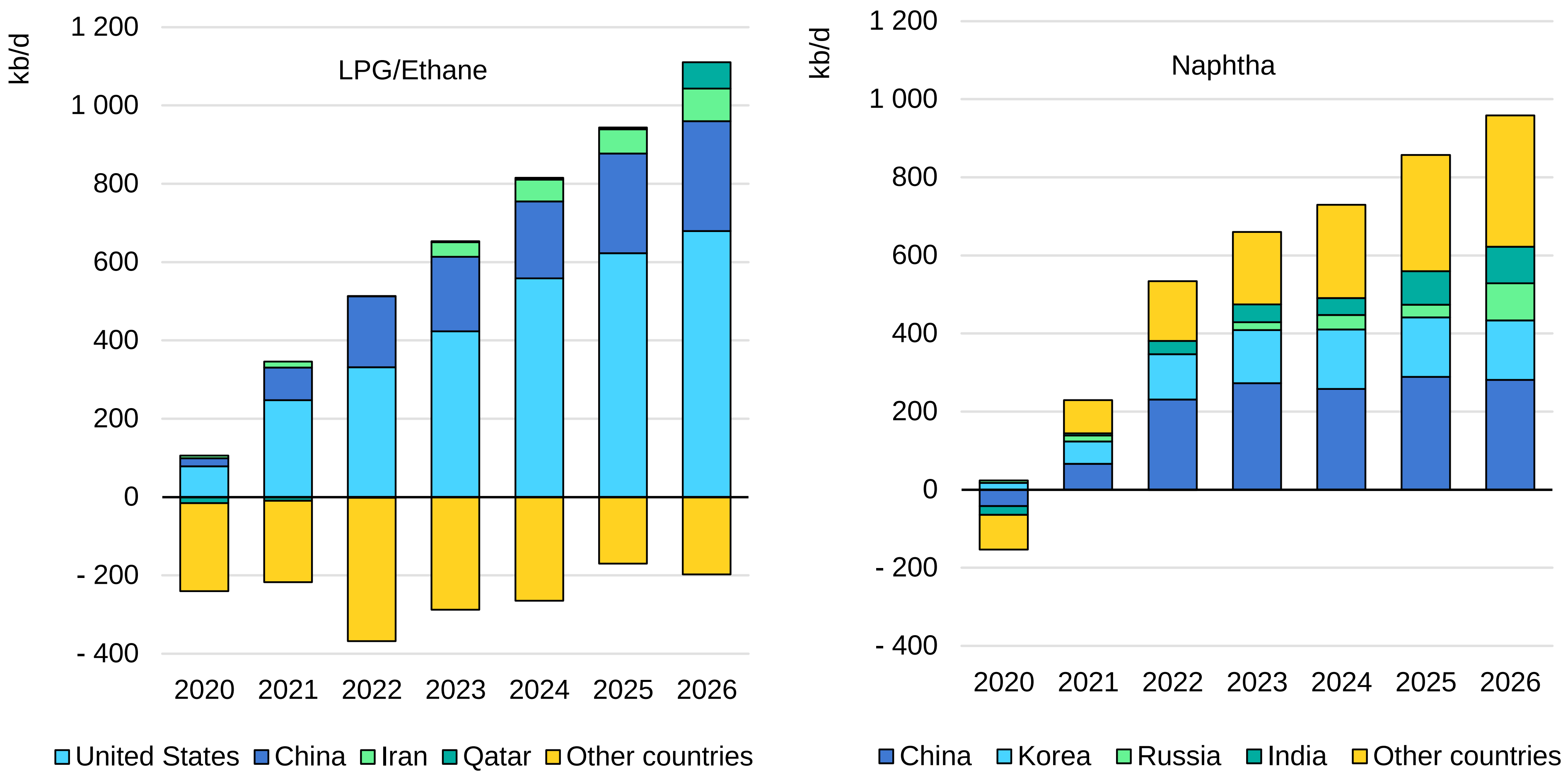
Petrochemicals weather the pandemic

Demand changes in five-year intervals



Petrochemical feedstocks demand supported by cracker additions

Incremental demand for petrochemical feedstocks 2019-2026



Sources: Industry press and company reports.

Petrochemical plant additions led by the United States and Russia

Selected petrochemical capacity additions

Projects	Country	Nameplate Capacity ('000 t/y')	Feedstock and maximum demand (kb/d)		Scheduled year
INEOS Cracker, Antwerp	Belgium	1000	Ethane	55	2023
SINOPEC Gulei JV Cracker, Zhangzhou	China	800	Naphtha	65	2022
PetroChina Cracker, Korla	China	600	Naphtha	48	2025
Carbon Holdings Cracker, Ain Sokhna	Egypt	1500	Naphtha	121	2023
HPCL-Mittal Energy Limited (HMEL) Cracker, Bathinda	India	1200	Naphtha/Kerosene	97	2022
PT Lotte Chemical Titan Cracker, Merak	Indonesia	1000	Naphtha	81	2023
Dehloran Sepehr PC Cracker, Dehloran	Iran	500	Ethane	28	2024
Ganaveh-Dashtestan PC Cracker, Ganaveh	Iran	500	Ethane	28	2025
Nizhnekamskneftekhim Cracker 2, Nizhnekamsk	Russia	650	Ethane/Naphtha	43	2023
Sibur-Amur Cracker, Svobodny	Russia	1200	Ethane/Propane	73	2025
Rosneft-VNHK Cracker, Nakhodka	Russia	1400	Ethane	78	2026
Aramco-Sabic Cracker, Yanbu	Saudi Arabia	2000	Naphtha	161	2026
Lotte-Hyundai Cracker, Daesan	South Korea	750	Naphtha/LPG	57	2022
GS Caltex Cracker, Yeosu	South Korea	700	Naphtha	56	2023
PTTGC Cracker 5, Map Ta Phut	Thailand	525	Naphtha/LPG	40	2022
Shell Cracker, Monaca	US	1497	Ethane	83	2022
Exxon-SABIC Cracker, Corpus Christi	US	1800	Ethane	100	2023
Formosa Cracker 1, St. James	US	1200	Ethane	67	2024
Borouge Cracker 4, Ruwais	UAE	1500	Ethane	83	2025

Source: Industry press and company reports.

Efficiency improvements and electric vehicles will reduce transport fuel demand growth

Efficiency improvements will occur for all fuels (not only road transport fuels) and are expected to reduce the growth in oil demand by roughly 850 kb/d per year over the forecast period.

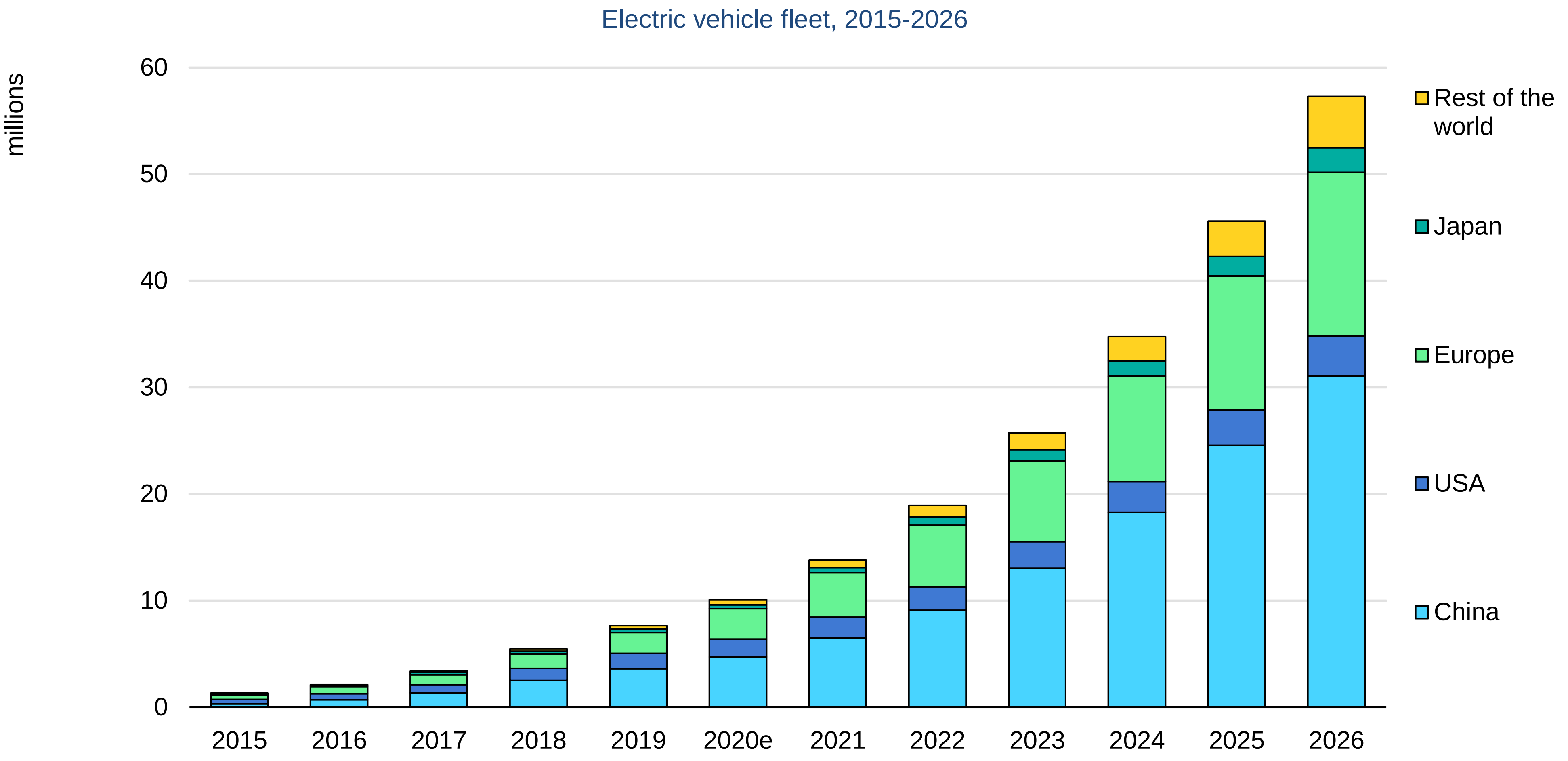
The largest improvements will occur in the transport sector. The European Union approved in 2019 a target of an average of 95 g of CO_2 per km for new passenger cars from 2020. It corresponds to a consumption level of 4 litres/100 km for gasoline cars. The target will decline to 81 g/km from 2025 onwards (3.3 l/100 km) and 59 g/km from 2030 onwards (2.3 l/km). Of course the targets will largely be met by increasing sales of plugged electric vehicles (EVs), but improving efficiency of ICE vehicles and full or mild-hybrids (not plug-in) will also help. The market share of EVs in European car sales jumped from 3% in 2019 to 11% in 2020, while the share of full and mild hybrids rose from 5.7% in 2019 to 12% in 2020. The International Council on Clean Transportation (ICCT) estimates that the average new European car CO_2 emission dropped from 122 g/km in 2019 to 107 g/km in 2020 (1 g/km per month reduction in 2020 while in 2015-19 reduction was 0.6 g/km per year).

In the United States, President Joe Biden signed an Executive Order on his first day in office ordering the review of the previous administration's lowering of car fuel standards under the Safer Affordable Fuel-Efficient (SAFE) rule to just 1.5% improvement per year for model years 2021-26. The Obama administration had called for an annual fuel economy improvement of 5% under the Corporate Average Fuel Economy standards (CAFE). The new US administration is expected to return to standards closer to CAFE. Canada generally sets targets similar to the United States.

India has a target of 4.8 litres/100 km for 2023 compared to a current consumption of 5.5 litres/100 km, representing an improvement of 1.5% per year. Chinese Phase V passenger car fuel consumption standards, published at the end of 2019, reduces fuel use for new cars to 4 litres/100 km by 2025 from 5 litres/km for 2020 under Phase IV. Japan approved in 2019 a tightening of light vehicle standards through 2030, requiring fuel consumption of 3.95 litres/100 km by 2030, or an improvement of 32% versus average consumption in 2016. ASEAN countries target 5.4 litres/100 km by 2025 from a goal of 7.3 litres/100 km in 2015.

The IEA expects global electric car sales to reach over 12 million in 2026, with a total fleet size close to 60 million. More than half of all electric cars will be situated in China, which took an early lead in their development, a quarter in Europe, the rest in Japan, the United States and other countries. By 2026, electric cars and buses will displace more than 1 mb/d of oil demand – 700 kb/d of gasoline demand and 300 kb/d of diesel – compared to 2020 levels.

Electric vehicles fleet should be close to 60 million in 2026



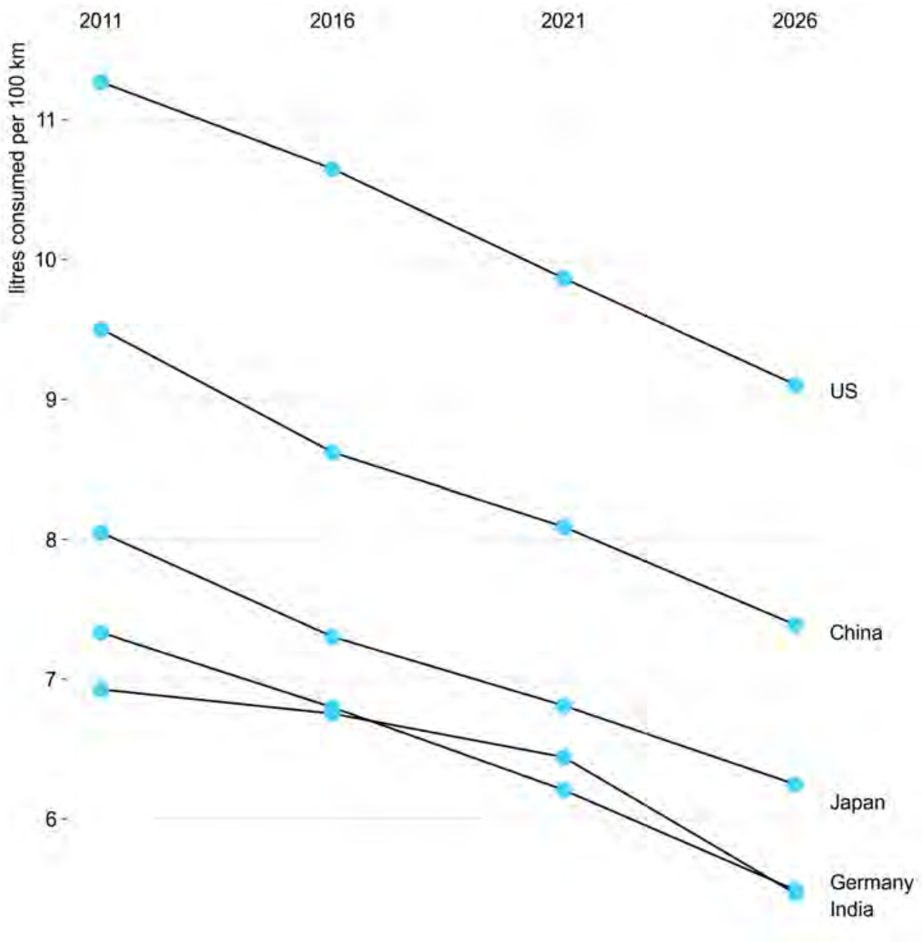
Global gasoline demand has peaked

Global gasoline consumption is unlikely to ever return to its 2019 level. Strong growth in developing countries is no longer enough to offset declines within the OECD, where fuel efficiency improvements are making an impact. As a result, gasoline use falls by 690 kb/d from 2019 through 2026, to 25.9 mb/d.

Gasoline demand fell by a record 2.9 mb/d in 2020, as many governments asked the public to stay at home to reduce infection rates. This is expected to continue into the early part of 2021, due to the ongoing spread of the virus, but gasoline demand will recover by a strong 1.7 mb/d y-o-y, as consumers progressively resume their normal activities once vaccines are widely distributed.

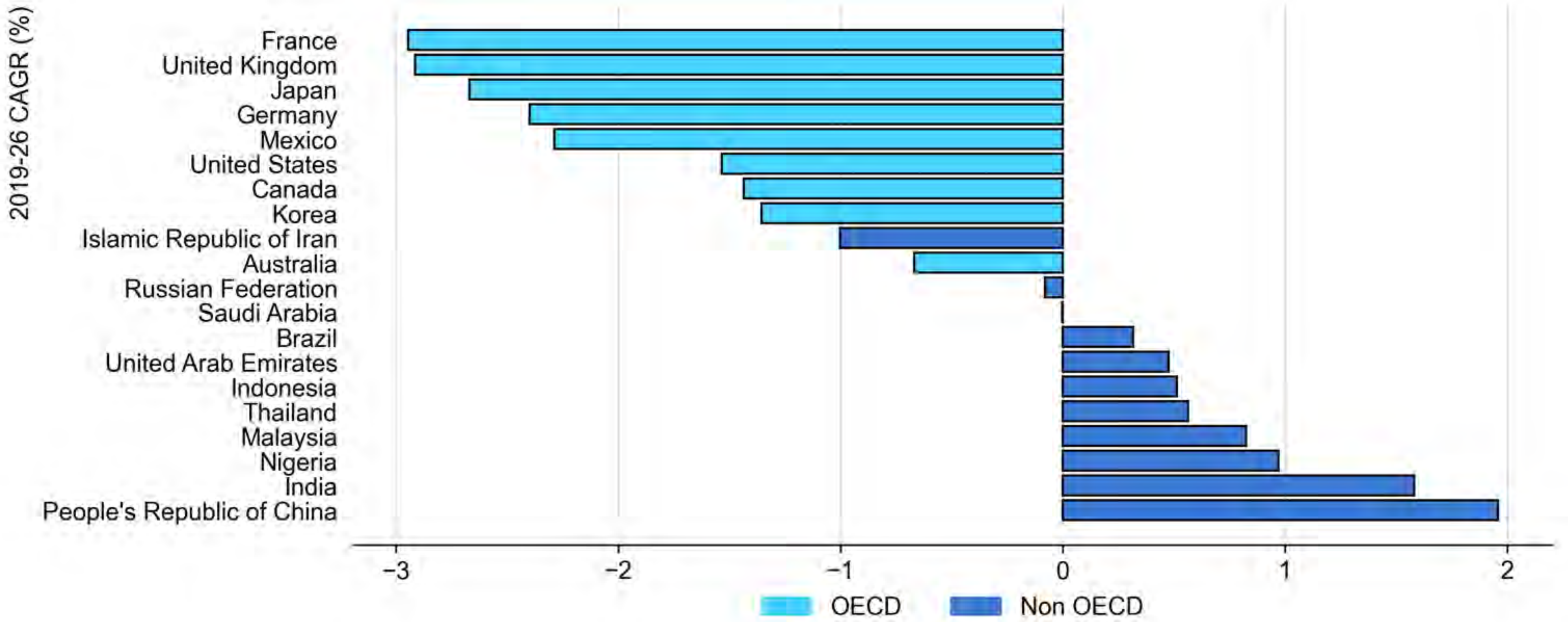
Consumption should continue to rise strongly in 2022, by 470 kb/d, narrowing the gap with pre-pandemic levels. However, beyond that, gasoline demand is likely to stagnate for several years. Demand from OECD countries will fall by 200 kb/d on average from 2023 as a result of the continued reduction in car fuel consumption as well as displacement by EVs and biofuels. Car manufacturers will introduce new, more fuel efficient models. By contrast, growth will remain strong in countries such as Indonesia, India and China, as middle-class consumers seek greater mobility. Growth from non−OECD countries will average just over 200 kb/d per year between 2023 and 2026. Efficiency improvements will occur in the non-OECD too, but will not be enough to offset growth from more driving.

Historical and forecast car fleet consumption



Gasoline's future is outside the OECD

Top 20 gasoline consumers: expected 2019-2026 growth



Teleworking likely to have a small but long-lasting demand impact

Efforts to halt the spread of Covid-19 triggered a huge increase in the number of people working from home and this caused transport fuel consumption (gasoline and diesel) to fall by more than 800 kb/d in 2020, roughly one fifth of the total fall in road transport fuel demand. The level of teleworking is expected to remain elevated in 2021 to support ongoing social distancing measures but easing government restrictions will mute the subsequent impact. Remote working is expected to continue to displace around 250 kb/d of oil demand in the later years of the forecast as many companies and employees maintain some of the new working practices.

Underlying the demand forecast is the assumption that, for the most part, future teleworking will be limited to developed economies where those that can will work from home one or two days a week on average (double the 2019 level).

Prior to the pandemic, around 8% of the workforce teleworked (ILO 2020). While remote working is not even an option for many, for example, those in the manufacturing and construction sectors, recent studies suggest that up to 20% of jobs can be done from home on an ongoing basis.

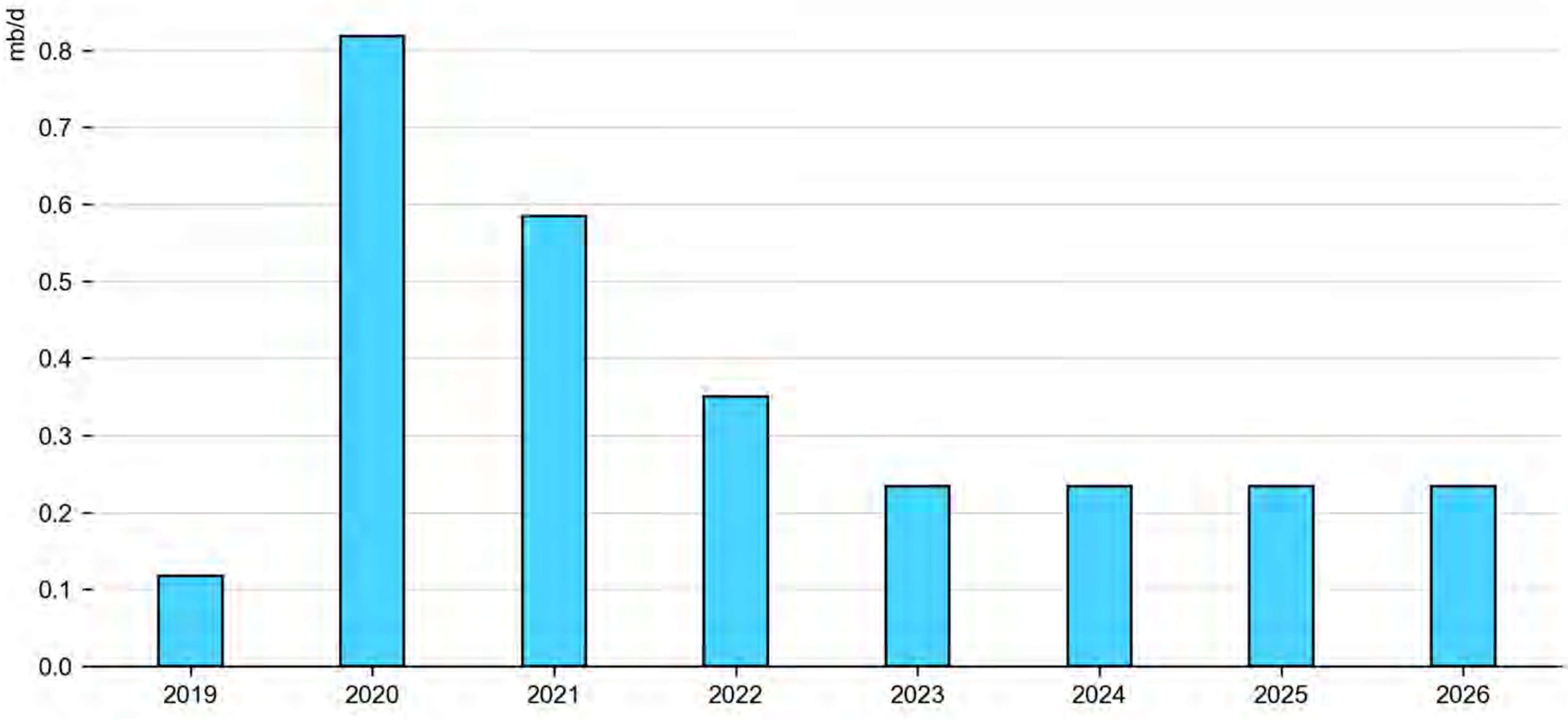
The potential is strongly linked to a country's level of economic development. Those with a higher GDP offer better access to the required technology and tend to have more of the workforce in service sector jobs, for which there is less need to be physically present in the office. Many firms, particularly in the tech, legal, consulting and banking fields, have announced plans to shift to indefinite teleworking, or a hybrid model, thereby saving money on office rental and offering employees additional flexibility.

Most surveys available in the early part of 2021 point to the fact the majority of service workers (90%+) would enjoy a mix of office and remote work in the future, with only a minority of respondents (around 25%) are keen on a fully remote arrangement. Most people would also consider going to a decentralised office closer to home. However, these arrangements are unlikely to affect workers in non−service industries.

The largest impact on oil demand will be seen in the United States and Europe, where up to 40% of jobs can be done from home. In the non-OECD, at most 25% of jobs are suitable for teleworking and even in countries likely to permanently adopt the practice, such as Brazil and India, the impact on total fuel consumption is negligible.

A future marked by more teleworking would have a larger impact on oil demand trends. In a scenario where workers in the OECD and largest non-OECD countries work from home three and two days a week, respectively, consumption would be around 900 kb/d lower in 2026 compared to our base case.

Impact of teleworking on transport fuel demand as included in our forecast



Gasoil: A tale of two worlds

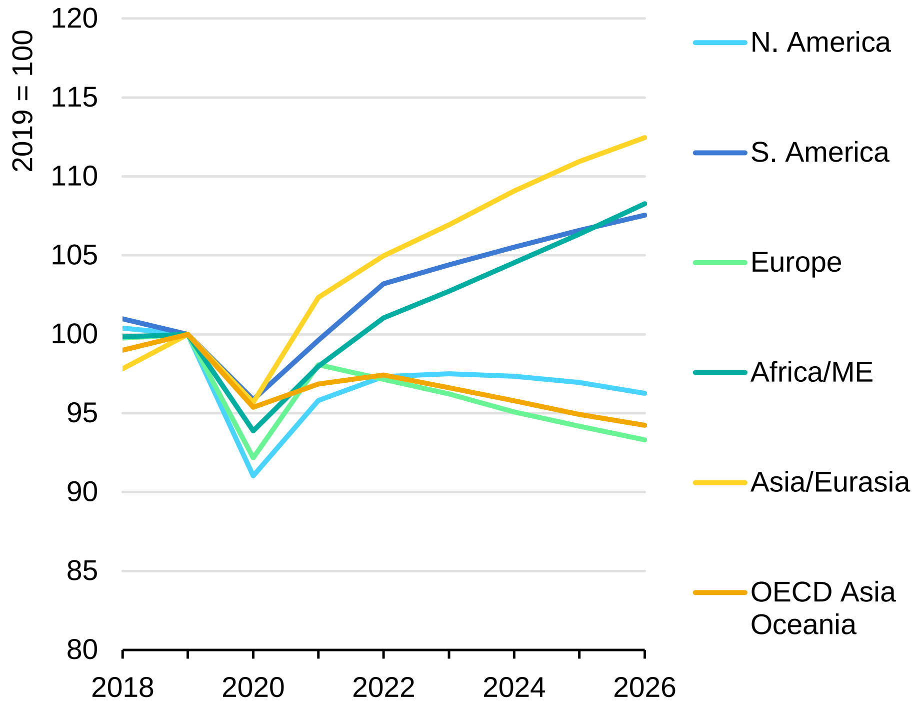
The Covid crisis led to a decline of 1.8 mb/d, or 6%, in global gasoil demand in 2020. Road diesel demand fell by 8% and other gasoil use (heating, marine fuel and industry) declined by 4%. While diesel consumed in personal cars fell in line with government-imposed lockdowns, especially in Europe, truck traffic remained resilient on strong demand for goods transportation.

Industrial production and goods transportation will continue to support global gasoil consumption in the medium term, with demand expected to recover to the 2019 level by 2022. However, OECD gasoil demand will never return to the levels of 2019.

We expect OECD gasoil demand to increase through 2022 in line with a strong recovery in economic activity, but to contract thereafter on low growth in industrial production, fuel efficiency gains, and due to a strong slowdown in diesel vehicle sales in Europe. European gasoil demand is set to decline by 570 kb/d between 2019 and 2026. During the same period, OECD Asia demand will contract by 110 kb/d and North American demand by 190 kb/d.

Non-OECD gasoil demand, by contrast, reaches its 2019 levels as early as 2021, and continues to post strong growth thereafter. Gasoil demand in non-OECD Asia increases by 830 kb/d from 2019 to 2026, supported by China and India in particular. Gasoil demand is also expected to increase in other non-OECD economies, by 120 kb/d in Latin America and 290 kb/d in Africa/Middle East.

Regional gasoil demand indexes



Changes in the European car fleet: City policies to keep diesel cars out

Since the Dieselgate scandal in 2015, the share of diesel vehicles in new car registrations in Europe has fallen from 52% in 2015 to less than 30% currently. Several European cities have announced that they will ban diesel cars from inner cities, including Oslo, Paris, Rome, Hamburg and Madrid, from 2024. Many other cities announced a similar ban starting between 2025 and 2030. According to *Bloomberg*, a total of 24 European cities (with population of 62 million) are banning diesel engine cars over the next decade.

As a result, diesel car demand has fallen and the share of diesel engine cars in the total European internal combustion engine (ICE) car fleet is expected to decline from more than 50% in 2018 to less than 44% in 2026. We estimate that the change in car fleet composition could reduce diesel demand in Europe by 150 kb/d by 2026.

Gasoline cars are not really benefitting from the shift. In 2020, conventional ICE cars lost market share in the European Union representing only 75% of total passenger car sales in 2020. Total car sales declined by 3 million units due to the Coivd-19 crisis, with gasoline and diesel cars hit the hardest. Gasoline cars sales dropped by 37% and diesel car sales by 32%. Battery electric vehicles sales, by contrast, rose by 117% and plug-in hybrids by 262%. The share of electric cars jumped from 3% in 2019 to 11% in 2020. Plug-in hybrid and battery electric car sales have been boosted in part by government incentives in response to the Covid-19 crisis.

Several European cities are announcing a phasing-out of all ICE cars as of 2030, including Stockholm, Paris, Amsterdam, Bergen and Oslo. Others, such as Tokyo, London, New York or Los Angeles have 2050 all-electric targets. In China, cities set goals regarding the share of electric vehicles on the road by the end of the 13th Five−Year Plan period (2016-2020). These goals were generally outpaced by 2019. Shenzhen, for example, had a goal of 3-5% of electric vehicles in 2020 and achieved more than 10% in 2019.

Policy measures to discourage the use of diesel cars, and more generally ICE cars in cities, should have a moderate but intensifying impact on diesel consumption in the next five years. Later on, additional constraints on the sales and use of ICE cars are likely to significantly impact transport fuel demand.

Jet fuel demand hardest hit by pandemic regulations halting travel

Out of all oil products, jet fuel was proportionally the most affected by the pandemic, as governments closed international borders, business meetings and conferences went online, and consumers cancelled holidays. Given the time it takes to achieve vaccine protection, the recovery of jet fuel to pre-pandemic levels is likely to be more gradual than for gasoline and diesel. We expect jet fuel and kerosene demand to grow just 830 kb/d in 2021, less than a quarter of the volume lost in 2020, as governments wait until the second half of the year to allow cross-border traffic to reopen and as consumers remain cautious about international travel. Most of the growth is likely to occur in domestic or short-haul international travel.

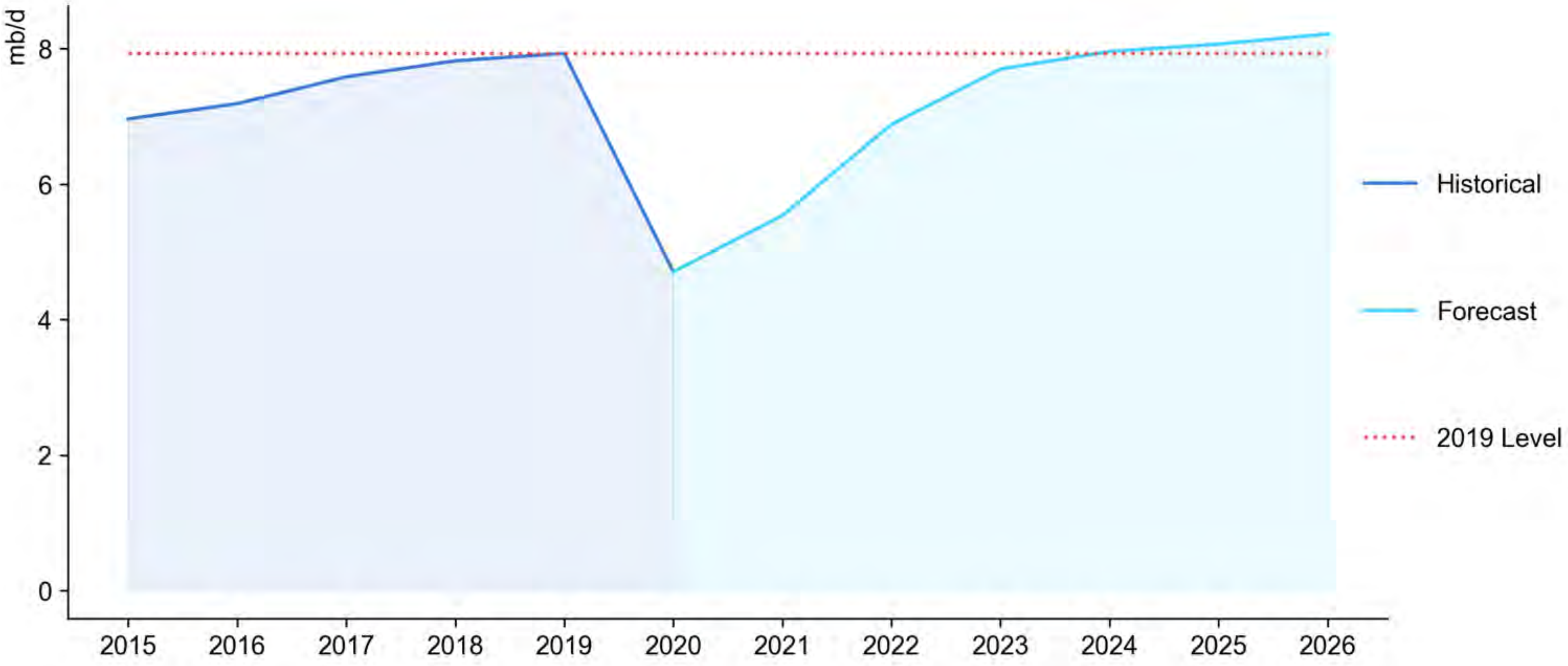
There is pent-up demand for travel from well-off consumers, but it will not be visible until 2022 when we expect jet and kerosene consumption to grow 1.4 mb/d y-o-y. In volume terms, the Americas and Asian regions will see the highest growth, but in relative terms, Europe and Latin America will increase the most, as they were particularly affected by the Covid-19 crisis. The economic situation and the virus' persistence in some parts of the world will combine to hold travel below pre-pandemic levels of consumption until the second half of 2023, or the first half of 2024. Those who have suffered financially because of job losses or business failures will not have the means to travel, which will weigh on the industry in the medium term.

Finally, the decision by many airlines to retire older, less efficient aircrafts will reduce fuel consumption. In our forecasts, annual demand growth slows to 820 kb/d in 2023, 260 kb/d in 2024, and 130 kb/d for the rest of the forecast. By the end of the forecast period, growth in demand is more prominent in non−OECD countries, due to the impact of a growing middle class that is increasingly keen to travel.

Business travel, which nearly ground to a halt in 2020, is expected to return progressively over the forecast period. By 2026, we estimate that business travel will be back to 90% of its pre-crisis levels. With business travel estimated to represent roughly 20% of air-traffic demand, an expected 10% reduction in business trips would cut less than 150 kb/d of jet fuel demand in 2026. This assumes that, while some conferences move online in order to reach a broader audience, the vast majority of industry events return to being physical meetings.

Jet fuel demand only returns to pre-pandemic level by 2024

Global jet fuel and kerosene demand



Fuel oil demand: IMO 2020 resulted in a very strong increase in VLSFO

The International Maritime Organization's (IMO) switch to low sulphur bunker fuel continues to shape global fuel oil markets. International bunkers represent more than 3 mb/d of a total 6 mb/d of fuel oil demand. In 2020, due to the Covid crisis and a decline in international trade, bunker demand is estimated to have fallen by 4.3%. As the new IMO rules were introduced, we estimate that higher sulphur fuel oil (HSFO) consumption more than halved, to 1.1 mb/d as ship operators switched to marine gasoil and very low sulphur fuel oil (VLSFO) to comply.

The new VLSFO fuel benefited the most from the switch, increasing by a sharp 1.4 mb/d in 2020. VLSFO demand increased rapidly in major bunkering hubs such as Fujairah, Rotterdam and Singapore. In Rotterdam, HSFO demand declined by 12% q-o-q in 1Q20, replaced by VLSFO. In Singapore the switch was more spectacular, with HSFO consumption dropping from 750 kb/d in most of 2019 to 190 kb/d in 2020. VLSFO demand jumped from 15 kb/d in the first three quarters of 2019 to 615 kb/d in 2020.

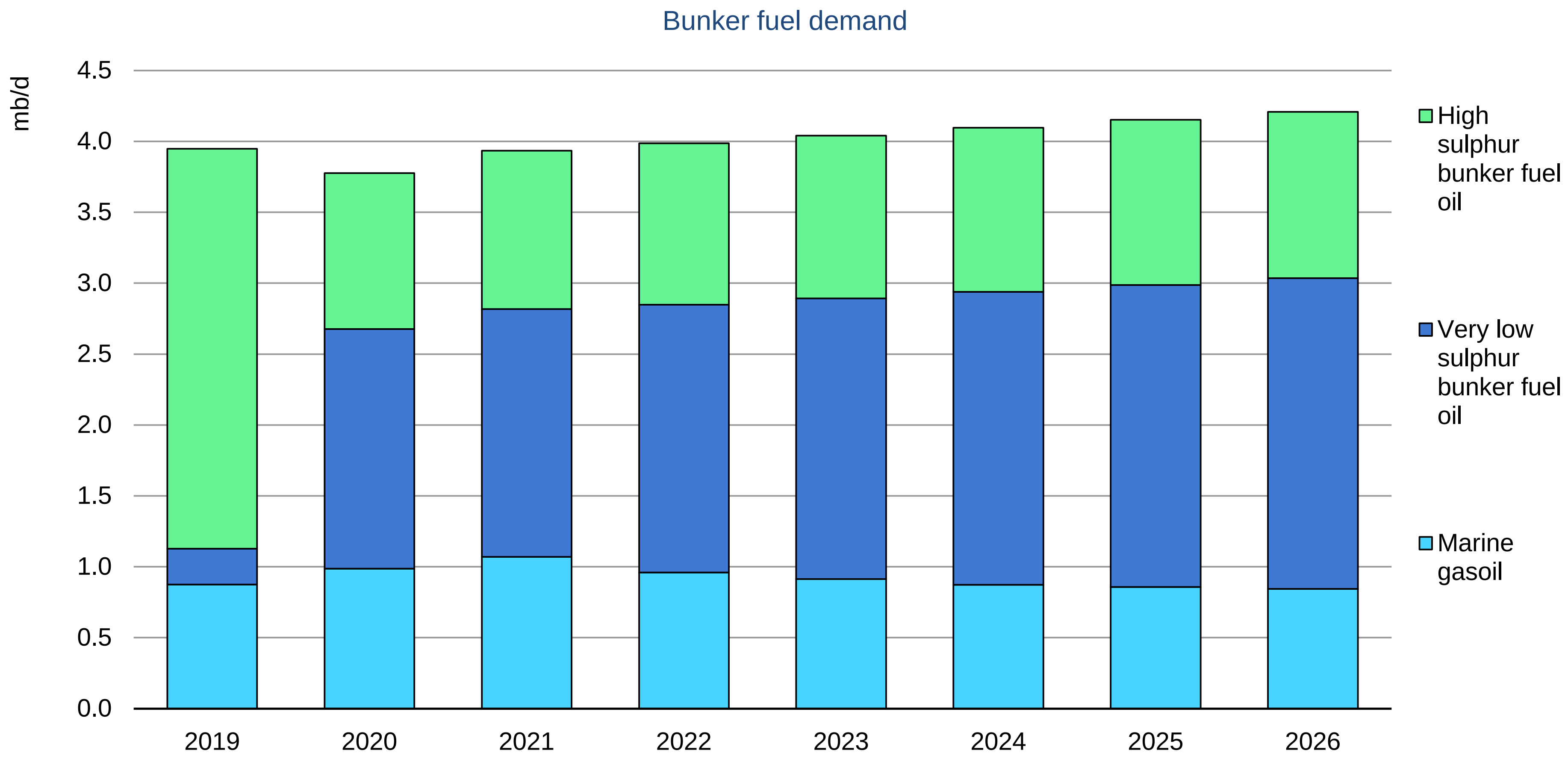
Marine gasoil demand benefited from a small boost of 110 kb/d in 2020 (+13%) but is unlikely to grow in the medium term, as it will be replaced by other fuels such as VLSFO or HSFO (with the deployment of scrubbers). Bunker demand will increase by 160 kb/d in 2021 and by 55 kb/d per year thereafter, to reach 4.2 mb/d by the end of the forecast period. VLSFO will account for 2.2 mb/d of the total in 2026.

Bunker demand is expected to remain relatively subdued in the forecast period, as the recovery in international trade remains slow with the re-organisation of supply chains and increasing concerns regarding the security of supplies of sensitive materials. In addition, the IMO has approved a very strong mandatory improvement in vessels' energy efficiency to reduce greenhouse gas emissions from shipping by 2030, likely to reduce bunker demand growth in the medium term.

Outside the bunker market, fuel oil demand in 2020 also suffered from the sharp drop in economic activity. Over the forecast period, we see little support for fuel oil in the power sector, as several large consuming countries are in the process of replacing both fuel and direct crude use with natural gas. These include Saudi Arabia and Egypt. This will offset moderate growth elsewhere. Overall, we project fuel oil demand outside the bunker sector to recover to 2019 levels by 2022 and to remain roughly unchanged through the end of the forecast period, ending at 3.3 mb/d in 2026.

Globally, we expect total fuel demand (including VLSFO bunker material) to increase from 6.3 mb/d in 2019 to 6.7 mb/d in 2026. VLSFO should benefit from additional bunker demand and a partial switch back from marine gasoil to fuel oil.

Very low sulphur fuel oil overtakes the marine market



Regional developments

Oil demand growth will differ across regions

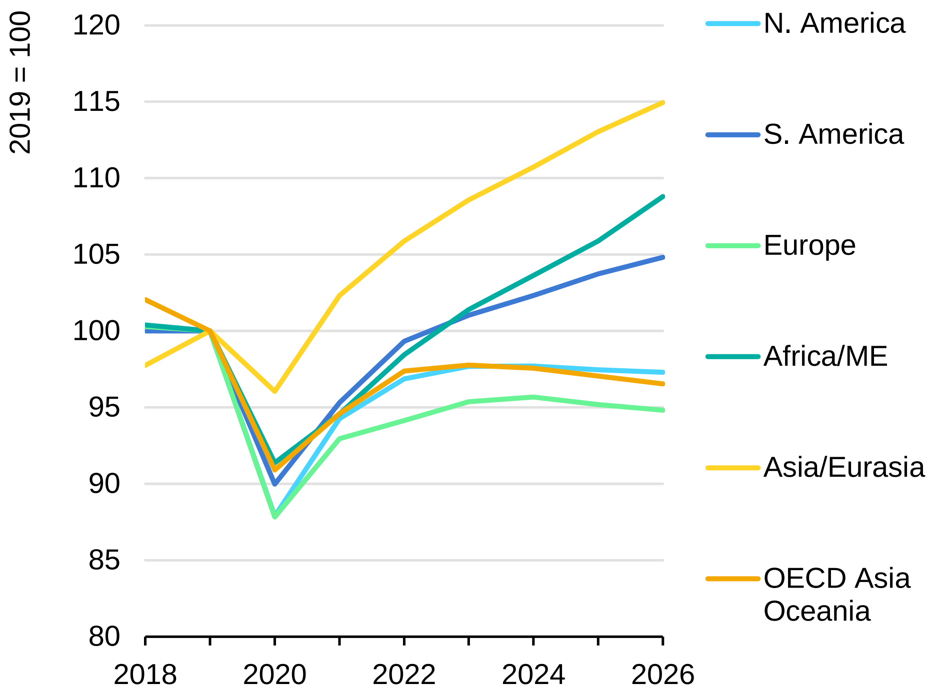
After a strong recovery in oil demand globally through 2022-23, oil demand in high-income economies stagnates while robust demand growth continues in developing economies in the second half of the forecast.

The fastest recovery will occur in non-OECD Asia, supported by demand in China, India and other growing economies. Chinese oil demand dropped y-o-y in 1Q20 but recovered above the previous year's levels as soon as 2Q20. Indian demand also accelerated substantially in 4Q20. Demand in Africa, the Middle East and South America, although more impacted by the Covid outbreak, will grow over the forecast period.

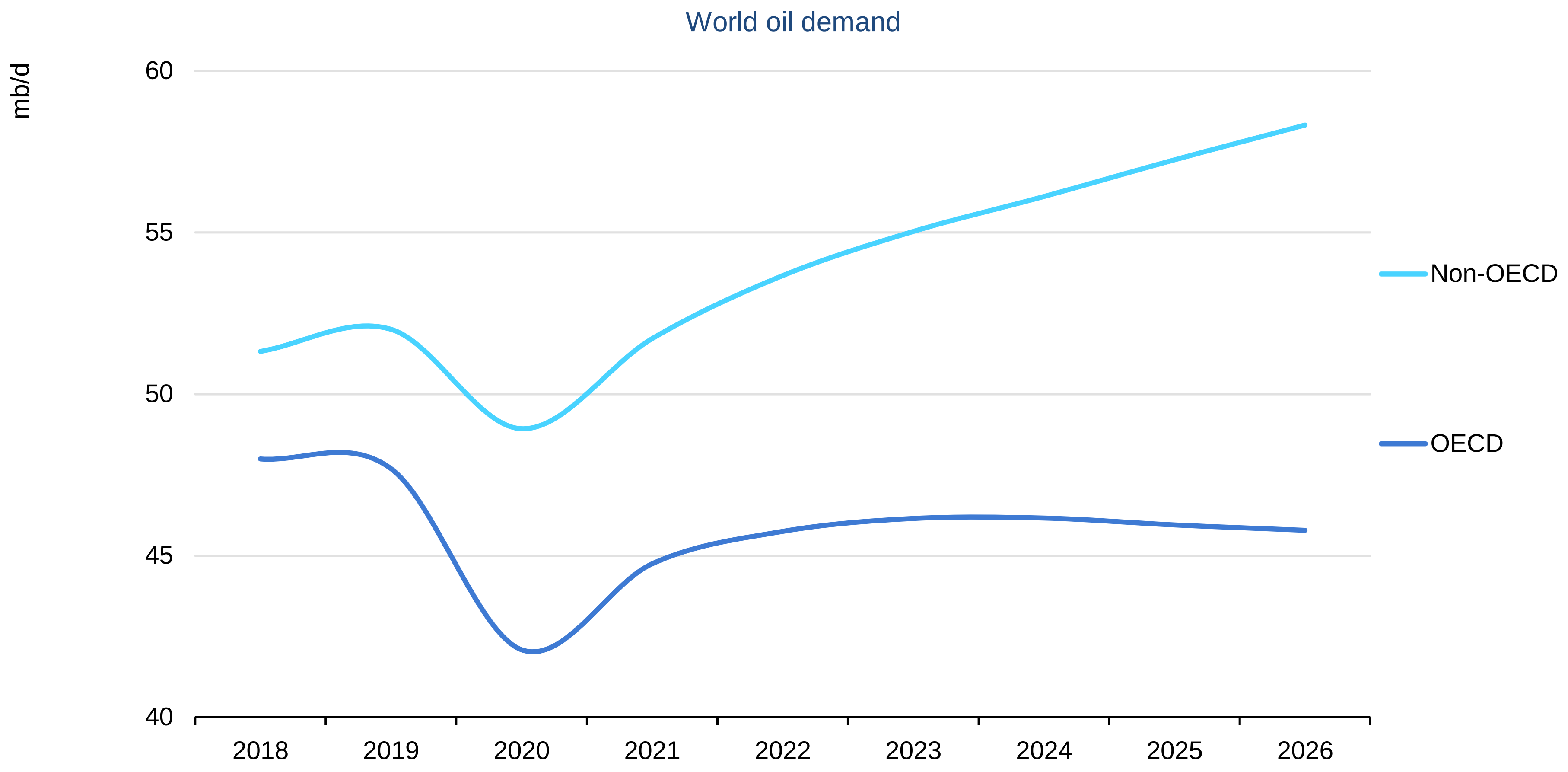
OECD demand, by contrast, will stagnate from 2023, and even decline at the end of the forecast period. At this stage, oil demand will not have completely recovered from the Covid crisis, and therefore we anticipate that OECD oil demand will never return to 2019 levels. The peak in OECD demand was likely reached in 2005. The reason for the stagnation expected post-2023 is the relatively low-demand response to economic activity, moderate economic growth, and rapid progress in transport energy efficiency. In 2026, European oil demand will be 140 kb/d lower than in 2019; North America down 670 kb/d and Asia/Oceania 270 kb/d lower.

Vehicle efficiency improvements will occur in all regions and, together with higher penetration of electric cars, significantly reduce transport oil demand in the medium term. We estimate that efficiency improvements cut roughly 850 kb/d of oil demand per year while EVs displace 1 mb/d by 2026 (700 kb/d of gasoline and 300 kb/d of diesel).

Oil demand indexes



OECD oil demand will never recover above 2019 levels



OECD demand starts to contract after the Covid recovery

The North American and European regions will witness the largest demand growth within OECD in percentage terms in 2021 (6-7%), as they catch up with the volume lost in 2020 to the pandemic. We estimate that oil demand will grow by 1.6 mb/d in North America and by 740 kb/d in Europe, or around half the decrease seen in 2020. After growing by 2% in 2022, growth in the OECD grinds to a halt as higher energy efficiency in the transport sector, penetration of EVs and substitution by other energies curbs fuel use. Other factors, such as teleworking and less business travel, will also contribute, albeit marginally.

Americas: Demand grows by 1.6 mb/d in 2021 and by 670 kb/d in 2022, helped by the progressive recovery of transport fuels from the pandemic. Thereafter, consumption growth eases to 210 kb/d in 2023 and 10 kb/d in 2024, before turning negative in 2025, on improved fuel economy in passenger cars. Demand never returns to its 2019 level.

US demand for transport fuels grows robustly in 2021 due to the recovery from Covid-19, before falling to near-zero from 2023. Gasoline, which provided a large chunk of US demand growth in the past few decades and remains the country's biggest oil use sector, will decline from 2023 onwards, indicating that a demand peak may have been reached. Demand for jet fuel will grow until 2023, before flattening by 2024. Meanwhile, consumption of LPG and ethane continues to rise robustly well into the forecast period, buoyed by new cracker installations and strong demand for plastics. Overall, US oil demand contracts from 2025.

Europe: Consumption increases by 740 kb/d in 2021, 110 kb/d in 2022 and 160 kb/d in 2023. Growth then falls to 20 kb/d in 2024 and turns negative in 2025. By 2026, it will still be below its 2019 level. Gasoline and diesel grow in the early part of the forecast period, but decline after 2023. Jet fuel and kerosene demand grows by 160 kb/d in 2021. As the international aviation sector reopens, demand rises more strongly in 2022 (330 kb/d) and 2023 (280 kb/d), when it returns to its 2019 consumption level. Petrochemical feedstocks LPG, ethane and naphtha see little demand growth.

Asia Oceania: Oil demand was less impacted in Asia Oceania by the pandemic than in the Americas or Europe. In our forecast, demand grows by 70 kb/d in 2021, 140 kb/d in 2022 and 60 kb/d in 2023. As in other regions, transport fuels lead the gains in the initial stages of the recovery. Overall demand is not expected to return to its 2019 level.

China and India lead non-OECD demand higher

From 2023 onwards, growth rates in the Asia Pacific, Africa and the Middle East overtake those seen in Europe and North America, due to more dynamic population growth and an increasing middle class eager for more mobility. Non-OECD countries will prop up the oil demand outlook throughout the decade.

Chinese oil demand continues to grow throughout the forecast period and was the only major consumer to do so in 2020. Only jet fuel declined due to the shutdown of international air travel. In 2021, demand is expected to increase sharply for all oil products (including jet fuel), due to increased mobility and higher energy use in the industrial sector. From 2022 onwards, we see growth moderating to ordinary speed for most products and a total annual oil demand growth of roughly 270 kb/d. The high growth rates seen in China in the late 2010s are unlikely to be replicated over the forecast period.

Indian oil demand fell sharply in 2020, as the country was heavily impacted by the pandemic. Demand for most products contracted, and gasoil/diesel, which is heavily used in the transport sector, saw the largest fall in volume. 2021 should see robust gasoil and gasoline demand growth. The country's demographic expansion as well as higher economic growth means oil demand should continue to rise well into the 2020s. Gasoil/diesel will continue to account for a larger share of oil demand growth, despite improvements in energy efficiency, but gasoline, jet fuel and LPG will all increase as well. Total oil demand growth is expected to average 140 kb/d in 2022-26.

Other non-OECD Asia: Oil demand is expected to continue to expand over the forecast period in other parts of the non-OECD Asia region, such as Indonesia (70 kb/d per year in 2022-26) and the Philippines (20 kb/d per year in 2022-26).

Africa and Middle East: In both regions, demand increases in every year of our forecast period, reflecting dynamic population growth, stronger economic activity and the post-Covid recovery. Demand growth will be strongest in the years 2021-22, owing to the recovery from the pandemic. However, in both regions, demand continues to expand by 100-200 kb/d per year thereafter. Transport fuels will be responsible for the lion's share of the gains. In the Middle East, petrochemical feedstocks also grow robustly.

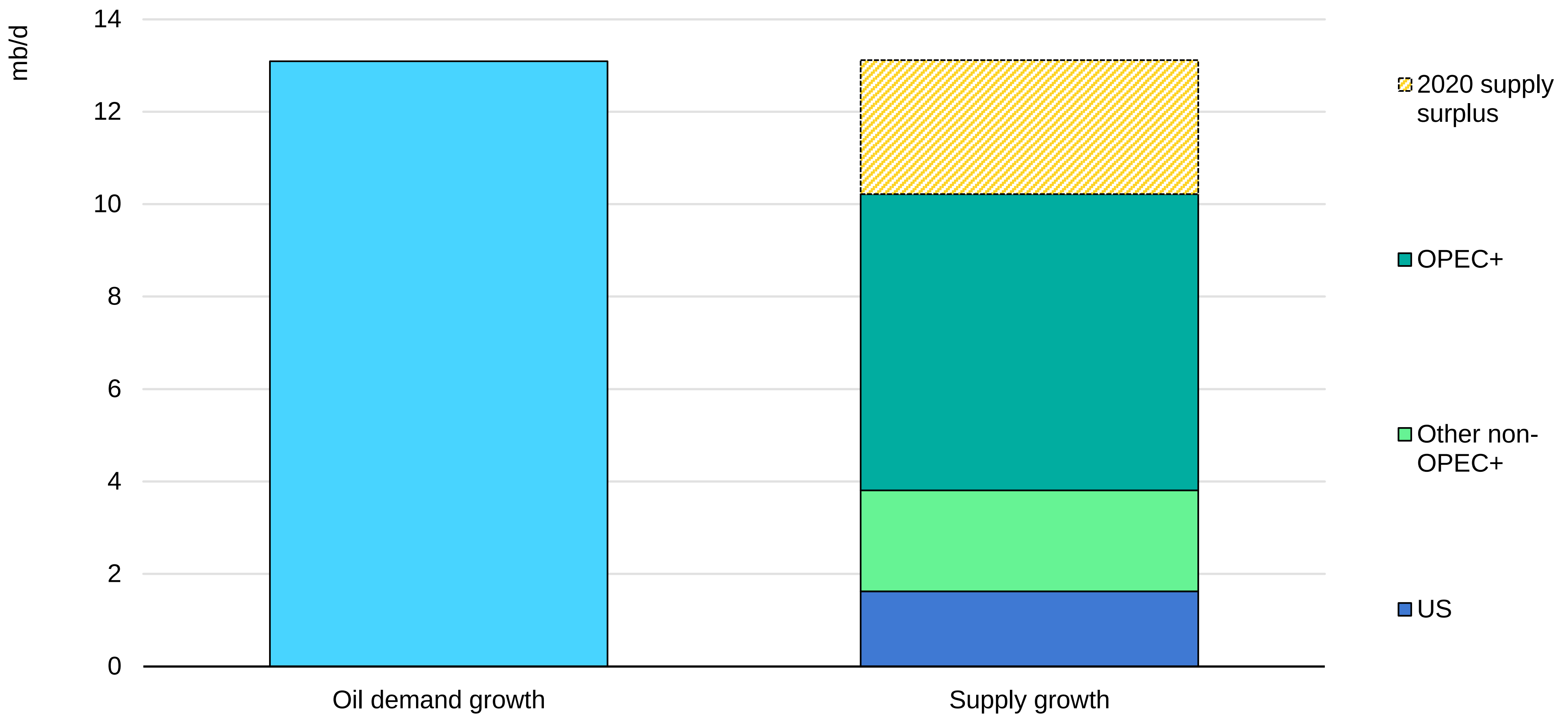
Central and South America: The region will see one of the lowest growth rates in oil demand among major regions, with total demand increasing by 130 kb/d on average in 2022-26. This is largely due to weaker economic prospects. Brazil oil demand growth is expected to average 40 kb/d in the 2022-26 period.

Supply

Global supply overview

Ample spare capacity from Covid-19 demand collapse keeps oil market comfortable

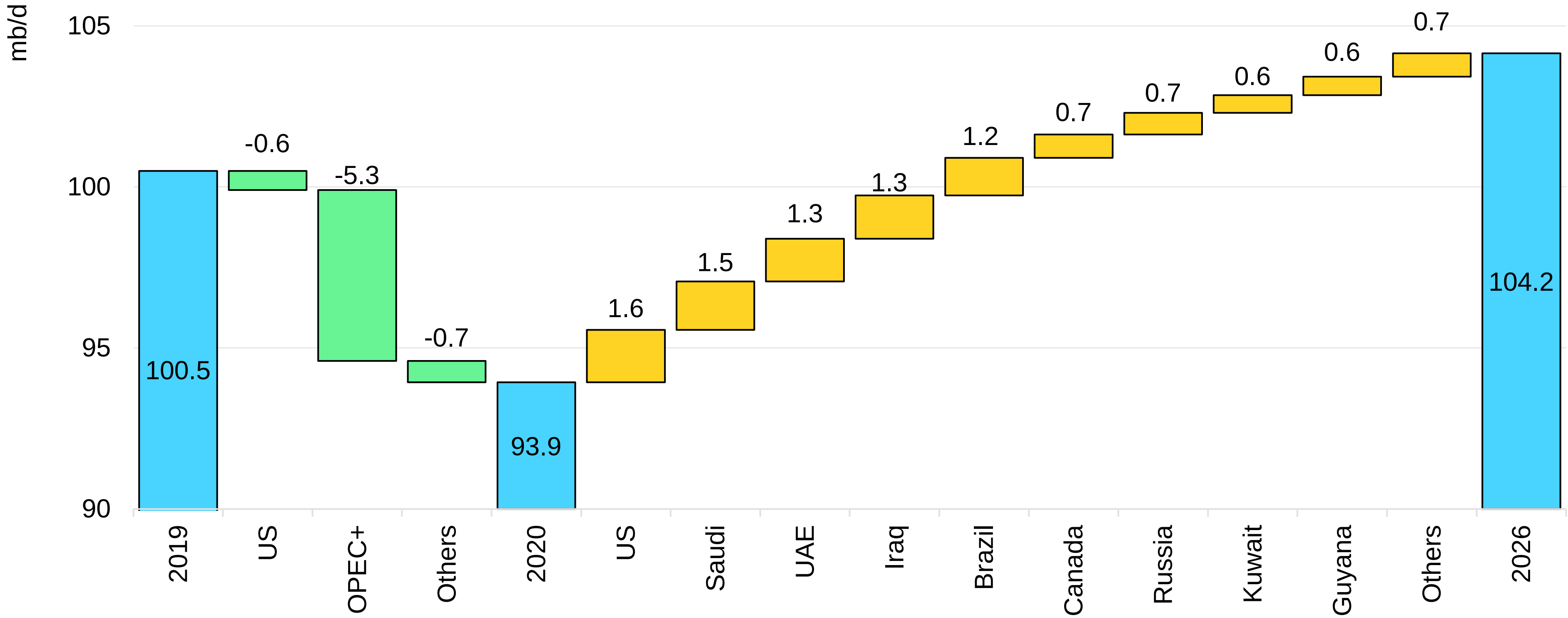
Global oil demand and supply growth 2020-2026



Note: In 2020, global oil supply exceeded demand by 2.9 mb/d.

Following record 2020 production decline, the Middle East drives world oil supply increase

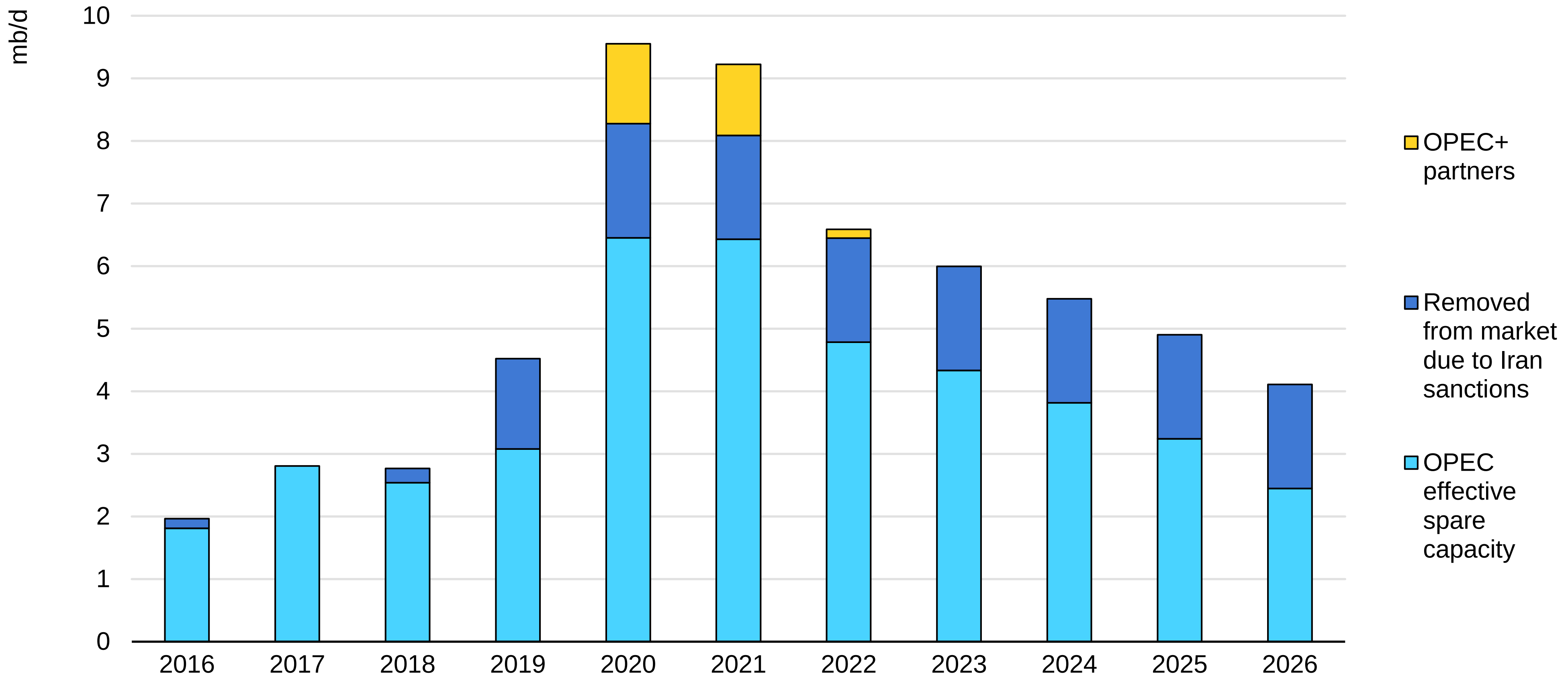
Global oil supply 2019-2026



Note: Global oil supply in 2019, 2020 and 2026 in blue; changes for 2019-20 in green and yellow for 2020-26. OPEC+ changes from 2020-26 assume call on OPEC crude oil is met (i.e. production rises in line with demand) and Iran remains under sanctions.

OPEC effective spare capacity could shrink to lowest since 2016

OPEC+ spare production capacity



Global oil supply growth slows due to spending cuts, project delays, and demand uncertainty

Expansion of the world's oil production capacity is expected to slow in the medium term in the wake of the Covid-induced demand shock and a shift towards clean energy. At the same time, the historic collapse in demand resulted in a record 9 mb/d spare capacity cushion, mostly in the Middle East, which could keep world markets comfortable for the next several years. That, and heightened uncertainty over demand growth, are creating a dilemma for governments and oil companies reluctant to leave resources in the ground or build new capacity that may sit idle.

Our forecast shows sharp spending cuts and project delays in response to low oil prices in 2020 are already constraining growth in almost all oil producing regions. Yet global capacity is projected to increase 5 mb/d by 2026 versus 2020. OPEC crude capacity is now set to rise by a relatively small 1 mb/d, with Iraq and the UAE providing the largest gains. OPEC natural gas liquids (NGLs) and condensates will add 250 kb/d. Non-OPEC countries taking part in OPEC+ are not expected to add overall net new capacity. Those not part of the group are slated to raise output by 4 mb/d, with the United States and Brazil combined accounting for 75% of the increase.

The US shale sector has been hit especially hard as the financial crisis triggered company bankruptcies and production shut-ins. Major oil companies are also scaling back conventional, more expensive oil projects as they shift strategy to include plans for the energy transition. The companies' pivot to a lower-carbon operating environment may also be hastened by governments directing economic stimulus packages to climate-friendly investments. These initiatives and lower spending may start to have an impact at the tail-end of the forecast and will be more pronounced in the second half of the decade. Middle East National Oil Companies (NOCs) such as Saudi Aramco and Abu Dhabi National Oil Co (Adnoc) will continue to focus on traditional strategies that feature capacity building, but the steep loss of oil revenues in the past year has forced many to curb investments and delay projects (See Annex).

The resulting lower global capacity growth, together with resurgent post-Covid demand, will slowly contract the global supply cushion over the outlook period. In tandem with projected higher oil demand, total oil production by 2026 is set to rise by 10.2 mb/d from a six−year low of 94 mb/d in 2020. Producers from the Middle East are expected to provide half the increase, largely from existing shut−in capacity. That marks a dramatic change from the past few years when the United States dominated world supply growth.

At the start of the forecast, as OPEC+ unwinds record output cuts of 2020 and ramps up towards pre-Covid levels, there will be ample supply available to maintain a reasonable spare cushion. But if the shift to clean energy does not speed up, demand for oil supply by from there. Should Iran remain under sanctions, our analysis shows that at the end of the forecast period, *effective* spare production capacity could fall to 2.4 mb/d to the lowest level since 2016. In that case, Saudi Arabia, Iraq, the UAE, and Kuwait, with their surplus capacity and relatively low-cost reserves, may have to pump at or near record highs to help keep the world oil market in balance. Led by Saudi Arabia, the four Gulf countries would contribute 46% of the increase in supply from 2020 to 2026.

The Gulf producers, along with Russia, form the backbone of the OPEC+ group of nations that account for more than half the world's oil production. Total oil output from the 23 OPEC+ countries would rise by over 6 mb/d from 2020 to 2026 to reach 54 mb/d, while non-OPEC+ would contribute 4 mb/d to 50 mb/d.

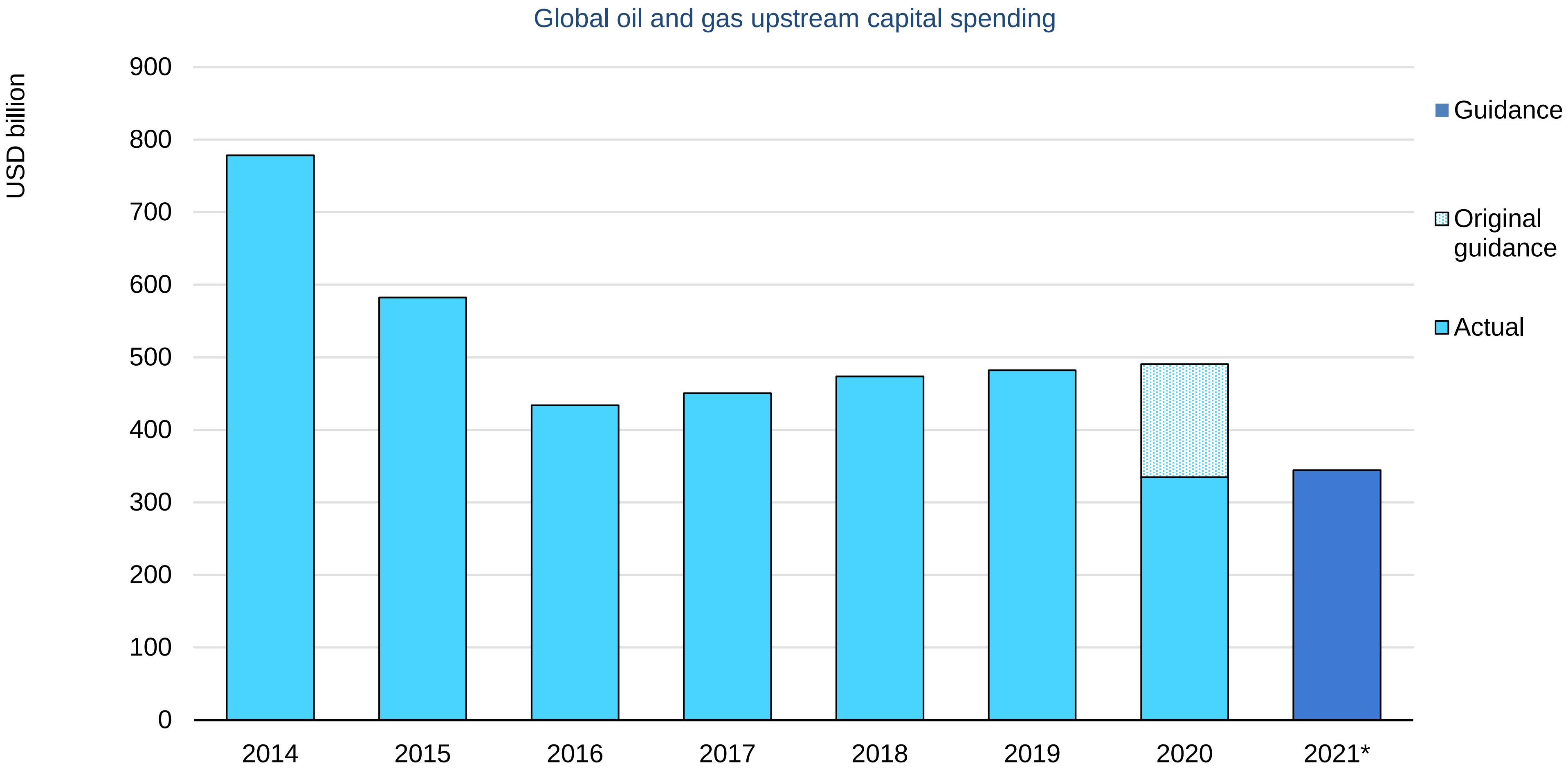
Outside of OPEC+, production prospects are subdued. The slump in oil prices in 2020 and the uncertain recovery in demand have seen the sanctioning of new projects fall to the lowest level in recent history. Upstream investments fell last year by a record 30% versus 2019. Brazil, Guyana and Russia provided 70% of the resources sanctioned for development in 2020. All the 2020 projects combined globally will add less than 1 mb/d of production by 2026.

The United States is expected to see only modest growth through the next six years. Although costs of production in the shale patch have fallen, the availability of cheap capital is not as plentiful as it was in the boom years. The industry is consolidating and is taking a more conservative approach to investment than was the case when smaller independent companies were the dominant players. They are also becoming wary of Environmental, Social and Governance (ESG) criteria and the potential for increased regulations under the new Biden administration.

The slowdown in US production growth clears the way for OPEC+ to fill much of the supply gap as it taps into its spare capacity. It could also encourage Saudi Arabia and other key Middle East producers to boost investments and accelerate expansion plans. The producer group is set to recover market share it forfeited in its bid to rebalance supplies when demand plummeted in the wake of the pandemic in 2020. However, during the early years of our forecast, OPEC+ is likely to maintain active supply management.

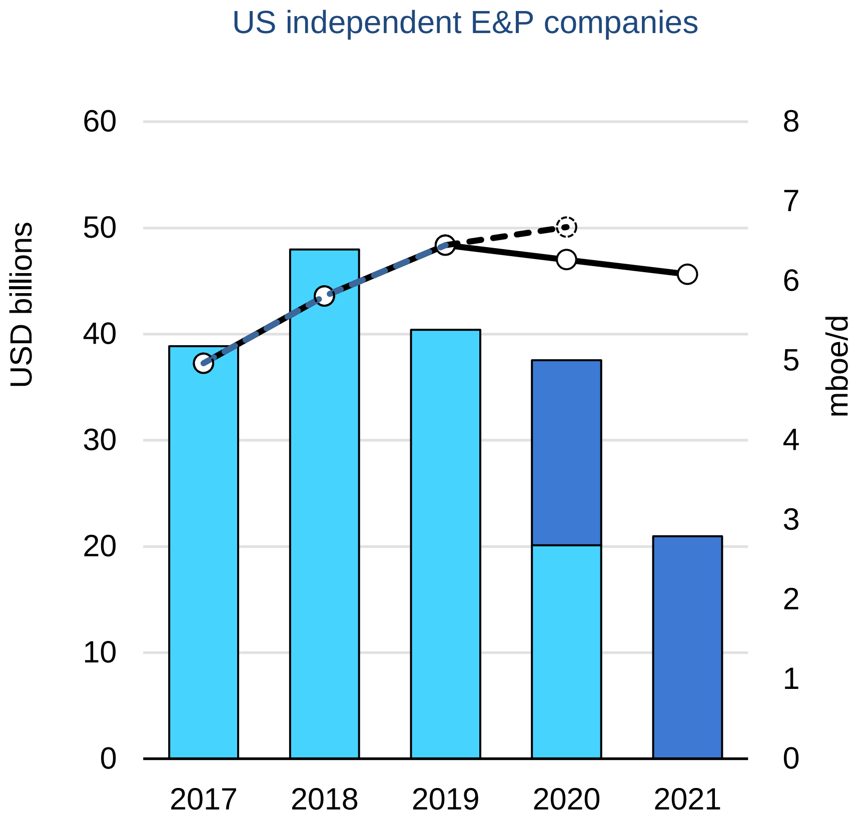
Investment

Upstream spending plunged 30% in 2020 and will remain depressed in 2021



Note: *Preliminary data based on company reports. 2020 data: Patterned light blue is original company guidance; solid blue is actual spend.

Covid-19, energy transition force huge cuts in upstream investment



Note: 2020 actual spend is preliminary. 2021-2022 guidance as of 26 February 2021.

Sources: Company reports. Majors includes BP, Chevron, ConocoPhillips, Eni, ExxonMobil, Shell and Total. US E&Ps include EOG, Occidental, Pioneer, Apache, Continental Resources, Marathon, Devon Energy, Murphy Oil, Whiting, Diamondback, Callon, Laredo, EQT Corp., Centennial Resource Development, Antero Resources, Cimarex and SM Energy.

Companies slash spending in response to Covid demand shock

Demand destruction, and its uncertain recovery due to Covid-19, continues to have a dramatic impact on upstream investment. In 2020, capital expenditure fell to its lowest since 2006 as operators spent one-third less than they planned to at the start of the year. In 2021 total upstream investment is expected to recover marginally.

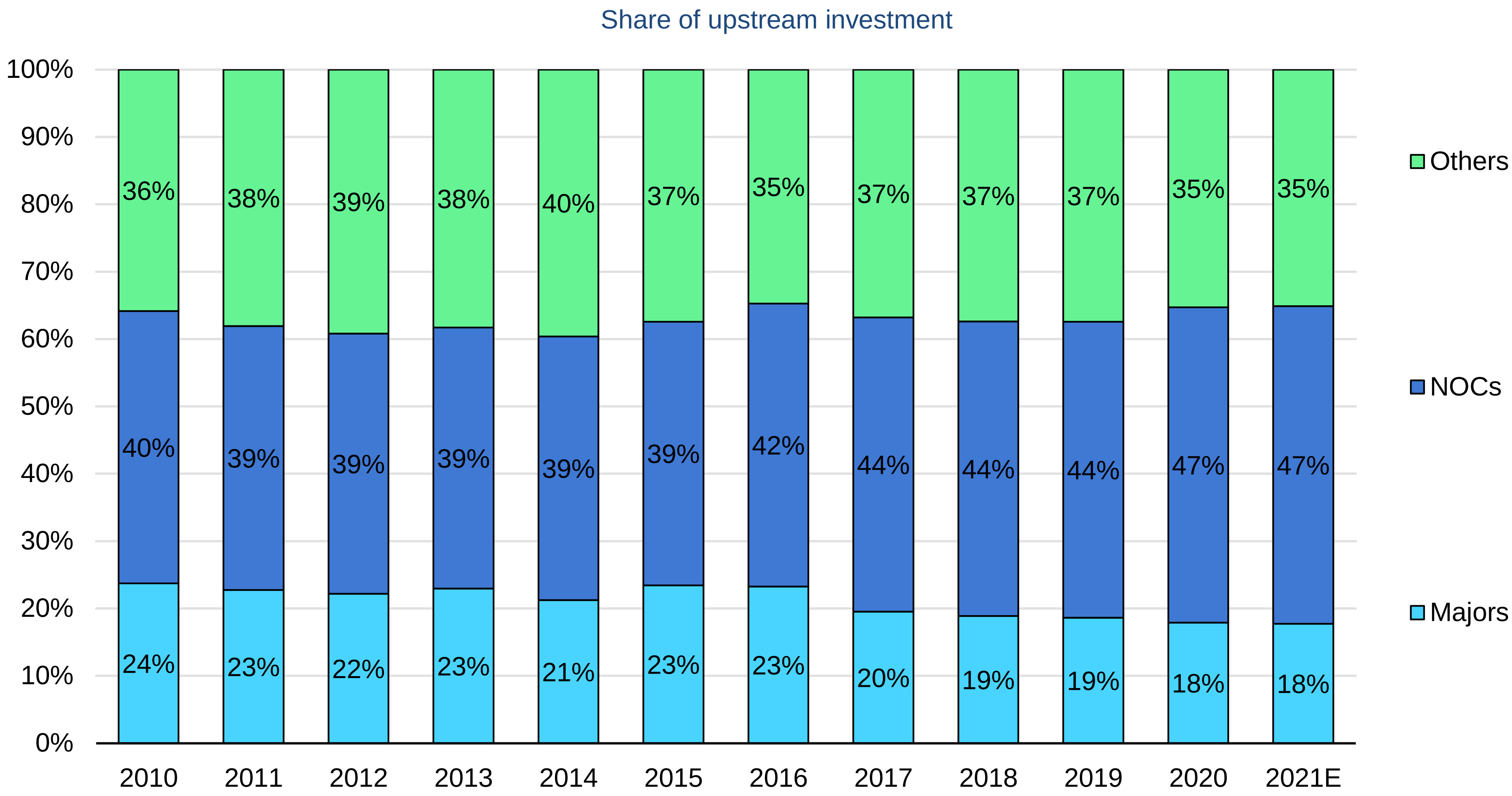
Spending cuts were seen in all regions across the globe, with US companies accounting for more than half the decline. The 2020 Covid-induced financial crisis has triggered another rebasing of costs, even after years of capital discipline and cost control, which, along with lower activity, has been responsible for the drop in spending. In the United States, the IEA's shale upstream cost index fell over 10%. In 2021, increased spending in South America may prove the exception, where it will almost return to 2019 levels. This rebound is eclipsed by falling investment in other regions, notably North America, Asia and Africa.

The **Majors** slashed their upstream capex by 30% in 2020 and their combined production fell by 6%. While spending looks set to remain constrained this year, a modest return to growth has been flagged further ahead. Strategy outlooks show that spending is likely to stay around 15% below 2019 levels in the medium term. Some, such as BP and Shell cut dividends in 2020, a historic first, while others were unable to make their usual increases in payments to shareholders. Now the focus is to regain investor trust by prioritising debt and dividend payments, and move on from impairments.

The 2Q20 oil price crash was devastating for the balance sheets and growth plans of the **US independent shale producers,** who have worked hard in recent years to improve their financial positions. In 2020, the sector's spending fell almost 50% y-o-y and guidance suggests a recovery of less than 5% in 2021. While operators tout their ability to respond quickly to higher prices, the focus of the short-term strategy is clearly survival by debt management and sustaining, rather than growing, output. The industry has seen permanent change due to the pandemic as over 60 companies went bankrupt and free-falling company valuations triggered M&A activity. Significant deals were made by Chevron, ConocoPhillips and Pioneer who increased their shale footprint by acquiring Noble Energy, Concho Resources and Parsley Energy, respectively (transactions ongoing).

Many **National Oil Companies (NOCs)** were also forced to slam the brakes on spending in 2020, with capex down 20% y-o-y. In economies that are heavily reliant on oil revenues, governments have had to make difficult decisions about the allocation of dwindling receipts, leaving fewer funds available for upstream spending. Furthermore, foreign investment has been deterred by the uncertain macro environment.

NOCs committed to hydrocarbons; Majors shift towards transition



Note: 2020 actual spend is preliminary. 2021 is guidance based on company reports.
Sources: Company reports, Rystad.

Oil industry steps up energy transition efforts

While the pandemic has clearly been the key driver for short-term spending adjustments, the Majors continue to boost their strategy shift in response to energy transitions (see Annex). BP and Total have pledged over 15% of their total capital budgets for transition investment (including renewables and electricity). Shell has committed the same level of investment on the transition as for the upstream and its oil production is set to decline 1-2% p.a. BP has announced that its total hydrocarbon production will see a "managed decline" of 40% from 2019 levels in the next decade.

Although the US majors have been more reluctant to change their business models, pressure from governments, activists and some investors has made its mark. ExxonMobil has now introduced goals for GHG emissions reduction, but like Chevron, has yet to follow the European Majors' lead in tackling Scope 3 emissions. Under the Greenhouse Gas (GHG) Protocol, Scope 1 refers to emissions from operations, Scope 2 from power used for operations, and Scope 3 from combustion of fuel by end-users. In 2020, Shell pledged to achieve net zero Scope 1, 2 and 3 carbon emissions by 2050 and Total is targeting the same for its European operations. BP and Eni had already made net-zero commitments in 2019.

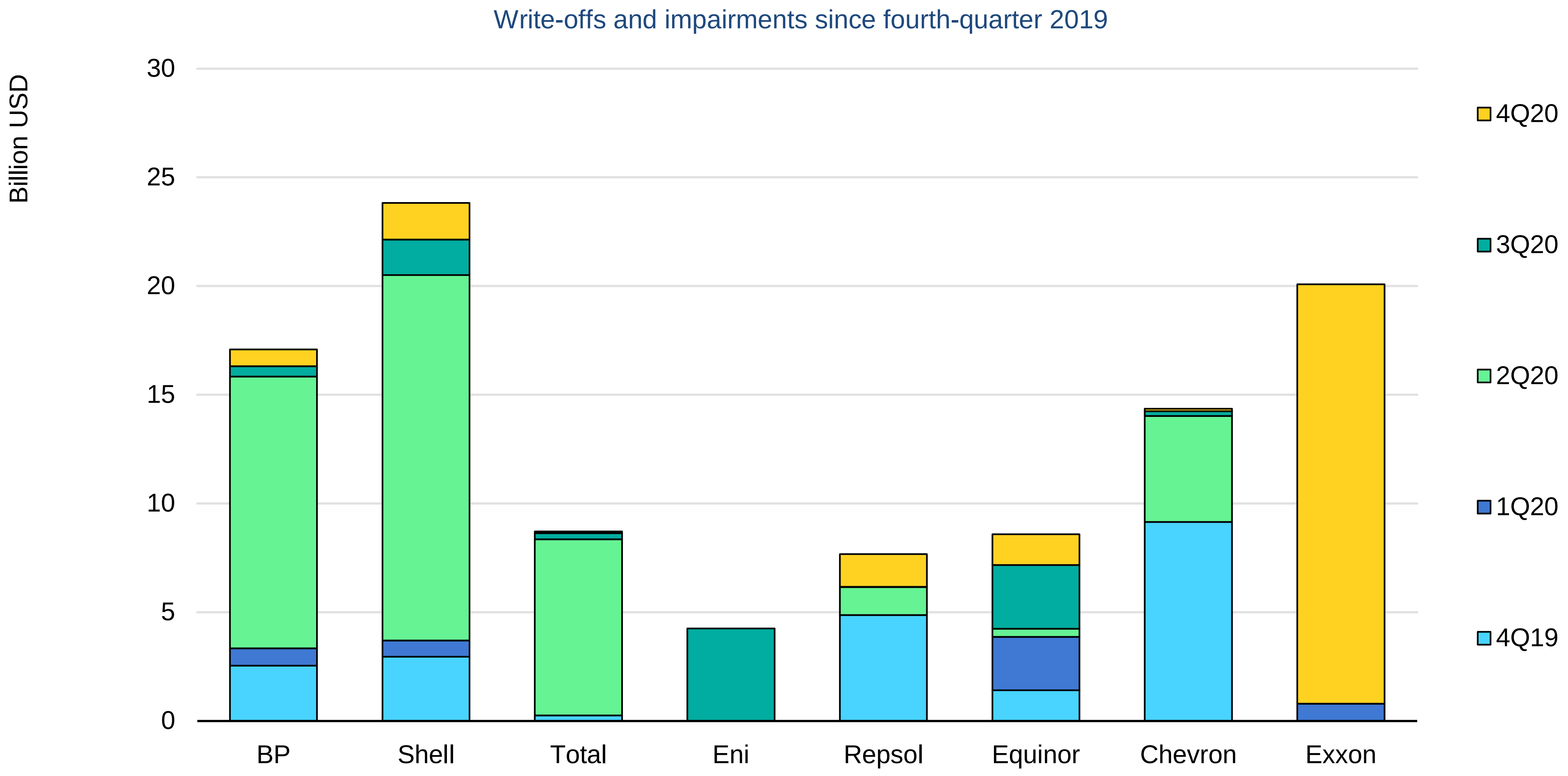
The change in focus is even more evident in the Majors' exploration budgets, which have taken another hit and will fall to $5.6 billion in 2021, 25% below the 2019 level. The world's appetite for hydrocarbons looks increasingly likely to slow in the long term and operators see less incentive to invest in future high-cost supply sources, returns for which may not be realised for decades.

Despite the tumultuous year, the US independents have started to recognise the potential impact of energy transitions and some have announced targets to reduce Scope 1 and 2 emissions, even if these tend to be short-term and of limited scale. So far, only Occidental has stated its ambition to reduce Scope 3 emissions.

The response of the NOCs to the challenges presented by the energy transition is as varied as the firms themselves. Some, including Qatar Petroleum, Saudi Aramco, Abu Dhabi National Petroleum Corp (Adnoc), Petrobras and Equinor have introduced emissions targets and/or sanctioned "cleaner" investments such as in CCS or renewable energy. For others, such as the Chinese national oil companies, some investment in renewable technology is planned but this will mainly fall into the remit of other domestic firms. Elsewhere, the dramatic impact of the drop in oil revenues on the economy has pushed climate issues down the priority list.

While the efforts to mitigate climate change by individual companies are significant, if they involve withdrawing from investments it remains to be seen whether assets will be picked up by other players to determine the actual impact on supply and emissions.

International oil companies write off $105 billion as outlook dims



Note: Includes impairments and write-downs for integrated company.
Sources: Company reports.

Oil majors wipe billions off books, lay off thousands

The world's top energy companies slashed the value of their oil and gas assets by a record amount last year as the global health crisis, falling oil prices and a push to slow climate change significantly altered the industry’s view of the future. Since 4Q19, eight international oil companies (IOCs) wiped a record $105 billion off their books and announced plans to lay off up to 40 000 workers.

The largest reductions in absolute terms were made by Shell, who is planning a major restructuring as part of "a complete overhaul" to reduce greenhouse gas emissions to net zero by 2050. Since 4Q19, Shell has written down the value of its assets by more than $23 billion, a record in the company’s history. In line with plans to shrink its oil and gas portfolio, the company will shift more capital to renewables, hydrogen and its power business. It will also cut back its refining business and has annouced up to 9 000 job cuts, or more than 10% of its workforce.

Over the same period, BP wrote down the value of its assets by $17 billion. The company said it might leave some of its oil and gas in the ground as it expects the pandemic to have a lasting economic impact, leading to fragile energy demand and lower prices. BP expects the economic impact of the virus to help accelerate the world’s shift to a lower carbon economy. BP has announced plans to cut nearly 10 000 jobs, or 14% of its workforce.

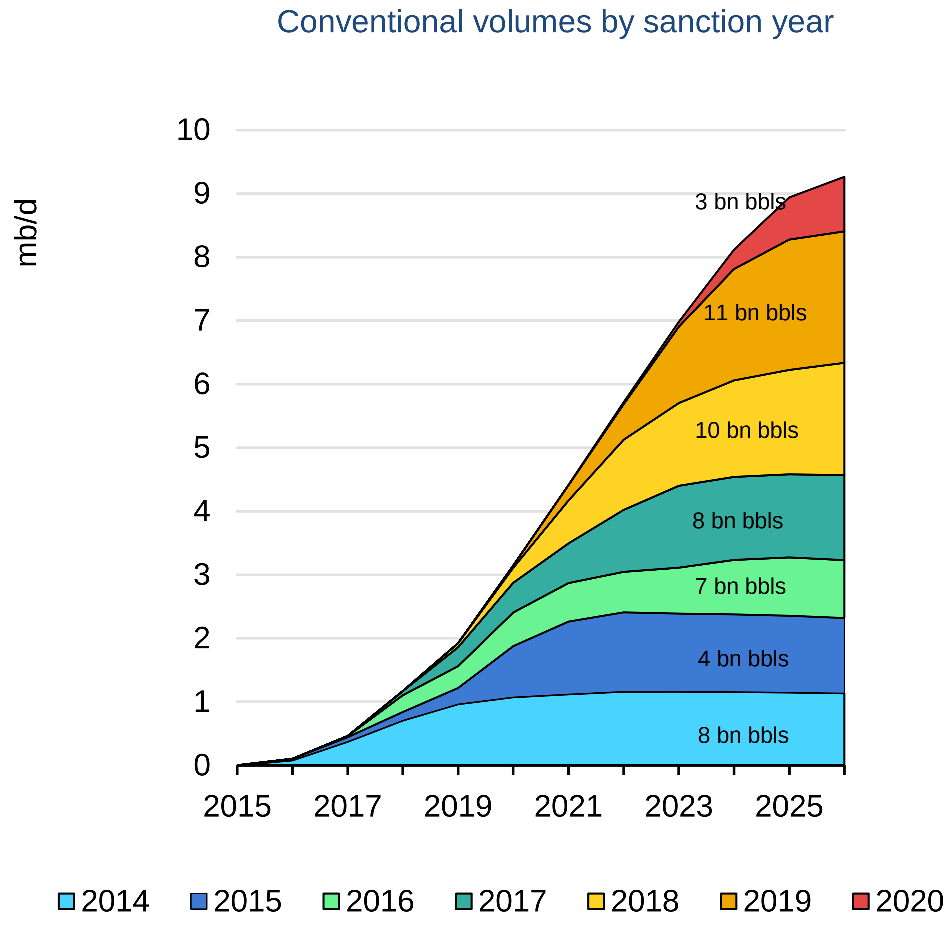
Chevron, too, plans to reduce its workforce by up to 15% and has written down its assets by a total of $14 billion. The company took a charge of more than $10 billion in December 2019 as it lowered the value of its natural gas properties. As oil prices slumped, Chevron has made further adjustments to its balance sheet, writing down its entire investment in Venezuela.

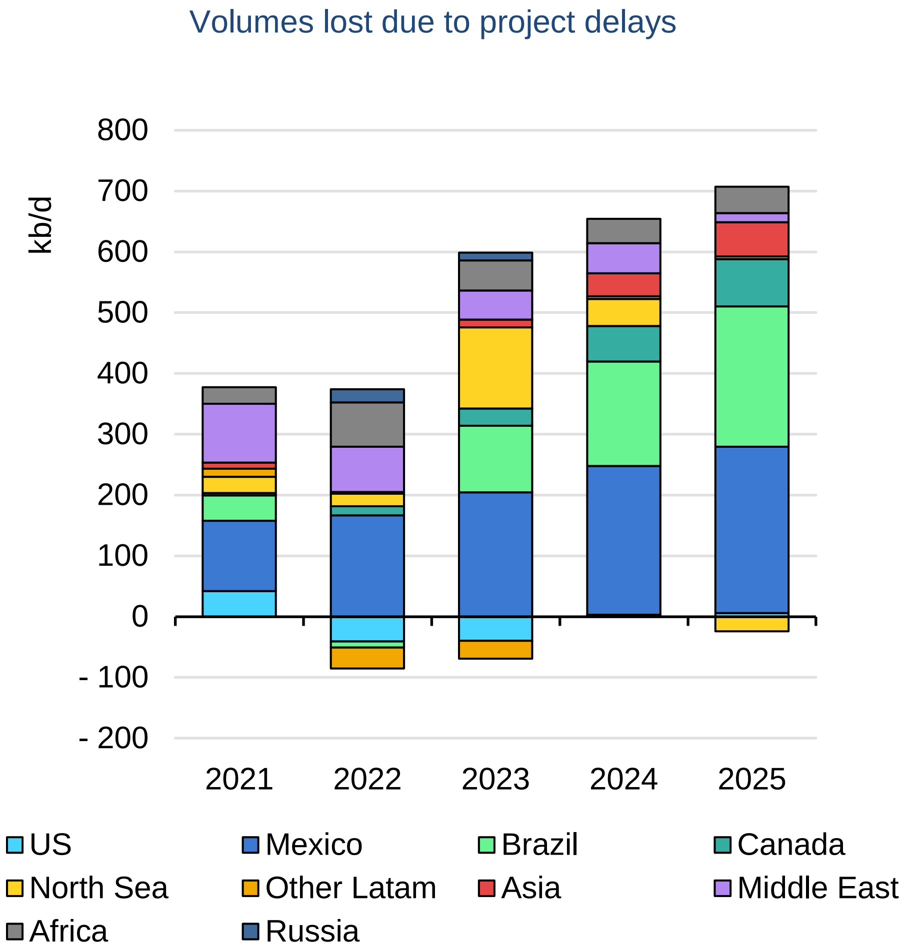
ExxonMobil, the largest US oil company, announced it would write down the value of its oil and gas assets by $17-20 billion, its biggest ever impairment following the sharp drop in energy prices last year. Most of Exxon's impairments focused on legacy assets from its $30 billion acquisition of US shale producer XTO Energy in 2010, a deal former CEO Rex Tillerson had previously said was "ill-timed."

Total announced an $8.1 billion writedown after the push to curb carbon emissions and the coronavirus pandemic challenged assumptions about the viability of some oil and gas assets and the timing of peak demand. The bulk of the impairment -- about $7 billion -- applies to Canadian oil sands, which are costlier and more carbon intensive than conventional fields.

Following the impairments, companies will focus on the parts of the business that are able to withstand the lowest oil and gas prices. Balance sheets now reflect the lowest portfolio breakevens in two decades and are therefore the most resilient to future commodity price shocks.

Newly approved projects add less than 1 mb/d by 2026, barely make up for Covid-19 delays





Note: Left-hand graph reflects expected production by year of sanction and total oil volumes sanctioned each year. Labels show total oil resources sanctioned per year. Right-hand graph shows estimated impact of project delays compared with previous forecast published in OIL 2020 (March 2020).

Development delays, sanctions stymie medium-term supply growth

The hefty investment cuts seen in 2020 and supply-chain disruptions due to Covid led to a sharp decline in project approvals last year and delays to many project timelines. Conventional approvals fell to a multi-decade low in 2020, with projects accounting for only 3 bn barrels given the green light. The postponement of planned project sanctions means that operators may have wiped out over 2 mb/d of potential supplies by 2026. In particular, the industry has hesitated to progress deepwater opportunities such as Shell's Whale in the Gulf of Mexico. Market uncertainty triggered by the pandemic is a key cause of the low level of approvals, but the energy transition is also clearly playing its part as firms reassess their portfolios, ditch projects and take the write down.

Meanwhile, just a handful of major projects are moving into development, the largest of these in Brazil (Mero 3 and Ipatu) and Guyana (Payara). In Norway, the government introduced a tax relief package to support crisis-hit firms and this was credited with allowing the advancement of the Balder Future and Hod projects.

Furthermore, delays to projects already underway will have a material impact on supply in the forecast period. Aside from the huge change to the outlook for LTO growth, 700 kb/d of conventional production has been lost by 2025. Notably, project schedules in Brazil and for Norway's Johan Castberg slipped due to FPSO construction holdups while the pace of drilling was slower than anticipated in Mexico.

Delays due to Covid-19 are both strategic, as companies adjust their plans in response to heightened uncertainty and low prices, and operational, due to disruption to supply chains and activity.

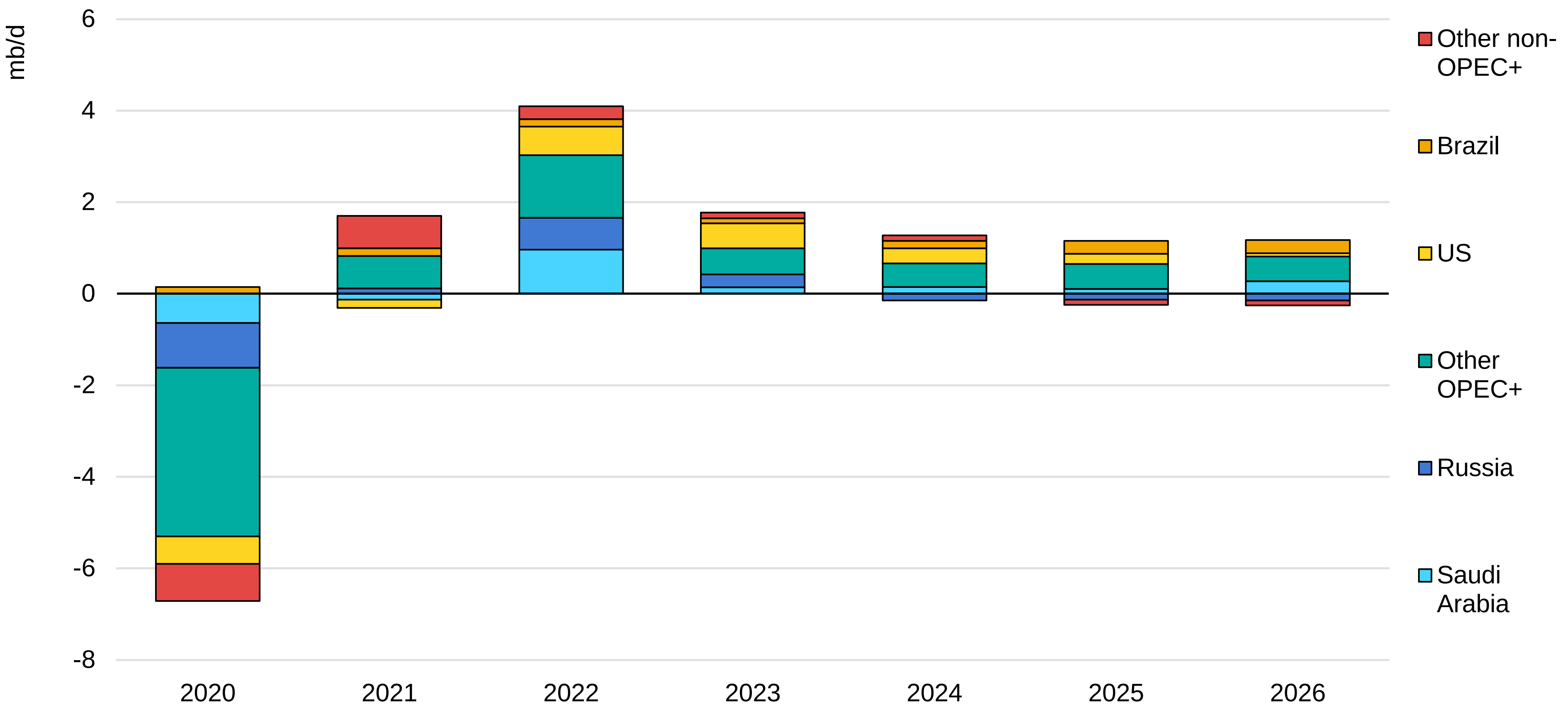
Covid-19 outbreaks saw oilfield workers down tools and evacuated, halted construction of production facilities at Asian shipyards, and complicated the availability of specialised workers. The industry, already heavily focused on workplace safety, introduced social distancing and quarantine measures that increased the scheduled timelines and the cost of many operations. The use of shared infrastructure meant that some delays had a knock-on impact. One example is in the UK North Sea, where major maintenance of the Forties pipeline was deferred by one year to reduce offshore manning requirements, forcing the tie-in of Buzzard Phase 2 flows to be shifted back.

Tighter budgets also took their toll as operators revisited development plans and, in a few cases, such as Cenovus Energy's West White Rose Extension in Canada, seemingly abandoned them all together. Ongoing OPEC+ production cuts are also thought to have slowed new capacity projects in participating countries, for example Saudi Arabia's Marjan and Berri expansions that were sanctioned in 2019.

OPEC+ supply

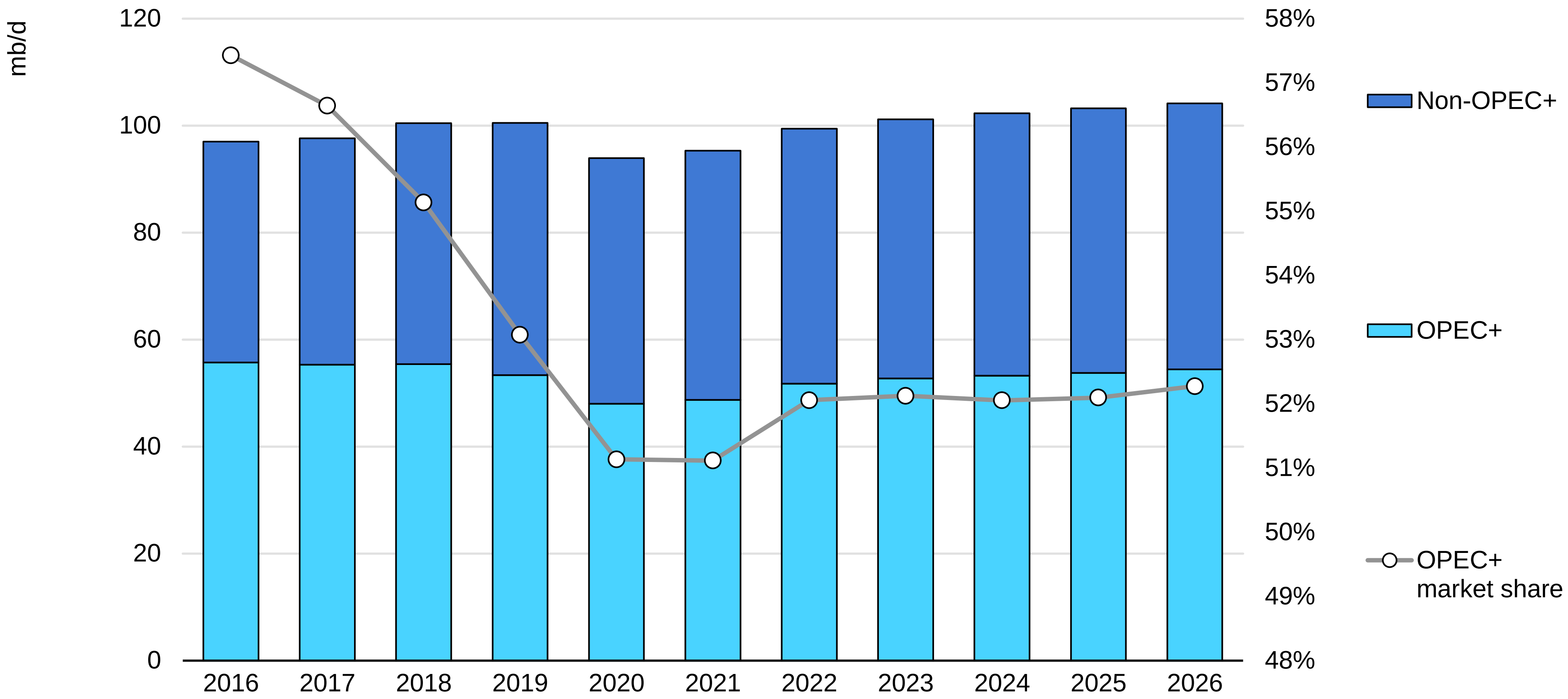
Gulf OPEC+ set to dominate supply increase as demand recovers

Global oil supply changes, 2019-2026



OPEC+ market share to recover from 2020 low

World oil production, OPEC+ market share, 2016-2026



Note: OPEC+ includes all OPEC members plus Russia, Kazakhstan, Azerbaijan, Malaysia, Mexico, Oman, Brunei, Bahrain, Sudan and South Sudan. Global biofuels and processing gains included in Non-OPEC+ data.

Middle East to lead global supply increase through 2026

OPEC+ producers forged an historic cut of nearly 10 mb/d with their April 2020 pact in response to the collapse in global oil demand. Since then, the agreement has been revised to ease the production cuts but, with the impact of Covid-19 lasting longer than expected, OPEC+ is likely to maintain active supply management at least during the early years of our forecast.

The call on OPEC crude is expected to reach 30.8 mb/d by 2026, 5.3 mb/d more than the group produced at the start of 2021. As demand recovers and upstream investments lag in other parts of the world, Saudi Arabia, Iraq, the UAE, and Kuwait may have to ramp up production to ensure the world is adequately supplied. By the end of the forecast, the Gulf heavyweights may have to pump flat out to keep pace with demand if Iran remains under sanctions.

Along with Russia, these nations are the core producers in the OPEC+ bloc that makes up half the world's supply of oil. Total oil production from the 23 OPEC+ countries is expected to increase by more than 6 mb/d by 2026 to 54 mb/d while non-OPEC+ contributes 4 mb/d. That rate of growth would see OPEC+ fighting to sustain its market share of 52% from 2022. Supply cuts, sanctions and civil unrest eroded the bloc's market share to 51% in 2020 from 57% in 2016, when it was formed.

As the group raises output, OPEC *effective* spare capacity will fall from nearly 6.5 mb/d in 2020 to as low as 2.4 mb/d in 2026, assuming Iran remains under sanctions. This is despite the fact that OPEC countries will add 1 mb/d of new crude oil capacity and 250 kb/d of condensates and NGLs by 2026.

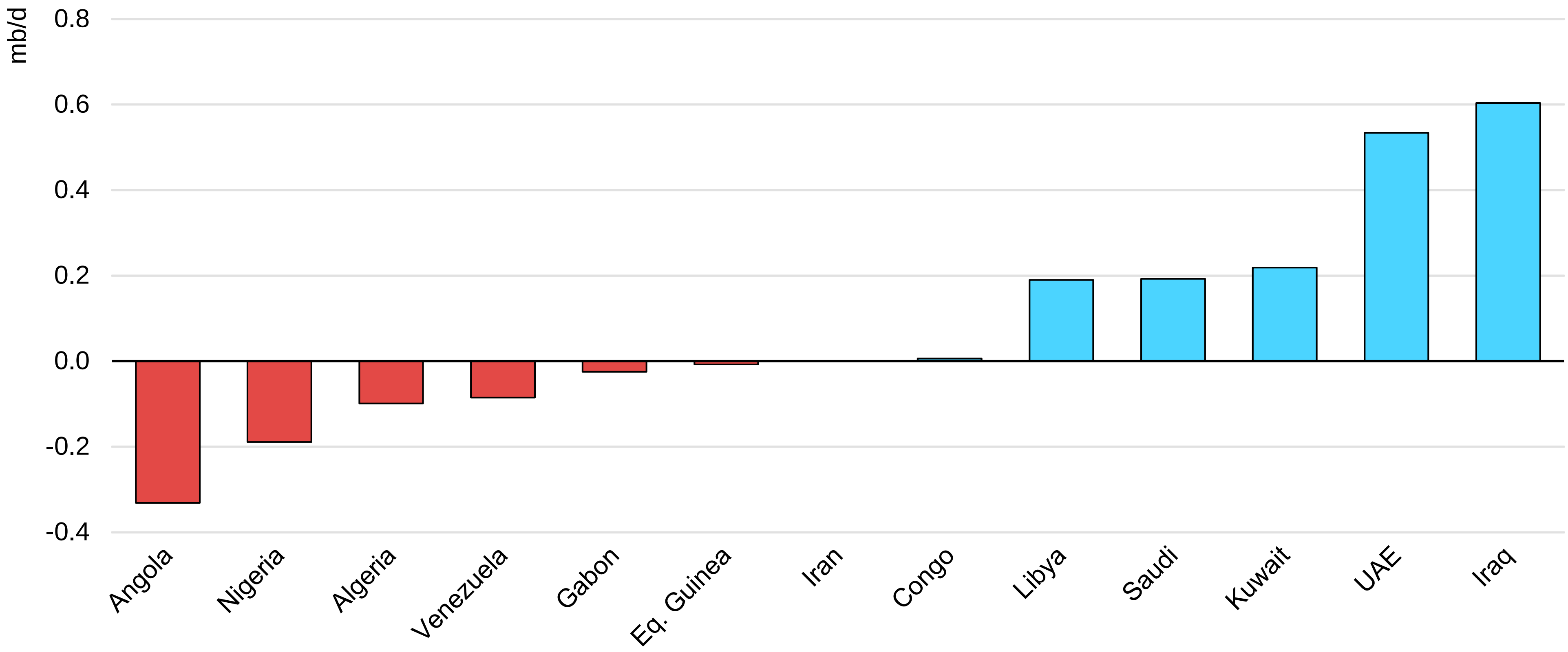
Iraq and the UAE are poised to build enough capacity for them to pump at fresh record highs, while Saudi Arabia and Kuwait benefit from a gradual increase of flows from the Neutral Zone. As for Venezuela, we have written off any prospect of an imminent recovery with the current Maduro Administration in place.

In this forecast, we have assumed that Iran remains under sanctions. If Iran were to be released from sanctions over the forecast period, around 1.7 mb/d of crude supply could be made available to the market in relatively short order. The new Biden Administration is trying to revive talks with Iran over the nuclear agreement that the former administration scrapped in 2018. However, many contentious issues still need to be resolved before sanctions could be eased.

Libya is expected to provide a substantial near-term boost to OPEC crude supply over the forecast period after the September 2020 lifting of a blockade that shut in production. However, the situation remains fragile under a new interim government and recent gains of more than 1 mb/d could be at risk of disruption.

OPEC crude oil capacity rises modestly; Iran remains wild card

OPEC crude capacity growth, 2020-2026



Note: Forecast assumes Iran remains under sanctions.

Gulf heavyweights dominate supply increase, capacity building

Tapping into its spare capacity**, Saudi Arabia** could provide one of the biggest increases over the six-year forecast and pump at its highest ever annual level in 2026. The call on Saudi crude could climb by 1.3 mb/d to reach 10.5 mb/d in 2026. OPEC+ cuts reduced its 2020 annual average crude output to a 10-year low of 9.2 mb/d. Saudi production *capacity* is now expected to grow modestly over the period. Following the full restoration of the Neutral Zone fields it shares with Kuwait, capacity is set to rise to 12.25 mb/d in 2022 and remain at that level through the remainder of the forecast. Before Neutral Zone output was suspended in 2015, the offshore (mainly al-Khafji) and onshore (mostly Wafra) fields were pumping about 450 kb/d.

Saudi Arabia has for years been bringing new projects online to compensate for natural declines and allow older reservoirs in Ghawar, the world's biggest oil field, to run at lower rates. Now Aramco is turning to higher cost offshore projects for that effort. But in a cost cutting move, the expansion of the Marjan oil field reportedly has been pushed back by two years to 2025 while the Berri field expansion has been delayed by a year to 2024. Aramco in 2019 awarded $18 billion worth of contracts to boost their capacity by a combined 550 kb/d. Aramco also reportedly delayed by a year to 2021 the award of contracts to raise output from the Zuluf and Safaniya offshore fields.

Although the timeframe was unclear, Aramco last year announced plans to boost capacity to 13 mb/d, the first increase in over a decade. It has the lowest average production costs in the industry: the 2019 lifting cost was $2.8/boe and capex was $4.7/boe. The capacity boost, which could cost at least $20 billion, will include the giant offshore fields and could yet be accelerated to come on line within the forecast period.

Iraq, including the Kurdistan Regional Government (KRG), may see crude production rise by 1.3 mb/d to 5.4 mb/d by 2026. In 2020, its annual output fell to 4 mb/d, the lowest since 2015. It intends to build up capacity and its expansion is expected to be the largest within OPEC. Capacity is projected to grow by 600 kb/d to reach 5.5 mb/d in 2026. While there are numerous above-ground hurdles that can complicate project execution, Iraq has some of the world's lowest-cost resources. Most of the growth will spring from the southern Basra oil hub, where IOCs are managing mega projects. Near-term growth may stall, however, after Baghdad asked them last year to cut costs and reduce budgets by 30%. BP, Eni, Exxon and Lukoil operate roughly 3 mb/d at Rumaila, Zubair, West Qurna−1 and West Qurna-2, respectively.

The potential for raising capacity at Iraq's giant southern fields would improve if Baghdad were finally to advance the long-delayed

Common Seawater Supply Project. The first phase, expected to take at least three years to build, aims to pipe 5 mb/d of treated seawater to fields across Basra and to Nasiriya in Dhi Qar province. At the same time, the Ministry of Oil is planning for the Southern Iraq Integrated Project. This is expected to raise output from the Nahr Bin Umar and Ratawi fields from combined levels of 80 kb/d to 500 kb/d. The revenue generated would fund the upgrading of southern infrastructure, including Gulf export terminals, which can now handle around 3.6 mb/d.

Water is not as vital for greenfields in the south such as Halfaya and Majnoon. Halfaya is climbing towards 400 kb/d and there are plans to lift capacity to 450 kb/d. Majnoon is able to produce around 200 kb/d and the near-term goal is to boost capacity to 400 kb/d. Iraq's oil ministry and Chevron have meanwhile signed a memorandum of understanding that paves the way for negotiations for an exploration, development, and production contract in Dhi Qar province. Talks will focus on Nasiriya, which is pumping 100 kb/d.

The northern Kirkuk oil fields and the capacity that is controlled by the KRG are expected to contribute only modest growth. There are plans to raise Kirkuk's capacity to 1 mb/d from roughly 500 kb/d. However, efforts to boost output have been frustrated by the 2014-17 battles with Islamic State as well as the long-running feud between Baghdad and the KRG over control of land and oil. The KRG is also suffering from lower oil revenues and has been unable to pay foreign firms.

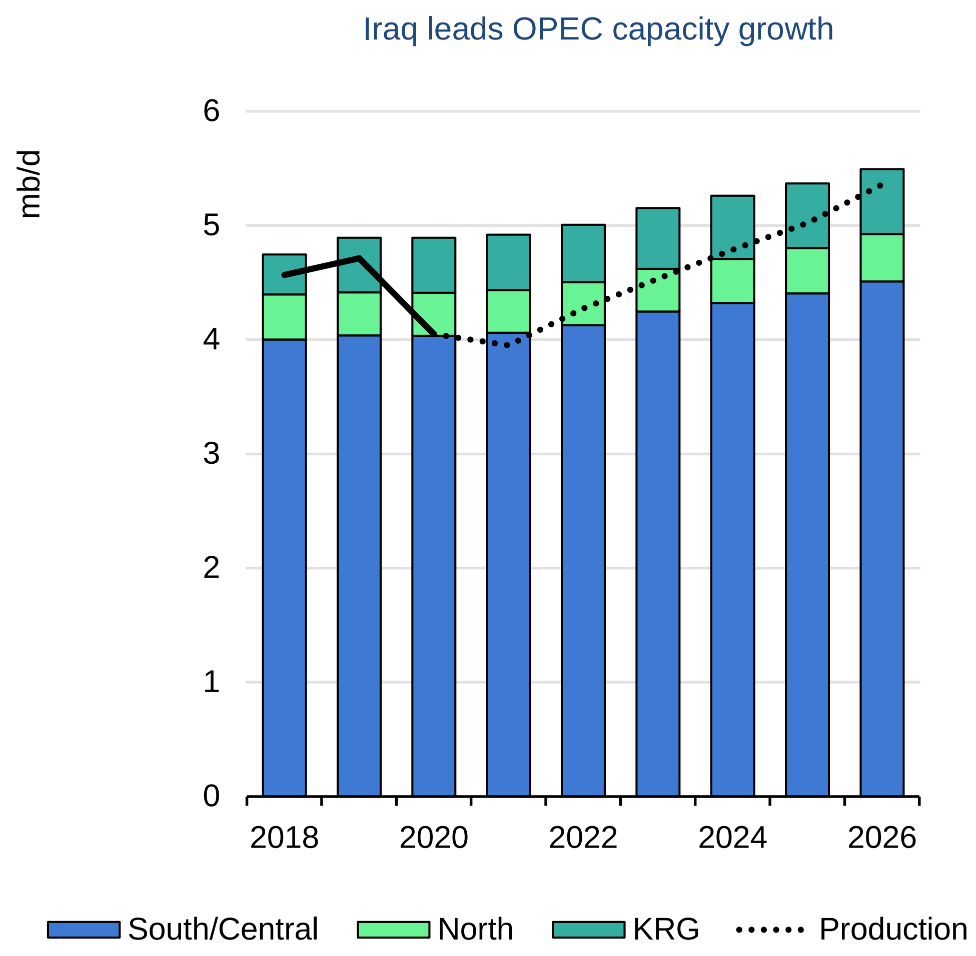
By 2026, the **UAE** could raise crude supply above 4 mb/d, for an increase of 1.2 mb/d over the six-year period. The emirate has been expanding its crude oil capacity in recent years in a bid to push to new highs. It pumped at a record 3.5 mb/d in April 2020, but average annual crude output fell to a six-year low of 2.9 mb/d due to OPEC+ cuts.

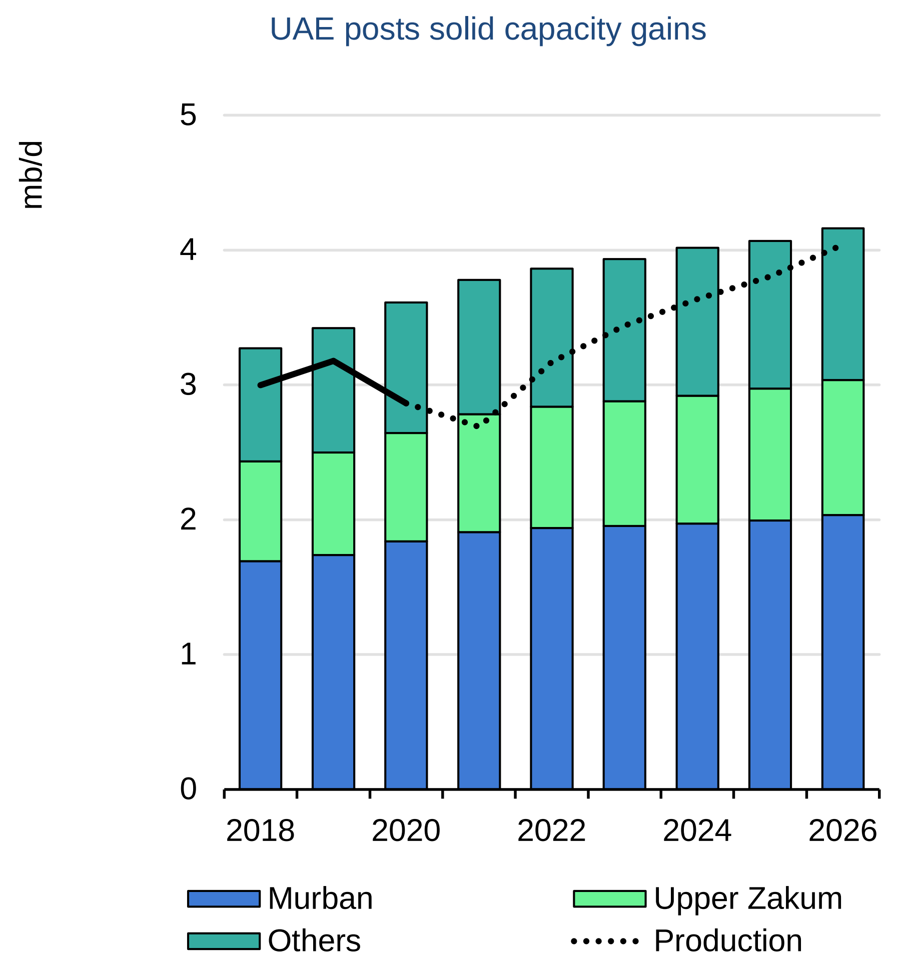
Thanks to its comparatively low-cost resource base and secure operating environment, the UAE's crude capacity is expected to grow by 530 kb/d, rising to 4.2 mb/d in 2026. The Exxon-operated Upper Zakum offshore field, one of the world's largest, is key to the expansion. Output is around 800 kb/d and is set to reach 1 mb/d by 2024. More supply will come from offshore oil fields Ghasha, Dalma and Hail. For its onshore sector, which pumps flagship Murban crude, Adnoc has secured foreign partners for a 40% share of the concession. The official aim is to boost Murban beyond 1.8 mb/d.

To further support capacity building, Adnoc is moving ahead with its second bidding round. It has awarded Eni and Thailand's PTTEP an exploration concession for Offshore Block 3, while Cosmo won a 100% stake in Offshore Block 4. Occidental Petroleum won the first concession.

Even as it pushes ahead in the upstream, Adnoc is belt-tightening. It plans to spend $122 billion in 2021-25, roughly $10 billion less than its previous five-year capital expenditure budget. At the same time, it notified contractors and suppliers that it would scrutinise existing deals to cut costs by around 30%.

Iraq, UAE build up crude oil capacity to support record production





Iran primed for oil market return

Iran is the oil supply wild card. If it is released from sanctions, production could ramp up gradually by around 1.7 mb/d to 3.8 mb/d. Before US sanctions were imposed in 2018, Iran was expected to rank as one of the world's leading sources of supply growth, but its expansion plans have been set back. The impact of the sanctions has been to cut its *effective* capacity to roughly 2.1 mb/d. Iran's production of crude oil fell during 2020 to an average 2 mb/d, the lowest annual rate since 1986. Exports of crude and condensate slowed to a trickle from 2.8 mb/d in 2018.

Lower wellhead production most likely led the National Iranian Oil Co (NIOC) to shut in more wells, especially at its high-cost offshore fields, and complete maintenance at its mature oil fields. Shutting in output can be helpful for ageing oil fields as it will allow pressure to rebuild and make it easier for operations to restart.

Given the obstacles posed by the collapse of exports and the lack of foreign investment due to sanctions, Iran's capacity building has largely stalled. The previous round of international sanctions had already left the oil sector in urgent need of foreign cash and technology, particularly in enhanced oil recovery methods to sustain and raise output at older oil fields.

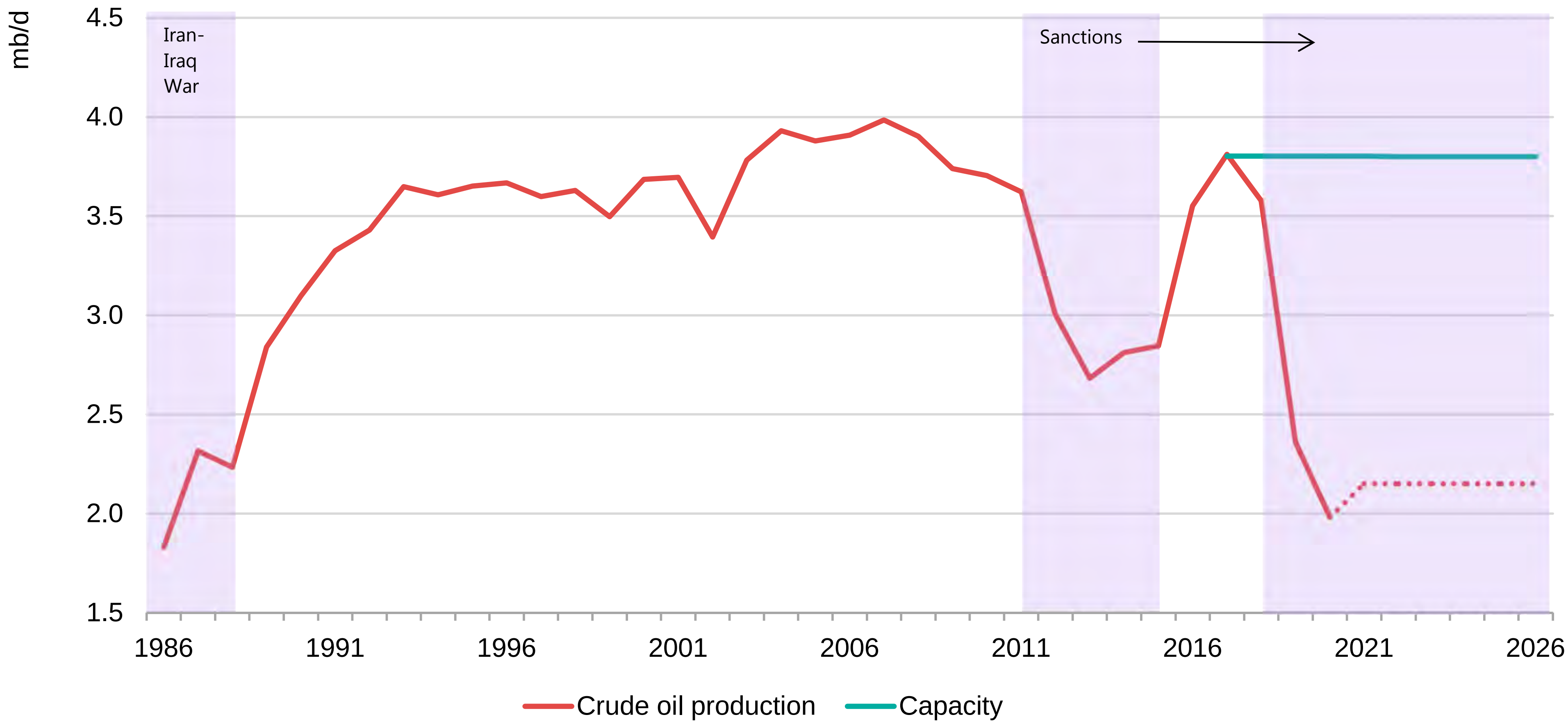
The virtual absence of foreign investors has left Iran striving to move forward with projects already under development by local companies, especially the West Karun oil fields of Azadegan, Yadavaran and Yaran. These fields, which straddle the border with Iraq, will help to sustain capacity and drive future growth beyond the medium term. Target output for West Karun is 1 mb/d versus current flows of 300 kb/d.

Petropars, a subsidiary of NIOC, has secured a contract to more than double output at the South Azadegan field that borders Iraq, to 320 kb/d. Additionally, Persia Oil & Gas Industry Development Co has signed a contract to develop the 30 kb/d Yaran field. NIOC has also approved a new tranche of projects in a multi-billion-dollar programme to boost production by 355 kb/d at 33 oil fields. The latest eight projects, reportedly worth $1.2 billion, could raise output by 95 kb/d.

US sanctions have also frustrated Iran's plans for the giant South Pars gas field, which is being developed to meet rising domestic demand. Whereas the earlier round of international sanctions in 2012-2015 allowed Iran to export condensate, unilateral US sanctions since 2018 ban shipments that had been running at 300 kb/d. Petropars is moving forward with the South Pars Phase 11 project after the withdrawal of Total and China National Petroleum Corp due to US sanctions. The first well is expected to start producing in 2021.

Iran awaits oil market return; sanctions shut in nearly 1.7 mb/d of crude supply

Crude oil production in Iran, 1986-2026



Note: Iranian annual crude oil production from 1986 through 2020, from 2021 production held flat at February 2021 level.

Russia, Caspian producers ramp up as OPEC+ cuts ease; capacity growth limited

Russia, the other crucial player in OPEC+, could see oil production rise by 700 kb/d over the forecast period, to reach 11.3 mb/d in 2026. Following one of the worst years in the history of the industry, Russian oil production is expected to see a modest increase in 2021 as OPEC+ restrictions remain in place and as producers feel the pinch from higher taxes following reforms approved this year. More substantial increases are expected in 2022 and 2023, as restrictions are lifted allowing shut-in volumes to return. Thereafter, growth will taper off as declines at mature fields overwhelm new project developments. Huge resources in the Arctic, however, could provide a boost to supplies if developed in a timely manner. For now, Russian oil supply is expected to recover to 2019 levels by 2024 and post modest declines thereafter.

According to Alexander Novak, deputy prime minister in charge of the country's energy sector, Russia will continue to cooperate with OPEC in balancing supply and demand. Novak has earlier stated that Russia prefers oil prices in a $45-$55/bbl range that will allow its output to recover but cap growth from other producers, most notably the United States. To that end, Russian producers have reportedly taken a leaf out of the US shale play book, drilling but not completing wells to be able to ramp up production quickly once demand recovers.

In the longer run, Russian oil production could be negatively impacted by tax changes, described as the largest in the country since 2002. The new legislation, which scraps tax breaks enjoyed for mature fields, will force companies to optimise portfolios and possibly abandon mature and depleted fields. Some experts have calculated that the tax changes would cost the industry 1.15 trillion rubles ($16 billion) in 2021-25. Of this, companies would be able to claw back some 500 billion rubles, thanks to the new breaks.

One project that would still benefit from tax-breaks is Rosneft's massive Vostok Oil project in the Arctic. In early 2021, energy trader Trafigura acquired 10% in the venture, that will include the Payakha group of fields. The fields will be a core resource for the venture. The project aims to produce 600 kb/d as early as 2024, growing to 2 mb/d by 2030 and 2.3 mb/d by 2033, according to the latest plan.

Production is expected to recover also in neighbouring **Azerbaijan** and **Kazakhstan** as OPEC+ output cuts ease. Later on, regional supplies will be supported by the expansion of Tengiz from 2022 and the start-up of the BP led Azeri Central East platform from 2023. Plans to increase production at the Karachaganak and Kashagan fields remain on hold for the time being.

Crude oil capacity largely declines in African OPEC+

With the notable exception of Libya, capacity in most African OPEC+ members is set to slide as producers struggle to attract enough investment to stem declines.

Libyan supply rebounded strongly to top 1 mb/d in November 2020 after the end of an eight-month blockade that cut flows below 100 kb/d. Crude oil capacity is expected to edge higher over the forecast period and reach 1.3 mb/d by 2026. This will depend on political stability and sufficient revenue to fund infrastructure repairs.

Core to the recent recovery is the southwestern El Sharara oil field, Libya’s largest, which is ramping up towards full capacity of 300 kb/d. The nearby Elephant field, which can produce up to 80 kb/d, has also restarted. In the east, the Abu Attifel and Zueitina oil fields, each with capacity of around 70 kb/d, have restarted. Other oil fields in the east operated by Arabian Gulf Oil Co (Agoco) and Sirte Oil Co have been pumping since September at around 200 kb/d and 80 kb/d, respectively. The offshore Bouri and Al Jurf fields, unaffected by the blockade, produce 80 kb/d between them.

Located in the northeast Sirte basin, the Waha Oil Co, currently able to pump roughly 300 kb/d, is also key to further growth. A top priority is to repair damage to the Es Sider and Ras Lanuf terminals. There is some hope that IOCs will return to the upstream.

Crude oil capacity in **Angola** is set to fall 330 kb/d, to just above 1 mb/d by 2026 as operational and technical issues beset high-cost deepwater oil fields. Output fell to 1.3 mb/d in 2020 from a recent peak of 1.8 mb/d in 2015. Given high production costs, companies are reviewing projects. Eni is re-phasing its Cabaca North and Agogo projects. Total reportedly is seeking to sell its stake in offshore Block 14 that pumps around 40 kb/d of oil equivalent to focus on its larger oil and gas fields.

In **Nigeria**, crude oil capacity declines from 1.8 mb/d in 2020 to 1.6 mb/d by 2026 due to underinvestment. As other producers in Africa seek to improve commercial terms, Nigeria plans to raise taxes on its deepwater oil production, which will make investments less attractive. OPEC+ supply cuts reduced crude oil production to 1.5 mb/d in 2020, the lowest level since 2016.

The oil price collapse, in addition to an increase in deepwater government royalties, may prompt IOCs to review projects. Total reportedly has pushed back development of the 70 kb/d deepwater Preowei field and is seeking to sell its 12.5% stake in deep water OML 118, which includes the Bonga field. Output from the block is expected to rise whenever the Shell-operated Bonga Southwest project gets off the drawing board. However, the final investment decision on the project may be further delayed by uncertainty over commercial terms.

Mexico outlook deteriorates; Venezuela comeback uncertain

Mexico is set to post a 260 kb/d supply loss during the forecast period. Hopes of a sustained recovery have been dashed following sharp spending cuts by Pemex and independent operators as well as delays to new project developments. Mexican oil output is forecast to fall to 1.7 mb/d by 2026.

Pemex had earmarked billions for upstream developments, but the pandemic led it to curtail its planned 2020 investment budget by 40.5 billion pesos. Spending was still marginally higher than in 2019. The priority fields announced at end-2019 are key to Pemex's strategy to reverse losses and lift output over the next four years. While their output rose steadily to around 150 kb/d by end-2020, investment and drilling significantly lagged original plans. Despite efforts to stabilise declines, output continued to slump with Ku−Maloob-Zaap dropping nearly 80 kb/d to 690 kb/d in 2020. Declines are expected to accelerate over the medium term.

The 2013 energy reform that opened the oil sector to foreign investment and allowed international operators to bid for offshore exploration blocks has yet to bear fruit, with no new developments sanctioned last year. The start-up of Talos' Zama field, previously expected to add 150 kb/d of supply by 2023, will likely be delayed.

After losing 1.4 mb/d in three years, output in **Venezuela** may be bottoming out. US financial sanctions, poor reservoir management and chronic underinvestment cut production to just 530 kb/d on average in 2020. That's just a small fraction of the 3.4 mb/d peak level reached just before President Chavez took office in 1999.

We have held our capacity estimate at 550 kb/d through the remainder of the forecast, although things could turn out quite different. A turnaround in the political situation would provide the opportunity to rebuild the energy sector.

Its battle with a long-running drop in supply has seen Petroleos de Venezuela (PDVSA) shut in high-cost wells. Output from mature conventional oil fields has plunged. Upgraders managed by foreign joint-venture partners in the vast Orinoco heavy oil belt have malfunctioned due to lack of maintenance and difficulty sourcing equipment, poor security and corruption. PDVSA has also proposed a restructuring that would boost the participation of private companies. The government aims to raise production to 1.5 mb/d "with new mechanisms of production, financing and commercialisation," according to President Nicolas Maduro. In any case, US sanctions are likely to temper investor enthusiasm.

If Venezuela's diaspora of skilled oil workers return and investment capital were available, production could recover significantly over time. In the meantime, the Maduro government has looked to Russia and China to help revive the oil sector.

OPEC plans show only modest production capacity increase by 2026

OPEC crude oil production capacity (mb/d)

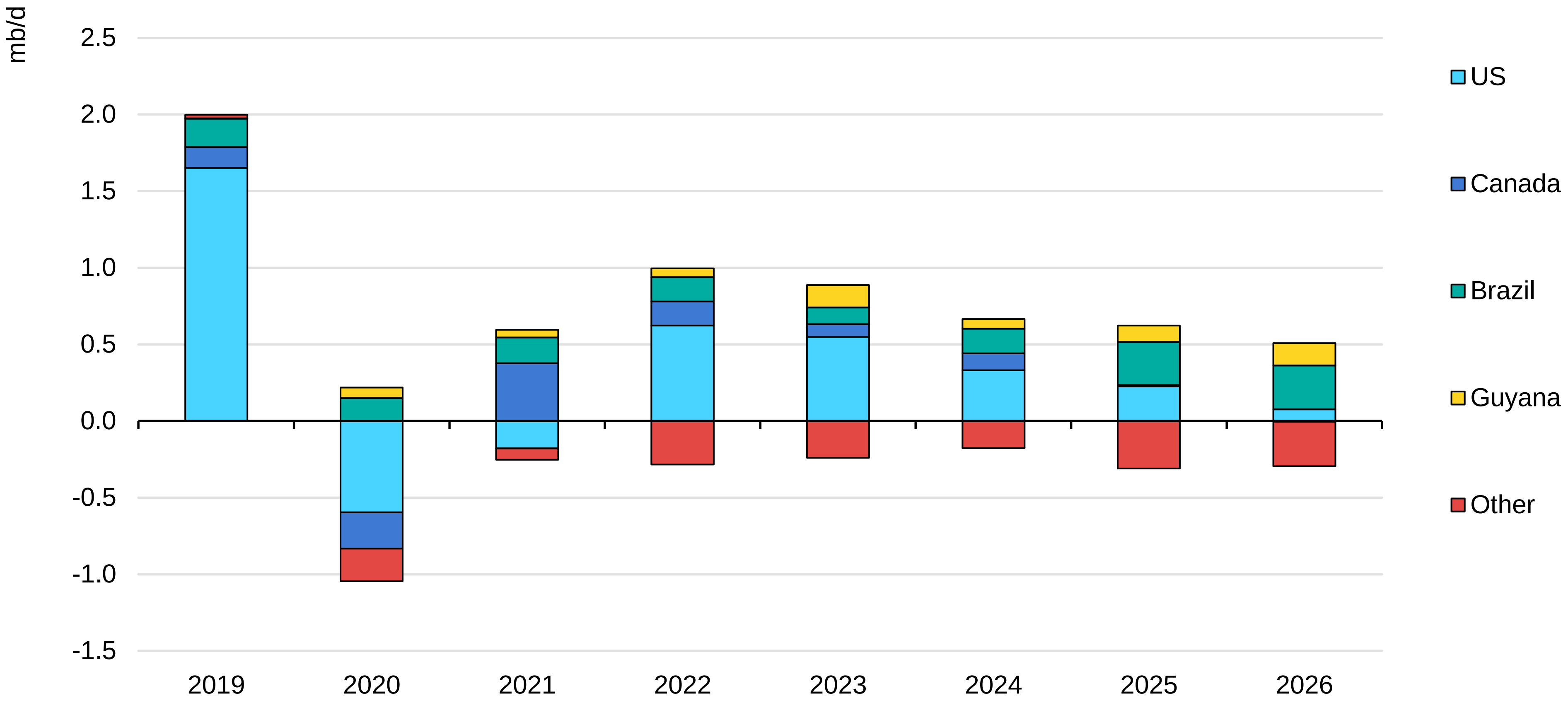
	2020	2021	2022	2023	2024	2025	2026	2020-26
Algeria	1.0	1.0	1.0	1.0	1.0	0.9	0.9	**-0.1**
Angola	1.4	1.3	1.2	1.2	1.1	1.1	1.0	**-0.3**
Congo	0.3	0.4	0.4	0.4	0.4	0.4	0.4	**0.0**
Eq. Guinea	0.1	0.1	0.1	0.1	0.1	0.1	0.1	**0.0**
Gabon	0.2	0.2	0.2	0.2	0.2	0.2	0.2	**0.0**
Iran	3.8	3.8	3.8	3.8	3.8	3.8	3.8	**0.0**
Iraq	4.9	4.9	5.0	5.2	5.3	5.4	5.5	**0.6**
Kuwait	2.9	3.0	3.0	3.1	3.1	3.1	3.1	**0.2**
Libya	1.1	1.2	1.2	1.2	1.3	1.3	1.3	**0.2**
Nigeria	1.8	1.8	1.8	1.7	1.7	1.7	1.6	**-0.2**
Saudi Arabia	12.1	12.2	12.2	12.2	12.2	12.3	12.3	**0.2**
UAE	3.7	3.8	3.9	4.0	4.0	4.1	4.2	**0.5**
Venezuela	0.6	0.5	0.5	0.5	0.5	0.5	0.5	**-0.1**
Total OPEC	**34.0**	**34.2**	**34.4**	**34.6**	**34.7**	**34.8**	**35.0**	**1.01**
Annual Change	*-0.1*	*0.3*	*0.2*	*0.2*	*0.1*	*0.1*	*0.1*	

Note: Kuwait and Saudi Arabia include their respective shares of the Neutral Zone.

Non-OPEC+

Outside of OPEC+, slower growth limited to a few countries

Oil supply growth from producers not part of OPEC+ group



Note: Total oil supply from non-OPEC countries outside of OPEC+ deal (Russia, Kazakhstan, Azerbaijan, Bahrain, Brunei, Oman, Malaysia, Mexico, Sudan, South Sudan). Excludes biofuel and processing gains.

US supply growth set to resume, but this time likely to be different

Oil production in the **United States** fell by 600 kb/d last year as lower prices and unprecedented financial challenges forced massive shut-ins and capex cuts. Crude supply dropped from a record 12.8 mb/d in November 2019 to 10 mb/d by May 2020 before rebounding to around 11 mb/d by year-end.

Over the medium term, supply growth will resume as investment and activity levels pick up in tandem with rising prices. A WTI price of $60/bbl will provide tight oil producers with strong incremental cash from operations, which can justify substantial capex increases. Yet, growth will likely not be near lofty levels seen in the past.

The tight oil industry appears to have shifted to a new business model that focuses on disciplined spending, free cash flow generation, deleveraging and cash returns for investors. According to Rystad Energy, the reinvestment rate – or the share of upstream cash from operations going into capex – for Permian tight oil activity fell from 121% in 2019 to 84% in 2020. We expect the industry to remain cautious in 2021 and do not expect to see rapid recovery in activity and capex. A wave of bankruptcies and consolidation in the industry during 2020 will likely reinforce this trend.

In addition to providing value to shareholders, listed companies will also be under pressure to be accountable in terms of ESG. The Biden presidency is putting climate action at the top of its agenda, and companies will likely have to spend more to mitigate methane emissions, halt flaring, and on carbon sequestration. A suspension of new lease approvals on federal land is not expected to have a material impact on output in the near and medium term due to a substantial inventory of drilled but uncompleted wells and permits to sustain activity at current levels for some time. If a permanent freeze on new drilling permits and leasing on federal acreage is approved, production could start to decline from 2024.

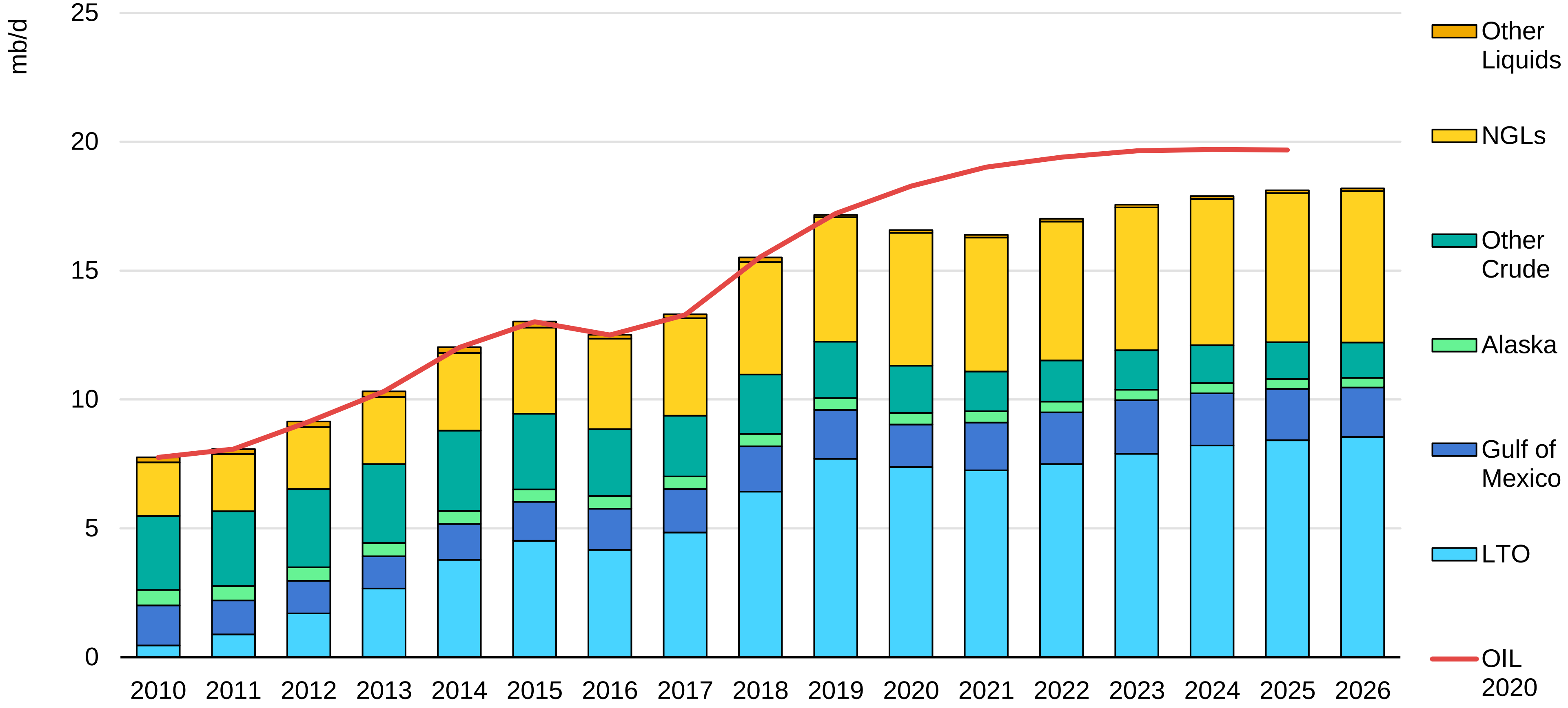
Elsewhere, output is expected to rise, especially in the Permian, as incremental cash flow is directed towards the most prolific areas. For now, we expect LTO output to rise by 1.2 mb/d through 2026.

Higher prices than those reflected by the forward curve used as input in this *Report* could change the trajectory of US production quite dramatically, however. Operators have in the past responded rapidly to price signals. According to a Dallas Fed Energy Survey, oil firms generally need a WTI price of $45-50/bbl to profitably drill a new well, with the best locations coming in below $30/bbl.

As for the Gulf of Mexico, crude oil production output is expected to rise from 1.7 mb/d in 2020 to a high of 2.1 mb/d in 2023, then hover around the 2 mb/d-mark through 2026. NGL production, meanwhile, is forecast to expand by 720 kb/d to 5.9 mb/d, led by higher ethane extraction and as natural gas production shifting to more liquids-rich plays. All in all, US total oil supply is projected to reach 18.2 mb/d in 2026, 1.6 mb/d more than the 2020 average.

Modest US growth expected as investment strategy shifts

US oil supply



Canadian takeaway capacity constraints ease as production outlook dims

Canadian oil supply is expected to recover in 2021 following two years of mandatory production curtailments and massive shut-ins due to the Covid pandemic. Growth will continue through 2024, as export bottlenecks ease, allowing oilsands projects to ramp up towards nameplate capacity levels. However, continued legal challenges and delays to new pipeline projects, along with sharp spending cuts across the upstream industry, has led companies to put a number of new oil projects and expansions on hold, limiting growth thereafter. By 2026, total oil output will average 6 mb/d, 730 kb/d more than in 2020 but only 200 kb/d above end-2019 levels.

New capacity is limited to Imperial's 15 kb/d Grand Rapids expansion, expected onstream sometime this year. In 2019, Imperial put on hold its 75 kb/d Aspen development and has stated that it will not provide a revised timeline until it sees progress on pipeline development and improved crude-by-rail economics. Suncor equally put on hold the development of Meadow Creek West and the previously approved 80 kb/d Meadow Creek East projects until 2023 at the earliest as it focuses on lower cost expansions of its existing oilsands facilities.

As for the offshore, Suncor and its partners are evaluating options for its Terra Nova field, which was forced shut at the end of 2019 due to safety concerns. Plans to proceed with a project that will extend the asset's life to 2031, with an aim to capture roughly 80 million additional barrels of oil, are also uncertain. Husky Energy is reviewing its planned 75 kb/d West White Rose Project that was set to start up in 2022. Construction activities on the project, that is 60% complete, were suspended last March due to the Covid pandemic and continued market uncertainty, and Husky is undertaking a full review of the project.

Oil firms Equinor and Husky Energy have decided to postpone the Bay du Nord project off Canada due to the fall in oil prices. The companies had previously expected the project, with estimated reserves of 300 million barrels, to start production in 2025. Even before the Covid outbreak, Canadian oil projects were being challenged. Teck Resources cancelled its planned C$20.6 billion ($15.6 billion) Frontier oil sands mine in February 2020, citing uncertainty about Canada's climate policy.

Meanwhile, the government is continuing to press for the timely completion of vital pipeline projects. Immediately after taking office, US President Biden revoked the permit for the Keystone XL pipeline. The Trans Mountain pipeline and Enbridge Line 3 expansions are progressing as planned, however, which should provide sufficient takeaway capacity for Alberta's reduced growth expectations. Significant rail capacity is also available.

Brazil, Guyana dominate non-OPEC+ oil supply growth

With US and Canadian growth tapering off, **Brazil** is poised to be one of the key sources of growth over the medium term. Total oil supply is expected to grow by 1.2 mb/d to 4.2 mb/d in 2026 as new low-cost resources are tapped in the prolific pre-salt layers offshore.

State oil company, Petrobras, expects its production of oil and gas to rise from 2.85 moeb/d in 2020 to 3.3 mboe/d by 2024, and hold steady in 2025. In its latest business plan, Petrobras cut its five-year investment budget by 27% from a year ago, to $55 billion, in order to preserve cash. Approximately 84% of the total, or $46 bn, will go towards exploration and production, with approvals limited to new projects that can be profitable at oil prices as low as $35/bbl.

Petrobras plans to bring on stream 13 new floating production, storage and offloading (FPSO) vessels by 2025. The biggest developments will go into the Búzios field, which will see four additional units installed, lifting capacity from 600 kb/d currently to 1.35 mb/d. A further four FPSOs could be brought online from 2026. The Mero field that Petrobras is developing with Total, Shell, CNOOC and CNPC will start up this year, with capacity set to reach 540 kb/d by 2025. Contracting of a fourth 180 kb/d FPSO that was to start up in 2025 has been delayed. Meanwhile, Sepia will come online in 2021 and Itapu in 2023.

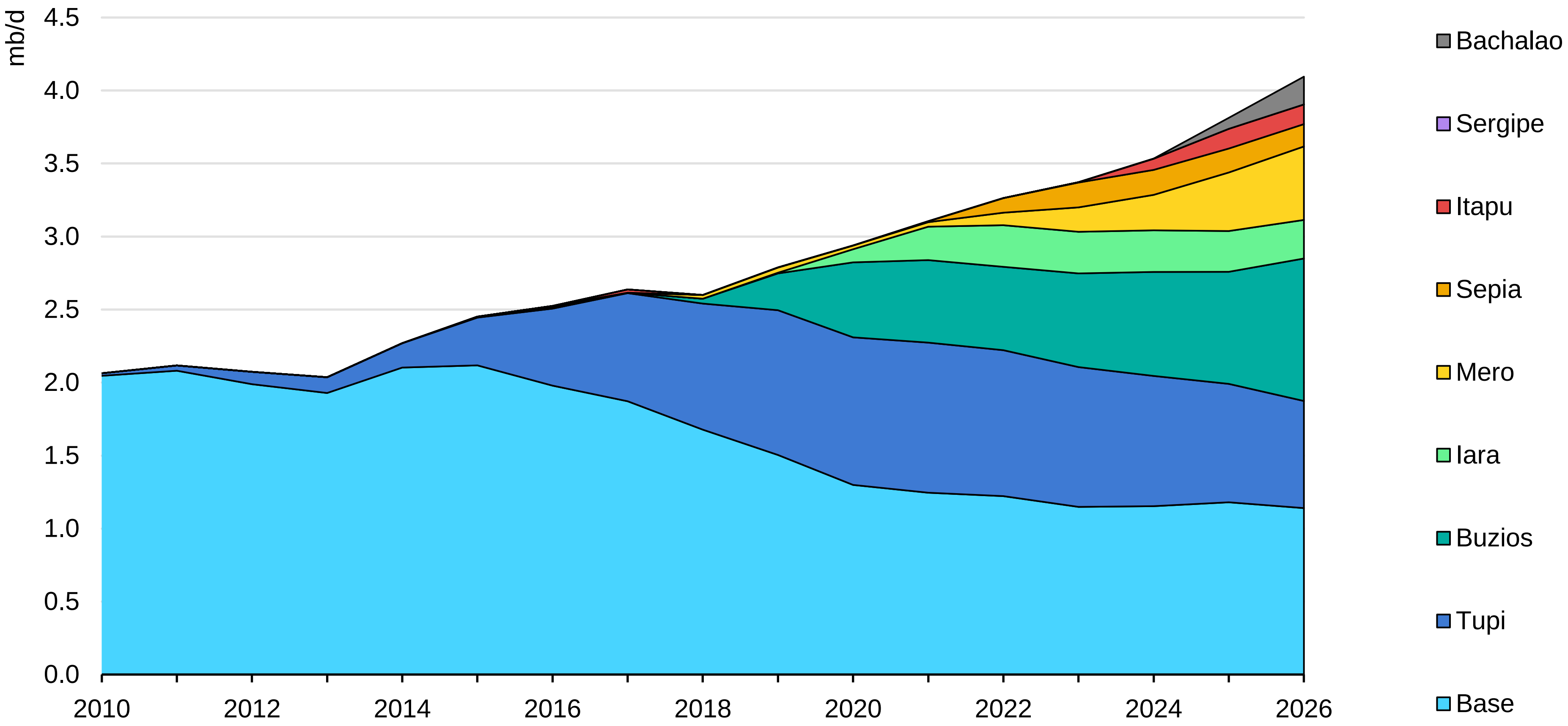
Redevelopment efforts are also ongoing at the Marlim fields. Petrobras plans to divest 600 kb/d of onshore and shallow water assets, including the Marlim cluster and the Albacora fields. Petrobras plans to spend $13 billion over 2021-25 to reverse declines in the Campos Basin. Additional volumes will come from the Bacalhau field, which Equinor is developing with ExxonMobil and Petrogal Brazil. While FID is only expected for the project in 2021, a number of contracts have been awarded and output of up to 220 kb/d is expected from 2024.

Significant growth will also come from **Guyana**, where ExxonMobil, Hess and CNOOC have made some of the biggest discoveries in recent years. Since 2015, more than 8 billion barrels of recoverable oil equivalent resources have been found, and in 2019, oil started flowing from the 120 kb/d Liza Phase 1 development in the Stabroek block. Phase 2 of the project, which will add 220 kb/d of production, is expected to start up in 2022, and last September, FID to proceed with the Payara field was taken. Payara will produce up to 220 kb/d after start-up in 2024. Further developments are likely to be sanctioned and onstream in coming years, with the consortium stating they expect to produce more than 750 kb/d by 2025/26.

Elsewhere in **Latin America**, prospects have dimmed, with investment cuts expected to take their toll on supply over the medium term. Tight oil developments in Argentina have slowed, and output in Colombia is expected to fall sharply towards 2026, with few new developments on the books.

Búzios, Mero developments fuel Brazil expansion

Brazilian oil production



Note: Forecast for Brazil includes several phases of the Búzios and Mero developments not yet sanctioned, but included in latest Petrobras business plan. Also includes the Bacalhau project that has not yet been officially sanctioned, but where contracts have been awarded.

Diverging trends in North Sea

North Sea oil production is expected to hold relatively steady over the medium term, as gains in Norway largely offset declines in the United Kingdom and Denmark.

Along with Brazil, **Norway** stood out as one of a select few sources of growth in 2020. Despite the downturn, and voluntary output restrictions, total oil supply rose by 270 kb/d y-o-y, fueled by the ramp up of the massive Johan Sverdrup field. Operators also found nearly 600 bn of oil equivalent of reserves, the highest amount since before the oil crash of 2014.

A new tax relief package announced last year has helped operators improve project economics, encouraging companies to give the final push to develop the Balder Future and Hod Redevelopment projects. Equinor also decided to move forward with its Breidablikk development, which includes the Grane D and Grane E fields. The project is expected to cost nearly $2 billion and start up in 2024.

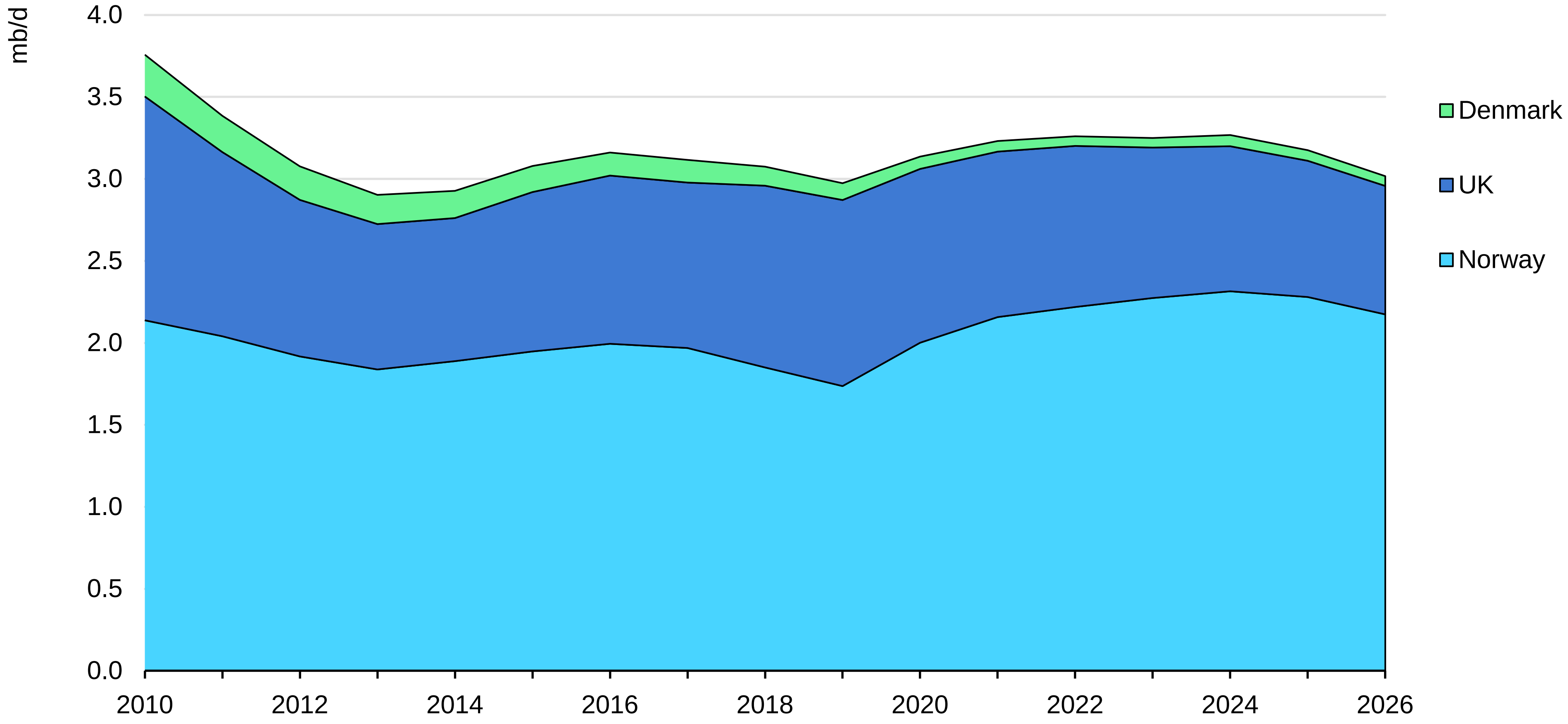
While several projects, including Johan Castberg, Martin Linge, Yme, and Fenja, have been delayed due to Covid or technical issues, Norwegian oil production is expected to see continued growth in the medium term. Other new projects include a second phase of the Johan Sverrup field, due onstream by end-2022, which will be a key contributor to growth. Based on current development plans, supply rises from 2 mb/d in 2020 to a peak of 2.3 mb/d in 2023 before falling marginally thereafter.

By contrast, the **United Kingdom** will see continued declines through 2026. With few projects in the pipeline, total oil supply falls by 280 kb/d over the period to 780 kb/d in 2026. According to the Oil and Gas Authority (OGA), upstream spend, which slumped by 24% last year to £11.5 billion, will likely fall further over the medium term. OGA projects that expenditures that include exploration and appraisals, capex, operating costs, and decommissioning will fall below £9 billion by 2025, about half of the 2016 level.

As part of its pledge to reduce greenhouse gas emissions, **Denmark** announced that it will phase out North Sea oil and gas production by 2050. The country's eighth licensing round and all future rounds have been cancelled. Denmark, which began producing oil and gas in 1972, currently has 19 oil and gas fields in operation. Danish crude production averaged 75 kb/d in 2020 while gas output stood at 130.9 mcf/d. Production has been constrained since the Tyra field and its satellites were shut down for a redevelopment project in September last year. The project is not expected to be completed until the second quarter of 2023, having been delayed by a year by the Covid-19 pandemic.

Norway gains offset by United Kingdom; Denmark declines

North Sea total oil supply



Asia, Africa on the decline; non-OPEC+ Mideast expands

In **Asia**, oil production continues to slump. Following declines of 750 kb/d from 2015 through 2020, regional output will fall by a further 780 kb/d by 2026. The biggest decreases will come from India and Indonesia followed by China, Thailand and Viet Nam. There are few development projects targeting oil resources and high decline rates at mature fields will weigh on output. After several years of growth that was led by LNG projects, Australian liquids supply will also start to decline again, falling to 370 kb/d in 2026.

The Covid pandemic dealt another blow to **African** nations looking to join the oil producer's club. Long plagued by delays and technical problems, the timeline for the start-up of new projects slipped again in 2020. In **Uganda**, Total and its partner CNOOC had been expected to make a FID in 2020 on the Lake Albert project that includes the Tilenga and Kingfisher fields. However, faced with delays to securing financing for the export pipeline that will run through neighbouring Tanzania, the project now looks set to get the final go-ahead by mid-2021 at the earliest. Between them, the Tilenga and Kingfisher assets are expected to produce 230 kb/d.

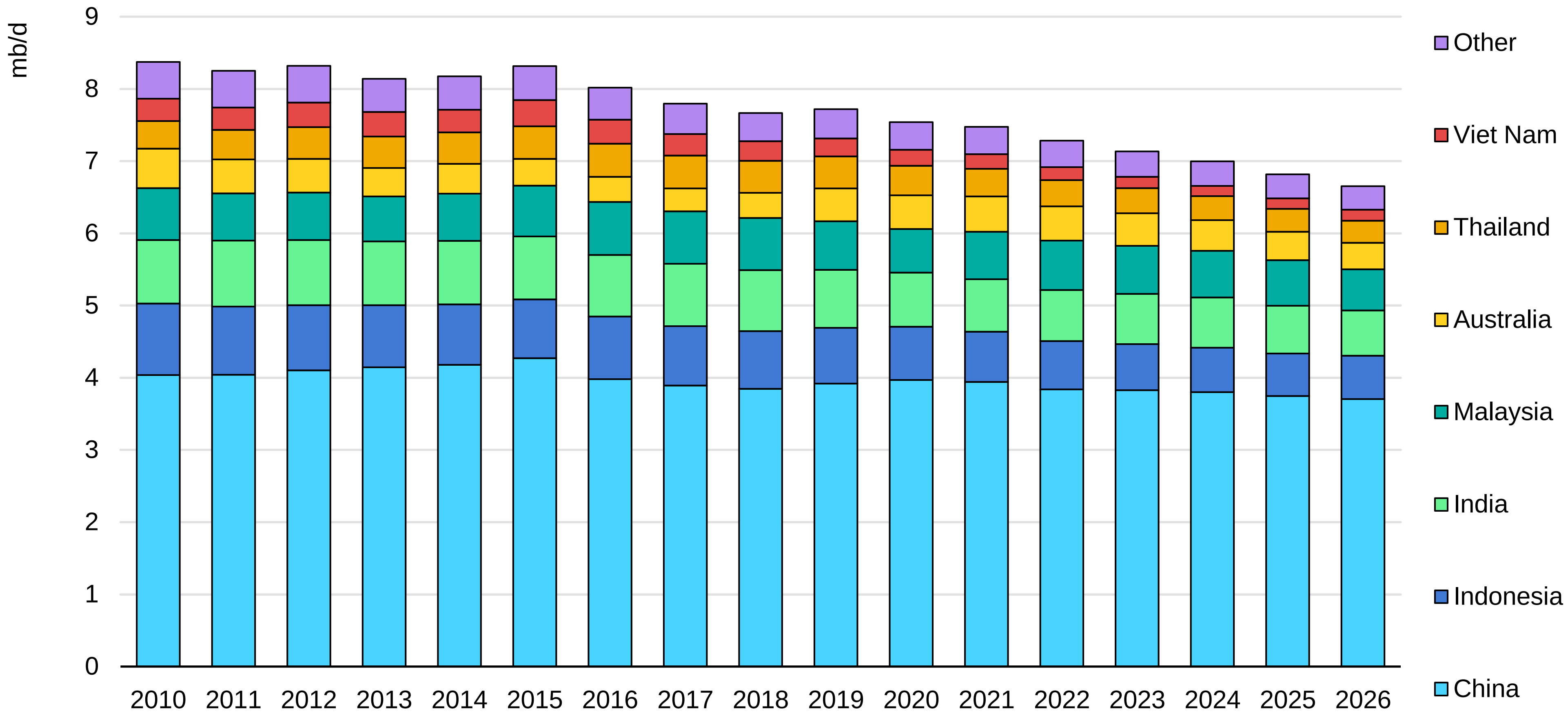
Also, in neighbouring **Kenya** the FID that was set to launch the South Lokihar development last year has been delayed. Operator Tullow is reassessing the development plans to come up with a phased project that is economic at low prices. The first phase was expected to yield 60-80 kb/d of oil. Tullow is instead focusing on addressing issues at its Jubilee and Tweneboa-Enyenra-Ntomme (TEN) fields in **Ghana** to achieve its production targets. Aker Energy's Pecan project remains on hold while the company is working on a new feasibility study for the development.

In **Senegal**, the Sangomar project seems to be moving ahead. Despite some delays due to Covid, Woodside, the field's operator, said it expects to begin production of up to 100 kb/d in 2023.

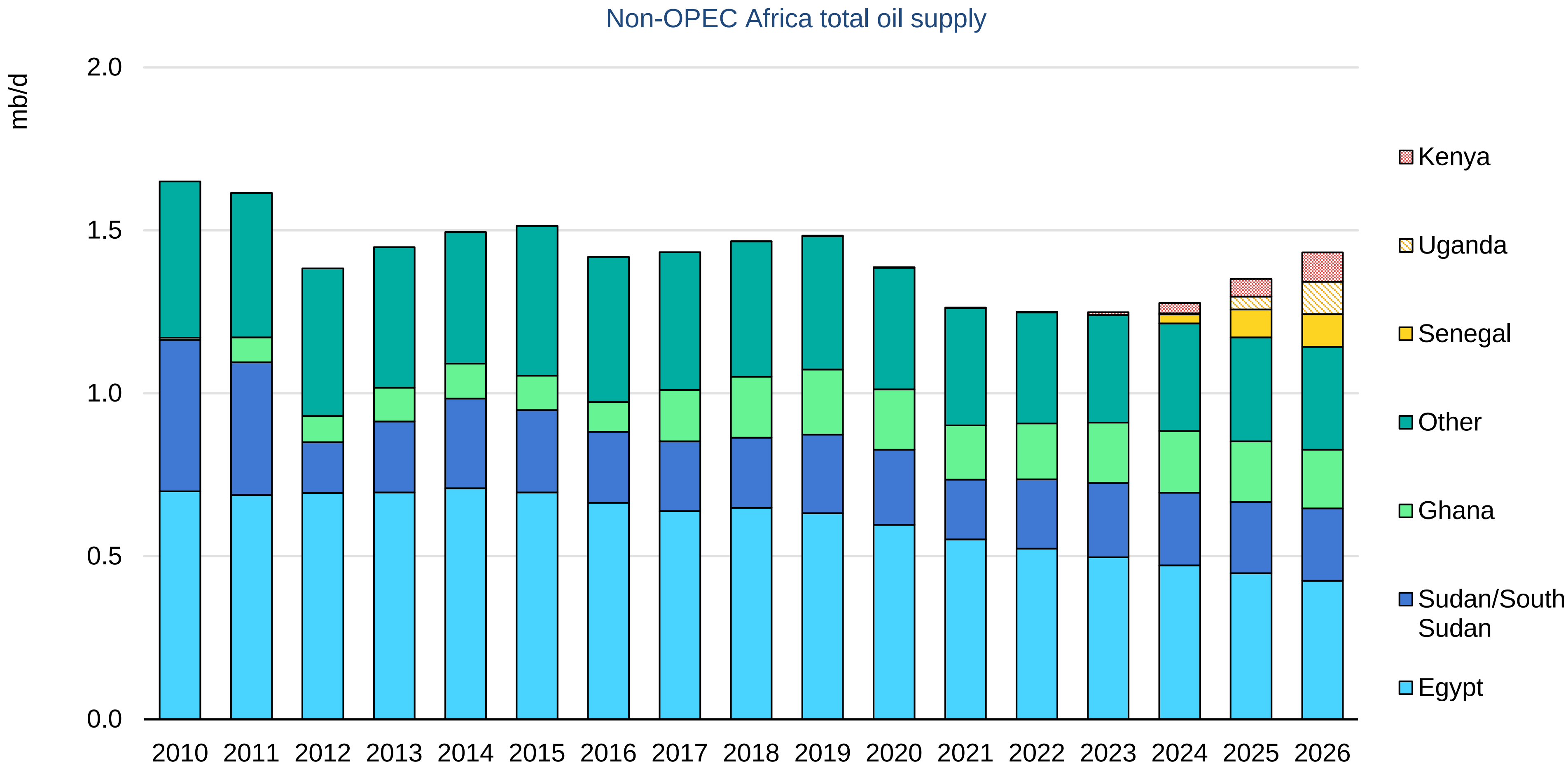
Qatari oil supply is set to grow by 170 kb/d over the forecast period as it further taps condensates from the North Field. Its total oil supply is due to rise to 2 mb/d by 2026. Qatar Petroleum (QP) in early February awarded an EPC contract to a Chiyoda/Technip joint venture for the first phase of a project to raise LNG capacity from 77 million tonnes a year (mt/yr) to 110 mt/yr and increase the supply of NGLs. The $28.75 billion expansion, one of the world's largest energy projects, is expected to start producing by the fourth quarter of 2025. QP is prepared to go it alone at the North Field project, but reportedly plans to open a bidding process for IOCs to take up to a 30% stake. The four-train expansion is expected to produce some 260 kb/d of condensate, 11 000 tons per day (t/d) of LPG, and 4 000 t/d of ethane. A proposed second phase would boost LNG capacity to 126 mt/yr. Qatar's crude production of around 600 kb/d is expected to stay broadly steady over the next six years.

Asian oil supply set for further declines

Total oil supply for Asia Pacific countries



African growth depends on projects getting off drawing board



Note: Supplies from Uganda and Kenya are not included in the forecast as project sanctioning has been delayed.

Global biofuels production set to expand

Following a 200 kb/d decline to 2.6 mb/d in 2020 amid the pandemic, global biofuels supply is expected to reach 3.3 mb/d by 2026. In the near term, a recovery in mobility and on-road transport fuel demand will underpin growth, while strengthened policies and planned capacity additions will drive gains thereafter. The United States, Indonesia and Malaysia lead the charge in hydrotreated vegetable oils (HVO) and biodiesel capacity expansions, while China, India and Brazil increase ethanol output the most. Global ethanol production is set to grow by 330 kb/d from 2020 to 2026, while biodiesel/HVO expands by 380 kb/d over the same period.

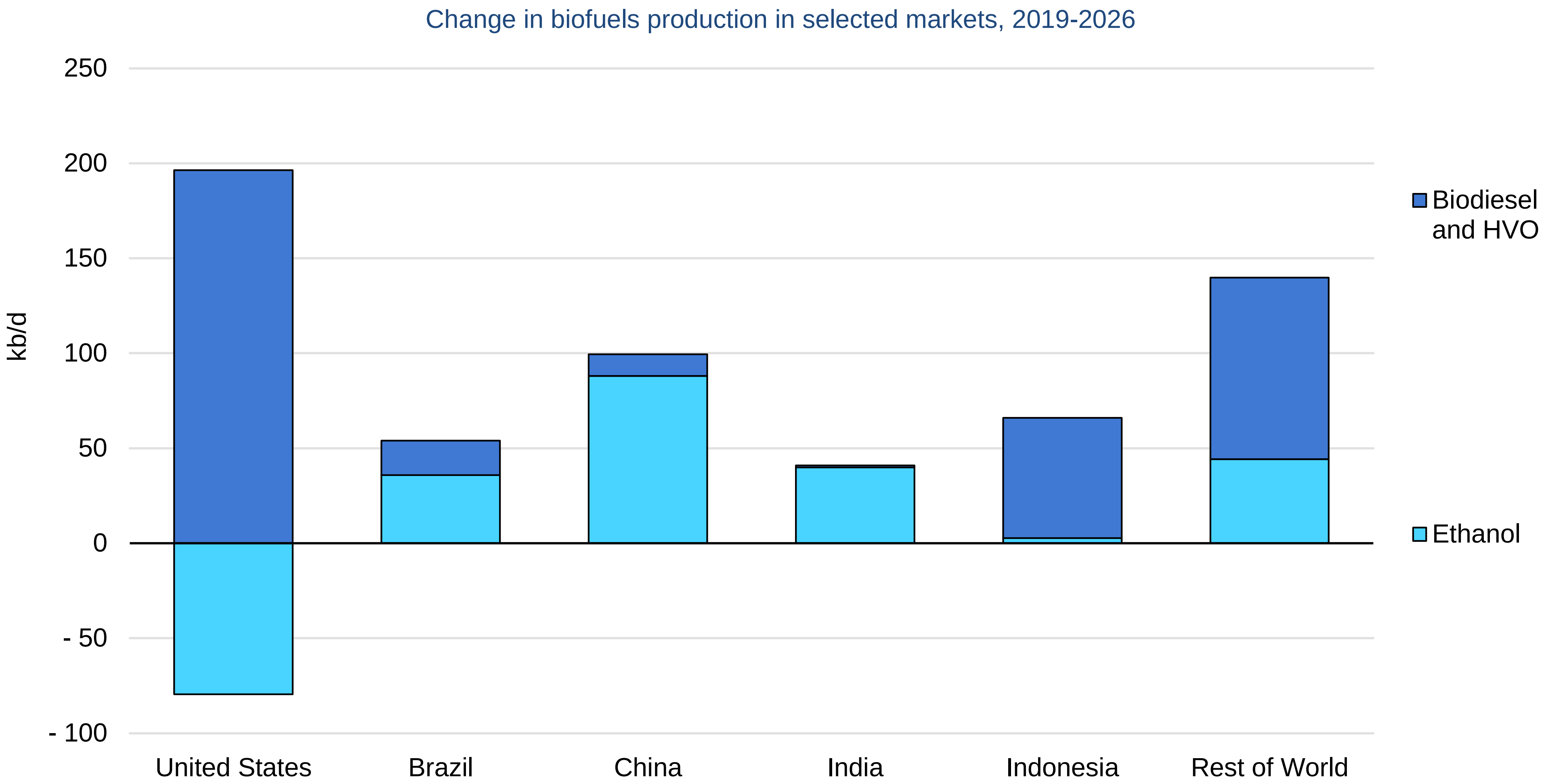
US ethanol production will not recover to 2019 levels during our forecast period. Assuming no policy changes and stable exports, production in 2026 will be 80 kb/d lower than in 2019 as domestic gasoline demand starts to decline. By contrast, HVO production continues to grow strongly, supported by a number of policies that drive HVO investments, including the Renewable Fuel Standard, Renewable Identification Numbers prices, LCFS credits, and biodiesel blender credit.

A recovery in gasoline demand and higher RenovaBio goals for decarbonisation credits will underpin a rebound in **Brazilian** ethanol production over the medium term. Corn ethanol production is set to expand, with a number of new plants in development. Drier than normal weather conditions are expected to negatively impact the sugar harvest during 2021/22, however, which could see production switch to sweeteners at the expense of ethanol. Brazilian ethanol supply is set to average 660 kb/d in 2026, up 90 kb/d compared with 2020 and 35 kb/d higher than in 2019.

China will see the strongest growth in ethanol production, with output rising from 70 kb/d in 2020 to 160 kb/d by 2026. Robust gasoline demand growth, a net-zero commitment by 2060, E10 mandates in some provinces, and the start-up of new facilities will support growth. **Indian** ethanol production is set to rise from 30 kb/d in 2020 to 70 kb/d by 2026. India’s proposal to move its 20% blending target forward to 2025 from 2030, increased loans for new capacity and expanded biofuel feedstocks will support growth.

Biodiesel production in **Indonesia** will grow from 140 kb/d in 2020 to 190 kb/d in 2026. While the planned hike in blending mandates from B30 to B40 has been delayed until late 2022 or early 2023, several new production sites will come online over the coming years. **Malaysian** biodiesel production is expected to reach 40 kb/d in 2026, supported by a B20 blending mandate that was delayed until early 2022. Palm oil prices at their highest in nearly a decade have widened the price premium over crude for biodiesel.
In **Europe** meanwhile, the implementation of RED II and increasing quotas as well as new capacity additions, should see HVO and biodiesel production expanding by 40 kb/d to 320 kb/d.

Five countries account for 70% of growth in global biofuels production to 2026



Non-OPEC supply to rise by 4.6 mb/d from 2020-2026, to near 68 mb/d

Total non-OPEC supply (mb/d)

	2020	2021	2022	2023	2024	2025	2026	2020-26
OECD	27.9	28.2	29.0	29.6	29.9	29.9	29.7	1.8
OECD Americas	23.8	24.0	24.8	25.4	25.7	25.9	25.9	2.1
OECD Europe	3.5	3.6	3.7	3.6	3.6	3.5	3.4	-0.2
OECD Asia Oceania	0.5	0.6	0.5	0.5	0.5	0.5	0.4	-0.1
Non-OECD	30.5	30.6	31.5	32.0	32.0	32.1	32.1	1.7
FSU	13.5	13.6	14.4	14.8	14.7	14.6	14.4	0.9
Europe	0.1	0.1	0.1	0.1	0.1	0.1	0.1	-0.0
China	4.0	3.9	3.8	3.8	3.8	3.7	3.7	-0.3
Other Asia	3.0	3.0	2.9	2.8	2.7	2.6	2.5	-0.5
Non-OECD Americas	5.3	5.6	5.7	5.9	6.0	6.4	6.7	1.4
Middle East	3.1	3.2	3.3	3.4	3.4	3.4	3.5	0.3
Africa	1.4	1.3	1.2	1.2	1.2	1.3	1.2	-0.1
Non-OPEC Oil Supply	58.4	58.8	60.6	61.5	61.9	62.0	61.8	3.5
Processing Gains	2.1	2.2	2.4	2.4	2.4	2.5	2.5	0.4
Global Biofuels	2.6	2.8	3.0	3.1	3.2	3.3	3.3	0.7
Total-Non-OPEC Supply	63.1	63.9	66.0	67.1	67.5	67.7	67.6	4.6
Annual Change	-2.5	0.8	2.1	1.1	0.4	0.2	-0.1	0.8

Note: FSU = Former Soviet Union.

Refining and trade

Refining and trade overview

Rationalisation of refining capacity underway

A third wave of refinery closures has been ushered in by the Covid−19 pandemic. Refining activity in 2020 fell almost 10% to 74.4 mb/d, a level last seen in 2010. Annual average refinery margins plunged to their lowest in at least two decades even as crude prices fell to 16−year lows. For the refining sector, the pandemic also offered a glimpse of the future, when clean energy transitions are expected to dramatically affect transport fuel demand, and petrochemicals become the only growing, or stable, oil demand segment. In 2020, as transport fuel demand fell by 13%, the petrochemical sector remained resilient.

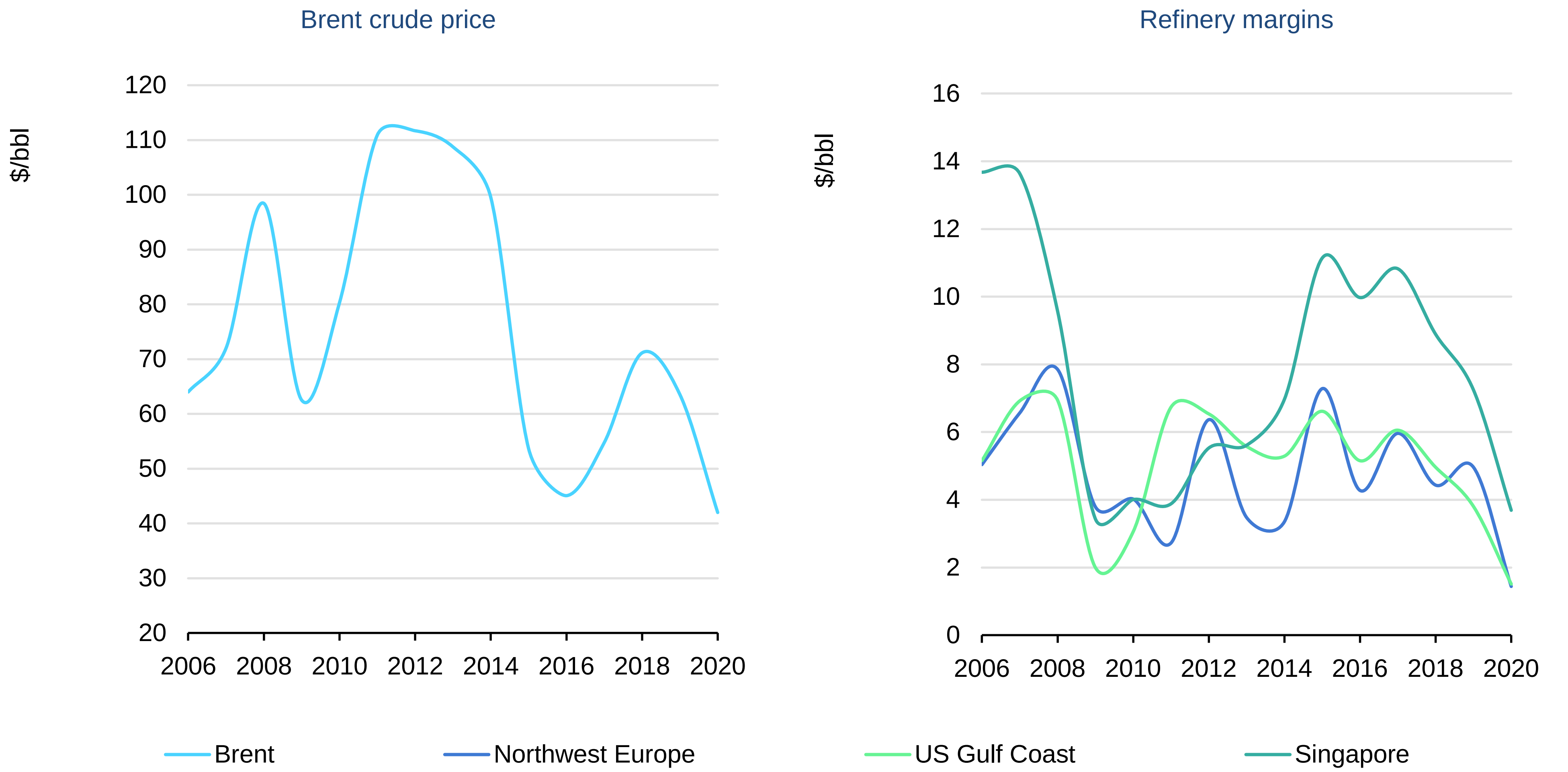
The contraction in refinery activity is being driven by the downward shift in transport fuel consumption trends. A third of oil demand growth in 2019-2026 is now forecast to be met by products bypassing the refining sector, such as NGLs and biofuels. Refiners are increasingly looking at petrochemical integration to offset declines in transport fuels, and renewable diesel and electrolysis hydrogen production projects for refinery needs or for external users.

In the meantime, the new very low sulphur marine bunker fuel, a premium product, offers a last opportunity for traditional fuel-oriented refiners as combined demand for refinery-supplied gasoline, diesel and kerosene in 2026 remains below 2019 levels.

The Covid-19 demand shock, the continued capacity build-up and expectations of long-term structural demand decline have created a refining capacity overhang that can only be resolved through massive closures. We believe that a third round of worldwide refinery rationalisation is in the making: shutdowns of at least 6 mb/d will be required globally to allow utilisation rates to return to above 80%. Meanwhile, China, the Middle East and India continue to drive new refining capacity growth. Chinese petrochemical companies will have added 2 mb/d of refining capacity between 2019 and 2024 as the country strives to reach self-sufficiency in base petrochemical materials.

East of Suez will account for all the growth in refining activity. Asian crude oil imports will surge to 26.6 mb/d by 2026, requiring record levels of both Middle Eastern crude oil exports and Atlantic Basin production to fill the gap. The OPEC+ group will see crude oil exports declining in 2026 relative to 2019 due to lower production or higher domestic refining. Brazil, Guyana, Norway and Canada will drive crude oil exports growth. The United States will solidify its position as a net seaborne oil exporter, shipping more crude oil, refined products and NGLs to international markets than it imports. The center of gravity for refined products trade is also shifting to Asia, where Australia, Indonesia, New Zealand and Singapore combined overtake Africa in net product import requirements.

Margins plunge to multi-decade lows in 2020 as product prices fall more than crude



Note: Global indicator refining margins.
Sources: IEA and KBC Advanced Technologies.

Refining capacity

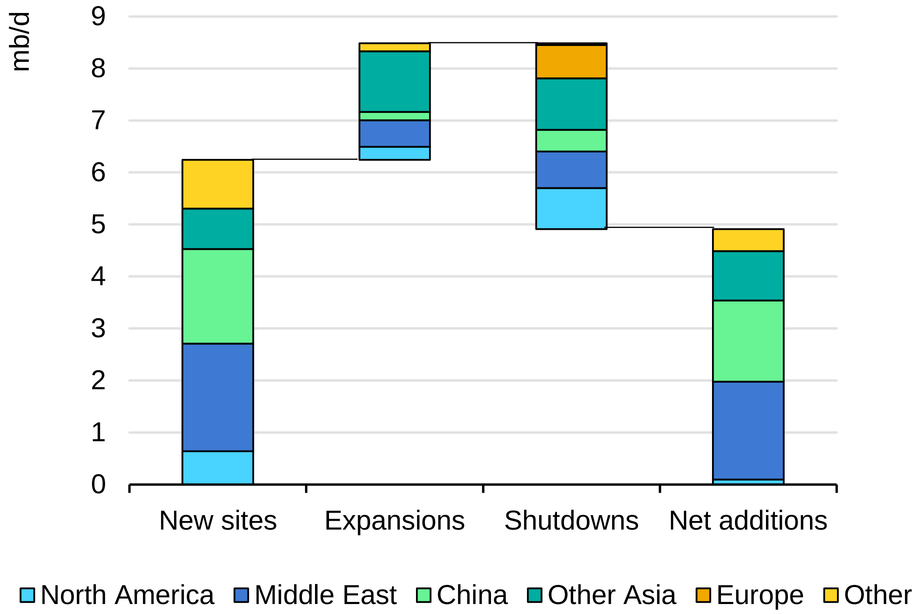
Great downstream migration continues despite downward shift in demand

Despite the dramatic slowdown in oil demand growth, refinery capacity additions continue unabated. Currently at some 102 mb/d, global crude distillation capacity is already 20 mb/d in excess of pre−pandemic refinery runs. Between 2020 and 2026, 8.5 mb/d of new refining capacity is expected to come online. With 3.6 mb/d of announced refinery closures, net additions will amount to 4.9 mb/d, similar to net capacity growth in the last seven years, but almost double the forecast growth in demand for refined products. This will result in a growing capacity overhang, which will require additional refinery shutdowns in the coming years.

The geographical pattern of capacity additions, mostly East of Suez, continues to hold. East of Suez accounts for 90% of net capacity additions through 2026, as African projects account for all net growth in the Atlantic Basin.

New sites dominate capacity increases. Around 6.2 mb/d of new capacity will come from greenfield projects, of which one-third is in China. Expansion projects account for another 2.2 mb/d. We note a particularly broad base of capacity shutdowns. Europe, North America, Asia and the Middle East each contribute about a quarter to the planned 3.6 mb/d capacity shutdowns. In the Middle East, the majority of capacity closures are due to new replacement capacity coming online.

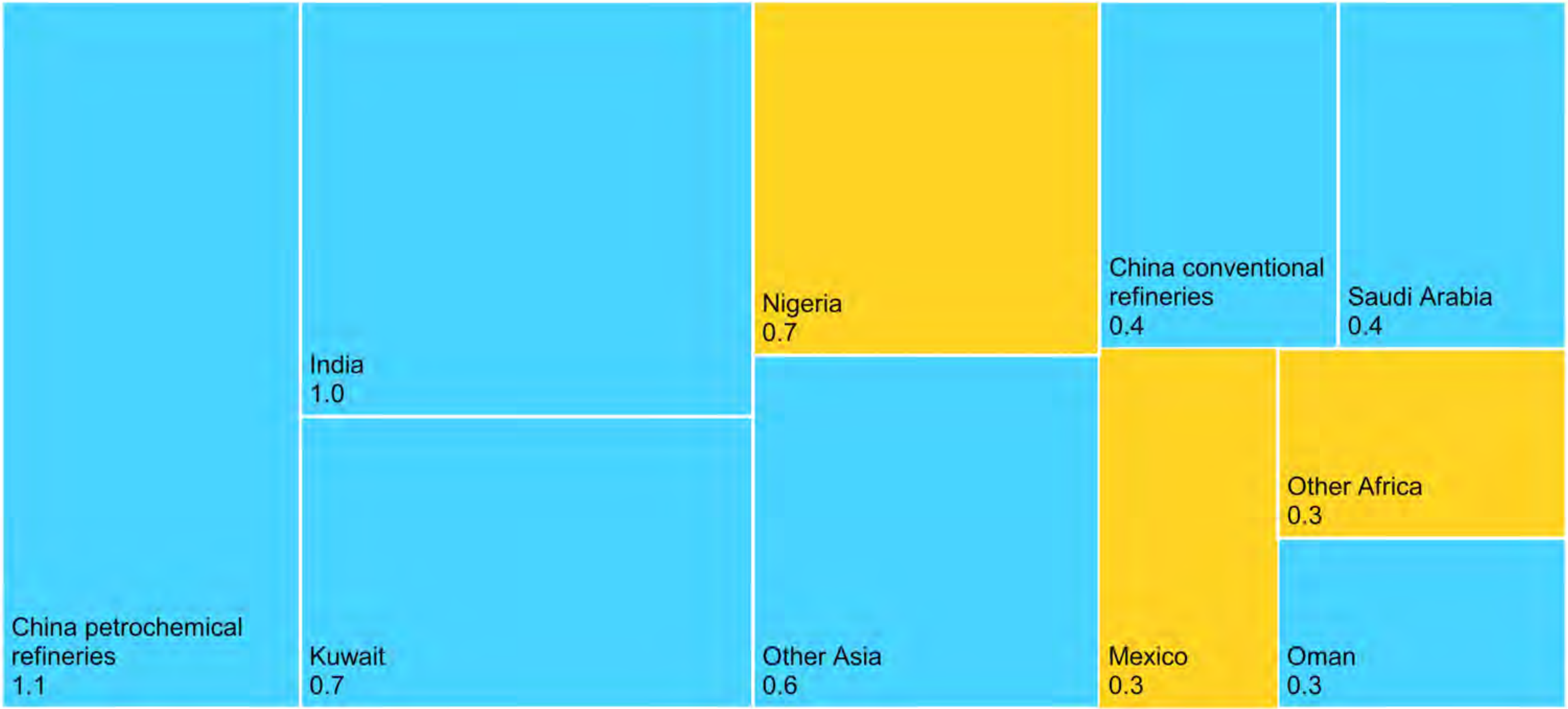
Refinery capacity changes 2020-2026



Note: Capacity changes include only announced shutdowns for the period of 2020-2026.

East of Suez accounts for 90% of net capacity additions by 2026

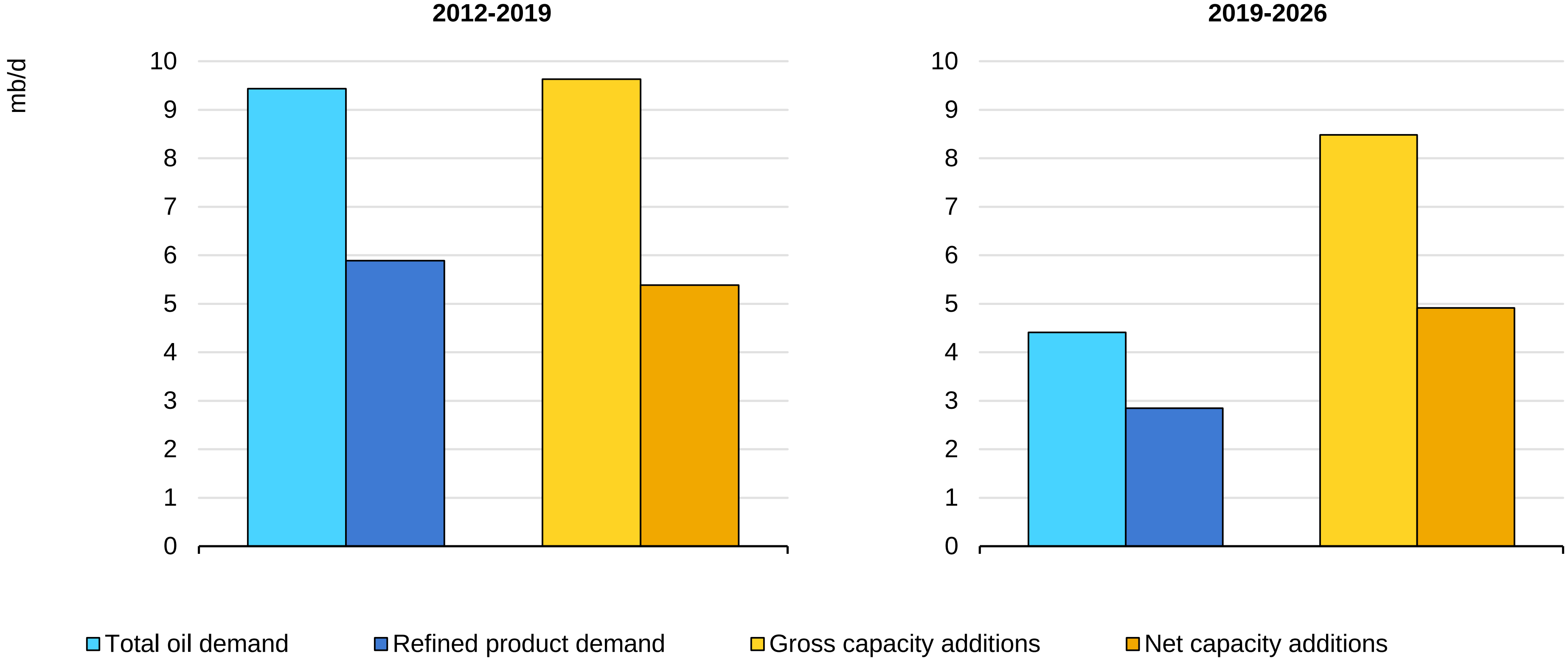
Crude distillation capacity additions in 2020-2026 in selected countries and regions, mb/d



Notes: Blue indicates East of Suez regions, orange indicates Atlantic Basin regions. Only capacity shutdowns announced as of February 2021 are included for each region. The total is higher than global net capacity additions as regions with net capacity decrease are not shown.

Capacity additions continue despite sharp decline in oil demand and call on refineries

Demand and refinery capacity changes



Note: Call on refineries is calculated as the difference between total liquids demand and product supply bypassing the refinery sector.

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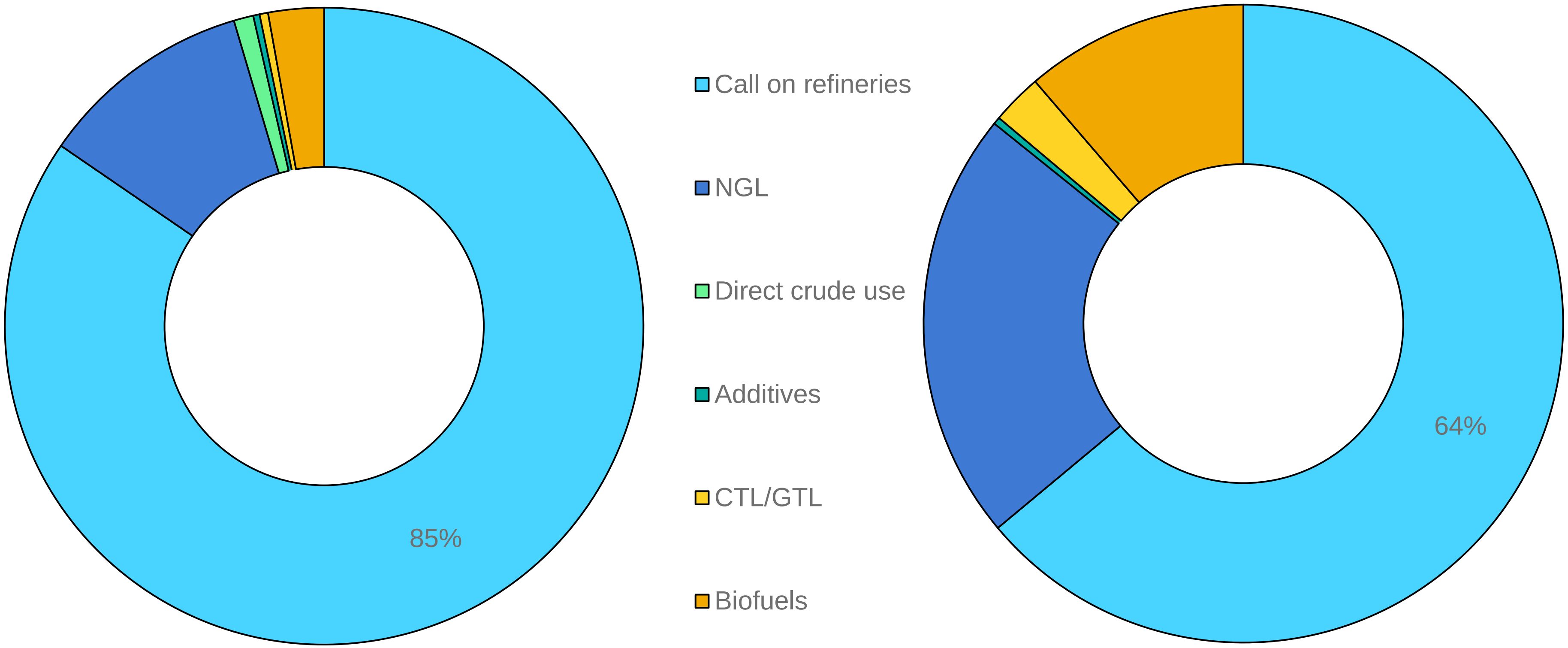
A third of oil demand growth in 2019-2026 bypasses the refining sector

Call on refineries in total oil demand in 2019 (left), and in oil demand growth 2019-2026 (right)



Note: Refinery market share includes processing gains.

Refinery market share contracts with conitnued growth in NGLs and biofuels

Oil demand and call on refined products (mb/d)

	2019	2020	2021	2022	2023	2024	2025	2026	2019-26
Total liquids demand	99.7	91.0	96.5	99.4	101.2	102.3	103.2	104.1	4.4
Biofuels	2.8	2.6	2.8	3.0	3.1	3.2	3.3	3.3	0.5
Total oil demand	96.9	88.5	93.7	96.4	98.0	99.0	99.9	100.8	3.9
CTL/GTL*/additives	0.7	0.8	0.7	0.8	0.8	0.8	0.9	0.9	0.1
Direct use of crude oil	1.0	1.0	0.9	0.9	0.9	0.9	0.9	0.9	0.0
Total oil product demand	95.2	86.7	92.1	94.7	96.3	97.3	98.1	99.0	3.8
Fractionation products**	10.8	11.0	11.0	11.3	11.4	11.5	11.6	11.8	1.0
Refinery product demand	84.3	75.7	81.0	83.4	84.8	85.7	86.4	87.2	2.8
Refinery market share	84.6%	83.1%	84.0%	83.9%	83.9%	83.8%	83.8%	83.7%	-0.8%

Notes: *CTL/GTL: Coal-to-liquids and gas-to-liquids. **Ethane, petroleum liquefied gas (LPG) and pentanes plus, excluding estimated diluent use in North America.

Covid-19 speeds up third round of global refinery closures

We are witnessing the world’s third round of massive refinery capacity shutdowns. Closures can happen at any time, due to accidents or change in corporate strategy, but synchronised widespread closures are a relatively rare occurrence. Historical analysis shows that these are generally triggered by global average utilisation rates falling below 80%.

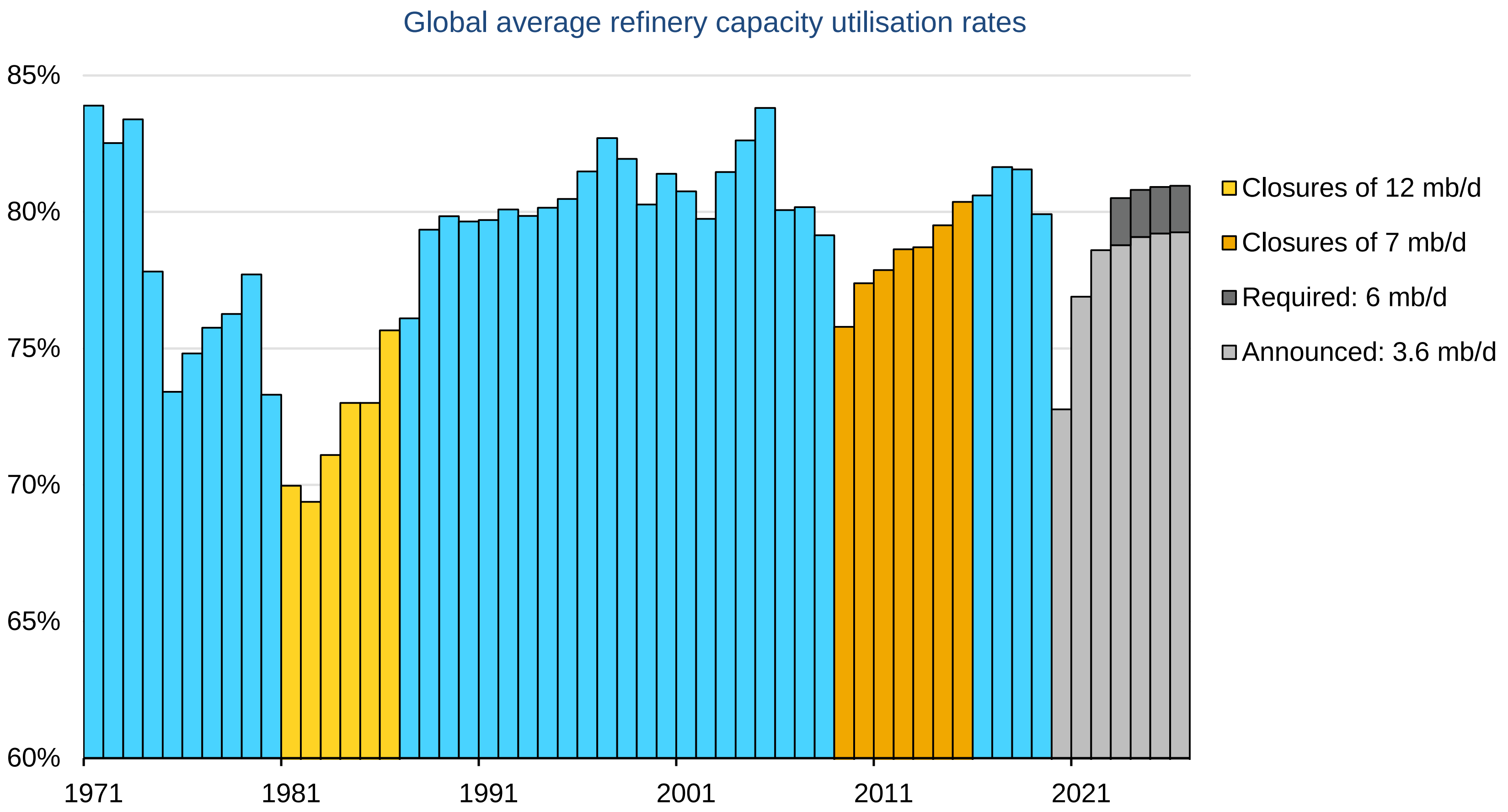
The refining industry witnessed the first, and largest, wave of capacity shutdowns in the first half of the 1980s. Then, 12 mb/d of refining capacity was closed worldwide, half of which was in Europe. Between 1979 and 1983 oil demand fell by 6.3 mb/d, due to the double impact of the second oil price shock and the rapid switching from fuel oil to natural gas and nuclear in power generation. The closures, along with a recovery in demand in the mid-1980s, allowed utilisation rates to increase from 70% to close to 80% by the end of the decade.

Following the financial crisis in 2008, another 7 mb/d of capacity was permanently closed between 2009 and 2015 as refinery economics deteriorated. A decline in transport fuel demand in OECD countries due to macroeconomic factors, and the tangible impact of fuel efficiency standards were mostly to blame. A growing gasoline-diesel imbalance in Europe that resulted in gasoline oversupply and poor margins for simple refineries also contributed.

We have anticipated the third round of capacity shutdowns for some time now given the extensive build-up of new capacity in Asia and the Middle East amid long-term oil demand trends. Covid-19 has merely acted as a catalyst. In 2020, global average utilisation rates fell to 73%. So far, planned shutdowns for 2020-26 amount to 3.6 mb/d, of which 840 kb/d is at various planning stages for conversion to bio-refineries. However, for capacity utilisation rates to reach 80%, another 2.4 mb/d of shutdowns are required.

Shutdowns generally affect the smaller sites, where the scale has not justified investments into upgrading units or petrochemical production, even as location and the overall business strategy of the operator also play a crucial role. Since 2012, the average size of permanently closed refineries has been around 100 kb/d. This has increased the global average operating refinery size from 147 kb/d in 2012 to 154 kb/d in 2020 (excluding refineries with capacity under 20 kb/d). The average size of new greenfield projects coming online between 2020 and 2026 is 185 kb/d, while the average size of refineries slated for closure is 110 kb/d. This helps push the global average refinery size to 160 kb/d in 2026.

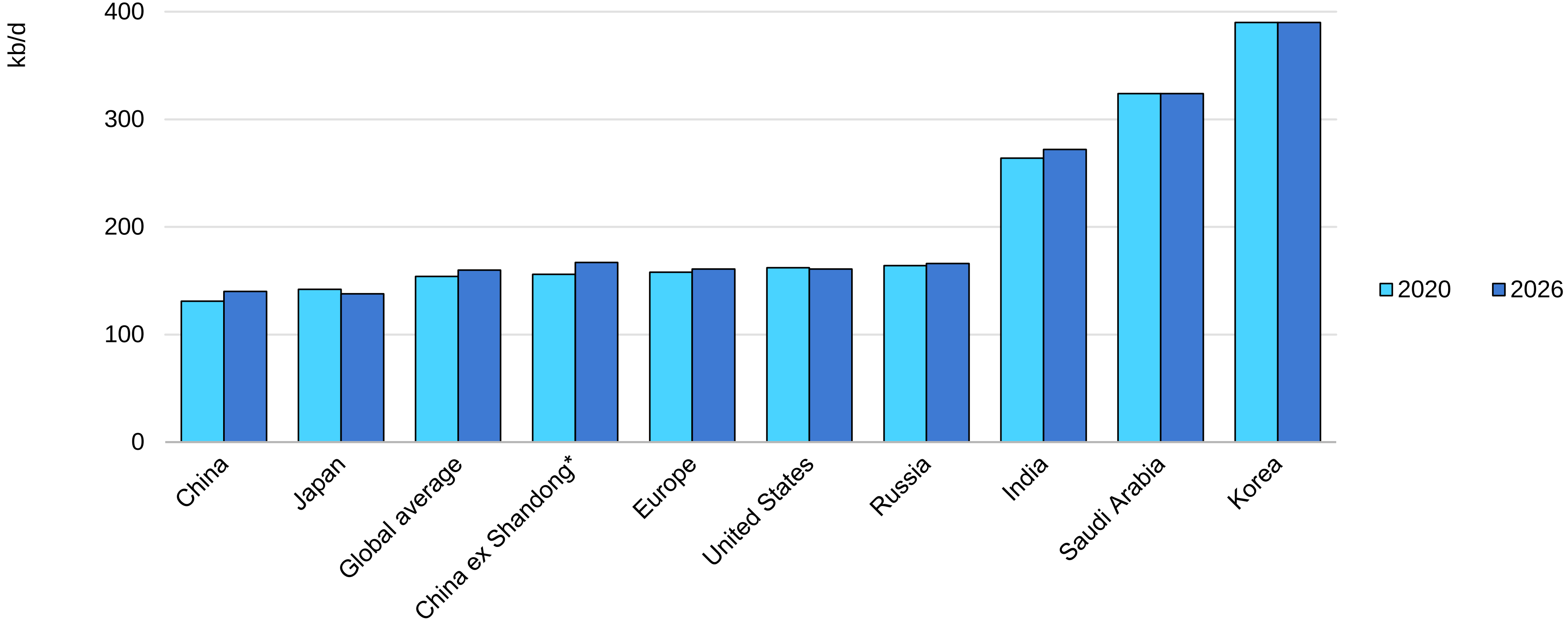
Capacity of 6 mb/d must close to push global refinery utilisation rates back above 80%



Note: 2021-26 forecast includes only refinery closures announced as of February 2021.
Source: Pre-2006 capacity data are from BP World Energy Statistical Review 2020.

Global refinery size set for slight increase but wide disparity between countries, regions

Average refinery size in selected countries and regions



Note: Only primary distillation capacity is included. Refineries with capacity under 20 kb/d are excluded from calculations. China ex Shandong excludes independent refineries located in Shandong province, but includes refineries of state-owned companies.

Implications of supply, demand and the energy transition

IMO 2020 offers traditional refineries one last chance, while light ends supply-demand mismatch creates a new niche for refiners

The modest oil demand growth in 2019-2026, when broken into refined and non-refined components, presents an even grimmer picture for refiners in both the quantitative and qualitative sense. The combined demand for *refinery-supplied* gasoline, kerosene and diesel is forecast to decline by 170 Kb/d from 2019 to 2026, a sharp contrast to the previous seven years, when it increased by 6.2 mb/d. These products usually price at a premium to crude oil and are essentially the backbone of refinery economics.

The forecast growth in very low sulphur bunker fuel (VLSFO) demand, which is gradually replacing high sulphur fuel oil in the marine sector, will provide some relief for refiners. The switch started in 2019 and is expected to be more than halfway complete by 2026. VLSFO is generally priced close to 10 ppm diesel fuel, although some of the premium goes to blenders rather than refiners, given the more challenging blending constraints.

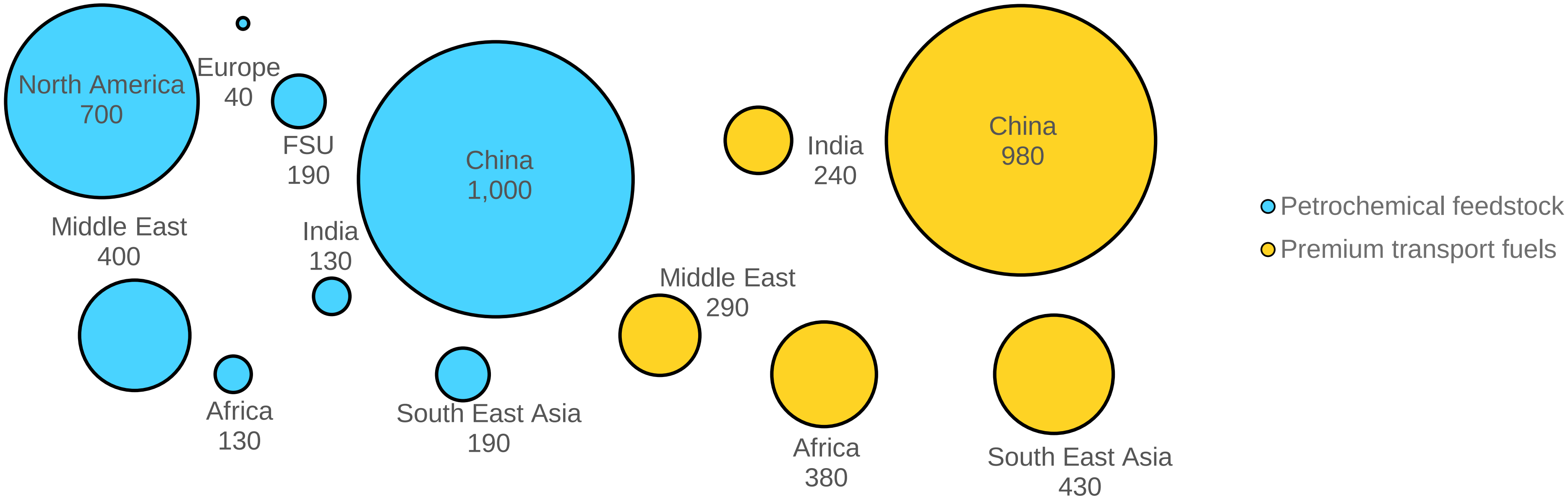
Overall, with the inclusion of VLSFO, premium refined product demand is forecast to grow by 1.8 mb/d, compared to 4.9 mb/d of net capacity additions. For existing refiners to keep their product yields unchanged, new refineries would need to cap yields of premium transport fuels at 30%. For comparison, in 2019, the combined yields of gasoline, kerosene and diesel were 72%. However, even the most petrochemical-oriented refineries still produce at least 40% of fuels, and not all new refineries will be equipped to maximise petrochemical output. Switching yields from gasoline, the most affected transport fuel, to naphtha, a rapidly growing petrochemical feedstock, is relatively easy. The problem is that naphtha usually prices at a discount to crude oil. Petrochemical-integrated refineries, however, can earn significantly higher margins from petrochemical products than from transport fuels.

With a marked slowdown in NGL production expected, there is an opportunity for refiners to increase LPG output. However, a positive LPG margin against crude oil can for now only be achieved by entering into the petrochemical value chain or retail and distribution. This means that the end of traditional refining, i.e. earning margins from producing transport fuels, is getting closer.

The pandemic has effectively offered refiners a sneak peek into the future of sharply lower transport fuel demand. They should use this opportunity to adjust their strategies accordingly. This bears bad news for petrochemical producers, too. Barring higher than expected NGL output, they will have to share some of their margins with refiners to secure feedstock production in refineries. This may completely change cross-product price relationships.

Petrochemical feedstock accounts for two-thirds of oil demand growth in 2019-2026, and has a wider regional base than transport fuels

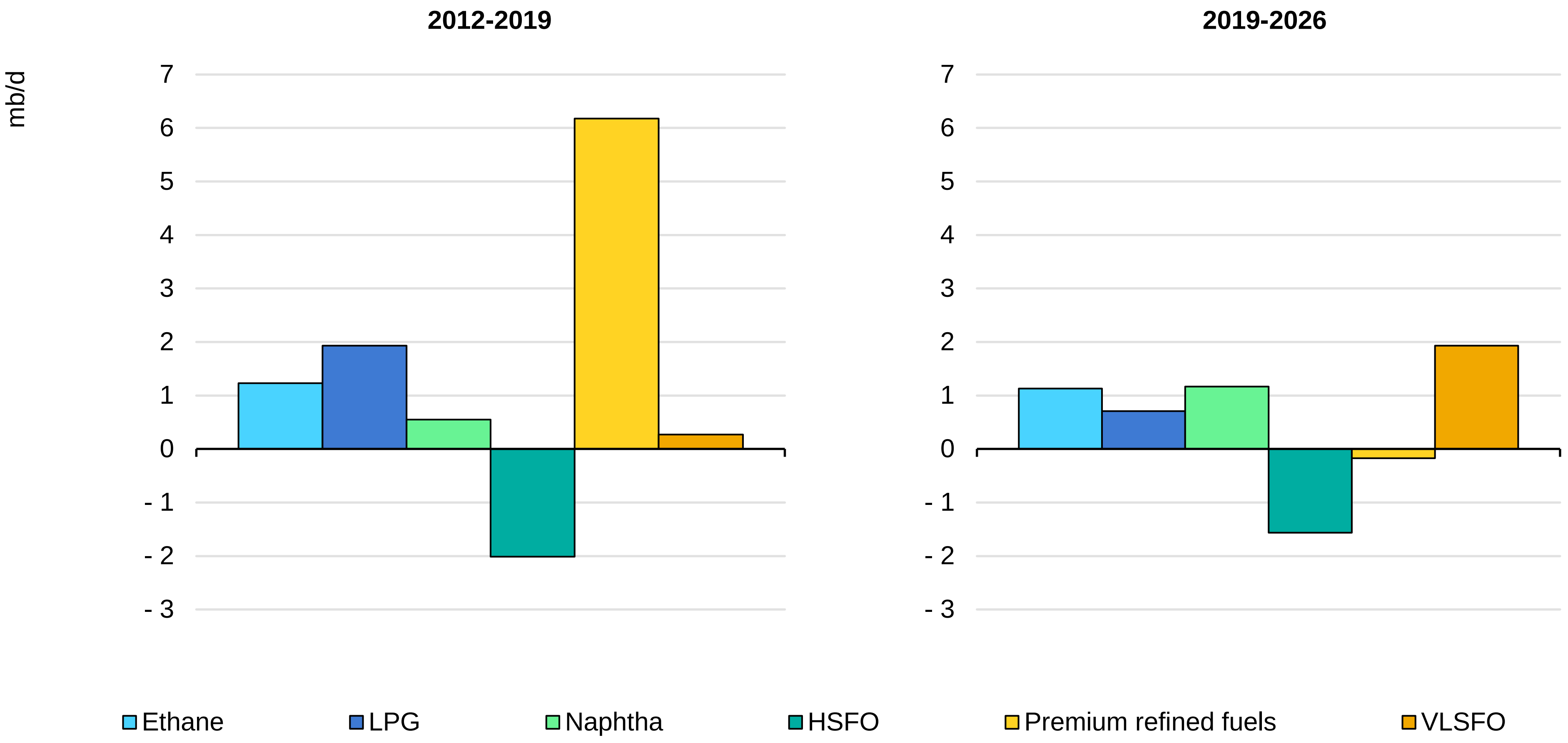
Oil demand growth in 2019-2026 across petrochemicals and premium transport fuel segments by region, kb/d



Notes: Premium transport fuels include gasoline, diesel and kerosene and are net of non-refinery supply (biofuels, CTL/GTL and additives). Transport fuel demand declines in North America, Europe and FSU are not shown. Latin American demand in both categories is relatively unchanged.

Demand for refinery-supplied premium fuels swings from growth in 2012-2019 to a decline in 2019-2026

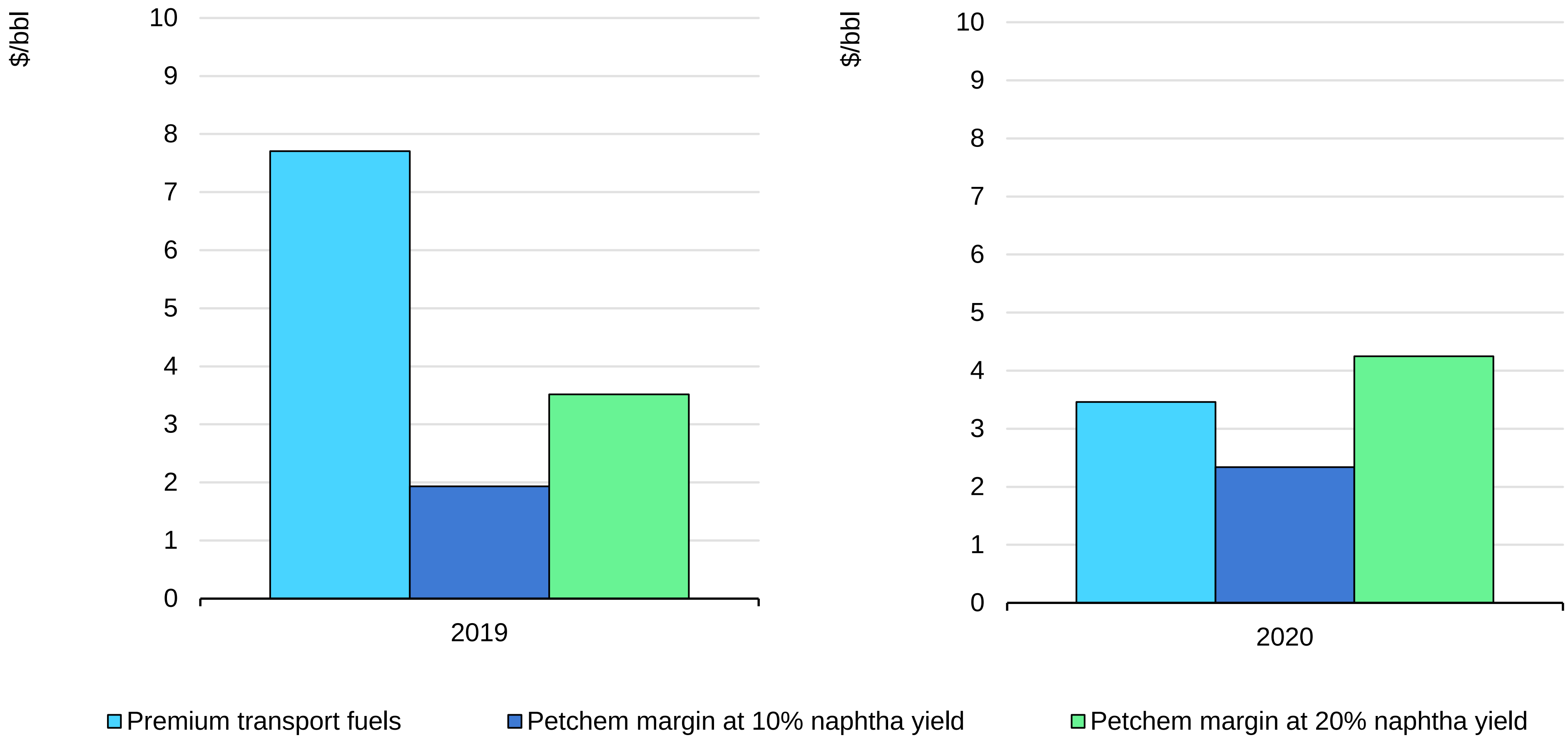
Oil product demand growth, excluding non-oil components



Notes: Premium transport fuels include gasoline, diesel and kerosene and are net of non-refinery supply (biofuels, CTL/GTL and additives). HSFO = high sulphur fuel oil. VLSFO = very low sulphur fuel oil.

Petrochemicals resilient amid Covid-19, price volatility shows benefits of integration

Indicative margins from premium fuels and petrochemicals



Notes: Premium transport fuel margin is calculated as a weighted average of gasoline, diesel, kerosene and 0.5% sulphur marine fuel oil cracks. The yields total 63%. Petrochemical margins are calculated on the basis of an indicative naphtha steam cracker margin in Europe, weighted for 10% and 20% naphtha yields.
Sources: Argus Media, Bloomberg.

Energy transition a challenge for refiners, but renewable diesel, green hydrogen and chemical recycling offer expansion paths

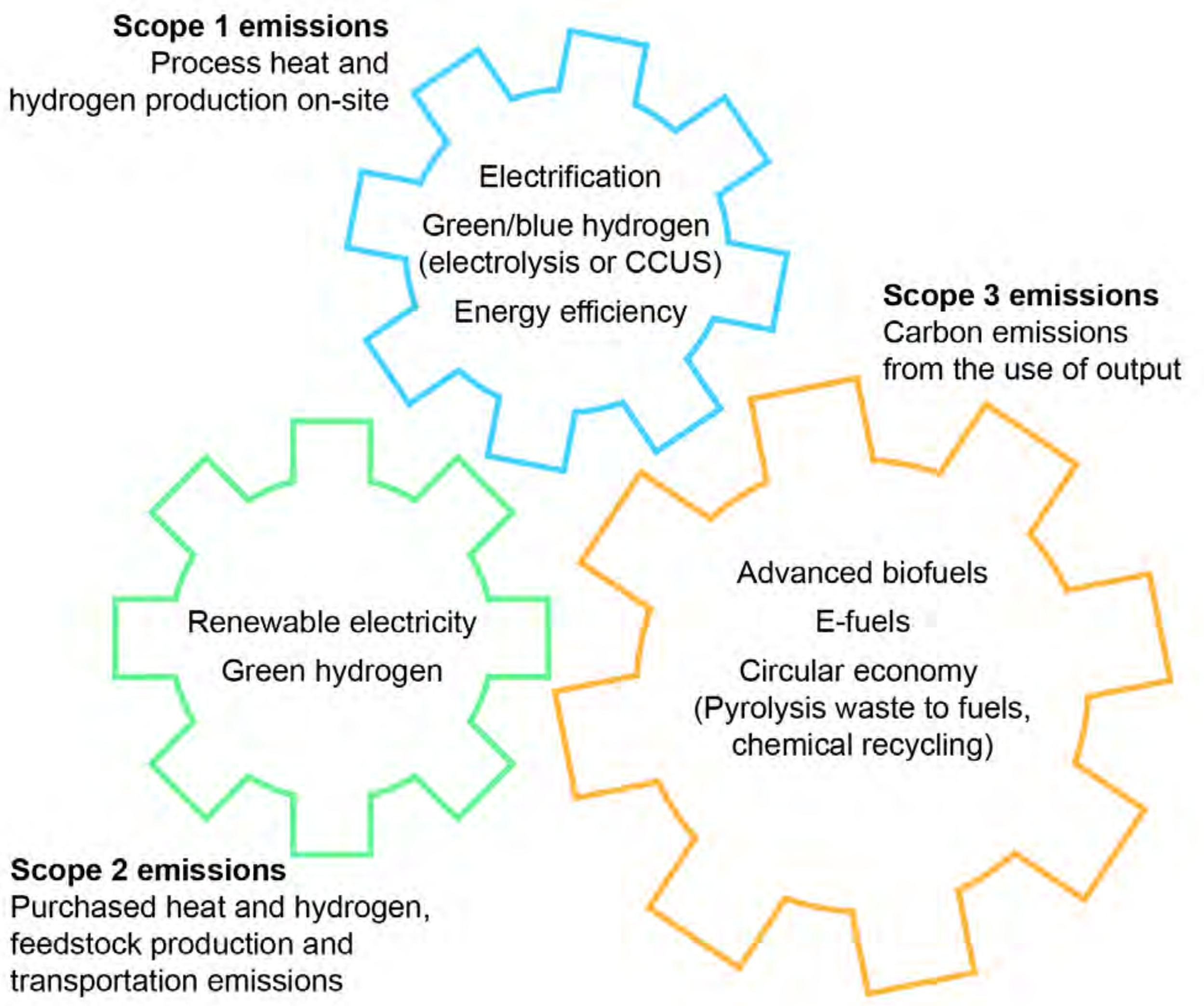
Refining is a significant part of business for many oil companies, and successfully managing the energy transition will be their most important challenge in the coming years. Western majors and Asian oil companies often refine and sell more oil products than their upstream output. Refining is subject to a two-fold impact from decarbonisation. First, the market for traditional refined products shrinks due to substitution by biofuels and other low carbon options. Second, as an energy-intensive industry, refiners face the challenge of reducing the CO_2 intensity of their production activities. Covid-19 exacerbated the already serious overcapacity situation in the industry, likely to result in large wave of capacity closures. For those that will remain onstream, strategic decisions made in the next five years will define their longer-term viability.

Decarbonisation brings challenges, but it also creates opportunities. Petrochemical integration seems to be a popular strategy, but may result in the spillover of refining overcapacity into petrochemical overcapacity. Nevertheless, petrochemical refiners may have an advantage over non-integrated petrochemical players in tackling challenges of decarbonisation. As a complex industrial sector with suitable equipment, highly-skilled workers, researchers and engineers, refiners can develop technologies for chemical recycling, processing of plastic waste and waste oil along plastics-to-plastics or plastics-to-fuel paths.

Another strategic pathway is the integration of the biofuels value chain. Previously, the role of oil companies was generally limited to trading and blending of biofuels, benefitting from logistical synergies and retail networks. Now, they are moving into the production of advanced biofuels. Production of hydrotreated vegetable oil (HVO) is a natural fit for refining activities, as it involves processing renewable feedstock into diesel and other products (LPG, naphtha and sustainable aviation fuel). Some 345 kb/d of refining capacity has already been converted to bio-refineries and there are plans for 840 kb/d more. These figures do not include co-processing of renewable feedstock in conventional refinery units together with oil.

Refining is an energy-intensive industry, requiring steam, heat and electricity, sourced predominantly from hydrocarbons. It is also the largest hydrogen-consuming sector, deriving it almost entirely from oil (naphtha reforming) or natural gas (steam reforming). Several projects for blue hydrogen (natural gas-based hydrogen production with carbon capture and storage) and green hydrogen (from electrolysis) are currently at development or construction stages. By 2026, 200 MW of electrolysis projects, associated with refineries, are expected to come online in Europe, producing some 14 kt per year of green hydrogen. Another 1100 MW worth of projects have not reached FID stage yet, but may come online in the same timeframe if favourable policies are adopted. .

Decarbonisation a challenge, but pathways are compatible with refiners' industrial activities



Regional developments

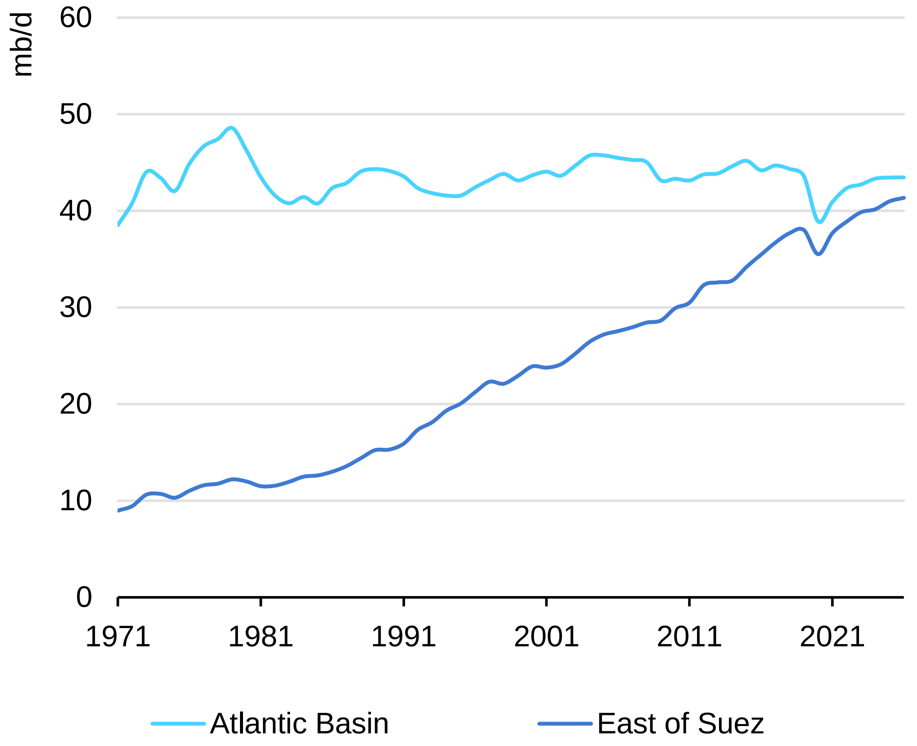
East of Suez drives increase in global refining throughput

Atlantic Basin refining activity fell to its lowest in 50 years in 2020 following the unprecedented decline in demand. In our forecast, throughput recovers partially, staying below 2019 levels in 2026. Total oil demand, net of biofuels and other non-oil components, declines in the region by 600 kb/d, while demand for refined products falls by 1.4 mb/d. In the forecast period, net additions amount to 480 kb/d, similar to 2012-19 increase of 450 kb/d, coming from African and North American projects (Nigeria, Mexico and the United States) and shutdowns announced as of early 2021. This will further intensify competition in the refining industry and is very likely to result in additional capacity closures.

Meanwhile, activity continues to expand East of Suez, driven by the downstream ambitions of the Middle East national oil companies and Chinese and Indian demand growth. Effectively, all the demand growth for refined products occurs East of Suez, but it still lags net capacity growth. This means that overcapacity issues will not be confined to the Atlantic Basin.

Perhaps epitomising the contrasting trends between the Atlantic Basin and East of Suez refining sectors, the gap between the world's top two refining countries, the United States and China, continues to shrink. In 2026 it will narrow to just 660 kb/d from 3.6 mb/d in 2019.

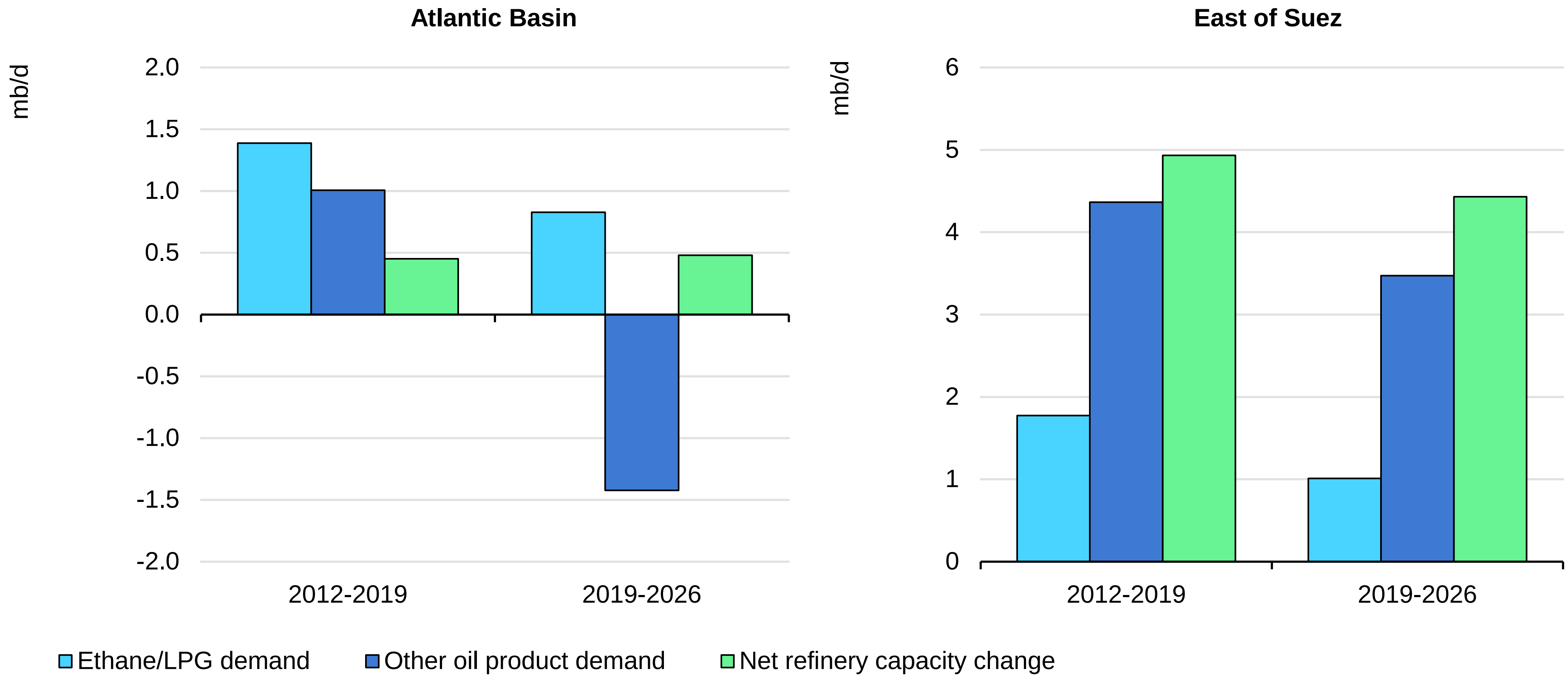
Refinery throughputs



Notes: Atlantic Basin includes Americas, Europe, FSU, North and West Africa. East of Suez includes Asia, the Middle East and South and East Africa.

East of Suez refiners better shielded from the demand slowdown and capacity overhang, but competition is intensifying there, too

Demand and refinery capacity changes



Note: Non-oil components (biofuels, CTL/GTL/additives) are netted off demand. Refinery capacity changes include only permanent closures announced as of February 2021.

No more tailwinds for US refiners: falling domestic demand, shrinking export markets in Mexico and Latin America, and narrowing feedstock cost advantages reverse growth trend

The United States remains nominally the largest oil refiner in our forecast, even as its lead over China contracts considerably and throughputs only recover to 2014 levels by 2022. The refining boom of recent years that culminated in historical peak run rates in 2018 is largely thought to be fuelled by domestic and Canadian oil supply growth, helping to provide discounted feedstock to refiners relative to international markets. However, two important factors were also present: new export markets and a strong recovery in domestic demand.

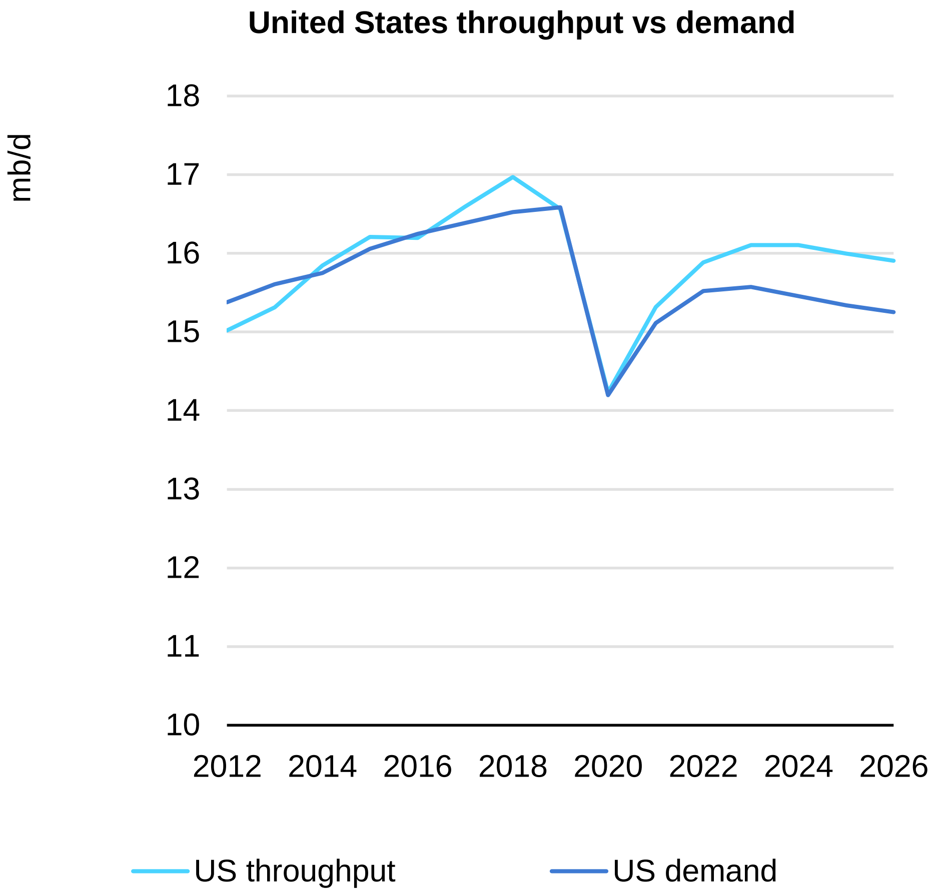
Refining activity in Mexico and Latin America declined in recent years due to operational issues, creating export markets for US refiners. Most crucially, US demand increased over the last decade, recovering from the financial crisis of 2007-08. Between 2012 and 2019 US refinery throughputs increased by 1.5 mb/d as demand for refined products (excluding biofuels, LPG and ethane), rose by 1.2 mb/d.

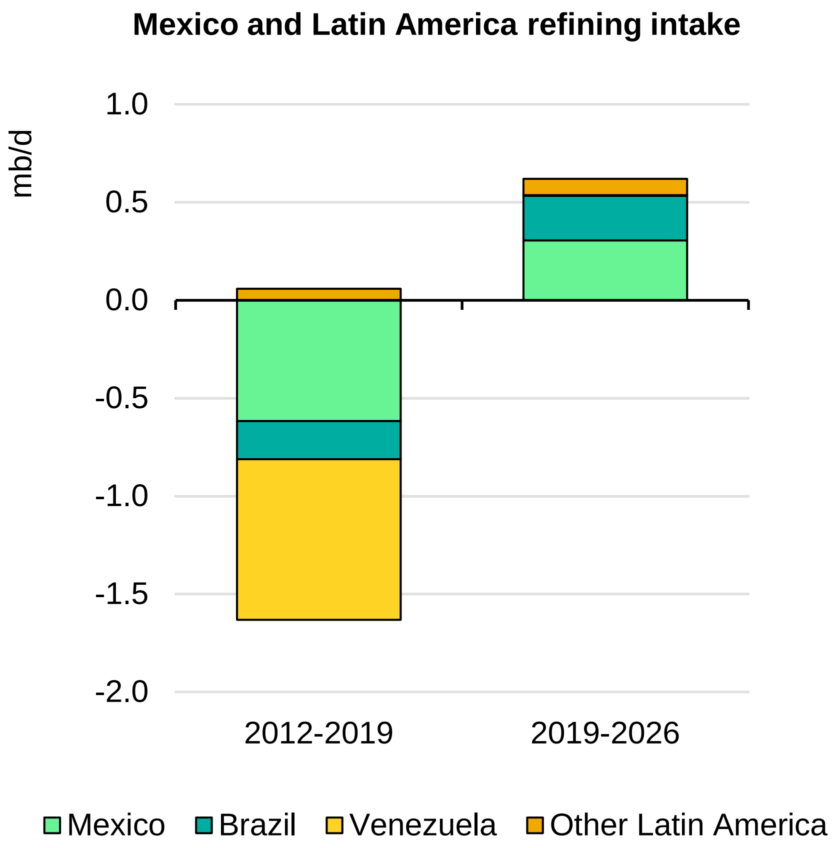
While US and Canadian crude production is expected to recover to 2019 levels by the end of our forecast period from the declines last year, the feedstock advantage for the export-oriented refiners in the US Gulf Coast is likely to erode with higher crude oil exports and pipeline constraints due to delays and cancellations of new projects. Demand for refined products is set to fall by 1.3 mb/d, leading refinery runs lower by 660 kb/d. The close correlation of US refining activity with domestic demand was well illustrated in 2020. While the United States accounts for 20% of global throughput, declines in 2020 accounted for 30% of the global total, as the share of private sector road fuel consumption in domestic demand is higher than in any other large consuming country. Gasoline demand will only partly recover from the fall in 2020 and is set to decline again from 2024 onward. Confirmed refinery shutdowns since early 2020 reached 790 kb/d as of February 2021, and more are likely to be announced over the next months and years. Nevertheless, ExxonMobil's 250 kb/d expansion at its Beaumont refinery is going ahead according to local reports.

Mexican and Latin American throughput is set to reverse declines of recent years and increase by around 300 kb/d each, adding to the pressure faced by the US refiners. The Mexican government is going ahead with the 340 kb/d Dos Bocas plant and repairs at several other refineries. Nevertheless, our forecast for runs at 900 kb/d in 2026 is lower than official government targets. In Latin America, the gains come mostly from higher utilisation rates in Brazil and the restart of a 200 kb/d train at the US Virgin Islands refinery, formerly a 500 kb/d plant that was closed in 2012. In Brazil, Petrobras has started a massive refinery divestment programme, aiming to sell half of its 2.2 mb/d assets.

US refinery runs set to fall due to domestic demand decline. Mexico, Latin America recover

Western Hemisphere refining developments





Note: US demand calculation excludes biofuels, additives, ethane and LPG.

Europe gears up for streamlined, greener operations, Russia stays on conventional path

Europe is often seen as the most vulnerable refining region due to its high dependence on feedstock imports, an unbalanced product demand barrel, which requires middle distillate imports and gasoline and other product exports, as well as the longer-term demand decline due to some of the world's most stringent decarbonisation policies. The latter also have an impact on refinery economics through carbon taxation and restrictions on operational emissions.

European refining has certainly fallen from the peak rates seen in the early 2000s. Lower oil prices since 2014 helped stabilise activity levels. Growing demand over the same period did not result in higher refinery runs, increasing instead product imports.

With new capacity coming online in the Atlantic Basin, notably in Mexico and Nigeria, European refiners will find themselves in an increasingly competitive market. Over the next six years, the downward demand trend returns. We forecast refinery runs falling 950 kb/d from the 2019 level, paralleling the decline in refined products demand. The change in product balances towards higher net imports mostly occurs through reduced exports of gasoline and fuel oil, as middle distillate imports decline, with higher yields and lower demand.

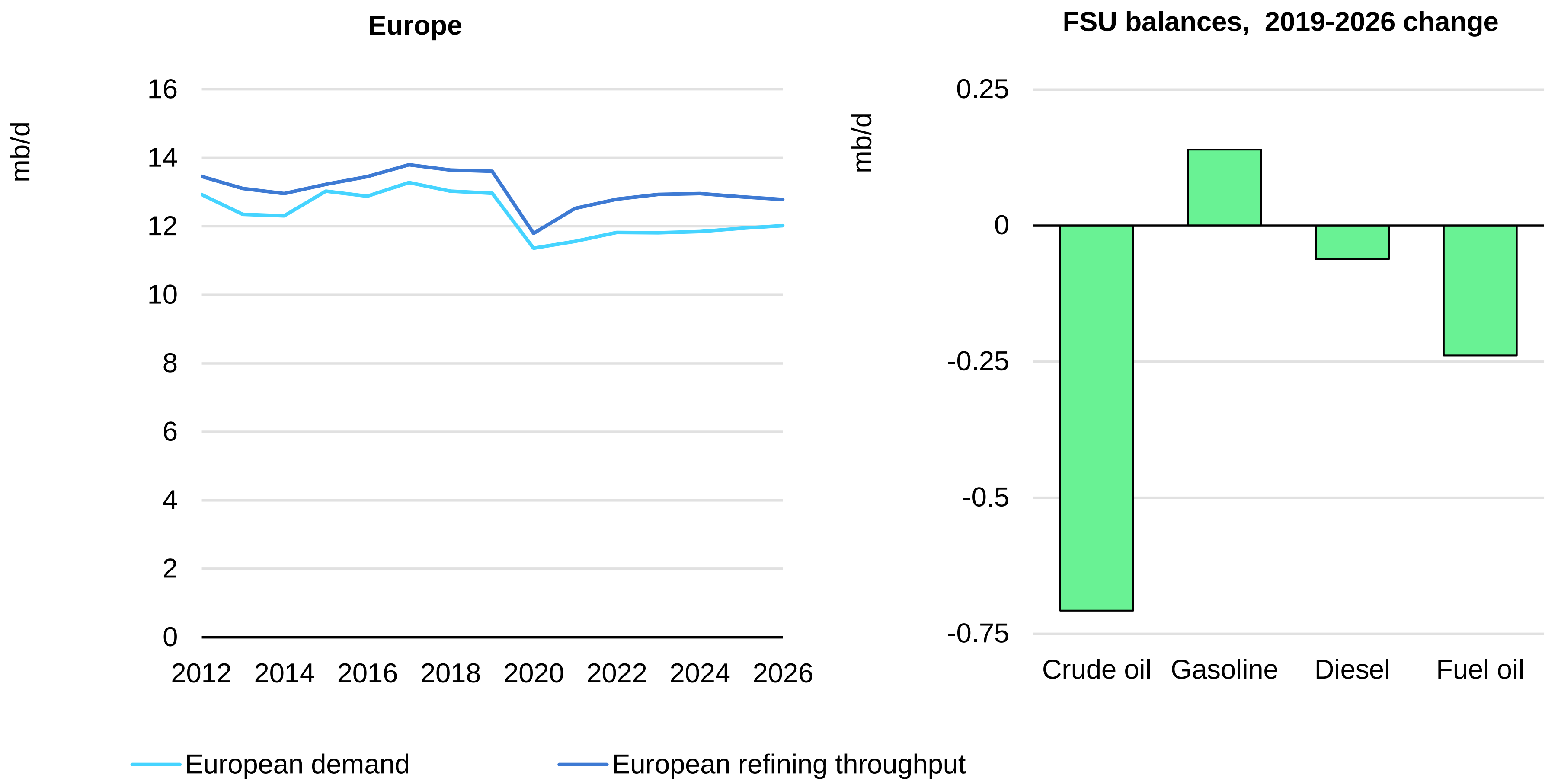
Some 2.6 mb/d of refining capacity was closed in Europe between 2007 and 2016. Since the start of the Covid-19 pandemic 640 kb/d has been slated for shutdown, with more rationalisation likely to follow in the coming years. Refineries located in industrial hubs with potential for integration with chemical and green hydrogen production will be more resilient than traditional fuel-oriented refiners located in areas that can easily be supplied from international product markets.

While optimising and rationalising capacity, European refiners are leading in the field of green hydrogen, with several electrolysis projects at various stages of completion. They are also increasingly opting out of conventional upgrading unit investments and into renewable fuels production through co-processing and refinery conversions. Several circular economy projects, using mainly pyrolysis technology, are at planning or demonstration stages, aimed at converting municipal or plastics waste into fuels.

Russia and other Former Soviet Union countries will see slight declines in refining activity, while demand for refined products grows modestly. With crude and condensate production set to stagnate, it is expected that preference will be given to exports of crude oil rather than products, in particular as the main product outlets in the Atlantic Basin will shrink due to declining demand.

Slowdown in European demand hits European, FSU refiners

Refining developments in Europe and the FSU



Note: Europe includes OECD and non-OECD Europe.

Middle East remains traditional refining stronghold, Africa to start reclaiming market share

Middle Eastern NOCs remain committed to building out conventional downstream portfolios. While western majors plan refinery divestments and increasingly include biofuels processing, renewable electricity and hydrogen into their downstream portfolios, and Asian refiners have been focused on petrochemical integration, Middle Eastern NOCs are focusing on increasing their physical assets, in large part to underpin their new and expanding global trading operations. Historically, the producer countries focused on crude oil output, missing out on margins from the fuel and petrochemical value chain and not benefitting from counter−cyclicality of downstream earnings. The strategy shift in recent years is aimed at controlling and capturing more profits across the value chain.

In our forecast horizon, the region's refiners will largely conclude major refinery projects in what is likely to be the last bout of capacity expansion anywhere in the world. Only a fifth of the 1.8 mb/d net capacity additions will be required to meet the growing oil demand in the region, with the rest destined for product exports. The Middle East will thus overtake Russia as the largest net exporter of refined products. Coincidentally, it will also retake its position as the largest net exporter of NGLs from the United States.

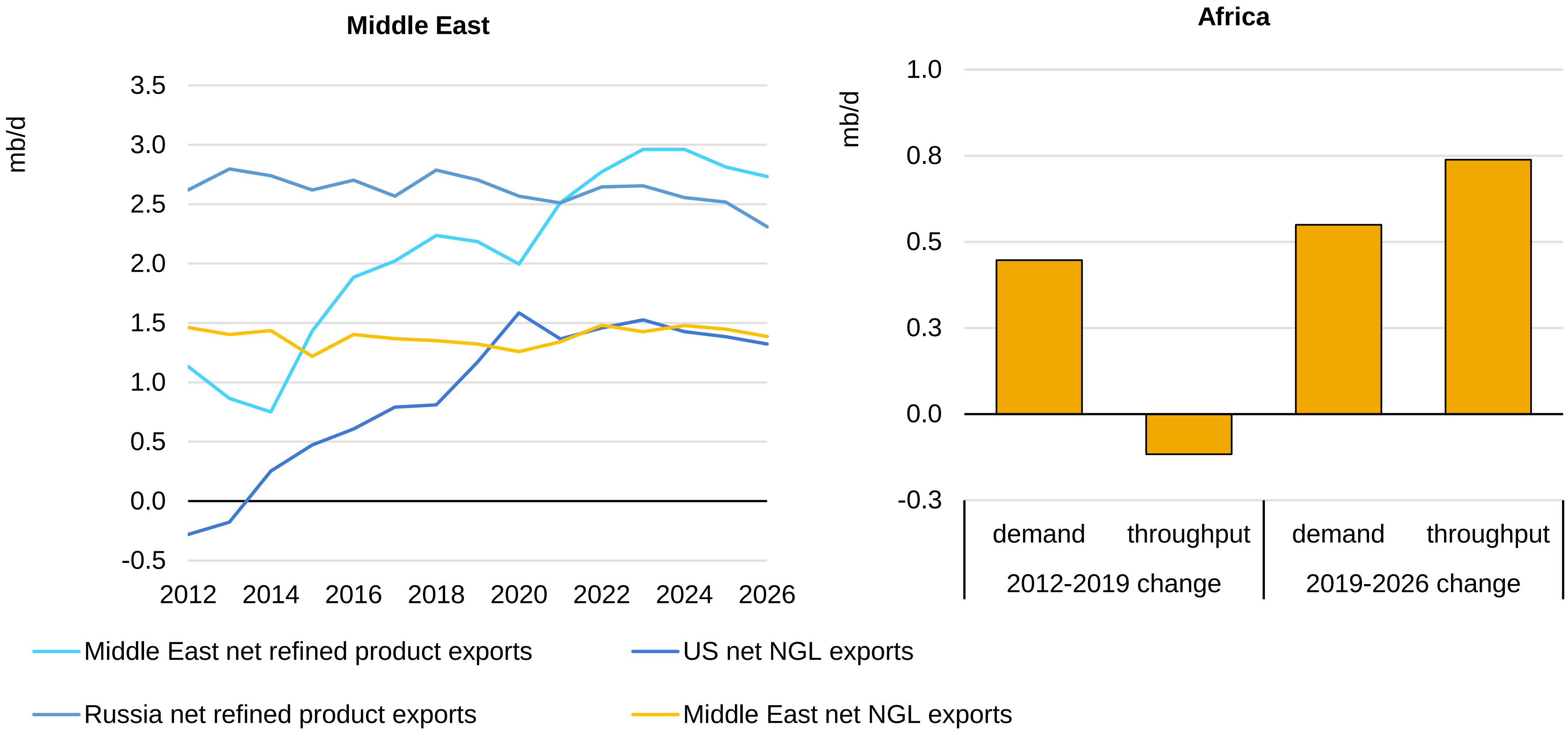
African refiners missed out in the past decade's oil demand growth. The world's second-most populous continent, Africa has become a major oil product import market, especially the sub-Saharan region. The start-up of the 650 kb/d refinery in Lekki, Nigeria, expected in the next three years, will mark a turning point in the continent's refining fortunes. At the same time, the plans to repair and re-launch the country's three existing refineries that have not been operating in the recent years, are unlikely to materialise.

In general, smaller refineries might be better suited for Africa, where investors and operators are constrained in terms of cash flows and working capital. In addition to this, per capita consumption remains at very low levels, and underdeveloped road and storage infrastructure complicates product distribution over a larger area. There has been a flurry of small African refining projects just as shutdown announcements of European and American refining assets started rolling in. Meanwhile, we have pushed back Uganda's first refinery start-up date, due to a setback in crude production plans, now unlikely to commence within our forecast horizon.

A 100 kb/d new refinery is expected to come online in Algeria, while Egypt is upgrading its secondary capacity. South Africa may see refinery shutdowns due to aging assets and worsening refinery economics.

Middle East becomes the largest refined product exporter, African runs catch up with demand

Middle East and African developments



China benefits from petrochemical expansion, robust growth in transport fuels

China's petrochemical producers, as opposed to traditional refiners, will have launched 2 mb/d of refining capacity between 2019 and 2024, accounting for 40% of global net capacity additions and 90% of Chinese capacity increases over the same period. New projects by oil refining companies in China also tend to be petrochemical-oriented, with product yields adjusted towards olefins and aromatics. The objective is to replace imports of petrochemical base materials, which is likely to be achieved in the second half of this decade.

However, even the most specialised refineries will still produce 30-40% of transport and other fuels in their yield slate. The expansion of petrochemical base material production thus is resulting in a growing surplus of fuels, but external trade is not yet deregulated. Domestic product prices are regulated, and exports are subject to a quota system operated by the Ministry of Commerce, which has started including private sector refiners in quota allocations.

Oil consumption by the Chinese petrochemical industry grows by 1 mb/d through 2026 and is the single largest component of global oil demand growth. But the country's transport fuel demand growth, at 980 kb/d, is also impressive in the current landscape, even if it has markedly slowed from the recent past.

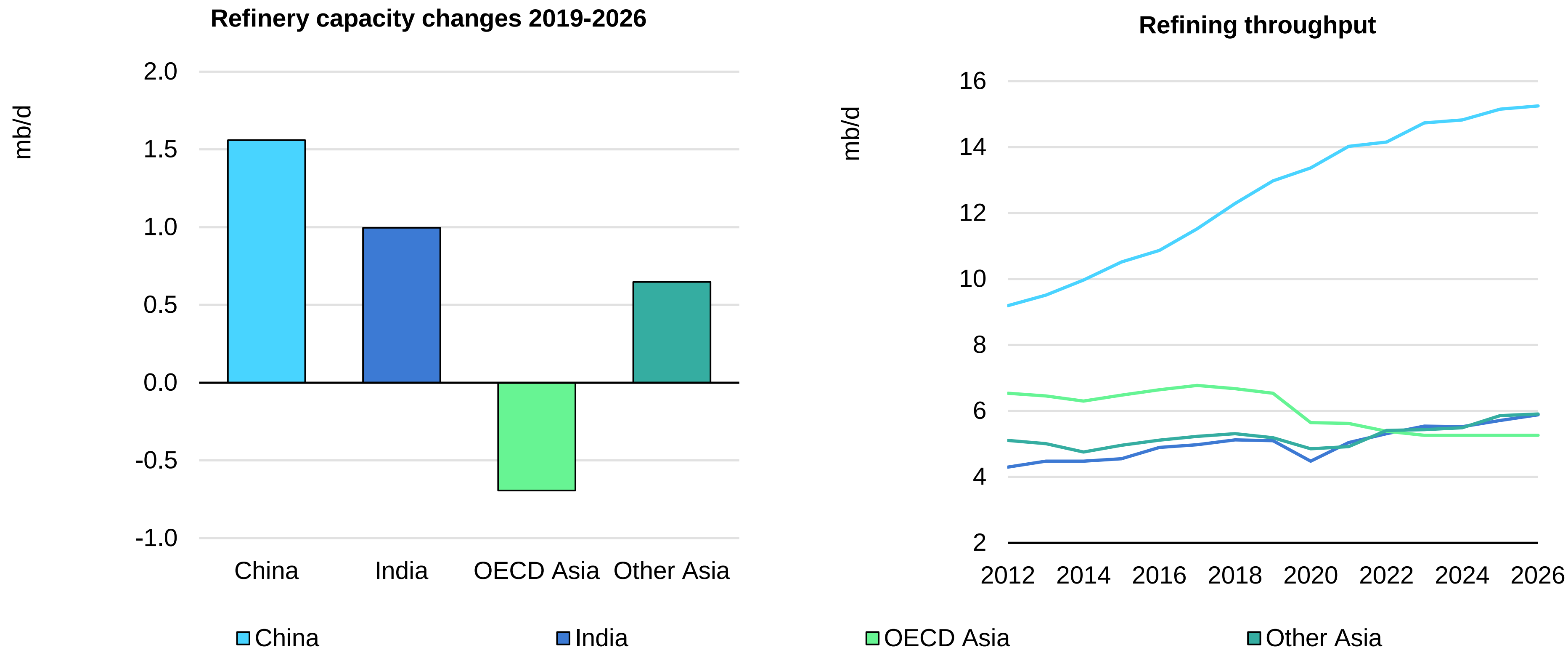
With refinery runs forecast to increase by 2.3 mb/d between 2019 and 2026, Chinese net product surplus will increase by 210 kb/d. This will come both on the account of lower imports for petrochemical feedstocks (primarily naphtha), and higher product exports (primarily diesel).

Indian refining capacity additions accelerate compared to recent years, with 1 mb/d expected to come online by 2026, which is double the forecast growth for refined products demand. India overtakes Russia, becoming the third largest refining country. Diesel and gasoline exports are thus expected to increase again, after having declined in recent years.

Another 850 kb/d of capacity additions are expected in the rest of Asia, primarily in the South East Asian region. The largest addition is a 280 kb/d expansion project in Brunei at a refinery owned by Hengyi, a Chinese chemical fibre conglomerate. At the same time, about 890 kb/d of refining capacity is slated for closure in OECD Asia and Singapore. Australia accounts for a third of this as all but one of the country's refineries are expected to close permanently.

Strong domestic demand drives China, India refinery activity, but higher exports cap growth elsewhere in region

Refining developments in Asia



Note. Refinery capacity changes include only planned shutdowns.

Crude and products trade

Final destination: Asia

It will take record levels of Middle Eastern and Atlantic Basin crude oil exports to satisfy Asia's surging appetite. Asian oil imports are expected to recover from the 2020 decline and continue to grow at the pre-pandemic pace. Declining local output and growing demand drive crude oil imports to 26.6 mb/d, up 3.5 mb/d from 2019. Asia's net oil dependence increases to 82% from 77% in 2019. Australia and New Zealand become the only two net crude oil exporters in Asia as their domestic refining activity dwindles.

Middle East crude oil export availabilities are expected to reach 20.2 mb/d in 2026, which, while a new record level, will not be sufficient to fill the gap in Asian supply. The net call on the Atlantic Basin increases to 6.6 mb/d over the period, met by record levels of crude output that exceeds the 50 mb/d mark for the first time.

While several Middle Eastern producers increase crude oil exports, notably the UAE and Saudi Arabia, OPEC+ as a whole sees its crude oil exports fall slightly from 2019. Incremental supplies to the global markets come from outside the group, led by Brazil, Guyana, Norway and Canada. The United States also contributes to the interregional oil trade with growth in seaborne exports.

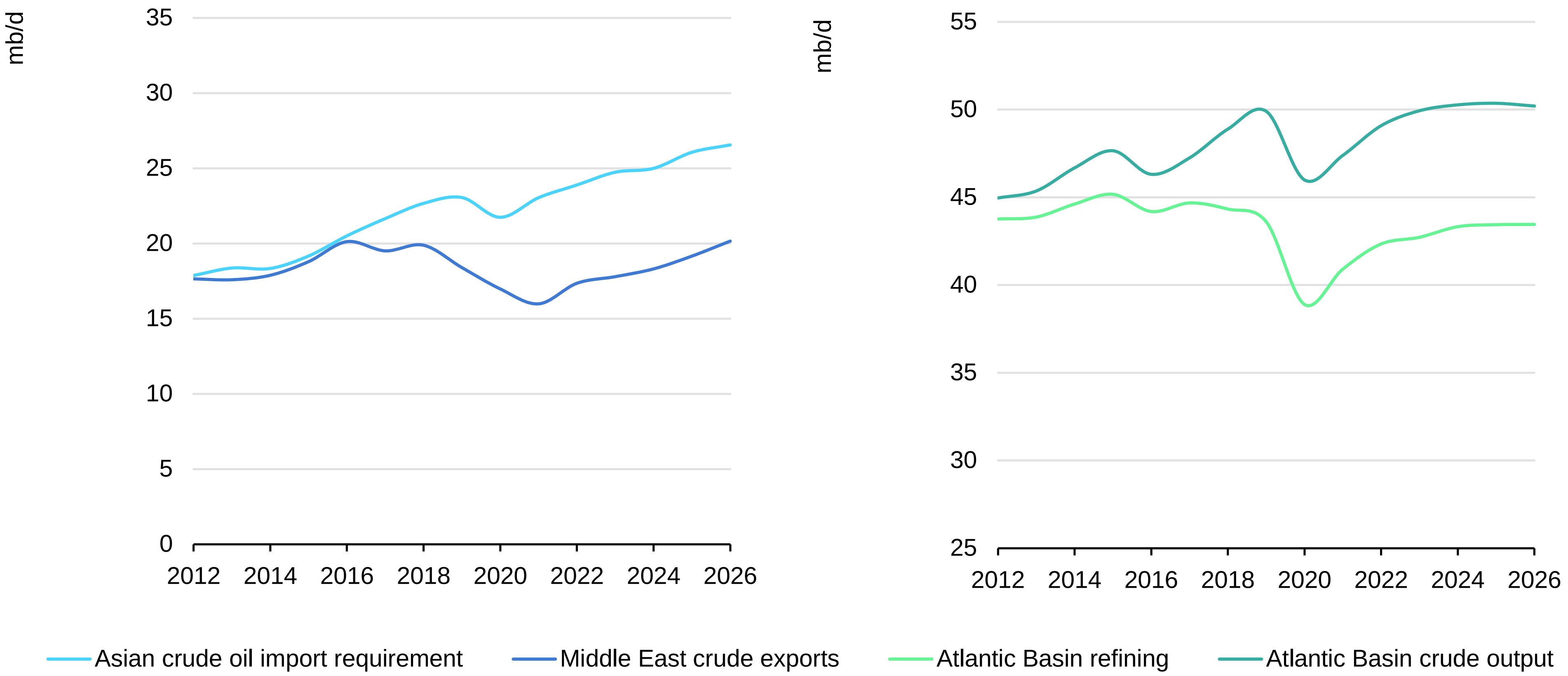
The US seaborne trade balance (i.e. excluding Canadian imports) was positive across all categories in 2020 (crude oil, NGLs and refined products) for the first time and is expected to remain so even as demand recovers from the 2020 declines. Net oil exports from the US Gulf Coast reached 4.5 mb/d in 2020, the third largest volume after Saudi Arabia and Russia. These included 1.5 mb/d of net crude oil exports. Taking into account imports into the East and West coasts, US total net seaborne exports were 2.9 mb/d in 2020, including 530 kb/d of crude oil.

In the Atlantic Basin, product markets undergo noticeable changes, with European refined product imports forecast to increase due to lower refining activity while product imports into West Africa and Latin America decline. Africa finally loses the title of the largest product importing continent to a group of four Asian economies located at or south of the Equator: Singapore, Indonesia, Australia and New Zealand see their combined refined product imports surge from 1.6 mb/d in 2019 to 2.4 mb/d in 2026, well past any other region.

Nevertheless, overall refined product trade flows are expected to start declining in the final years of our forecast period, while NGL product trade (LPG/ethane) continues to expand. Crude oil movements will see a rapid expansion in the forecast period. This, combined with longer average distances for Asian imports, will boost oil on water volumes to new record levels.

Atlantic Basin crude supply hits record 50 mb/d; the gap East of Suez rises to 6.6 mb/d

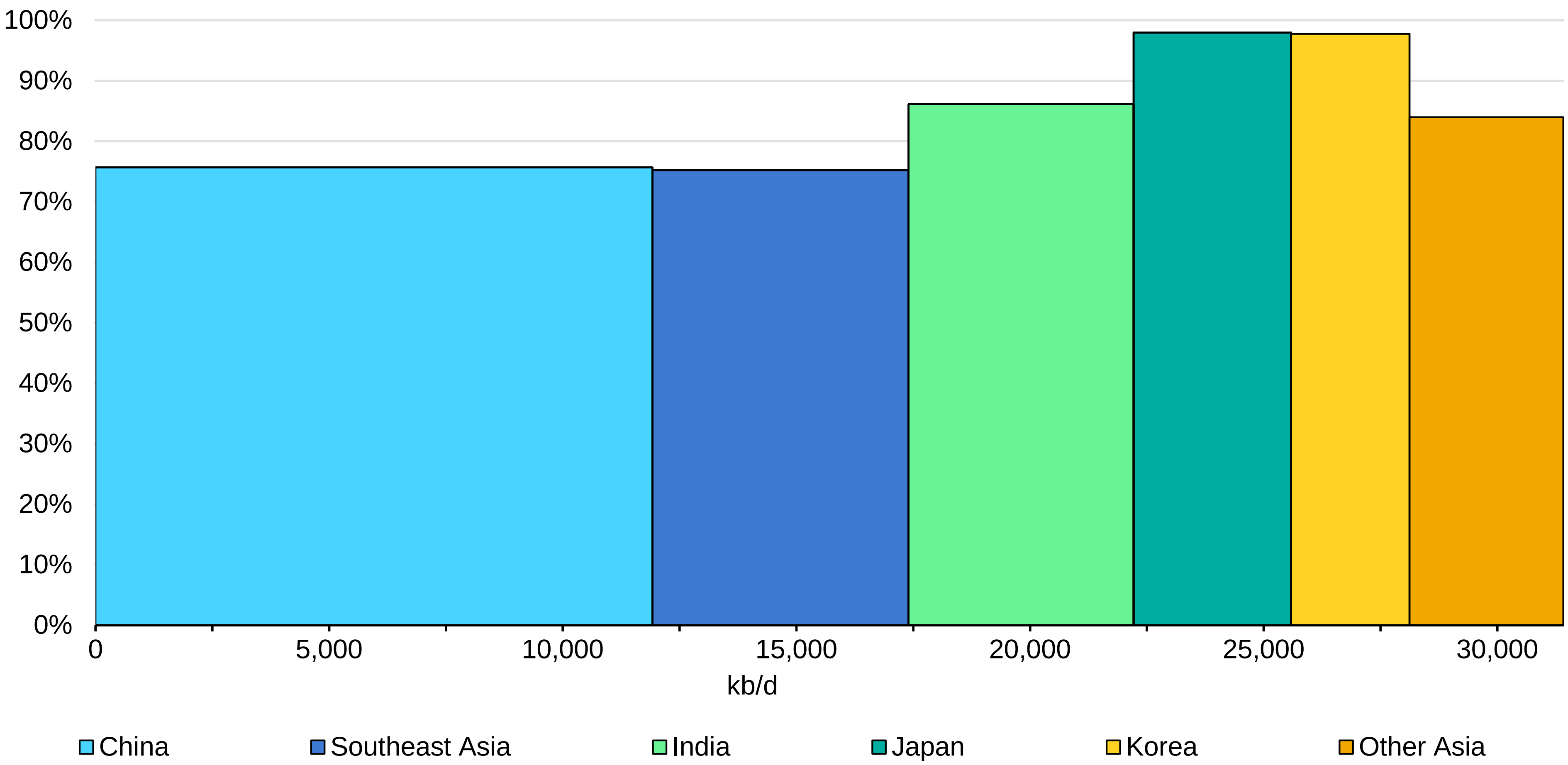
Atlantic Basin and East of Suez crude oil fundamentals



Notes: Crude production includes condensate. Atlantic Basin includes Americas, Europe, FSU, North and West Africa. East of Suez includes Asia, the Middle East, and South and East Africa.

Asia oil import dependence rises to 82% in 2026

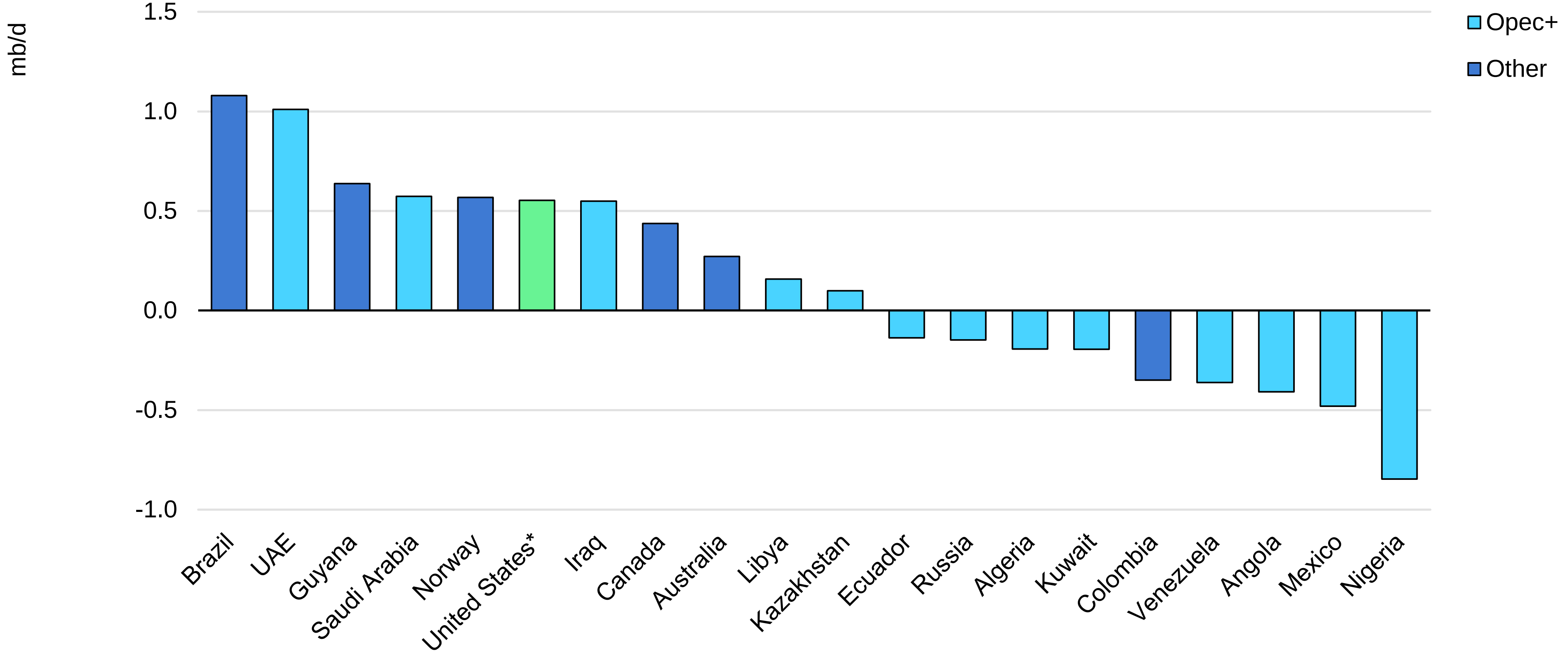
Ratio of net oil imports to oil demand



Notes: Southeast Asia includes ASEAN countries.

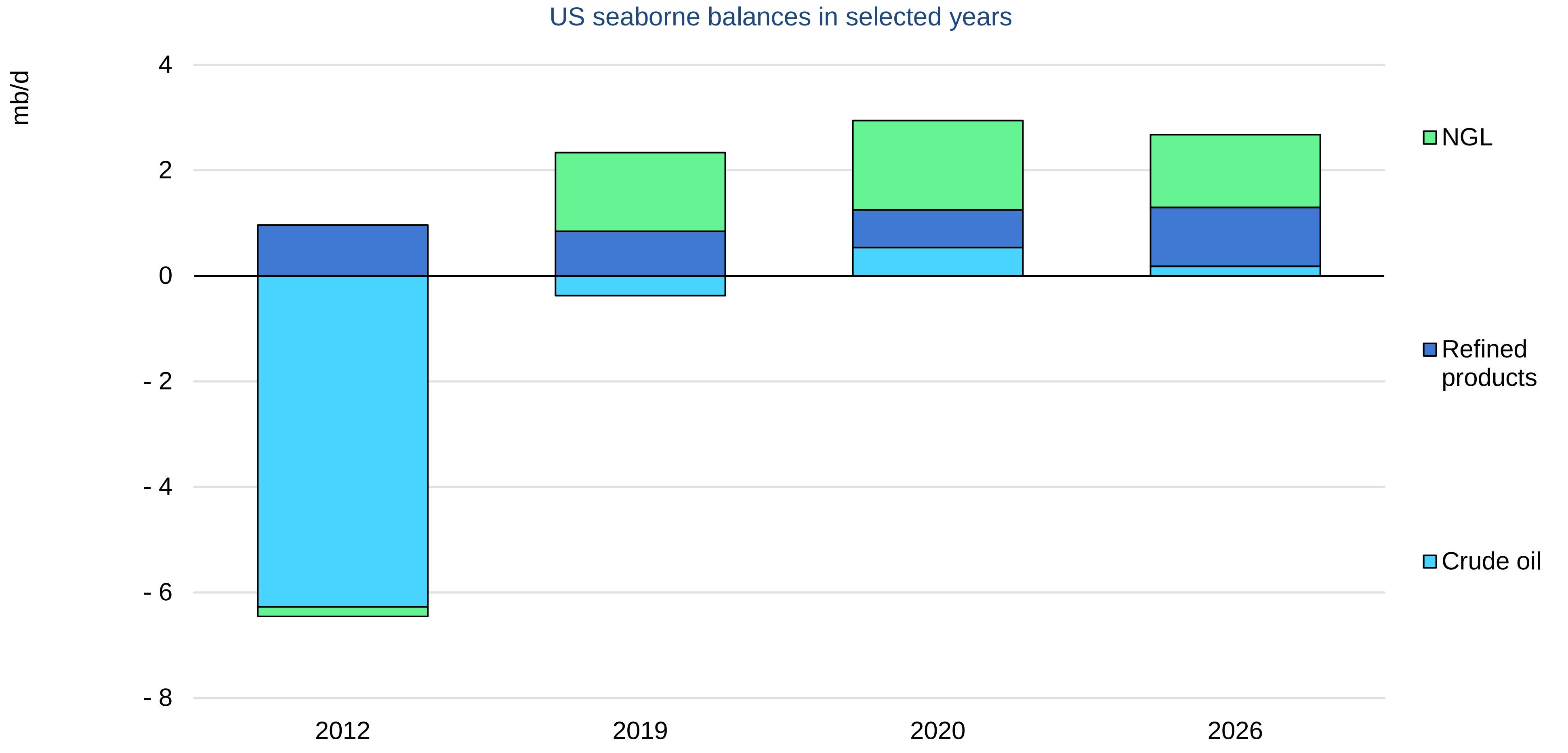
UAE, Saudi, Iraq ramp up crude oil exports, but most other OPEC+ see decline

Changes in net crude oil exports, 2026 vs 2019



Notes. Includes only changes over 100 kb/d in either direction. Australia turns from a net importer to a net exporter. *US change in net seaborne crude exports.

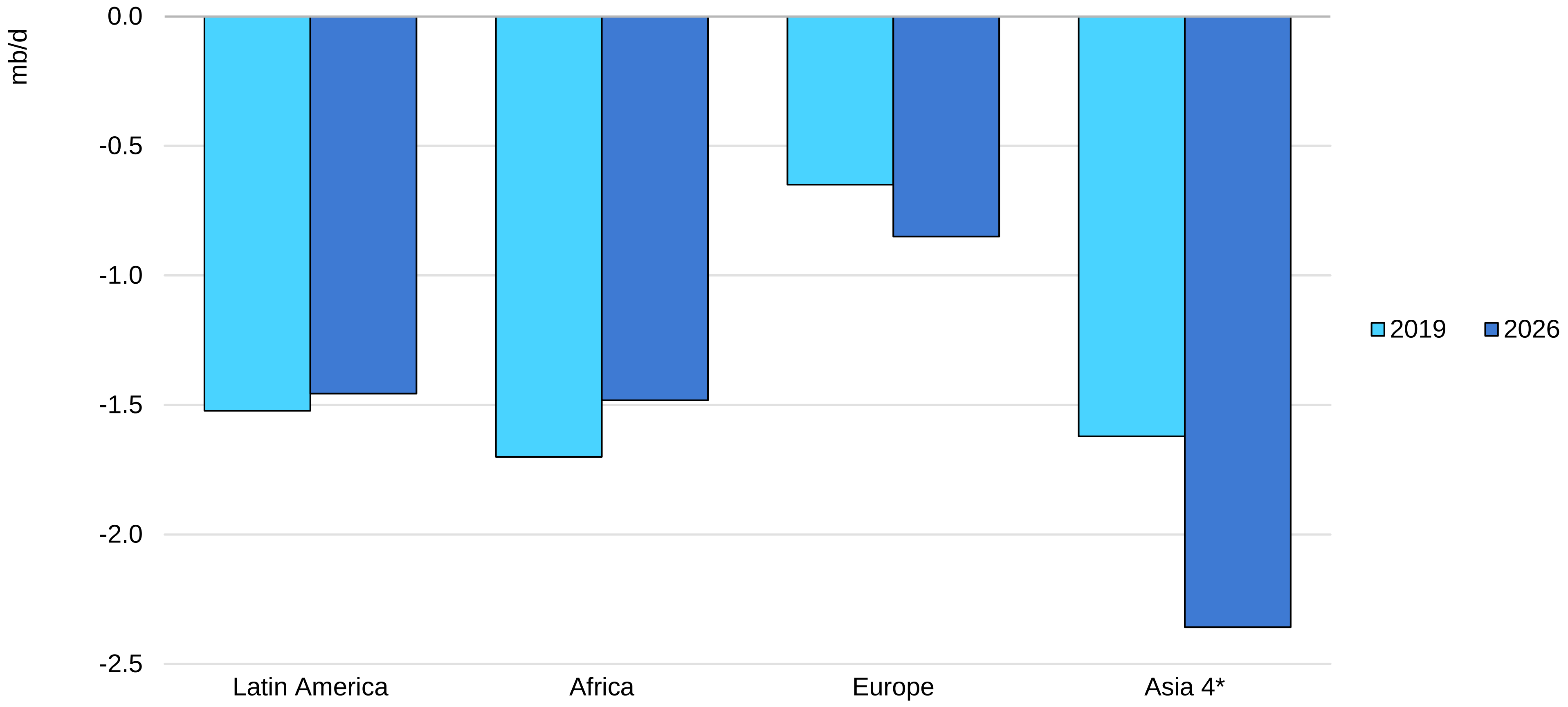
United States solidifies position as a net seaborne oil exporter, helped by Canadian overland flows



Notes: 2012 data is based on EIA. 2019 and 2020 data are based on Kpler. 2026 is forecast.

The centre of gravity for products trade shifts to Asia

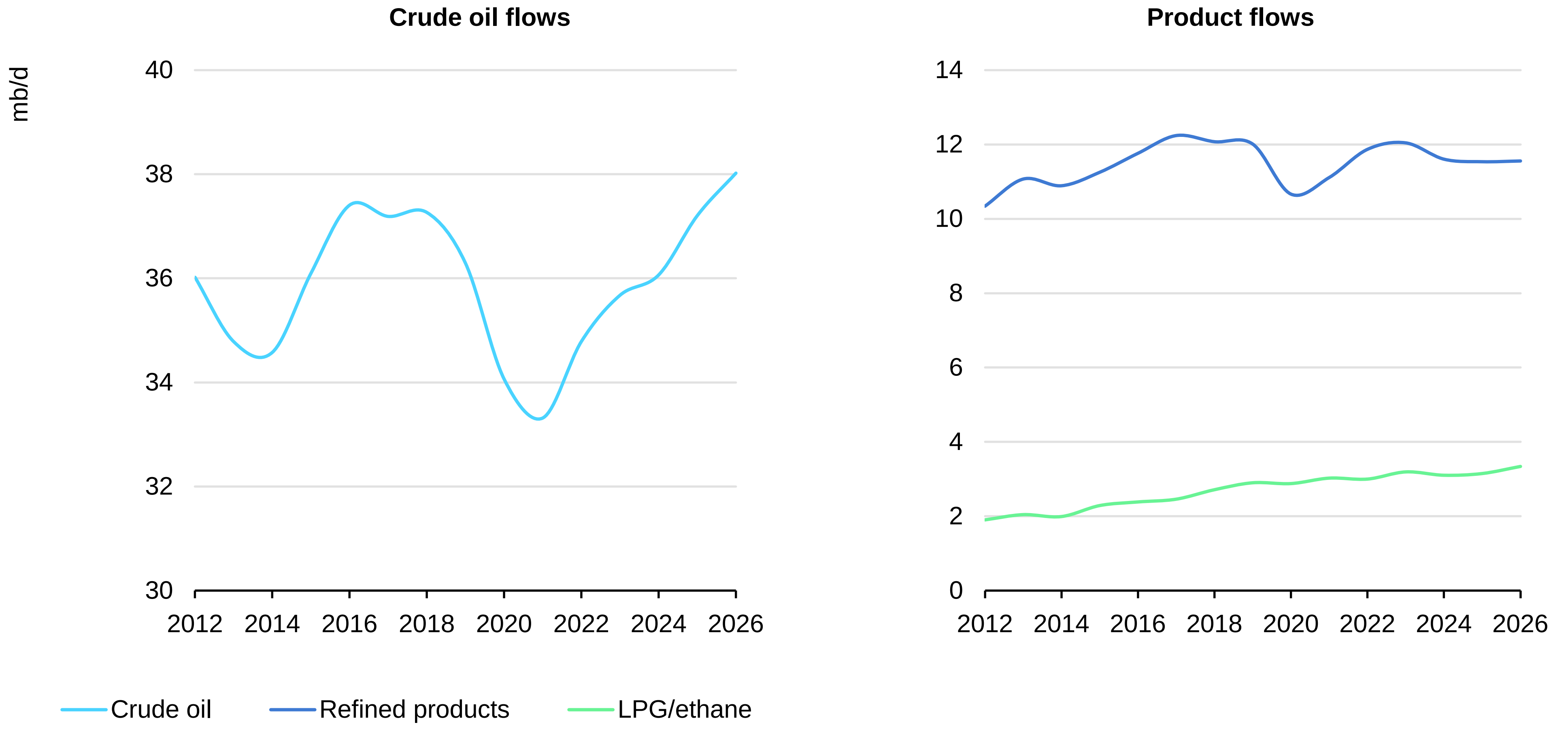
Net refined product imports



* Asia four includes Australia, New Zealand, Indonesia and Singapore. Europe includes OECD and non-OECD Europe.

Crude oil trade expands dramatically; NGL growth slows; refined products decline

Crude oil and product movements



Global oil stocks

Global oil stocks overview

Global oil stocks on course to reach pre-pandemic levels in the second half of 2021

World oil markets are working off a massive inventory surplus that built up in the first half of 2020 after Covid lockdowns cut oil demand by a record amount. Onshore oil tanks were filled to the brim while oil on water and in floating storage absorbed the excess. A particularly acute shortage of storage capacity in Cushing, Oklahoma, ultimately contributed to pressure WTI prices to a negative $37/bbl last April. Since then, unprecedented supply cuts from OPEC+ and other producers along with a gradual recovery of demand has led to destocking of crude and product inventories.

For 2020 as a whole, more than one billion barrels of crude oil, feedstocks and oil products accumulated in various storage sites around the world. Based on data available by early March 2021, global oil inventories are estimated to have built by a record 7.9 mb/d during 1H20 followed by a draw of 2.0 mb/d in 2H20.

The 2020 global crude balance showed stocks rose by 1.7 mb/d on average. In particular, 1H20 saw a surplus of more than 4.5 mb/d in the market as refinery runs dropped amidst the Covid-19 pandemic. Crude stocks began to draw down in June, after record OPEC+ supply cuts were enforced, uneconomic non-OPEC output was shut in and refinery runs started to recover from a May low point.

China accounted for some 60% of global crude oil stock builds last year, increasing its stock holdings by an estimated 367 mb over the course of the year, according to IEA calculations. Chinese stock building has largely been earmarked for its commercial stocks held in tank terminals and refineries. In addition, some portion of crude oil has been stored as strategic reserves, which traditionally helps tighten the market since the supplies are considered locked-in storage.

Massive stock overhang clearing

As demand recovers further and OPEC+ countries continue to withhold oil from the market, both crude oil and product stocks are expected to see accelerated stock draws during 2021. Not all of the inventories will make their way back on the market, however. Several countries, including India, Australia and, most notably, China took advantage of relatively low oil prices to build up their government strategic reserves to improve energy security.

By contrast, in the United States, where the current Strategic Petroleum Reserve (SPR) holdings are well above the requirement to meet IEA obligations, the government plans to draw down supplies by up to 10.1 mb in the first half of this year, in-line with existing legislation mandating sales from SPR holdings over the period to 2028.

Net of the strategic stock build that took place last year, global inventories are expected to return to pre-pandemic levels early in the second half of 2021.

Focus on Chinese crude oil storage

China mops up excess oil, fills new tanks with low-cost crude

China helped to soak up much of the world's excess oil in 2020, buying big volumes of relatively cheap crude for its new storage tanks. China, the first country to go into lockdown to prevent further virus contagion in early part of 2020, showed a steep implied crude oil stock build of 300 mb or 1.7 mb/d in 1H20, according to data derived from reported crude production, refinery runs and net crude imports. China's massive stock build was almost equal to total volumes observed in the rest of the world, which saw crude oil stock rise by 330 mb or 1.8 mb/d in the same period.

The initial stock builds of China seen in 1Q20 were driven by sharply lower refinery activity as the lockdown imposed in major cities restricted travel and halted economic activity. Net crude oil imports to the country remained above 10 mb/d in the same period and helped push inventories higher.

In 2Q20, Chinese refinery throughputs recovered rapidly to 13.5 mb/d on average and rose above 14 mb/d for the first time in June 2020. At the same time, net crude oil imports hit a record high at 12.8 mb/d in June 2020 based on China Custom's data. Low crude prices and the recovery in domestic economic activity from late March to May encouraged Chinese crude importers to order cargos scheduled for delivery in May through July.

Since April 2020, China continued to build stocks, filling their newly completed crude storage capacity. By contrast, the estimated crude oil surplus vs December 2020 in the rest of the world has been on a steady decline as producers cut output.

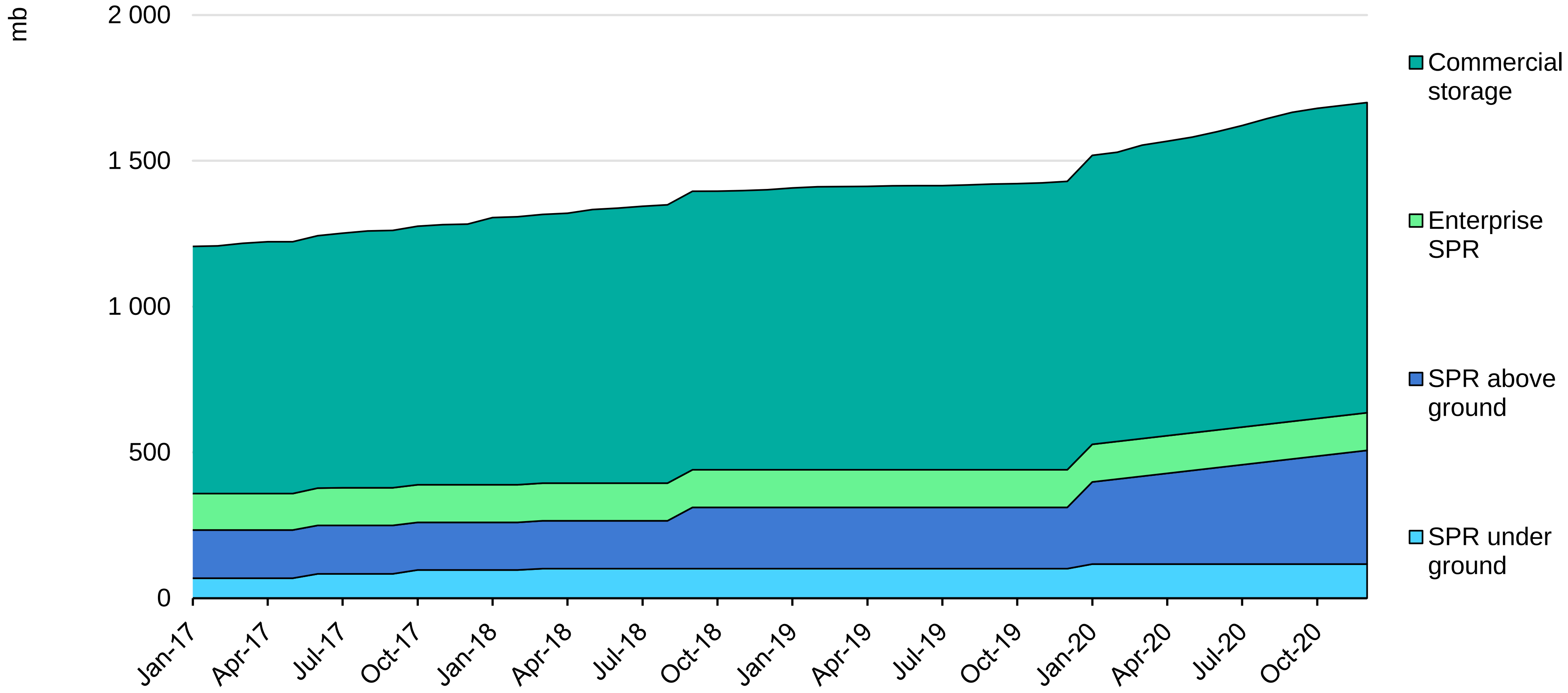
Chinese puzzle

Given its unique role in the global oil market, China's inventory strategy going forward will have important implications for the global oil market. Any additional builds in its strategic reserves will essentially amount to incremental demand. Chinese stock building has largely been earmarked for its strategic reserves over the past decade, which traditionally helps tighten the market since the supplies are considered locked in storage.

Taking into account China's steady crude storage capacity expansion over the past few years, it seems unlikely that Chinese stocks will be drawn down as quickly as in other countries in 2021. Chinese companies have sharply increased their commercial storage capacity at refineries and terminals in line with new builds and expansion projects. As a result, it is unclear how much of its commercial oil inventory building will make its way back into the market this year. It should be noted that considerable uncertainties regarding China's refining, demand and actual stock levels remain, due to data availability and transparency issues. We are continuously working on improving our methodology for estimating the Chinese crude balance and inventory situation and will update the analysis on an ongoing basis.

Commercial storage led the increase by more than 200 mb in the 2017-2020 period

Chinese crude oil storage capacity by type



Sources: IEA, Kayrros, Kpler and industry press.

Breaking down China's 1.7 billion barrel crude storage capacity

China accounts for more than 90% of global crude storage capacity built in 2017-2020. In 2020 their above-ground storage capacity increased by 74.7 mb, according to *Kayrros*. Storage at refineries and terminals led the increase. It is highly likely that these new facilities were filled in 3Q20 as net crude imports remained high at 11.55 mb/d on average for the same period.

Total crude storage capacity in China rose to around 1.7 billion barrels at the end of 2020, including both above and underground facilities. Its crude storage facilities are categorised as government SPR, enterprise SPR and commercial storage. Combined SPR storage capacity accounted for 37% of total capacity at the end of 2020 and commercial storage made up 63%.

In the past three years, commercial crude storage facilities led the capacity increase in the country by more than 200 mb and reached 1 064 mb at end-2020. Refineries rapidly installed new storage tanks from 2019 and in 2020 crude oil terminals at ports dominated the capacity additions, according to data from *Kayrros*.

Developments in SPR are less transparent compared with commercial storage due to their purpose and locations. Some of the government SPR sites are located in underground rock or salt caverns and cannot be observed by satellite imaging techniques. China's *National Bureau of Statistics* last released details on the status of each SPR facility and its capacity in mid-2017. In this *Report*, we provide an update of the SPR status using all available sources.

Phase 1 and the early part of Phase 2 SPR were completed and filled by 2017, for a combined total of 281.2 mb. This consists of 103.1 mb for Phase 1 and 178.1 mb for the early part of the Phase 2 programme. In the 2018-2019 period, it is likely that four additional Phase 2 SPR sites were constructed, one of which was underground storage using salt caverns. Sinopec completed two of them, namely, Nangang Phase 2 in Tianjin province (20.1 mb) and Caofeidian in Hebei province (38 mb). China National Petroleum Corporation constructed two: Jintan underground storage in Jiangsu province (15.7 mb) and Shanshan in Xinjiang province (39 mb). If these facilities in the Phase 2 are completed (112.8 mb), total capacity of Phase 2 could be 290.9 mb, making the combined total capacity of Phase 1 and 2 some 394 mb.

While locations currently remain uncertain, the capacity of Phase 3 SPR should be around 230 mb to achieve the overall target of 625 mb SPR capacity by end-2021. Given that Chinese implied crude oil stock build was more than 360 mb in 2020, it would have been enough to fill Phase 3 SPR capacities if these sites were already completed.

Strategic Petroleum Reserve capacity reached around 400 mb when Phase 2 completed

IEA estimate of China's SPR sites and their status

Phase	Operator	Location	Province	Type	Capacity (mb)	Status	Completion
Phase 1	Sinopec	Zhenhai	Zhejiang	above ground	32.7	filled	3Q06
Phase 1	Sinochem	Aoshan/Zhoushan Phase 1	Zhejiang	above ground	31.4	filled	4Q07
Phase 1	Sinopec	Huangdao Phase 1	Shandong	above ground	20.1	filled	4Q07
Phase 1	CNPC	Dalian	Liaoning	above ground	18.9	filled	4Q08
Total Phase 1					**103.1**		
Phase 2	CNPC	Lanzhou	Gansu	above ground	18.9	filled	4Q11
Phase 2	CNPC	Dushanzi Phase 1	Xinjiang	above ground	18.9	filled	4Q11
Phase 2	Sinopec	Nangang Phase 1	Tianjin	above ground	20.1	filled	Dec14
Phase 2	Sinopec	Huangdao Phase 2	Shandong	rock cavern	18.9	filled	3Q16
Phase 2	CNPC	Jinzhou	Liaoning	rock cavern	18.9	filled	1Q17
Phase 2	CNOOC	Huizhou	Guangdong	rock cavern	31.4	filled	4Q17
Phase 2	Sinochem	Aoshan/Zhoushan Phase 2	Zhejiang	above ground	19.0	filled	1Q17
Phase 2	Sinopec	Zhanjiang	Guangdong	rock cavern	32.0	filled	2017-2018
Phase 2	Sinopec	Nangang Phase 2	Tianjin	above ground	20.1	filled	2018-2019
Phase 2	Sinopec	Caofeidian	Hebei	above ground	38.0	filled	2018-2019
Phase 2	CNPC	Jintan	Jiangsu	salt cavern	15.7	filled	2018-2019
Phase 2	CNPC	Shanshan	Xinjiang	above ground	39.0	likely filled	2018-2019
Total Phase 2					**290.9**		
Total Phase 3					**231.0**	planned	by end-2021
Total Phase 1-3					**625.0**		

Strategic oil stock developments in other countries

Key crude importers increase strategic storage to strengthen energy security

India expanding strategic storage

India is another notable country aiming to build their SPR. The country completed the first phase of filling its SPR in mid-May 2020, which benefitted from lower oil prices. As of February 2021, crude oil stocks held in underground caverns at three sites stood at 39 mb according the government. The Visakhapatnam storage site on the east coast holds 9.6 mb. Mangalore and Padur sites on the west coast store 11 mb and 18.4 mb, respectively.

The Indian cabinet has approved the second phase of their SPR at two sites in Chandikhol (30 mb) and Padur (18.4 mb) with a combined 48.4 mb capacity. In February 2021, the government has reportedly allocated $29 million for capital expenditure in the fiscal year 2021 to build the facilities. As the second phase of SPR will be developed on a public-private partnership model, India plans to seek private participants to fund the remaining costs. Combining the two phases, India would have a total 87.4 mb of SPR capacity to enhance their energy security.

Australia established a new scheme for emergencies

The Australian government signed a lease agreement with the United States in June 2020 and bought 1.5 mb of crude oil to be stored in the country's SPR caverns, with an option to increase its stake. The agreement allows Australia to access this crude in an emergency.

In September 2020, the government announced a long awaited plan to enhance the country's fuel security. The Commonwealth Fuel Package foresees the construction of 5 mb of new diesel storage capacities in the country, which will be reserved for companies fulfilling the announced imposition of a stockholding obligation on industry. It would be the first ever stockholding obligation on industry in the country, which currently relies on minor public stocks and industry stocks on a voluntary basis.

Japan strengthens ties with the Gulf exporters

In December 2020, Japan signed an agreement with the Kuwait Petroleum Corporation (KPC) to start a joint oil storage project. Under the agreement, the government of Japan leases 3.14 mb of crude oil storage capacity to KPC.

In case of an emergency situation, KPC will preferentially supply the crude oil stored in the tanks to Japan. In non-crisis periods, KPC will make use of the tanks to supply oil to East Asian countries, including Japan. The government of Japan has already signed similar agreements with Saudi Aramco and Abu Dhabi National Oil Company.

US Congress mandated the sale of SPR oil

The US still has the largest SPR capacity in the world. It has a design storage capacity of 713.5 mb. The reserves are located in four underground storage sites in Texas and Louisiana with a total of 60 operational caverns. The US SPR played a role in 2020 to absorb excess crude oil from the market by offering available storage capacity to the private sector. Starting at end-April 2020, by mid-July more than 20 mb of commercial crude oil was stored in the SPR sites.

At end-2020, total crude oil stored at SPR sites stood at 638 mb. In recent years, Congressional mandates to sell oil from the SPR have reduced the SPR's total volume, which is expected to reach around 400 mb in 2028. The Consolidated Appropriations Act of 2018 directs the Secretary of Energy to draw down a total of 10 mb of SPR crude oil in the fiscal years 2020 and 2021. In addition, Section 403 of the Bipartisan Budget Act of 2015 requires the Secretary of Energy to sell a total of 58 mb of crude oil from the SPR, over eight consecutive fiscal years commencing in 2018. On 11 February 2021, the United States announced a notice of sale of up to 10.1 mb, in accordance with both congressional acts, with deliveries to take place in April and May 2021.

Tables

Demand annex

Global oil demand

Global oil demand by region (mb/d)

	2019	2020	2021	2022	2023	2024	2025	2026	2019-2026 Growth Rate	2019-2026 Growth
North America	25.3	22.2	23.8	24.5	24.7	24.7	24.6	24.6	-0.4%	-0.7
Central and South America	6.6	5.9	6.3	6.6	6.7	6.7	6.8	6.9	0.7%	0.3
Europe	15.7	13.8	14.6	14.8	15.0	15.0	14.9	14.9	-0.8%	-0.8
Africa	4.2	3.8	4.0	4.2	4.4	4.5	4.7	4.8	1.7%	0.5
Middle East	8.3	7.6	7.9	8.2	8.4	8.5	8.7	8.9	0.9%	0.6
Eurasia	4.4	4.2	4.3	4.4	4.5	4.6	4.6	4.7	1.1%	0.4
Asia Pacific	35.2	33.4	35.6	36.9	37.7	38.2	38.9	39.3	1.6%	4.1
World	**99.7**	**91.0**	**96.5**	**99.4**	**101.2**	**102.3**	**103.2**	**104.1**	**0.6%**	**4.4**

Global oil demand by product (mb/d)

	2019	2020	2021	2022	2023	2024	2025	2026	2019-2026 Growth Rate	2019-2026 Growth
LPG/Ethane	12.9	12.8	13.4	13.5	13.8	14.2	14.5	14.8	1.9%	1.8
Naphtha	6.3	6.3	6.5	6.9	7.1	7.2	7.3	7.5	2.5%	1.2
Gasoline	26.6	23.7	25.4	25.9	25.9	25.9	25.9	25.9	-0.4%	-0.7
Jet/Kerosene	7.9	4.7	5.5	6.9	7.7	8.0	8.1	8.2	0.5%	0.3
Gasoil/Diesel	28.8	27.0	28.5	28.9	29.1	29.3	29.4	29.5	0.4%	0.8
Residual fuel oil	6.3	5.8	6.1	6.3	6.4	6.5	6.6	6.7	0.8%	0.4
Other products	10.9	10.6	11.0	11.0	11.2	11.3	11.4	11.5	0.8%	0.6
Total products	**99.7**	**91.0**	**96.5**	**99.4**	**101.2**	**102.3**	**103.2**	**104.1**	**0.6%**	**4.4**

Oil demand by region

Oil demand by product (mb/d): North America

	2019	2020	2021	2022	2023	2024	2025	2026	2019-2026 Growth Rate	2019-2026 Growth
LPG/Ethane	3.8	3.8	4.0	4.1	4.2	4.3	4.4	4.5	2.4%	0.7
Naphtha	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.3	0.5%	0.0
Gasoline	11.0	9.5	10.2	10.4	10.2	10.1	9.9	9.8	-1.6%	-1.2
Jet/Kerosene	2.1	1.2	1.5	1.8	2.0	2.0	2.0	2.0	-0.2%	0.0
Gasoil/Diesel	5.2	4.8	5.0	5.1	5.1	5.1	5.1	5.0	-0.5%	-0.2
Residual fuel oil	0.5	0.4	0.5	0.5	0.5	0.5	0.5	0.5	-0.9%	0.0
Other products	2.4	2.3	2.4	2.4	2.4	2.4	2.4	2.4	0.2%	0.0
Total products	**25.3**	**22.2**	**23.8**	**24.5**	**24.7**	**24.7**	**24.6**	**24.6**	**-0.4%**	**-0.7**

Oil demand by product (mb/d): Central and South America

	2019	2020	2021	2022	2023	2024	2025	2026	2019-2026 Growth Rate	2019-2026 Growth
LPG/Ethane	0.7	0.7	0.7	0.7	0.7	0.7	0.7	0.7	1.1%	0.1
Naphtha	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.5%	0.0
Gasoline	2.0	1.7	1.8	1.9	1.9	2.0	2.0	2.0	0.5%	0.1
Jet/Kerosene	0.3	0.2	0.2	0.3	0.3	0.3	0.3	0.3	-0.2%	0.0
Gasoil/Diesel	2.2	2.1	2.2	2.3	2.3	2.4	2.4	2.4	1.0%	0.2
Residual fuel oil	0.5	0.4	0.5	0.5	0.5	0.5	0.5	0.5	0.3%	0.0
Other products	0.7	0.7	0.7	0.7	0.7	0.7	0.7	0.7	0.4%	0.0
Total products	**6.6**	**5.9**	**6.3**	**6.6**	**6.7**	**6.7**	**6.8**	**6.9**	**0.7%**	**0.3**

Oil demand by region

Oil demand by product (mb/d): Europe

	2019	2020	2021	2022	2023	2024	2025	2026	2019-2026 Growth Rate	2019-2026 Growth
LPG/Ethane	1.3	1.2	1.3	1.2	1.2	1.2	1.2	1.2	-0.6%	-0.1
Naphtha	1.0	1.1	1.1	1.1	1.1	1.1	1.1	1.1	1.4%	0.1
Gasoline	2.3	2.0	2.1	2.1	2.0	2.0	2.0	1.9	-2.2%	-0.3
Jet/Kerosene	1.6	0.8	0.9	1.2	1.5	1.6	1.6	1.6	-0.2%	0.0
Gasoil/Diesel	7.0	6.5	6.9	6.8	6.8	6.7	6.6	6.6	-1.0%	-0.5
Residual fuel oil	1.0	0.8	0.8	0.9	0.9	0.9	0.9	0.9	-0.6%	0.0
Other products	1.4	1.4	1.4	1.4	1.4	1.4	1.4	1.4	0.1%	0.0
Total products	**15.7**	**13.8**	**14.6**	**14.8**	**15.0**	**15.0**	**14.9**	**14.9**	**-0.8%**	**-0.8**

Oil demand by product (mb/d): Africa

	2019	2020	2021	2022	2023	2024	2025	2026	2019-2026 Growth Rate	2019-2026 Growth
LPG/Ethane	0.4	0.4	0.4	0.4	0.4	0.4	0.4	0.5	1.2%	0.0
Naphtha	0.0	0.0	0.0	0.0	0.1	0.1	0.1	0.1	24.0%	0.1
Gasoline	1.2	1.1	1.2	1.2	1.3	1.3	1.3	1.4	1.6%	0.1
Jet/Kerosene	0.3	0.2	0.2	0.2	0.3	0.3	0.3	0.3	0.6%	0.0
Gasoil/Diesel	1.7	1.6	1.7	1.7	1.8	1.8	1.9	1.9	1.7%	0.2
Residual fuel oil	0.3	0.3	0.3	0.3	0.3	0.3	0.3	0.3	0.2%	0.0
Other products	0.3	0.3	0.3	0.3	0.3	0.3	0.3	0.3	1.6%	0.0
Total products	**4.2**	**3.8**	**4.0**	**4.2**	**4.4**	**4.5**	**4.7**	**4.8**	**1.7%**	**0.5**

Oil demand by region

Oil demand by product (mb/d): Middle East

	2019	2020	2021	2022	2023	2024	2025	2026	2019-2026 Growth Rate	2019-2026 Growth
LPG/Ethane	1.7	1.7	1.7	1.7	1.8	1.8	1.9	2.0	2.1%	0.3
Naphtha	0.1	0.1	0.1	0.1	0.1	0.1	0.2	0.2	11.6%	0.1
Gasoline	1.7	1.4	1.5	1.6	1.6	1.6	1.7	1.7	-0.1%	0.0
Jet/Kerosene	0.6	0.3	0.3	0.4	0.5	0.5	0.5	0.5	-0.7%	0.0
Gasoil/Diesel	1.8	1.7	1.8	1.8	1.8	1.9	1.9	1.9	0.5%	0.1
Residual fuel oil	1.4	1.4	1.4	1.5	1.5	1.5	1.5	1.5	1.2%	0.1
Other products	1.0	1.1	1.0	1.0	1.0	1.0	1.0	1.0	0.2%	0.0
Total products	**8.3**	**7.6**	**7.9**	**8.2**	**8.4**	**8.5**	**8.7**	**8.9**	**0.9%**	**0.6**

Oil demand by product (mb/d): Eurasia

	2019	2020	2021	2022	2023	2024	2025	2026	2019-2026 Growth Rate	2019-2026 Growth
LPG/Ethane	0.8	0.8	0.8	0.8	0.8	0.8	0.9	0.9	1.9%	0.1
Naphtha	0.2	0.2	0.2	0.2	0.2	0.3	0.2	0.3	4.9%	0.1
Gasoline	1.0	1.0	1.0	1.0	1.0	1.1	1.1	1.1	0.7%	0.0
Jet/Kerosene	0.3	0.2	0.2	0.3	0.3	0.3	0.3	0.3	1.5%	0.0
Gasoil/Diesel	1.1	1.1	1.1	1.2	1.2	1.2	1.2	1.2	0.6%	0.1
Residual fuel oil	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2	-1.4%	0.0
Other products	0.7	0.7	0.7	0.7	0.7	0.7	0.7	0.7	1.0%	0.0
Total products	**4.4**	**4.2**	**4.3**	**4.4**	**4.5**	**4.6**	**4.6**	**4.7**	**1.1%**	**0.4**

Oil demand by region

Oil demand by product (mb/d): Asia Pacific

	2019	2020	2021	2022	2023	2024	2025	2026	2019-2026 Growth Rate	2019-2026 Growth
LPG/Ethane	4.3	4.2	4.5	4.6	4.7	4.8	4.9	5.0	2.3%	0.7
Naphtha	4.4	4.4	4.6	4.9	5.0	5.1	5.2	5.2	2.3%	0.8
Gasoline	7.4	7.1	7.5	7.6	7.7	7.8	7.9	8.0	1.0%	0.6
Jet/Kerosene	2.8	1.8	2.2	2.7	2.9	3.0	3.0	3.1	1.6%	0.3
Gasoil/Diesel	9.6	9.2	9.8	10.0	10.1	10.3	10.4	10.5	1.3%	0.9
Residual fuel oil	2.3	2.3	2.4	2.5	2.5	2.6	2.6	2.7	1.9%	0.3
Other products	4.4	4.3	4.6	4.6	4.7	4.7	4.8	4.9	1.5%	0.5
Total products	**35.2**	**33.4**	**35.6**	**36.9**	**37.7**	**38.2**	**38.9**	**39.3**	**1.6%**	**4.1**

Oil demand by product (mb/d): United States

	2019	2020	2021	2022	2023	2024	2025	2026	2019-2026 Growth Rate	2019-2026 Growth
LPG/Ethane	2.9	3.0	3.2	3.3	3.4	3.5	3.6	3.7	3.2%	0.7
Naphtha	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2	-0.5%	0.0
Gasoline	9.4	8.1	8.7	8.9	8.7	8.6	8.5	8.4	-1.5%	-1.0
Jet/Kerosene	1.8	1.1	1.3	1.5	1.7	1.7	1.8	1.8	-0.2%	0.0
Gasoil/Diesel	4.2	3.9	4.0	4.1	4.1	4.1	4.1	4.0	-0.5%	-0.2
Residual fuel oil	0.4	0.3	0.3	0.3	0.3	0.3	0.3	0.3	-0.5%	0.0
Other products	2.0	1.9	2.0	2.0	2.0	2.0	2.0	2.0	-0.2%	0.0
Total products	**20.9**	**18.4**	**19.7**	**20.3**	**20.5**	**20.5**	**20.4**	**20.4**	**-0.3%**	**-0.5**

Oil demand by region

Oil demand by product (mb/d): China

	2019	2020	2021	2022	2023	2024	2025	2026	2019-2026 Growth Rate	2019-2026 Growth
LPG/Ethane	1.7	1.8	1.9	2.0	2.1	2.1	2.2	2.3	4.0%	0.5
Naphtha	1.3	1.4	1.5	1.7	1.7	1.7	1.8	1.8	4.5%	0.5
Gasoline	3.3	3.4	3.5	3.6	3.6	3.7	3.7	3.7	2.0%	0.5
Jet/Kerosene	0.8	0.7	0.9	0.9	0.9	0.9	1.0	1.0	2.9%	0.2
Gasoil/Diesel	3.5	3.6	3.8	3.9	3.9	4.0	4.0	4.0	1.8%	0.5
Residual fuel oil	0.4	0.4	0.4	0.4	0.5	0.5	0.5	0.5	1.6%	0.0
Other products	2.6	2.6	2.7	2.7	2.8	2.8	2.8	2.9	1.3%	0.2
Total products	**13.7**	**13.9**	**14.8**	**15.2**	**15.5**	**15.7**	**16.0**	**16.1**	**2.4%**	**2.4**

Oil demand by product (mb/d): India

	2019	2020	2021	2022	2023	2024	2025	2026	2019-2026 Growth Rate	2019-2026 Growth
LPG/Ethane	0.8	0.9	0.9	0.9	0.9	0.9	0.9	1.0	2.2%	0.1
Naphtha	0.3	0.3	0.3	0.4	0.4	0.4	0.4	0.4	5.4%	0.1
Gasoline	0.7	0.7	0.7	0.7	0.8	0.8	0.8	0.8	1.6%	0.1
Jet/Kerosene	0.2	0.1	0.2	0.2	0.2	0.3	0.3	0.3	2.7%	0.0
Gasoil/Diesel	1.6	1.4	1.6	1.7	1.7	1.7	1.8	1.8	1.4%	0.2
Residual fuel oil	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.9%	0.0
Other products	1.0	1.0	1.0	1.0	1.1	1.1	1.1	1.1	1.3%	0.1
Total products	**5.0**	**4.5**	**5.0**	**5.1**	**5.3**	**5.4**	**5.5**	**5.7**	**1.8%**	**0.7**

Supply annex

Emissions reduction targets by selected international oil and gas companies

Company	Commitments/Targets
BP	Reach net-zero greenhouse gas (GHG) emissions from operations and upstream production by 2050. Target applies to Scope 1, 2 and 3 emissions. Cut carbon intensity of all products sold 50% by 2050. Reduce operated methane intensity by 50%.
Chevron	Cut upstream net GHG emission intensity for operated and non-operated oil and gas output by 35% by 2028 vs 2016. Target applies to Scope 1 and 2 emissions. Reduce methane intensity by 50% and flaring intensity by 65% by 2028 vs 2016. Zero routine flaring by 2030.
ConocoPhillips	Reduce GHG emissions intensity by up to 35%-45% by 2030 vs 2017, net zero by 2050 ambition. Target applies to Scope 1 and 2 emissions. Reduce methane emissions intensity by 10% by 2025. Zero routine flaring by 2025.
Eni	Cut net emissions 80% by 2050 vs 2018 (cut emissions intensity by 55%). Applies to Scope 1, 2 and 3 emissions. Net-zero upstream carbon footprint by 2030, net zero for group by 2040. Applies to Scope 1 and 2. Cut upstream methane emissions 80% by 2025 vs 2014 (achieved). Zero process flaring by 2025.
ExxonMobil	By 2025, reduce operated upstream emissions intensity by 15-20%, methane intensity by 40-50% and flaring intensity by 35-40% vs 2016. Eliminate routine flaring by 2030.
Repsol	Net-zero emissions by 2050 vs 2018. Applies to Scope 1, 2 and 3 emissions (of own production). Intermediate targets for 2025 (-10%) to 2040 (-40%). Cut methane emissions 25% by 2025 vs 2016.
Shell	Net-zero carbon emissions by 2050. Applies to Scope 1, 2 and 3 emissions. Intermediate targets for 2030 (-20%) and 2035 (-45%). Maintain methane emissions intensity for operated assets below 0.2% by 2025.
Total	Net-zero emissions for global operations by 2050 (scope 1 and 2). Net zero emissions for European production and energy products by 2050 (scope 1, 2 and 3). Cut carbon intensity of global energy products 60% by 2050 vs 2015 (scope 1, 2 and 3). Cut methane emissions intensity to below 0.25% to 2025.

Sources: Company reports.

Emissions reduction targets by selected national oil and gas companies

Company	Commitments/Targets
Qatar Petroleum	Reduce emissions intensity of LNG facilities and upstream facilities by 25% and 15%, respectively, and reduce upstream flaring intensity by 75% by 2030, eliminate routine flaring by 2030, methane intensity target of 0.2% by 2025, investment in CCS and "cleaner" forms of energy (LNG, GTL and CNG).
Adnoc	Reduce GHG emissions intensity 25% by 2030 (Scope 1 and 2), investment in CCUS.
Saudi Aramco	Signed the "OGCI Climate Investments" in 2020[1], sustain "best in class" methane flaring intensity, investment in CCS.
CNOOC	Aligning strategy to China's national carbon neutral target by 2060. Increase share of natural gas production to 50% by 2035, investment in offshore wind.
Petrochina / CNPC	Target to achieve near zero emissions by 2050 (Scope 1 and 2), OGCI signatory, investment in geothermal, wind, solar and pilot hydrogen projects.
Sinopec	No specific targets but conducting research on the strategic path of having CO_2 emissions peak and achieve carbon neutrality before 2030 (Scope 1 and 2), investments in hydrogen, biomass and geothermal.
Equinor	50% reduction in net carbon intensity by 2050 (Scope 1, 2 and 3), carbon neutral operations by 2030, globally operated CO_2 intensity below 8 kgCO_2e/boe by 2025, grow renewable energy capacity tenfold by 2026.

[1] Collective target to reduce the carbon intensity of signatories' fossil fuel production to between 20 kg and 21 kg, CO_2e/boe by 2025 (13% below 2017 levels). OGCI's membership includes: BP, Chevron, China's CNPC, Italy's Eni, Equinor, ExxonMobil, Occidental Petroleum, Petrobras, Repsol, Saudi Aramco, Shell and Total.

Company	Commitments/Targets
Petronas	Net-zero carbon emissions by 2050 (Scope 1 and 2), investment in solar, hydrogen and wind.
Petrobras	By 2030 reduce absolute operating emissions 25% and achieve zero routine flaring, by 2025 reduce upstream carbon intensity and methane emissions intensity 32% and 40%, respectively. Reduce carbon intensity of refining business 30% by 2030, investment in CCUS, no significant investment in renewables.
Gazprom	Reports Scope 1 and 2 emissions, currently no announced targets for emissions reduction.
Rosneft	By 2035, for Russian assets, reduce GHG emissions 5% which will prevent production of 20 mt of CO2e, reduce upstream emissions intensity 30%, reduce methane emissions intensity to below 0.25%, achieve zero routine flaring.
Ecopetrol	20% reduction in GHG emissions by 2030, reduce emissions to 3 mt of CO_2 by 2023.
Sonatrach	No announced targets.
PDVSA	No announced targets.
Pemex	No announced targets.

Sources: Company reports.

Emissions reduction targets by selected independent oil and gas companies

Company	Commitments
Occidental Petroleum	Net zero (Scope 1 and 2) by 2040, net zero (Scope 3) by 2050. No routine flaring by 2030. By 2025, reduce direct and indirect GHG emissions intensity to 0.02 tCO_2e/boe and methane emissions from marketed gas to 0.25%.
EOG Resources	By 2025, reduce GHG emissions intensity to 0.0135 tCO_2e/boe and methane emissions to 0.06% of natural gas production. Targets apply to Scope 1 emissions from operations.
Hess	No specific targets announced. OFC member[2].
Pioneer Natural Resources	Reduce Scope 1 and 2 GHG emissions intensity 25%, methane intensity 40% and end routine flaring by 2030.
Murphy Oil	GHG emission intensity reduction of 15-20% by 2030 vs 2019 (Scope 1).
Kosmos Energy	Net zero by 2030 (Scope 1 and 2).
Talos Energy	No reported targets, reports Scope 1 emissions.
Apache	By 2025 reduce global methane emissions to 0.37% of gross methane production (achieved). ONE Future Coalition member.

[2] The ONE Future Coalition is a group of 33 natural gas companies working together to voluntarily reduce methane emissions across the natural gas value chain to 1% (or less) by 2025, and below 0.28% for the production sector.

Company	Commitments
Continental Resources	No reported targets.
Marathon Oil	Reduce GHG emissions intensity to 30% below 2014 levels by 2030 (Scope 1 and 2).
Devon Energy	Reduce methane emissions intensity to below 0.28% by 2025.
Whiting Petroleum	No reported targets.
Diamondback	Reduce GHG emissions intensity by at least 50% by 2024 from 2019 levels (scope 1), reduce methane intensity by at least 70% for the same period
Callon Petroleum	No reported targets.
Laredo Petroleum	No reported targets.
EQT	No reported targets, ONE Future Coalition member.
Centennial Resource Development	No reported targets.

Company	Commitments
Antero Resource	By 2025 achieve 50% reduction in methane leak loss rate (to under 0.025%) and 10% reduction in GHG intensity, net zero carbon (scope 1) emissions ambition via operational improvements and carbon offsets.
Cimarex	2020 target to reduce methane intensity rate by 5%, no reported medium or long term targets.
SM Energy	Short-term (i.e. plan year) targets not published in advance.
Crysasor	30% reduction in carbon emissions from operated assets by 2025, further 20% by 2028 (Scope 1 and 2).
Siccar Point	No reported targets.
Neptune Energy	Carbon intensity of 6 kg CO_2e/boe by 2030 (Scope 1 and 2) [industry average is 18 kg CO_2e/boe].
EnQuest	10% reduction in emissions (Scope 1 & 2) by 2023.
Tullow	No reported targets.
Wintershall Dea	Net-zero upstream operations by 2030 (Scope 1 and 2), methane emissions intensity below 0.1% by 2025, no routine flaring by 2030.

Company	Commitments
Lundin Energy	Carbon neutrality from 2025 across operations (Scope 1 and 2, and Scope 3 emissions related to supply chain i.e. supply vessels, tankers and business travel).
OMV	Net-zero emissions for operations by 2050 (Scope 1 and 2), 30% reduction in carbon intensity by 2025, low carbon products to account for 60% of the portfolio by 2025.
BHP	Net-zero operational emissions by 2050 (Scope 1 and 2), reduce GHG emissions at least 30% by 2030.
Woodside	Net-zero GHG emissions by 2050 (Scope 1 and 2), reduce GHG emissions at least 30% by 2030, develop hydrogen exports.
Cenovus Energy	Net-zero GHG emissions by 2050 (Scope 1 and 2), reduce GHG emissions intensity by 30% by 2030 vs 2019.
Suncor	Reduce GHG emissions intensity by 30% by 2030 vs 2014.

Significant project delays

Country	Project	Operator	Details
United States	Vito	Shell	Sanctioned in 2018, start-up delayed to 2022 (from 2021) due to Covid-19 outbreak at Singapore shipyard where Vito facility was under construction.
United States	Anchor	Chevron	Possible three- to nine-month delay to drilling as project is progressed at “its most efficient pace”. First oil is expected 2024.
Norway	Martin Linge	Equinor	First oil delayed to summer 2021 (originally 4Q16). Platform evacuated in March 2020 due to Covid-19, subsequently reduced manning imposed. Project costs increased 96% due to well integrity issues, remedial work to topsides and infection control measures.
Norway	Johan Castberg	Equinor	Project start-up postponed to 4Q23 (from late 2022). FPSO delivery delayed as Covid-19 reduced operations at construction yard in Singapore.
Norway	Njord	Equinor	Start-up now planned for 2021 (from 4Q20), with delay due to Covid-19 measures and increased project scope.
Norway	Yme	Repsol	First oil 4Q21 (originally 2Q20). Covid-19 restrictions delayed construction of jack-up at Egersund yard and testing operations.
Norway	Fenja	Neptune	Start-up delay to 1Q22 (from 4Q21) after Covid-19 outbreak on drilling rig.
United Kingdom	Seagull	Neptune	Project now due online late 2022 (12-15 months late) as delayed maintenance due to Covid-19 caused tie-back to existing facilities to be postponed.
United Kingdom	Penguins Redevelopment	Shell	Start-up expect in 2022 (previously 2021) due to Covid-19-related delays in Chinese yard where the FPSO is being constructed.

Country	Project	Operator	Details
United Kingdom	Vorlich	BP	First oil November is now 2020 (few months of delay) due to Covid-19 restrictions.
United Kingdom	Buzzard Phase 2	CNOOC	First oil delayed to 2021 (from 2020) due to operational impact of Covid-19 safety measures.
India	KG-DWN 98/2	ONGC	First oil in 2022 at risk from delays at multiple equipment manufacturers.
Kazakhstan	Tengiz	Tengizchevroil (Chevron)	Future Growth Project now expected online in 2023 (one-year delay). Reduced manpower due to Covid-19 has hampered development and commissioning but did not fully halt operations.
Brazil	Peregrino	Equinor	Phase 2 start-up due in early 2021 (two-month delay) as severe coronavirus situation in Brazil hampers construction and installation of new facilities.
Brazil	Carioca FPSO	Petrobras	FPSO construction delayed due to Covid-19 outbreaks in Asian shipyard. Expected online at Sepia field in late 1H21.
Brazil	Guanabara FPSO	Petrobras	FPSO construction delayed due to Covid-19 outbreaks in Asian shipyard. Expected online at Mero field in 2H21.
Senegal	Sangomar	Woodside	Development drilling delayed from 1Q21 to end-June 2021 as Covid-19 has complicated staff mobility and supply. Impact on first oil under evaluation.
Guyana	Liza	ExxonMobil	Phase 1 plateau production achieved December 2020, one year behind schedule, due to equipment issues and as Covid-19 disrupted commissioning,

Country	Project	Operator	Details
Canada	West White Rose Extension	Cenovus Energy	Originally due online 2022, planned 2021 construction work cancelled due to pandemic and broader market uncertainty. No updated schedule announced.
United Kingdom	Buzzard phase 2	CNOOC	First oil delayed from 2H20 to 2H21 due to low oil prices and pipeline maintenance.
Saudi Arabia	Marjan	Saudi Aramco	Expansion project sanctioned in 2019 but delayed to reduce 2020 capital spend in light of lower oil prices.
Saudi Arabia	Berri	Saudi Aramco	Expansion project sanctioned in 2019, delayed to reduce 2020 capital spend amid lower oil prices.
Nigeria	Anyala-Madu	First E&P	First oil in November 2020, one year behind schedule, in part due to late delivery of FPSO caused by Covid-19.
Uzbekistan	GTL plant	Uzbekneftgaz	Construction of GTL plant (12 kb/d capacity) stalled in summer of 2020 as manning levels reduced due to Covid-19.

Significant project sanction delays

Country	Project	Operator	Details
United States	Whale	Shell	Sanction delayed from 2020, now expected 2021. Capacity 100 kb/d. First oil undisclosed.
Brazil	Bacalhau	Equinor	2021 FID target (delayed from 2020). Capacity 220 kb/d oil and 15 mcm/d gas. First oil 2024.
Brazil	Mero-4 FPSO	Petrobras	Contracting of FPSO delayed while operator assesses alternative subsea solution for development. 180 kb/d FPSO had been due online in 2025.
Brazil	Atlanta	Enauta	Operator revisited field development plan in 2020 and planning to issue FPSO tender in 1H21. First oil now targeted for 2023, plateau 50 kb/d.
Brazil	Parque das Baleias	Petrobras	100 kb/d FPSO contract award delayed from 2020, first oil postponed by at least one year from 2023.
Brazil	Sergipe-Alagoas FPSO	Petrobras	100 kb/d FPSO tender launch delayed, first oil postponed from planned 2024.
Angola	PAJ & Platina	BP	Projects put on hold in 2020 due to weak oil prices and their future is uncertain given BP's strategy shift. 100 kb/d FPSO had been planned.
Angola	Agogo	Eni	Full field development postponed by at least one year due to cost-cutting and market uncertainty.
Australia	Dorado	Santos	FEED in 1H21 (delayed from 2H20), FID targeted for 2022. Capacity 75-100 kb/d.

Country	Project	Operator	Details
United Kingdom	Clair South	BP	Sanction delayed beyond 2022 as result of oil price collapse. Plateau of 50 kb/d.
United States (Alaska)	Pikka	Oil Search	Early production system put on hold due to operator spending cuts. FID now slated for late 2021 and first oil 2025. Plateau 80 kb/d.
United States	Shenandoah	LLOG	FID delayed from 2020, now targeted for 2021. First oil originally planned for 2023 at risk. Plateau 70 kb/d.
United States	North Platte	Total	Sanction originally planned for 2021 but EPC tender suspended in March 2020 due to market uncertainty and cost cutting. Plateau 75 kb/d.
Canada	Bay du Nord	Equinor	Project deferred due to oil price collapse and economic environment. Originally planned to sanction in 2020, with first oil 2025. FPSO capacity 94-188 kb/d.
Ghana	Pecan	Aker Energy	Sanction of Greater Pecan project cancelled in March due to market uncertainty, operator now pursuing phased development approach. Originally planned to have 110 kb/d capacity.
Saudi Arabia	Zuluf expansion	Aramco	Slated for FID in 2019, new timeline unknown. Potential 400 kb/d plateau.
Nigeria	Bonga Southwest – Aparo	Shell	FPSO tender process in 2019, operator has repeatedly delayed award while Covid-19 crisis ongoing. Project cost of $10bn, plateau production 150 kb/d. 2021 sanction could mean first oil in 2024.
Nigeria	Preowei	Total	FEED suspended, FID originally targeted for 1Q21, first oil 2023. New schedule not disclosed. Plateau 65 kb/d.

Country	Project	Operator	Details
UAE	Belbazem	Adnoc	Greenfield development, plateau 45 kb/d oil + 27 mcfd gas. May be delayed until more clarity re OPEC+. EPC bid process delayed to at least end-January 2021.
UAE	Upper Zakum	Adnoc	Expansion development likely to be delayed until more clarity regarding OPEC+ agreement. Could add 200 kb/d at plateau.
UAE	Lower Zakum	Adnoc	Expansion development likely to be delayed until more clarity regarding OPEC+ agreement. Could add 70 kb/d.
Uganda	Tilenga	Total	Sanction delayed from end-2020, new target of mid-2021, due to financing issues with export pipeline (EACOP).
Uganda	Kingfisher	CNOOC	Operator delayed award of EPC contract and sanction, pushing back first oil to 2023 at earliest (originally slated for 2019). Dependent on EACOP. 40 kb/d oil at plateau.
Kenya	South Lokichar Phase 1	Tullow Oil	Operator revisiting development plan to reduce costs, submission to government planned for end-2021. Capacity 60-80 kb/d.
Mexico	Zama	Talos Energy	Plans to sanction development by end 2020, and achieve first production in 2023, derailed by failure to reach unitisation agreement with Pemex regarding neighbouring acreage. 150 kb/d oil at plateau, plus gas.
Malaysia	Limbayong	Petronas	Retender issued for 60 kb/d FPSO amid operator announcement projects at risk of delay due to Covid-19. FID expected in 2021.

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