Oil 2019

Analysis and forecast to 2024

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INTERNATIONAL ENERGY AGENCY

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FOREWORD

These are times of extraordinary change for the oil industry. Geopolitics is playing a big role again and the global economy is slowing down. Everywhere we look, new actors are emerging and certainties of past years are fading.

A large part of this is due to the United States, the main driver of global oil markets, leading supply growth worldwide over the next five years. Thanks to the remarkable strength of its shale industry, the United States is triggering a rapid transformation of global markets. Before the end of our forecast, it will export more oil than the Russian Federation ("Russia") and close in on Saudi Arabia as the world's largest exporter – a pivotal milestone that will bring greater diversity of supply to global markets.

Iraq will also reinforce its position as one of the world's leading producers. It ranks as the world's third-largest source of new supply to 2024 and drives growth within the Organization of the Petroleum Exporting Countries (OPEC). This is a story of tremendous weight which the International Energy Agency (IEA) is examining here, as well as in a forthcoming report dedicated to Iraq's energy system. This will be released later this year in Baghdad at an event hosted by the government of Iraq.

Global oil demand growth is set to slow modestly, but still averages 1.2 mb/d to 2024, meaning there is no peak demand on the horizon. While demand from the People's Republic of China ("China") is easing, jetfuel and petrochemicals are driving growth, as the IEA highlighted last year in the *Future of Petrochemicals* report.

In the downstream sector, we are on the verge of one of the biggest shake ups the product markets have ever seen, with the implementation of the International Maritime Organisation's (IMO) new rules governing bunker fuel quality in 2020. Although the industry has had several years notice, there are fears of shortfalls when the rules come into effect. Our analysis shows that refiners and shippers are relatively well prepared to respond, though the first year may bring some challenges.

The IEA's core mandate has always been energy security. Our mission has expanded over the years and the definition of energy security has also evolved beyond oil to include natural gas and electricity. But oil market analysis remains a central focus of the IEA, which we demonstrate through our vigilent analysis of market developments and their consequences. We hope this report contributes to a better understanding of the sector and helps develop policies supporting the longer-term transition to a more secure but also a more sustainable energy future.

Dr. Fatih Birol

Executive Director

International Energy Agency

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For questions and comments, please contact the OIMD.

For contact information, please see https://www.iea.org/oilmarketreport/contacts/

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EXECUTIVE SUMMARY

Global oil markets are going through a period of extraordinary change. The United States is increasingly leading the expansion in global oil supplies. Meanwhile, the production of heavier crude grades is hamstrung by sanctions and production restraint in key producing countries. All this contributes to a transformation of global oil supplies, with critical implications for energy security and market balances throughout our forecast period to 2024.

Although the United States had the largest increase in global demand in 2018, growth continues to move away from developed economies and transportation fuels, confirming a shift towards Asia and petrochemicals. These changes will have profound consequences for trade and refining. That sector will also have to adapt to new marine fuel specifications mandated by the International Maritime Organisation, which take effect in 2020, and an impending overhang in refining capacity that will require significant adjustments from refiners globally.

The United States leads global supply growth

The United States continues to dominate supply growth in the medium term. Following the unprecedented expansion seen in 2018, when total liquids production increased by a record 2.2 million barrels per day (mb/d), the United States will account for 70% of the increase in global production capacity until 2024, adding a total of 4 mb/d.

Important contributions will also come from other non-OPEC countries, including Brazil, Canada, a resurgent Norway, and newcomer Guyana, which together add another 2.6 mb/d in the next five years. In total, non-OPEC production is set to increase by 6.1 mb/d through to 2024.

Among OPEC countries, only Iraq and the United Arab Emirates have significant plans to increase capacity. These gains have to offset steep losses from Iran and Venezuela, which are subject to sanctions and political or economic turmoil. As a result, OPEC's effective production capacity falls by 0.4 mb/d by 2024.

The United States is also turning into a major player in the global oil trade

As a result of its strong oil production growth, the United States will become a net oil exporter in 2021, as its crude and products exports exceed its imports. Towards the end of forecast, US gross exports will reach 9 mb/d, overtaking Russia and catching up on Saudi Arabia. The transformation of the United States into a major exporter is another consequence of its shale revolution.

Greater US exports to global markets strengthen oil security around the world. Buyers of crude oil, particularly in Asia, where demand is growing fastest, have a wider choice of suppliers. This gives them more operational and trading flexibility, reducing their reliance on traditional, long term supply contracts.

Global trade is not simply a story for the United States. The second-largest increase in crude exports comes from Brazil, which ships an extra 0.8 mb/d of oil by 2024. Following Brazil, Norway is enjoying a renaissance and will overtake Kazakhstan and Kuwait in the next five years a remarkable achievement.

While upstream investment increases again in 2019, more is needed

Our forecast for supply growth depends on investment. The International Energy Agency (IEA) has argued for many years that with the demand for oil increasing for the foreseeable future, continued investment is necessary to ensure adequate spare production capacity. Our analysis last year looked at the rates of decline in oil fields and found that to keep production steady, the equivalent of the output from the North Sea needed to be offset each year.

This remains true today. It is therefore reassuring that 2019 upstream investment is set to rise for the third straight year, according to preliminary plans announced by key oil and gas companies. For the first time since the 2015 downturn, investment in conventional assets could increase faster than for the shale industry. While US production growth has exceeded expectations, we cannot be complacent about investment levels towards the end of our forecast period and beyond.

Oil demand growth eases in the next five years, but still no peak in sight

Fundamentally, oil demand depends on the strength of the global economy. Recently, the International Monetary Fund (IMF) downgraded its short-term outlook, reflecting weaker economic sentiment in many countries. Ongoing trade disputes between major powers and a disorderly Brexit could lead to a reduction in the rate of growth of international trade and oil demand. But while the economic mood is not encouraging, we expect oil demand to grow in our forecast, although at a more measured pace.

A key factor underpinning demand growth is that leading developing economies will continue to expand. China and India will account for 44% of the 7.1 mb/d growth in global demand expected to 2024. Despite its recent slowdown, China's GDP has more than doubled in real terms in the past decade and is still growing at a healthy clip. Income levels have grown sharply and the structure of oil demand is moving away from heavy industrial sectors towards consumer needs. As for India, while its GDP per capita is still only a fifth of China's, it is growing more strongly: By 2024, India's oil demand growth will match China.

As gasoline slows, petrochemicals and jet fuel are stalwarts of demand growth

Around the world, more consumer demand means more plastic, which in turn means more petrochemicals. Despite efforts to curb plastics use and encourage recycling, demand for plastics and petrochemicals is growing strongly. Led by the United States and China, we have identified more than 50 major projects due to come onstream through 2024. These are expected to add 2.2 mb/d in oil consumption over the forecast period, accounting for 30% of global growth.

This supports expansions in the early part of our forecast at a rate close to today's level. While the lack of complete visibility on new projects causes our estimate to fall towards the end of the forecast period, it is highly possible that more projects will be announced and that demand could be higher than currently anticipated.

The other major growth sector is aviation. In recent years, the air travel industry has witnessed a spectacular expansion thanks to rising passenger numbers. Demand will continue to grow strongly, supported by rising incomes in developing countries, more airports being built and growing airline fleets. Asia accounts for 75% of this increase over our forecast period. In absolute terms, while China sees the largest jump in demand, India posts the fastest rate of growth, at an impressive 8.2% a year.

At the same time, efficiency improvements and fast-expanding markets reaching maturity will tamper the increase in the global jet fuel market, according to our forecast.

As for gasoline, ongoing efficiency improvements will cause the global rate of growth to slow to less than 1% per year. In developing countries, however, the rate is twice as high, as rising income levels lead to more vehicles on the road.

The IMO regulations: Shippers and refiners prepare to comply

The 2020 IMO marine regulation change is one of the most dramatic ever seen to product specifications, although the shipping and refining industries have had several years notice. We believe that industry players are in a strong position to adjust in the medium term, with the largest incremental volumes coming from the United States, the Middle East, and China. Still, the market will initially be tight and there will be some non-compliance. Orders for scrubbers to be fitted on ships have increased, and our analysis of refiners' plans suggests that, as demand for high sulphur fuel oil plummets, there will be enough availability of marine gasoil and, in time, a new ultra-low sulphur fuel oil to plug the gap.

Prices for gasoil could rise at first as demand from the marine sector increases, but sluggish growth from inland sources of demand will limit the pressure. Meanwhile, unwanted high sulphur fuel oil could find a home in the power sector, with the Middle East a likely market.

Refiners face twin challenges: A capacity boom, and changes in crude and product quality

The refining industry is facing a wave of new capacity additions in the period to 2024, with a net growth of about 9 mb/d. China will overtake the United States to become the global leader in installed capacity. Given that these new additions far exceed the increase in demand for refined products, plant closures might be necessary to rebalance the market, though questions remain as to where and when that will happen.

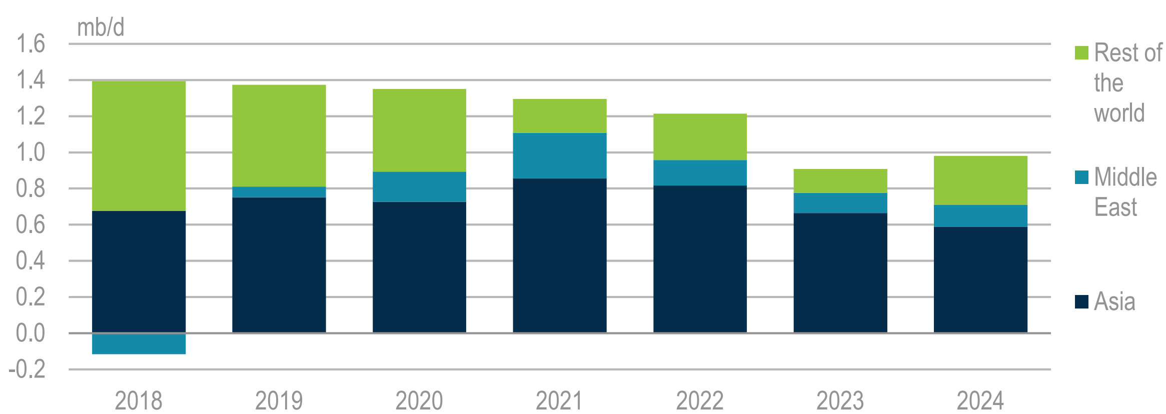
While the global average crude oil barrel produced remains predominantly a medium gravity sour grade, the availability of heavier crude from several countries is in doubt due to production cutbacks and geopolitical challenges. At the same time, the average global product barrel is getting lighter as fuel oil demand falls and petrochemicals grow in importance. As a result, the United States will be in prime position as a supplier of light types of crude oil that are in growing demand. Shale oil will also help meet the new IMO requirements and provide the quantities of naphtha required for the petrochemicals industry.

1. DEMAND

Highlights

- From 99.2 million barrels per day (mb/d) in 2018, we expect global oil demand to grow to 106.4 mb/d in 2024. This represents an annual average growth rate of 1.2 mb/d (1.2%) and a total volume increase of 7.1 mb/d.
- Asia Pacific will be the fastest growing region, contributing 4.4 mb/d of the total. The Middle East increases by 0.9 mb/d, while Africa and the Americas expand by 0.6 mb/d and 0.9 mb/d, respectively. European oil demand is expected to post a 0.1 mb/d decrease.
- Within the products, the fastest growth will come from liquefied petroleum gas (LPG) and ethane, as well as naphtha. New petrochemical facilities will add 2.2 mb/d to oil consumption over the forecast period comprised of 1.4 mb/d of LPG and ethane, and 0.8 mb/d of naphtha.
- Strong gains will also be seen in jet kerosene consumption as air travel becomes more accessible in developing countries. Demand is set to increase by 1.9% per year on average, adding 0.9 mb/d to total oil demand to 2024.
- Gasoline demand growth slows over the period to 0.7% per year due to efficiency improvements. Gasoil demand growth rises to 0.9%, supported by a switch away from fuel oil due to the 2020 International Maritime Organisation (IMO) regulations. Environmental policies, in People's Republic of China ("China") in particular, will nevertheless have a significant impact on inland gasoil demand in the medium term.
- The IMO regulations will push large volumes of high sulphur fuel oil (HSFO) out of the marine fuel pool. Some displaced HSFO is likely to be used for power generation, at least temporarily. Our overall view on the IMO regulations is that they are manageable in the medium term - see chapter *Special Feature: IMO 2020, Calm after the storm*.

Figure 1.1 Global oil demand, year-on-year change



Global overview

The increase in global oil demand slowed to 1.3 mb/d in 2018, as a rise in oil prices partially offset the benefit of robust economic growth. Demand in OECD countries rose by 430 thousand barrels per day (kb/d) in 2018 versus 450 kb/d in 2017 as a slowdown in OECD Asia and OECD Europe was more than compensated for by a very strong US expansion of 560 kb/d. In 2019, world oil demand should rise by 1.4 mb/d, supported by petrochemical developments and lower prices. Strong growth is expected to 2022 but the pace will slow at the end of the forecast period due to efficiency improvements. Demand in OECD countries will remain stagnant over the medium term. We project a slow increase for the OECD Americas, largely due to the start-up of petrochemical projects, and some decline in OECD Europe and in OECD Asia.

Non-OECD demand is set to increase by 2.3% per year to 2024. Asia will post the fastest increase, supported by growth in China and India. China's growth will slow over the forecast, from 450 kb/d in 2019 to 165 kb/d in 2024. Indian demand growth will also decelerate, but at a slower rate, from 235 kb/d in 2019 to 160 kb/d in 2024, at which point volume growth in India will be almost the same as in China. Demand in the Middle East will bounce back in 2019 and in 2020-21, following the implementation of the IMO marine fuel regulations, the region will benefit from a temporary increase in the use of fuel oil in the power sector.

Other non-OECD regions will post slower growth, from 1.2% per year in Latin America to 2.3% per year in Africa. The Former Soviet Union (FSU) and Latin America will nevertheless each add roughly 460 kb/d to world oil demand in 2018-24.

Table 1.1 Global oil demand by region (mb/d)

	2018	2019	2020	2021	2022	2023	2024	2018 - 2024 Growth rate	2018 - 2024 Annual growth
North America	25.2	25.6	25.7	25.6	25.7	25.6	25.7	0.3%	0.07
Central and South America	6.8	6.7	6.8	7.0	7.0	7.1	7.2	1.1%	0.08
Europe	15.8	15.9	15.9	15.8	15.8	15.8	15.7	-0.1%	-0.01
Africa	4.3	4.4	4.5	4.6	4.7	4.8	4.9	2.3%	0.10
Middle East	8.4	8.5	8.6	8.9	9.0	9.1	9.2	1.6%	0.14
Eurasia	4.2	4.3	4.5	4.5	4.6	4.6	4.6	1.5%	0.06
Asia Pacific	34.5	35.3	36.0	36.9	37.7	38.3	38.9	2.0%	0.73
World	**99.2**	**100.6**	**102.0**	**103.3**	**104.5**	**105.4**	**106.4**	**1.2%**	**1.19**

In the medium term, three major elements will impact product demand. First; expansion of the petrochemical sector on the back of strong Chinese demand for petrochemical products and growing US ethane output. Second; the fast growing aviation sector. Third; the new IMO regulations which will trigger deep changes in the structure of products demand.

LPG and ethane, as well as naphtha, post the strongest growth, supported by petrochemical developments. LPG/ethane and naphtha demand resulting from the start-up of new petrochemical projects accounts for roughly 30% of world oil demand growth by the end of the forecast, with demand for these products expected to rise by 2.6% per year to 2024. This is detailed in *Continuous demand growth for petrochemicals.*

Kerosene demand is expected to rise by 1.9% per year on average on booming air transport, particularly in China and India, and jet fuel has become a major contributor to global oil consumption growth. Jet/kerosene demand accounts for 13% of total growth to 2024. For analysis of jet kerosene demand by region see section *Strong Asian demand for jet fuel makes it a key contributor to growth*.

Table 1.2 Global oil demand by product (mb/d)

	2018	2019	2020	2021	2022	2023	2024	2018 - 2024 Growth rate	2018 - 2024 Annual growth
LPG & ethane	12.4	12.8	13.2	13.5	13.9	14.1	14.5	2.6%	0.35
Naphtha	6.3	6.5	6.7	6.8	7.1	7.2	7.4	2.6%	0.17
Motor gasoline	26.0	26.3	26.6	26.8	27.0	27.1	27.2	0.7%	0.20
Jet/kerosene	7.8	8.0	8.2	8.3	8.5	8.6	8.7	1.9%	0.15
Gasoil/diesel	28.5	28.8	29.9	29.9	30.0	30.1	30.2	0.9%	0.27
Residual fuel oil	7.0	7.0	6.2	6.6	6.7	6.8	6.9	-0.1%	-0.01
Other products	11.2	11.2	11.2	11.2	11.3	11.4	11.5	0.4%	0.05
Total products	**99.2**	**100.6**	**102.0**	**103.3**	**104.5**	**105.4**	**106.4**	**1.2%**	**1.19**

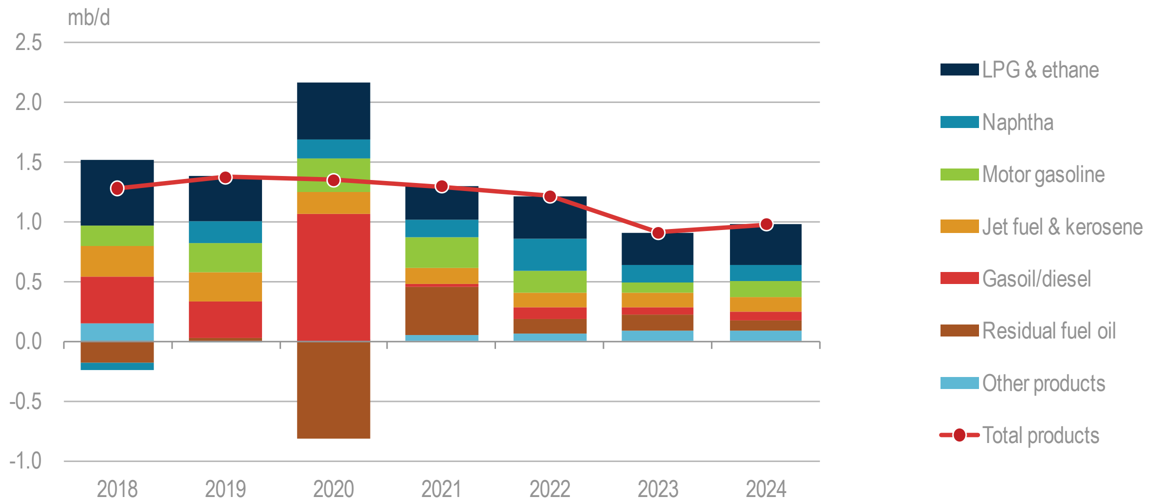
Note: Residual fuel oil includes the new 0.5% marine fuel.

The evolution of oil demand by fuel type largely reflects the major changes due to take place in marine bunker fuel demand in 2020. Fuel oil demand, after a sharp fall in 2020, recovers over the rest of the forecast period. HSFO bunker fuel is initially replaced by marine gasoil but over time a new very low sulphur fuel oil (VLSFO) increases its market share through the end of the forecast. In 2020, there will be a small, temporary, increase in fuel oil demand for power generation and cement production, as these sectors mop up some of the excess material resulting from the implementation of the IMO regulations. This is described in the section *IMO will temporarily boost fuel oil in the power sector*. Note that the new 0.5% sulphur marine fuel, which will replace some high sulphur bunker demand, is included in the residual fuel oil category.

To 2024, gasoline demand will rise by 0.7% per year on average. In non-OECD countries, more car ownership will see gasoline demand grow by 2.4% per year. In the OECD, disaffection with diesel in Europe and the freezing of US Corporate Average Fuel Economy (CAFE) standards at their 2021 levels should also reinforce gasoline demand. Improvements in the fuel economy of cars, however, will see gasoline demand decline by -0.6% per year over the forecast period.

Total gasoil demand growth is expected to average 0.9% per year to 2024. Marine demand will grow at 12.7% per year, supported by the IMO regulations from 2020, while inland demand will grow at a slower rate of 0.4% per year. Diesel demand in the United States recently benefited from booming industrial production along with increased crude oil trucking, due to infrastructure constraints, but the impact of these factors should diminish over the forecast period. The impetus of massive tax cuts will disappear in the medium term and new pipelines are coming on stream to support tight oil developments. Recently diesel demand growth has been particularly slow in Europe, reflecting lower economic growth, the falling popularity of diesel cars following the Volkswagen scandal and widespread action to ban diesel cars for environmental reasons. These factors have contributed to a plunge in the share of diesel cars in total European sales. Diesel consumption is also plateauing in China, due to reduced coal transportation and as the country moves towards a more "qualitative" growth model. Globally, the expected weakness in inland gasoil demand will help to alleviate any market disruption that follows the implementation of the IMO regulations in 2020.

Figure 1.2 Global oil demand by product and fuel oil breakdown, y-o-y change



Macroeconomic environment and prices

The International Monetary Fund's (IMF) *World Economic Outlook,* published in January 2019, provides the main macroeconomic assumptions for our oil demand outlook. After global gross domestic product (GDP) growth of 3.5% in 2019, the IMF expects world output to expand by around 3.6% per year to 2023. For our forecast we have assumed a growth rate of 3.5% in 2024.

Table 1.3 Real GDP growth

	2017	2018	2019	2020	2021	2022	2023	2024
United States	2.2%	2.9%	2.5%	1.8%	1.7%	1.5%	1.4%	1.3%
Japan	1.9%	0.9%	1.1%	0.5%	0.7%	0.5%	0.5%	0.5%
China	6.9%	6.6%	6.2%	6.2%	6.0%	5.8%	5.6%	5.5%
India	6.7%	7.3%	7.5%	7.7%	7.7%	7.7%	7.7%	7.8%
Germany	2.5%	1.5%	1.3%	1.6%	1.5%	1.3%	1.2%	1.0%
Russia	1.5%	1.7%	1.6%	1.7%	1.6%	1.3%	1.2%	1.1%
Brazil	1.1%	1.3%	2.5%	2.2%	2.2%	2.2%	2.2%	2.2%
South Africa	1.3%	0.8%	1.4%	1.7%	1.8%	1.8%	1.8%	1.8%
World	3.8%	3.7%	3.5%	3.6%	3.6%	3.6%	3.6%	3.5%

Note: World growth Purchasing Power Parity weighted.
Source: Based on IMF (2019), *World Economic Outlook*.

Confidence in the health of the world economy has deteriorated since last year's report. Tighter financial conditions, rising trade tensions, slowing Chinese growth and a deceleration in global industrial activity have dampened optimism. Even so, for now, there has been no major downward revision to the economic outlook. Slowing growth is expected to trigger monetary and fiscal policy reactions, prompting a rebound in world economic activity from 2020. Indeed, major central banks, in particular, are adopting a cautious approach to policy normalisation. Furthermore, emerging market currencies are starting to recover from the sharp depreciation experienced against the dollar and other major currencies in the summer of 2018.

In 2018, Chinese GDP grew at 6.6%, the slowest pace in almost 30 years, reflecting the fact that the economy is getting bigger and more mature. To combat this, the government has implemented fiscal and monetary stimulus such as $125 billion (United States dollars) of railway and subway projects, new quotas of bond sales to local governments to finance infrastructure projects and tax cuts to support small businesses and manufacturers. On the monetary front, the central bank is encouraging lending by cutting the required reserve ratio for Chinese banks and injecting record levels of liquidity into the banking system. However, rising trade tensions remain a major risk for the Chinese economy. GDP growth is forecast at 6.2% in 2019 and 2020, decelerating through the end of the forecast. This is still, however, a major driving force behind global economic growth.

The slowdown in China is putting pressure on its trade partners and partly explains the weakness seen elsewhere. At the end of 2018, industrial production in the Eurozone posted its largest decline in almost three years. In the United States, the economy will have to adapt to higher interest rates and the positive impact of 2018's tax cuts will fade. On the other hand, consumption remains strong and investment seems to be robust. US GDP growth is expected at 2.9% in 2018, slowing to 2.5% in 2019 and 1.8% in 2020 with the unwinding of the fiscal stimulus.

By contrast, GDP growth in India is set to accelerate from 7.3% in 2018 to 7.8% through the end of our forecast period. Lower oil prices, and slower monetary tightening as inflationary pressures remain subdued, will help.

Growth in Latin America is expected to accelerate from 1.1% in 2018 to 2% in 2019 and 2.5% in 2020. There is a high level of uncertainty for the region's economic prospects given the political situations in Brazil and Argentina and the possibility of a complete collapse in Venezuela. In the Middle East, growth is expected to accelerate slightly, from 2.4% in 2018 to 3% from 2020. In Africa, growth will also accelerate from 2.9% in 2018 to 3.5% in 2019 and 3.6% in 2020. Russian Federation's ("Russia") GDP growth is expected at 1.6-1.7% in 2018 to 2021, slowing thereafter.

In this five-year outlook, the Brent futures curve at the end of 2018 is used as the price indicator. An important exception to the generally moderate price climate in the next few years is gasoil. In 2020, prices could jump by roughly 20% as a consequence of the implementation of the IMO's new marine fuel specifications. This might trigger a temporary slump in demand in other sectors and an adjustment on the supply side, possibly helping refiners to produce enough compliant fuel for the bunker pool.

Continuous demand growth for petrochemicals

The petrochemicals industry will be a large source of growth for oil demand throughout the forecast period. New projects using LPG, ethane and naphtha as feedstock will see demand increase by 2.6% per year, more than any other category.

The projects, both steam cracker and propane dehydrogenation (PDH), identified in this section will likely add 2.2 mb/d to global oil demand by 2024. LPG and ethane will be the main beneficiary (1 440 kb/d), followed by naphtha (750 kb/d). Countries showing the strongest growth are China and the United States, with Russia also a major player. Growth in Islamic Republic of Iran ("Iran") is rather less certain due to political factors. For naphtha, strong growth will be observed in China and other developing countries, which account for more than 85% of cumulative naphtha demand growth to 2024.

Table 1.4 New LPG/ethane petrochemical feedstock requirements (cumulative, kb/d)

	2019	2020	2021	2022	2023	2024
United States	170	304	359	453	510	666
China	54	100	208	254	270	284
Russia	0	102	115	115	121	123
Iran	0	19	21	73	83	134
Other countries	31	56	57	161	218	236
Total *	**256**	**580**	**761**	**1 057**	**1 202**	**1 443**

* 16 selected countries.
Source: IEA calculations, press reports, company reports.

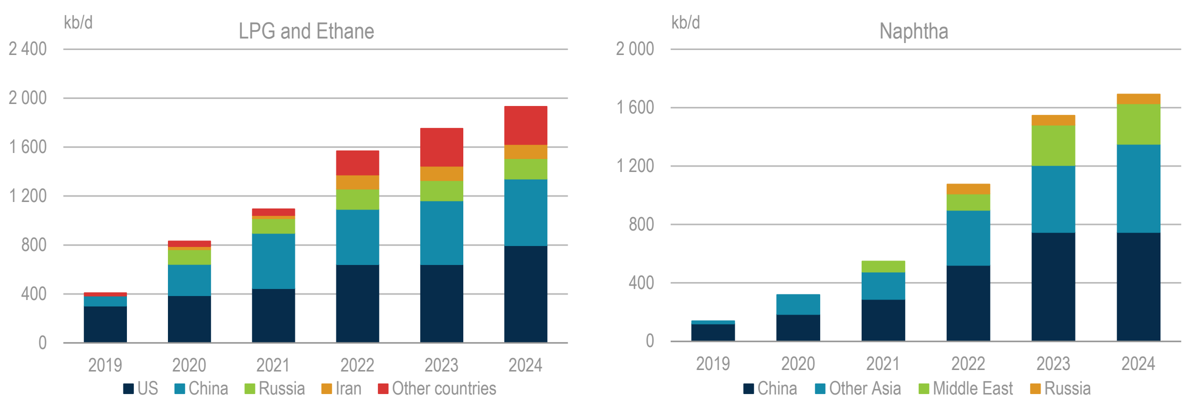
Table 1.5 New Naphtha petrochemical feedstock requirements (cumulative, kb/d)

	2019	2020	2021	2022	2023	2024
China	67	115	200	276	296	310
Indonesia	0	0	2	2	48	105
Korea	13	16	15	42	72	87
India	0	0	0	60	71	72
Malaysia	4	62	73	73	73	73
Other countries	0	14	22	83	97	102
Total *	**83**	**207**	**312**	**537**	**658**	**748**

* 16 selected countries.
Source: IEA calculations, press reports, company reports.

Projects currently under construction or confirmed are included in our demand projection. There is the potential for additional projects to be sanctioned. Figure 1.3 shows the maximum capacity feedstock requirement for petrochemical projects possibly coming on stream by 2024. Details of these projects are available in the appendix of this report.

Figure 1.3 Maximum additional capacity feedstock requirement (kb/d)



Source: Press reports, company reports.

The rapid growth of shale oil and gas production has seen the **United States** rapidly add capacity. By 2024, it is estimated that there will be a further increase in ethylene production capacity of nearly 14 million tonnes per year (mt), from the current level of 35 mt. Some of the large-scale ethylene plants are expected to be part of integrated petrochemical complexes with polyethylene units within them. This wave of new projects will help the United States to not only meet growing domestic demand but may also supply ethylene to export markets. Overall, these projects will cause US LPG/ethane demand to rise by 665 kb/d by 2024.

China is one of the world's largest producers and consumers of plastics. As the economy becomes increasingly consumer-focused, over 21 mt of petrochemical capacity is due to come on stream by 2024. Unlike in the United States, Chinese capacity additions are mainly naphtha crackers. However, this report sees a significantly increased estimate for LPG requirements because of newly announced PDH projects. The new crackers can switch part of their feedstocks from naphtha to gasoil or LPG. China is also planning to use ethane imported from the United States as a feedstock, for example at SP Chemical's 650 tonne per year (t/y) project that could be ready in 2019. When they come on stream, these projects will increase Chinese naphtha demand by 310 kb/d and LPG and ethane demand by 285 kb/d by the end of the forecast period.

In **Russia** over 3.5 mt of new production capacity is under construction. It is assumed that these will increase LPG and ethane demand by 125 kb/d and naphtha demand by 30 kb/d by 2024.

Steam cracker additions in **Iran** could bring a maximum of 2.4 mt of incremental capacity between 2020 and 2022. New ethylene capacity will be supplied from the development of the South Pars gas field, the world's largest, which straddles the border with Qatar. Overall, the development of the petrochemical industry would increase Iran's LPG and ethane demand by 135 kb/d by 2024, a slight upward revision from *Oil 2018* due to additions of PDH projects in 2022.

Korea will possibly add 3.2 mt of capacity, which would result in extra demand for LPG and ethane of 45 kb/d and naphtha of 85 kb/d. This is slightly higher than in last year's report as newly announced naphtha-based projects are included.

In Southeast Asia, **Malaysia** will start commercial operations of a 1.2 mt capacity naphtha cracker in 2020, which will add approximately 70 kb/d of demand.

Thailand will add 0.75 mt of capacity by 2021, which will increase LPG and ethane consumption by 20 kb/d and naphtha demand by 20 kb/d.

In **Indonesia**, a few naphtha crackers are expected to be on stream by 2024. If all these projects are sanctioned and start their operations on time, naphtha demand could increase by 105 kb/d.

Belgium will see propane demand increase by 50 kb/d due to new PDH projects in Antwerp expected to start operations by 2023.

IMO will temporarily boost fuel oil in the power sector

Demand for HSFO by the shipping industry will drop by 2.1 mb/d (-57%) in 2020 as the IMO's new sulphur regulations come into effect. Planned refinery investments will be capable of eliminating a large volume of HSFO, by reducing its sulphur content to an acceptable level, but there is still likely to be a surplus in 2020 and beyond. Clearly, this will have a negative impact on the price of HSFO, which may decline to a level where it encourages increased utilisation in urban heating, heavy industry and power generation. In the forecast, an increase in fuel oil demand in the power sector will be limited to countries with idle capacity that could increase utilisation or locations currently building new fuel oil-fired capacity. There is 150 gigawatts (GW) of fuel oil-fired capacity globally, with a further 11 GW under construction, most of which is in Saudi Arabia. It is assumed that, under favourable price conditions, these plants could increase their utilisation rate to a maximum of 50%, with 32% efficiency. Furthermore, it is assumed that the incremental global fuel oil demand largely displaces crude oil directly used in the power sector. Increasing fuel oil penetration will however face difficulties even if HSFO prices fall below the price of competitors. Fuel oil has been phased out of power generation in many countries for environmental reasons and regulations could prevent its reintroduction. In addition, we expect the additional fuel oil demand to be temporary. Fuel oil markets will rebalance relatively swiftly on refinery improvements and higher scrubber use by shippers. HSFO prices are expected to increase as the surplus narrows. Additional fuel oil demand is expected to remain largely in the Middle East and to peak in 2021, before declining through the end of the forecast.

Saudi Arabia, in anticipation of the coming changes in the structure of oil demand, has started to replace crude oil and gasoil-fired generation by natural gas and made investments to increase its fuel oil capacities. Of the 11.1 GW of fuel oil-fired capacity under construction today around the world, 8.5 GW are in Saudi Arabia. These include the Jazan 2.5 GW project associated with the new 400 kb/d Jazan refinery. The plant will use gasified vacuum residue and HSFO as a feedstock to produce synthetic gas for electricity generation. It is the largest gasifier-based power plant in the world, producing power for both the refinery and the national grid. Saudi Aramco expects the refinery and the power plant to be operational in 2019. A further 5 980 MW of large steam turbines using HSFO as a feedstock are also being commissioned. These projects come with fuel gas de-sulphurisation (scrubber) equipment. The two largest steam turbines using heavy fuel oil as feedstock are Saudi Electricity Company's Shuqaiq 2 880 MW plant and Saline Water Conversion Corporation's Yanbu 3 100 MW plant. Already, Saudi Arabia has 18.3 GW of oil-fired capacity. These plants used an estimated 400 kb/d of crude oil in 2018. They could relatively easily switch to using fuel oil as feedstock. Further to the oil-fired plants and new capacity additions, there is also 19.6 GW of existing power capacity currently using natural gas that is capable of using oil as an alternative. Overall, in Saudi Arabia the power generation sector is projected to increase its use of fuel oil from its 2019 levels by 110 kb/d in 2020, 170 kb/d in 2021 and 200 kb/d thereafter. The incremental fuel oil will initially be used in the new oil-fired projects coming on stream and will thereafter largely displace crude oil.

Iraq has 14.1 GW of capacity using crude oil or HSFO as a feedstock. There is limited opportunity to further increase fuel oil use as significant crude oil volumes have already been displaced. In 2018, Iraq used an estimated 240 kb/d of fuel oil for power generation, up 150 kb/d year-on-year (y-o-y). Meanwhile, crude demand fell by 40 kb/d y-o-y. Assuming that Iraq uses oil-fired capacities at 60% of capacity with an efficiency rate of 32%, fuel oil use could increase by 70 kb/d. The forecast assumes that fuel oil will grow compared to 2019 by 20 kb/d in 2020, 40 kb/d in 2021 with growth returning to 20 kb/d in 2024 as Iraq increases its use of Iranian natural gas and the fuel oil market rebalances.

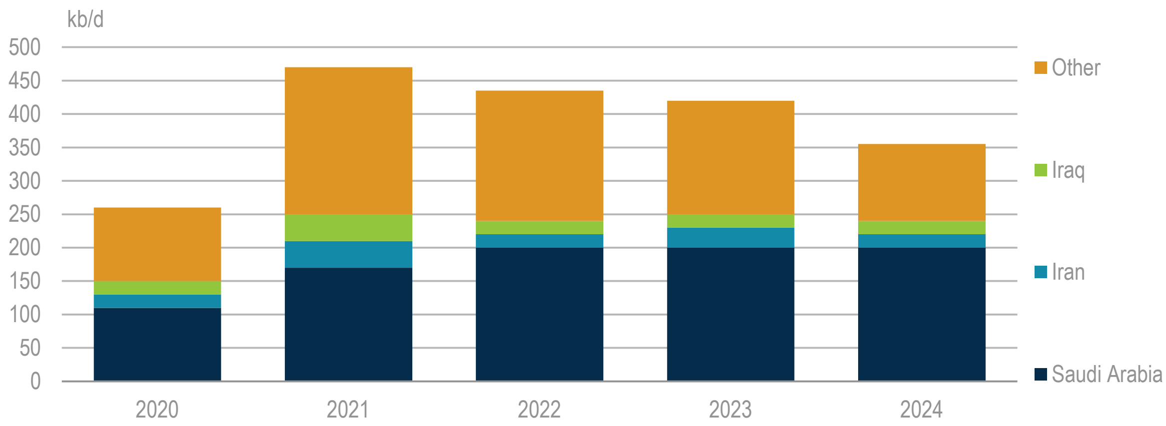
Iran could also increase consumption of fuel oil. It has largely switched is power fuel mix to natural gas but this could be temporarily reversed. Fuel oil consumption in the power sector fell to 75 kb/d in 2016, from 115 kb/d in 2015 and 260 kb/d in 2013. Some 32.4 GW of capacity, mainly using natural gas, is reportedly capable of switching to fuel oil and this could consume up to 680 kb/d, assuming a capacity utilisation rate of 50% and an efficiency rate of 32%. Furthermore, should US sanctions remain in place Iran may be forced to reduce its production of natural gas if it can no longer export the associated condensates. Iran's power sector is forecast to use an additional 20 kb/d of fuel oil in 2020 and 40 kb/d in 2021 compared to 2019. The use of fuel oil will thereafter decrease.

Kuwait has 8.3 GW of oil-fired capacity. Most of this is fed with fuel oil (105 kb/d), with crude oil used to a lesser extent (50 to 60 kb/d during the summer months). There is idle capacity that would allow a 60 kb/d increase in fuel oil consumption. However, the forecast sees demand growing compared to 2019 by 10 kb/d in 2020, 30 kb/d in 2021, with growth vs. 2019 returning to 20 kb/d from 2022.

Russia has the world's largest district heating network, mostly fuelled by coal and natural gas. This sector could use slightly more fuel oil, particularly as Russia is the world's largest producer and exporter and so could have large surplus volumes from 2020. Many Russian refineries plan to upgrade and add cokers, but these projects may not be operational before 2020 or 2021. Alternatively, HSFO could replace some coal or gas used as fuel in cement factories or be used as a domestic marine fuel in some areas. These opportunities allow incremental fuel oil demand compared to 2019 of 10 kb/d in 2020, and 20 kb/d in 2021 before market rebalancing sees the additional demand decline to zero in 2024.

It is also expected that there will be small increases of fuel oil utilisation in the power or cement sectors of several other non-OECD countries, including **Brazil**, **China**, **India**, **Thailand** and **Libya**, where there is some spare capacity at existing facilities. Overall, fuel oil demand would get a boost compared to 2019 of 260 kb/d in 2020 peaking at 470 kb/d in 2021 before returning to 420 kb/d in 2023 and 355 kb/d in 2024 as the fuel market rebalances, secondary refinery units come on stream and countries switch back to natural gas.

Figure 1.4 Incremental inland fuel oil demand vs. 2019



Strong Asian demand for jet fuel makes it a key contributor to growth

Air passenger traffic has soared thanks to the proliferation of low-cost air carriers (LCCs), investments in aviation infrastructure and as rising incomes allow more people to travel for work or leisure. This trend is set to continue and will underpin a 2.1% annual increase in demand for jet fuel, to 7.2 mb/d in 2024. Growth will continue to be led by Asian consumers as increasing prosperity swells the middle class, which has a much higher propensity to travel, and as LCCs penetrate the market. At the same time, governments are pursuing policies to improve connectivity to capture the associated economic benefits. Faster, cheaper and more comfortable air travel can encourage tourism and makes it easier to do business. Overall, non-OECD Asia jet fuel demand will grow by 5% per annum (p.a.) to 2 mb/d in 2024. In absolute terms, China has the largest increase in consumption (+255 kb/d by 2024) but it is India that posts the fastest rate of growth, an impressive 8.2% p.a. By 2024, the emerging Asian economies will account for 28% of global demand. The more mature markets of North America will also expand, with demand growing at a rate of 1.5% p.a. In the United States, which is the world's biggest market in terms of passenger numbers, demand is supported by healthy GDP growth and airport expansions that offer more routes. Meanwhile, in OECD Asia Pacific and OECD Europe demand is flat. In these regions, LCCs have already taken a large share of the market and alternatives, such as high-speed rail, are popular. Turkey is an outlier with 3.3% p.a. demand growth in the medium term thanks to the opening of the new Istanbul Airport which will become a regional hub.

Figure 1.5 Jet fuel demand growth

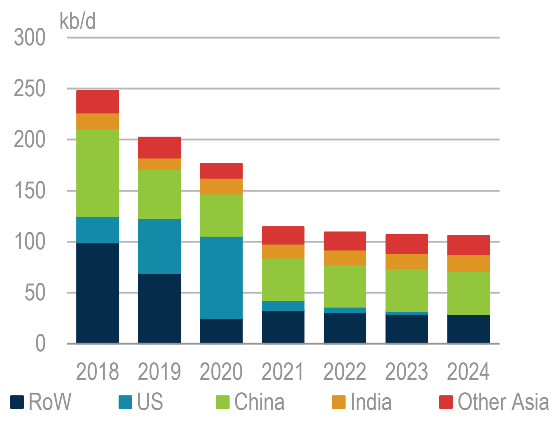
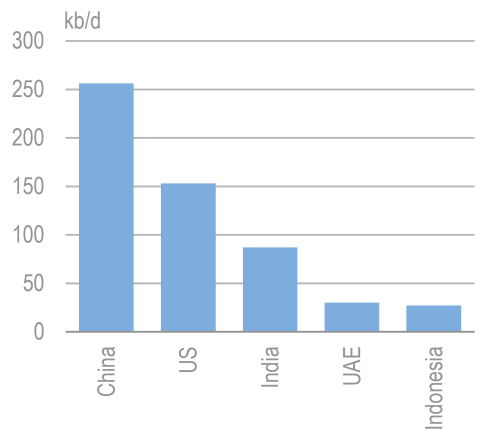


Figure 1.6 Top 5: Jet fuel demand growth (2018-24)



Thanks to jet engine improvements and sharply increasing load factors,[1] energy efficiency (measured as fuel use per RPK)[2], improved by 3.7% p.a. between 2000 and 2017. As fuel costs are typically 20% to 30% of an airline's expenses, there is a strong incentive to pursue further efficiency gains. The industry also has ambitious targets to tackle its carbon dioxide (CO_2) emissions, which, with strong passenger growth expected, could account for 3.5% of global emissions by 2030.[3] Electric planes and sustainable aviation fuels, such as biofuels, have an important role to play in the long term, but in the

[1] Load factor measures the number of passengers on the aircraft.

[2] Revenue passenger kilometres (RPK) measures the distance travelled by paying passengers. RPK is allocated to a country based on where the air carrier is registered. RPK data is sourced from Air Passenger Market Analysis, IATA.

[3] According to the World Energy Outlook 2018 New Policies Scenario (IEA).

medium term fundamental technological change is unlikely. More modest efficiency improvements of 1.5% p.a. to 2024 are driven by fleet turnover (which occurs relatively slowly in the aviation industry), higher load factors and better routing practices. For a comprehensive analysis of aviation energy efficiency policies and developments, see the IEA report *Energy Efficiency 2018 – Analysis and outlooks to 2040.*

For this report, our analysis shows that developing countries' demand has a stronger positive response to GDP growth than in the developed world. As the middle class grows, there is a strong increase in the propensity to travel. However, this is limited, for example, by the number of holiday days available, and at a certain level of economic maturity the GDP elasticity declines. Price elasticities are generally estimated to be lower than GDP elasticities, but price changes can be very significant and thus have a strong impact on demand.

Figure 1.7 Air passengers

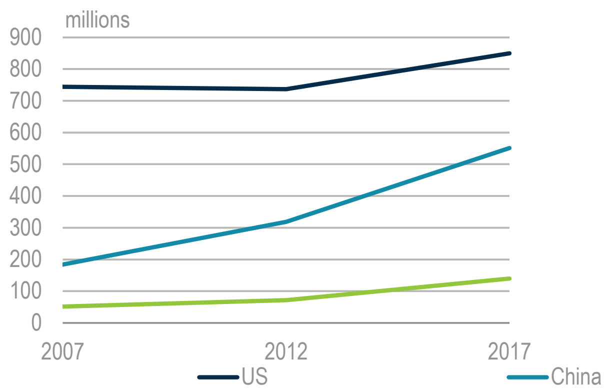
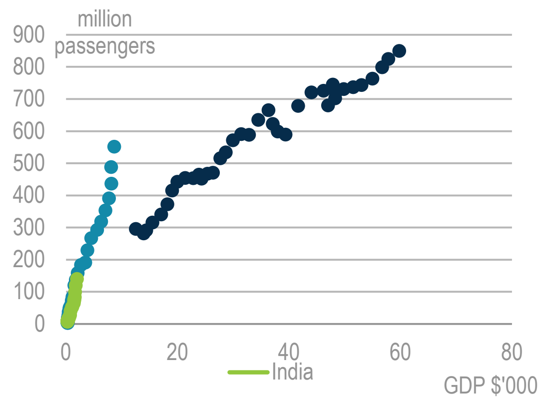


Figure 1.8 Passengers vs GDP/capita



Source: World Bank, International Civil Aviation Organization, Civil Aviation Statistics of the World, IMF

In 2000 to 2017, in **OECD North American** countries when GDP grew by 1%, jet fuel demand grew by 0.85%. North American jet fuel consumers are less responsive to price movements. The results of the simulation show that for a 1% increase in Brent prices, jet demand shrinks by 0.08%.

The **United States** is, by some distance, the world's largest consumer of jet fuel and, despite the aviation market being mature, further growth is expected. In July 2018, during the peak travel season, US RPK touched a record high of 160 billion, and in recent months growth has been consistently above the five-year average of 4.2%. Over the forecast period, US jet fuel demand is expected to grow at 1.5% p.a., on the back of strong forecasts for passenger growth and airport expansions. Having become a key issue in **Mexico's** 2018 election, the new government has halted the construction of Mexico City's new airport. Upgrades to existing infrastructure are planned and these, along with more routes to US cities, will support jet fuel demand growth of 1.3% p.a. in the medium term. **Canada** is also an important consumer, with demand of 150 kb/d in 2018. This will grow at 0.7% p.a. to 2024, a slowing of the pace seen in the past few years.

Jet fuel consumers in **OECD Europe and Asia** have the same response to GDP growth as those in North America, and they are slightly less responsive to price changes. The major demand centres of **France**, **Germany** and the **UK**, see little increase in consumption as efficiency improvements offset gains from modest GDP growth. LCCs have already made significant inroads into European markets, and they contributed to a 4.9% p.a. increase in jet fuel demand in the past five years. LCCs focus on maximising load factors to reduce costs and this has driven strong efficiency improvements. In 2018, with demand of 105 kb/d, **Turkey** ranked as the world's 17th largest consumer for jet fuel. Over the past decade its aviation sector has expanded dramatically, with passenger numbers increasing five-fold, while jet fuel demand has almost tripled. The expansion looks set to continue following the recent opening of a contender for the title of "the world's largest airport" in Istanbul. Capable of managing 90 million passengers per year, Istanbul Airport is increasing its capacity to 200 million by 2023. Jet fuel demand is forecast to grow by 3.3% p.a. to 2024, to 125 kb/d, on the back of strong GDP growth (2.5% p.a.) and an increase in passenger numbers of 40%.

Figure 1.9 Jet fuel demand OECD Europe

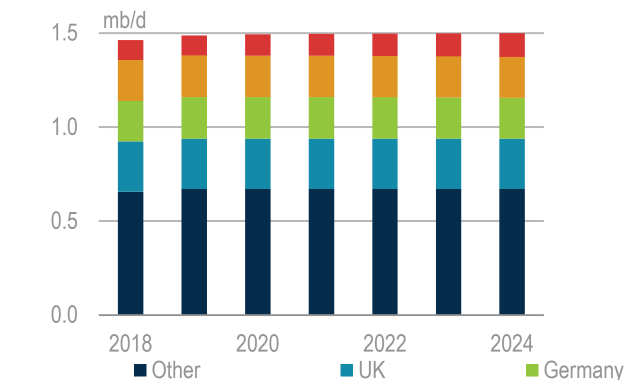
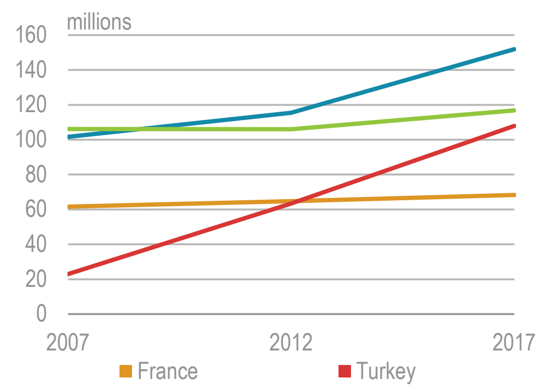


Figure 1.10 Air passengers



Source: World Bank, International Civil Aviation Organization, Civil Aviation Statistics of the World, IMF

In **Australia**, expansion at Perth airport will see it join the country's three other aviation mega-cities by 2022.[4] Jet fuel demand will grow at 1.4% p.a. putting Australia into the ranks of the world's top ten consumers by 2024. Increased availability of cheap flights, a geography that allows few alternatives to air travel, and higher tourism has seen passenger numbers increase by 2.9% p.a. for the past few years. Conversely, with the economy growing at only 0.6% p.a. to 2024, there will be a decline in **Japanese** jet fuel demand of 0.5% p.a. The expanded high-speed rail network, fuelled by electricity, as an alternative to air travel has weighed on jet fuel consumption.

Emerging markets in **non-OECD Asia** will be the major source of growth for jet fuel demand. Regression analysis for the period 2000 to 2017 shows the GDP elasticity was 1.05. For this region, increases in demand seen to 2024 are largely due to higher living standards and supportive government policy. The International Air Transport Association (IATA) forecast that **China** will overtake the United States as the world's largest market, in terms of RPK, by 2022. Passenger numbers have seen double-digit growth for the past five years, and this looks likely to continue. In late 2018, the Civil Aviation Administration of China unveiled an ambitious plan to almost double the number of airports by 2035, 74 of which could be operational by 2020, and improve efficiency in order to meet the growing needs of travellers. In addition, the 68 countries receiving infrastructure investment as part of the "Belt and Road Initiative" will see higher traffic to and from China. With an estimated 7 000 new planes required over the next 20 years, China will continue to be a key market for aircraft manufacturers and fleet additions are expected to be 20% more efficient than the aircraft

[4] An "aviation mega-city" is defined by Airbus as airport having more than 10 000 daily long haul passengers (Global Market Forecast: Global Networks, Global Citizens, 2018-2037, Airbus, 2018).

they replace. China will maintain its number two spot in terms of jet fuel demand, with growth of 5.6% p.a. to 2024 (+255 kb/d). However, this is much slower than the 11.5% p.a. seen in recent years.

India is the world's fastest growing aviation market, having seen double-digit y-o-y monthly RPK growth since September 2014. Over the past three years, a combination of a strong economy, increased airport connectivity and falling air fares have contributed to a surge in the number of passengers to over 160 million, when only a decade ago there were 50 million. In recent years the number of domestic carriers has almost doubled, and increased competition has seen fares drop by 20%, allowing many more Indians to enjoy the convenience of flying between major cities, as opposed to time-consuming travel by rail. Furthermore, keen to encourage connections to rural towns, the government intends to offer subsidies and cap fares. A rising middle class and ambitious government-backed plans to enhance the aviation infrastructure will likely see India's jet fuel demand continue to grow at 8.2% p.a. over the forecast period. At 280 kb/d in 2024, India will become the world's fourth-largest consumer. Other Asian economies, such as **Indonesia**, **Malaysia** and **Viet Nam**, will also post hikes in jet fuel demand, however, in absolute terms these markets remain small.

Figure 1.11 Jet fuel demand Asia

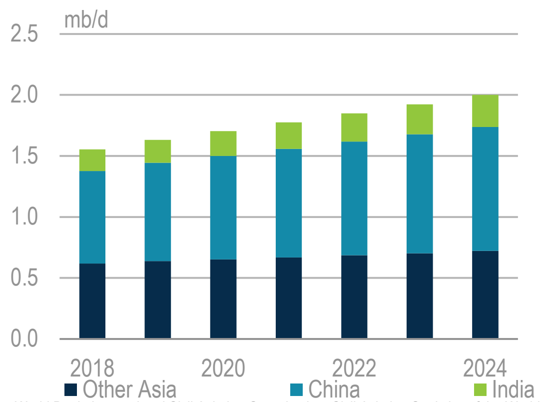
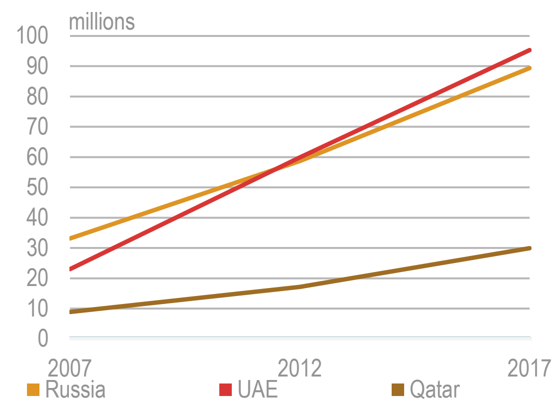


Figure 1.12 Air passengers



Source: World Bank, International Civil Aviation Organization, Civil Aviation Statistics of the World, IMF

Having plunged into recession in 2015, the **Russian** economy is recovering and jet fuel demand will grow at a rate of 0.6% p.a over the coming years. In 2018, domestic RPK increased by 9%, aided by airport capacity expansions associated with the Sochi Winter Olympics, Formula 1, and the Fédération Internationale de Football Association (FIFA) World Cup. Meanwhile, fleet turnover has seen fuel efficiency improvements at Russian airlines.

The **Middle East**'s major demand centre, the United Arab Emirates (UAE), has taken advantage of its geographic location to become a global hub for air travellers. Expansions at Dubai and Abu Dhabi airports saw passenger numbers grow by 14% p.a. from 2013 to 2015, but this has subsequently slowed, not least as lower oil prices have weighed on the region's economies. The UAE's aviation industry will profit from healthy global GDP growth and jet fuel demand will increase 2.8% p.a. to 2024. For similar reasons, Qatar's jet fuel demand is up 4.1% p.a. in the medium term.

Figure 1.13 Jet fuel demand Latin America

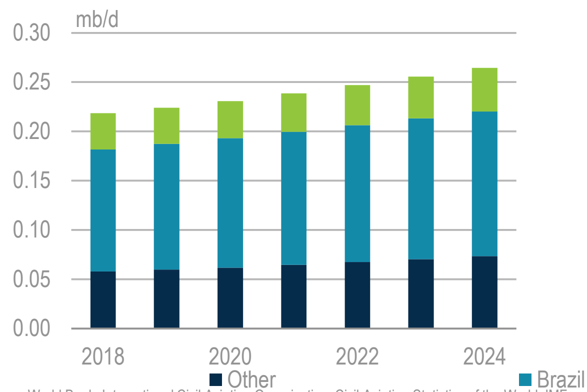
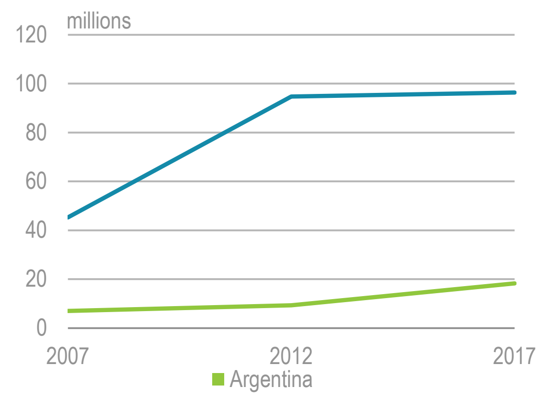


Figure 1.14 Air passengers



Source: World Bank, International Civil Aviation Organization, Civil Aviation Statistics of the World, IMF

Latin American jet fuel demand growth is set to bounce back to 3.5% p.a. to 2024, having been pared in recent years by economic woes. Consumers are more responsive to prices than in other parts of the world and the price elasticity of jet fuel demand has been estimated at 0.12. Having seen less expansion in recent years, travellers in the region have a much stronger demand response to GDP growth (elasticity of GDP is 1.6). This should decline over time as the market matures and LCCs make further inroads. Brazil is the largest consumer, having doubled capacity at Brasilia airport in 2015, and jet fuel demand is up 3.1% p.a. (25 kb/d) by 2024.

While **African** jet fuel demand will see a high rate of growth, thanks to GDP expansion and increasing population size, the markets are small. Infrastructure investment and political stability are pre-requisites for significantly increasing traveller numbers. In early 2018, the African Union launched a project to create a Single African Air Transport Market to promote travel amongst its 23 member states, but progress towards this goal has been slow so far.[5]

OECD demand

OECD oil demand is forecast to remain largely unchanged to 2024. Demand in OECD Americas will post some small gains while Europe and Asia will decline slightly.

Table 1.6 OECD oil demand by region (kb/d)

	2018	2019	2020	2021	2022	2023	2024	2018 – 2024 Growth rate
OECD Americas	25 618	25 926	26 078	26 007	26 090	25 980	26 068	0.3%
OECD Europe	14 299	14 406	14 329	14 258	14 183	14 141	14 076	-0.3%
OECD Asia Oceania	7 927	7 826	7 747	7 717	7 745	7 752	7 746	-0.4%
Total Products	**47 844**	**48 158**	**48 155**	**47 983**	**48 017**	**47 873**	**47 890**	**0.0%**

[5] Unlocking economic benefits from aviation in Africa, Alexandre de Juniac, IATA, June 2018.

OECD Americas

OECD Americas oil demand has been growing very fast since 2015, supported by gasoline demand and the commissioning of new petrochemical projects in the United States. Efficiency improvements and slower economic growth will cap the gains from 2020.

Table 1.7 OECD Americas oil demand by product (kb/d)

	2018	2019	2020	2021	2022	2023	2024	2018 - 2024 Growth rate
LPG & ethane	3 663	3 816	3 964	4 035	4 169	4 249	4 423	3.2%
Naphtha	296	316	318	317	319	320	321	1.4%
Motor gasoline	11 093	11 183	11 157	11 059	10 967	10 817	10 750	-0.5%
Jet fuel & kerosene	2 025	2 087	2 168	2 181	2 189	2 194	2 197	1.4%
Gasoil/diesel	5 402	5 378	5 416	5 332	5 339	5 275	5 234	-0.5%
Residual fuel oil	667	654	555	576	592	603	615	-1.3%
Other products	2 472	2 492	2 500	2 508	2 516	2 523	2 529	0.4%
Total products	**25 618**	**25 926**	**26 078**	**26 007**	**26 090**	**25 980**	**26 068**	**0.3%**

LPG and ethane will be the fastest growing components, supported by strong ethane demand in the **United States**. Jet fuel demand is also expected to post robust growth. On average, total demand is expected to grow by 0.3% per year over the forecast period.

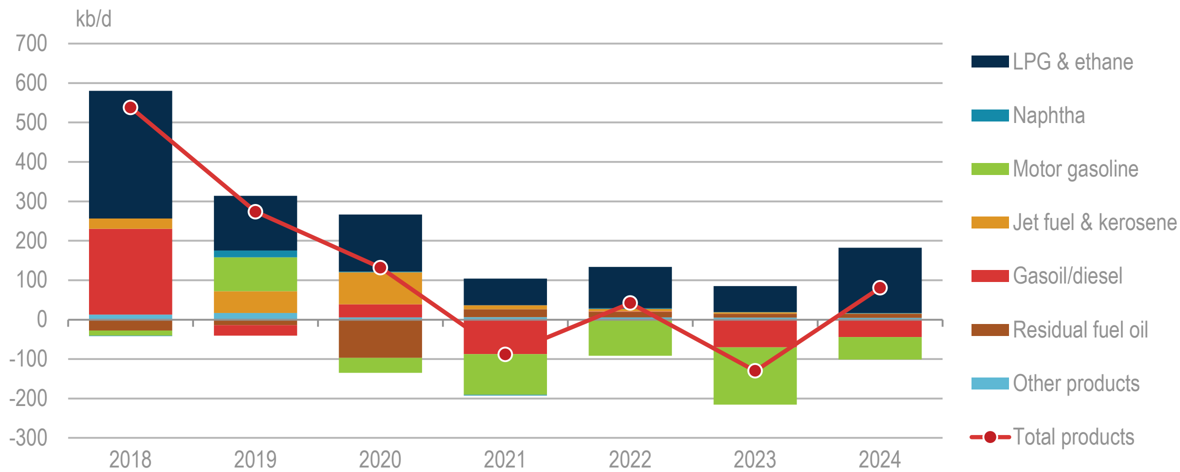
Improving fuel economy will contribute to a *contraction* in gasoline demand. The CAFE standards, introduced in 2012, mandate a 3.8% annual improvement in passenger cars fuel economy to 2025. This corresponds to personal car fuel consumption of 4.2 litres per 100 kilometer (l/100km), or 56.7 miles per gallon (mpg), and light truck fuel consumption of 6 l/100km, or 39 mpg, by 2025. In 2018, the CAFE standards were reviewed and updated with the Safer Affordable Fuel Efficient (SAFE) rule which fixed the post-2022 targets at the 2021 levels, rather than requiring further improvement. US gasoline demand will increase in 2019, but will start to decline from 2020 as efficiency gains make their mark. Further ahead, these declines are pared by the decision to freeze the standards from 2021. **Canada** has adopted similar fuel economy standards which will see efficiency improvements of 3.3% per year between 2010 and 2025. Overall, OECD Americas' gasoline demand will decline by 0.5% per year between 2018 and 2024, losing 345 kb/d over the period.

Table 1.8 OECD Americas oil demand by country (kb/d)

	2018	2019	2020	2021	2022	2023	2024	2018 - 2024 Growth rate
OECD Americas	**25 618**	**25 926**	**26 078**	**26 007**	**26 090**	**25 980**	**26 068**	**0.3%**
Canada	2 449	2 461	2 467	2 474	2 503	2 512	2 511	0.4%
Chile	368	375	379	380	381	383	384	0.7%
Mexico	1 990	2 006	2 016	2 025	2 036	2 046	2 053	0.5%
USA	20 811	21 085	21 216	21 128	21 170	21 040	21 120	0.2%
Annual change	562	309	152	-71	83	-109	87	

In 2018, US gasoil demand was extremely strong, supported by robust industrial growth, high imports and the needs of the shale oil industry. Truck transport benefited from the growth in e-commerce and booming industrial production. Shale oil production, in particular, makes extensive use of trucks to move equipment and materials used in the fracking process or to transport crude oil. New pipelines coming on stream in 2019 should reduce this. For OECD Americas as a whole, gasoil demand will decrease by an average of 0.5% per year over the forecast period, but in 2020 there will be some support from the implementation of the IMO regulations.

Figure 1.15 US oil demand by product, year-on-year change



Mexico’s oil demand has been declining by roughly 20 kb/d per year since the start of 2012 due to slow economic growth and the replacement of fuel oil by natural gas in the power sector. Demand is projected to increase by 10 kb/d on average over the forecast period.

OECD Americas’ fuel oil use will decline by 1.3% per year on average over 2019-24 due to a sharp drop in 2020 resulting from the IMO regulations. We should see strong growth thereafter, as the new 0.5% sulphur marine fuel gains market share.

OECD Europe

After eight consecutive years of decline (2007-14), OECD Europe’s oil demand rose by 190 kb/d on average in 2015-18, supported by lower oil prices and an improved economic environment. Gasoil demand was the main driver, gaining 130 kb/d per year on average. Meanwhile, gasoline demand remained unchanged between 2015-18, after losing 85 kb/d on average in the preceding decade due to progress in fuel economy and the increasing share of diesel cars in the fleet. Europe has very stringent fuel economy standards and the 2021 targets are the strictest in the world. An almost 30% improvement on the 2015 standards is required, that would see CO_2 emissions drop below 95 gramme per kilometer (g/km) and average fuel consumption of 4.1 l/100 km for gasoline cars by 2021. In January 2019, the European Union endorsed new rules stating that from 2030 new cars must emit on average 37.5% less CO_2 and new vans on average 31% less CO_2 compared to 2021 levels. Between 2025 and 2029, both cars and vans will be required to reduce CO_2 emissions by a further 15%.

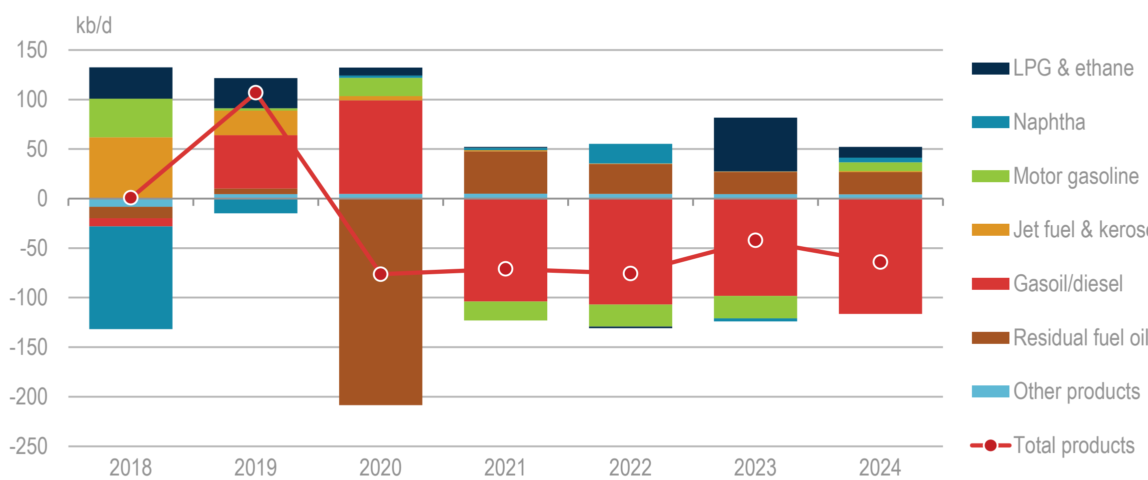
European car sales were negatively impacted by the introduction of a new environmental test, the worldwide harmonised light vehicles test procedure (WLTP), in September 2018. Aiming to assess car performance in more realistic driving conditions, the new test resulted in higher costs and delays for car manufacturers to conduct inspections.

Table 1.9 OECD Europe oil demand by product (kb/d)

	2018	2019	2020	2021	2022	2023	2024	2018 - 2024 Growth rate
LPG & ethane	1 155	1 185	1 193	1 194	1 193	1 247	1 258	1.4%
Naphtha	1 076	1 061	1 063	1 066	1 085	1 082	1 087	0.2%
Motor gasoline	1 929	1 931	1 950	1 931	1 908	1 886	1 895	-0.3%
Jet fuel & kerosene	1 518	1 543	1 547	1 548	1 548	1 549	1 550	0.3%
Gasoil/diesel	6 470	6 523	6 618	6 514	6 407	6 309	6 192	-0.7%
Residual fuel oil	878	883	675	718	748	770	793	-1.7%
Other products	1 274	1 279	1 284	1 289	1 293	1 298	1 302	0.4%
Total products	**14 299**	**14 406**	**14 329**	**14 258**	**14 183**	**14 141**	**14 076**	**-0.3%**

The most interesting change in Europe is the region's growing disaffection for diesel engine cars. Concerns about air pollution have considerably reduced their share in new sales. Demand could also be directly impacted by restrictions put on the use of older diesel cars. In several large German cities, restrictions have already been introduced and Paris, Barcelona, Milan, London and Madrid are set to follow suit from 2019 onwards. Their share in total sales reached a peak of 55% in the European Union (EU) in 2011-2012, and then declined to 44% in 2017. In France, the share fell from 77% in 2008 to 47% by 2016, as diesel's price advantage eroded. In Germany, diesel's share remained close to 48% in the past five years, but dropped to 33% in December 2017. The European Automobile Manufacturers Association (ACEA) data show a further drop in sales in 2018. In our forecast we assume that disaffection for diesel cars benefits both gasoline and electric cars.

Figure 1.16 OECD Europe oil demand by product, year-on-year change



In 2018, sharp declines in naphtha and gasoil demand were seen in Europe. Part of the drop was due to exceptional water conditions on the River Rhine, reducing deliveries to Germany and Switzerland. In 2019 there will be a rebound in gasoil deliveries, as European heating oil demand is expected to return to normal. In 2020, marine gasoil will benefit from the implementation of the IMO regulations, but thereafter it will be replaced by VLSFO. From 2019 to 2024, gasoline demand should continue to decline slightly, by 5 kb/d on average, with efficiency improvements offset by the expected switch from gasoil to gasoline. Road diesel demand declines by 85 kb/d per year on better fuel economy and as the share of diesel cars falls. In addition, diesel demand in Europe, like everywhere, will, suffer from a temporary price increase in 2020. On average, over our forecast period, total demand will decline by 35 kb/d per year.

Table 1.10 OECD Europe oil demand in selected countries (kb/d)

	2018	2019	2020	2021	2022	2023	2024	2018 - 2024 Growth rate
OECD Europe	**14 299**	**14 406**	**14 329**	**14 258**	**14 183**	**14 141**	**14 076**	**-0.3%**
Germany	2 327	2 313	2 297	2 277	2 253	2 225	2 209	-0.9%
France	1 711	1 725	1 705	1 686	1 669	1 651	1 634	-0.8%
Italy	1 271	1 277	1 266	1 256	1 246	1 235	1 225	-0.6%
Spain	1 334	1 356	1 351	1 349	1 344	1 340	1 335	0.0%
United Kingdom	1 600	1 610	1 598	1 580	1 567	1 580	1 570	-0.3%
Annual change	1	107	-76	-71	-76	-42	-64	

OECD Asia Oceania

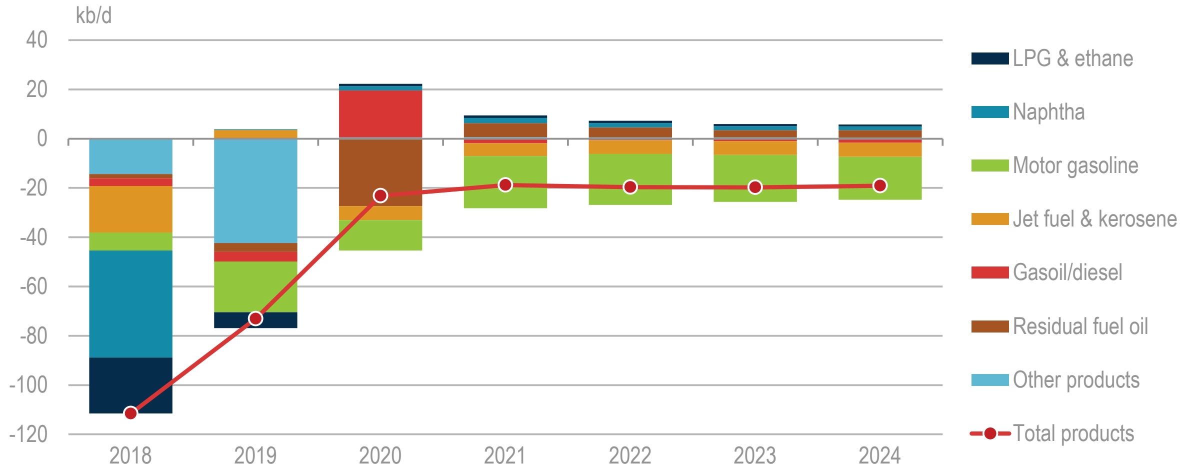
In the Asia Oceania region, demand is projected to decline by 0.4% per year over the forecast period as fuel economy improvements will more than offset rising transportation demand. **Japan's** demand picture in recent years was distorted by the temporary increase in crude oil direct use and fuel oil in the power sector post-Fukushima.

Table 1.11 OECD Asia Oceania oil demand by product (kb/d)

	2018	2019	2020	2021	2022	2023	2024	2018 - 2024 Growth rate
LPG & ethane	722	716	724	726	756	767	773	1.1%
Naphtha	1 987	2 027	2 038	2 046	2 081	2 118	2 140	1.2%
Motor gasoline	1 535	1 520	1 493	1 455	1 420	1 387	1 363	-2.0%
Jet/kerosene	907	915	912	911	909	907	904	0.0%
Gasoil/diesel	1 919	1 888	1 954	1 934	1 919	1 903	1 885	-0.3%
Residual fuel oil	556	553	417	437	451	461	472	-2.7%
Other products	301	207	208	208	209	209	210	-5.9%
Total products	**7 927**	**7 826**	**7 747**	**7 717**	**7 745**	**7 752**	**7 746**	**-0.4%**

In the period of our forecast, Japan's oil demand is expected to drop by 30 kb/d per year on average. Japan has a very efficient passenger car fleet partly due to the high penetration of hybrid vehicles. Its 2020 target for CO_2 emissions (122 g/km for passenger cars) was reached in 2013. This corresponds to fuel consumption of 5.3 l/100 km of gasoline equivalent. Japan is also a leader for light commercial vehicles, with a target of 133 g/km of CO_2 emissions by 2022. This corresponds to gasoline consumption of 5.7 l/100 km.

Figure 1.17 Japanese oil demand by product, year-on-year change



In **South Korea** fuel efficiency targets are also very strong, calling for an improvement of 5.5% per year from 2013 to 2020. In 2020, the standard for CO_2 emissions from personal cars is 97 g/km, corresponding to a fuel economy of 4.2 l/100 km of gasoline. South Korea's oil demand jumped by 45 kb/d per year on lower prices in 2015-18, but it will slow considerably to only 15 kb/d on average in 2019-24.

Table 1.12 OECD Asia Oceania oil demand by country (kb/d)

	2018	2019	2020	2021	2022	2023	2024	2018 - 2024 Growth rate
OECD Asia & Oceania	**7 927**	**7 826**	**7 747**	**7 717**	**7 745**	**7 752**	**7 746**	**-0.4%**
Australia	1 214	1 207	1 185	1 167	1 151	1 135	1 126	-1.2%
Japan	3 782	3 709	3 686	3 668	3 648	3 628	3 609	-0.8%
Israel*	237	241	241	241	240	241	241	0.3%
Korea	2 522	2 494	2 462	2 472	2 538	2 584	2 607	0.6%
New Zealand	172	175	172	170	167	165	164	-0.8%
Annual change	- 137	- 101	- 80	- 30	28	8	- 6	

*Discalimer: The statistical data for Israel are supplied by and under the responsibility of the relevant Israeli authorities. The use of such data by the OECD is without prejudice to the status of the Golan Heights, East Jerusalem and Israeli settlements in the West Bank under the terms of international law.

Overall, we expect a drop of 30 kb/d per year in OECD Asia oil demand in 2019-24, mainly due to gasoline (-30 kb/d) and road diesel (-20 kb/d).

Non-OECD demand

Efficiency and environmental policies are also likely to play a significant role in non-OECD countries over the forecast period. These will apply particularly to transport fuels with urban air quality a major concern. Some countries are expected to increase their use of fuel oil after the IMO 2020 switch. Non-OECD countries will add 7.1 mb/d to world oil demand by 2024.

Table 1.13 Non-OECD countries oil demand (kb/d)

	2018	2019	2020	2021	2022	2023	2024	2018 – 2024 Growth rate
LPG & ethane	6 840	7 045	7 355	7 561	7 748	7 867	8 018	2.7%
Naphtha	2 981	3 111	3 257	3 390	3 611	3 727	3 828	4.3%
Motor gasoline	11 490	11 663	11 980	12 399	12 723	13 012	13 227	2.4%
Jet/kerosene	3 334	3 482	3 581	3 698	3 814	3 932	4 052	3.3%
Gasoil/diesel	14 732	15 039	15 895	16 133	16 345	16 587	16 841	2.3%
Residual fuel oil	4 866	4 901	4 533	4 852	4 912	5 003	5 045	0.6%
Other products	7 153	7 213	7 208	7 245	7 303	7 382	7 461	0.7%
Total products	**51 395**	**52 455**	**53 810**	**55 277**	**56 457**	**57 509**	**58 472**	**2.2%**

Africa

Oil demand growth in Africa is projected at 2.3% per year to 2024 on the back of a relatively robust economic outlook. Economic growth in sub-Saharan Africa is strong in the early part of our forecast, reaching 3.5% in 2019-20.

Table 1.14 African oil demand by product (kb/d)

	2018	2019	2020	2021	2022	2023	2024	2018 - 2024 Growth rate
LPG & ethane	400	409	416	424	432	441	451	2.0%
Naphtha	22	22	22	23	23	23	23	1.2%
Motor gasoline	1 245	1 290	1 313	1 341	1 367	1 397	1 427	2.3%
Jet fuel & kerosene	282	292	300	309	317	327	337	3.1%
Gasoil/diesel	1 709	1 752	1 801	1 838	1 877	1 922	1 973	2.4%
Residual fuel oil	361	354	366	392	395	408	401	1.7%
Other products	280	283	285	291	295	300	306	1.5%
Total products	**4 299**	**4 402**	**4 504**	**4 618**	**4 707**	**4 819**	**4 917**	**2.3%**

Egypt's GDP growth is expected to be close to 6% per year over the forecast period, supporting relatively strong growth in energy demand. The switch to natural gas will, however, contain oil demand growth to 2.3% per year. The switch will be spurred on by the development of Eni's super-giant Zohr gas field, where production started in December 2017. This should enable Egypt to become self-sufficient and might even allow a return to exporting gas in the medium term. Three combined cycle gas power plants started operations in 2017 replacing several old fuel oil power plants. Egypt has also launched a $1.5 billion project to connect 1.5 million households to natural gas, likely displacing oil.

Table 1.15 African oil demand in selected countries (kb/d)

	2018	2019	2020	2021	2022	2023	2024	2018 - 2024 Growth rate
Africa	**4 299**	**4 402**	**4 504**	**4 618**	**4 707**	**4 819**	**4 917**	**2.3%**
Egypt	775	777	804	834	851	868	888	2.3%
Nigeria	494	519	523	530	537	543	549	1.8%
South Africa	637	645	645	644	644	643	642	0.1%
Annual change	23	103	102	113	89	111	99	

Nigeria is by far the most populous country in Africa with 190 million people and economic growth is picking up on higher oil production. Oil demand growth is expected to expand by 1.8% per year over the forecast period.

South Africa is the largest and most industrialised economy in the region, contributing 15% of African GDP. Economic growth is slowing, however, and oil demand declined slightly in 2017 and remained stagnant in 2018. With GDP growth expected to average only 1.7% per year over the forecast period oil demand growth will also remain weak at 0.1% per year.

China

During 2007-18, **China's** demand grew at an average rate of 485 kb/d and at the end of the period had reached 13 mb/d. The dramatic increase in transport fuel demand has contributed to severe environmental problems. Measures to improve poor urban air quality, including restricting vehicle use, will have a strong impact on demand in the coming years.

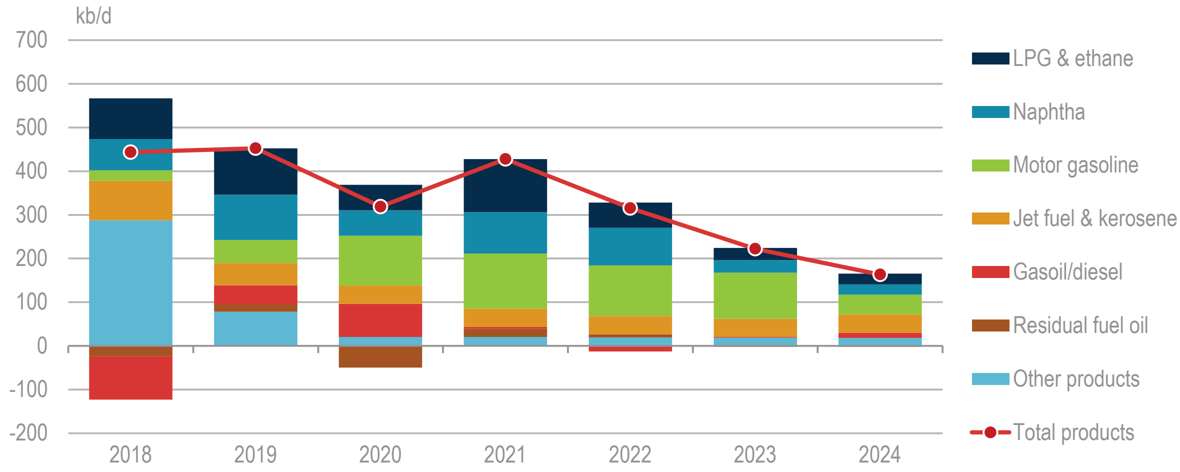
Motor gasoline demand grew by 140 kb/d per year in 2007-18 but the pace slowed to 60 kb/d per year in 2017-18. China has some of the strictest fuel economy standards in the world. The target for fleet average fuel consumption in 2020 is 5 l/100 km, 27% lower than in 2015, and, for 2025, China is considering a target of 4 l/100 km. Current standards call for an improvement of 5% per year in passenger car fuel economy between 2013 and 2020.

Table 1.16 Chinese oil demand (kb/d)

	2018	2019	2020	2021	2022	2023	2024	2018 - 2024 Growth rate
LPG & ethane	1 616	1 723	1 781	1 902	1 960	1 988	2 013	3.7%
Naphtha	1 243	1 347	1 405	1 500	1 586	1 615	1 638	4.7%
Motor gasoline	2 951	3 004	3 118	3 245	3 361	3 466	3 511	2.9%
Jet fuel & kerosene	800	851	892	934	976	1 018	1 060	4.8%
Gasoil/diesel	3 374	3 418	3 494	3 498	3 485	3 487	3 499	0.6%
Residual fuel oil	412	429	379	398	405	403	401	-0.5%
Other products	2 624	2 702	2 722	2 742	2 762	2 780	2 798	1.1%
Total products	**13 020**	**13 473**	**13 792**	**14 220**	**14 535**	**14 757**	**14 921**	**2.3%**

Action to regulate the use of cars in big cities is being taken in several ways. In Beijing, since 2010 licence plates for gasoline vehicles are awarded by lottery. In 2017, 2.8 million people competed for 6 460 plates. As a result, many residents registered their new cars in other cities. A new rule, however, limits the time non-registered cars can be used in the city to 84 days a year. Meanwhile, Beijing has improved public transportation, in particular, subways. The city has 22 lines, with a total length of 602 km. An additional 397 km is planned by 2021. In Shanghai, licence plates are sold through auctions and their price can be higher than that of the car. Since, 2012, Guangzhou uses both auctions and lotteries to limit the availability of plates. Many Chinese cities have circulation restrictions based on plate numbers. Even so, congestion and the lack of parking spaces remains a major problem.

Figure 1.18 Chinese oil demand, year-on-year change



Gasoil demand rose by 80 kb/d per year during 2007-18, but the trend has reversed in recent years, posting a decline of 40 kb/d per year in 2015-18. Demand has been impacted by the closure of old, energy intensive industries as China transforms itself into an increasingly consumer-led economy. Environmental policies have also reduced diesel demand, as provincial governments are keen to develop cleaner transport fuels or electric buses. In addition, a decline in coal and industrial goods production in 2015-16 resulted in a drop in rail and heavy duty transportation.

Although demand growth will remain robust, with China growing by 1.9 mb/d to 2024, we expect to see some slowdown in the transport sector. This, plus the switch away from heavy industry, will reduce oil demand growth to 315 kb/d per year in 2019-24. Within this total, gasoline growth will slow to 95 kb/d per year while gasoil demand will increase by 20 kb/d per year, impacted by the development of alternative fuels for trucks and buses.

China's natural gas and electric vehicles

China is making a major effort to reduce air pollution, 30% of which is estimated to come from internal combustion engines. Government incentives have contributed to booming sales of electric cars and a strong growth in the deployment of natural gas vehicles. China is the largest global market for electric vehicles. In 2018, while total passenger vehicle sales declined by 4.2% y-o-y, electric vehicle sales increased spectacularly to 1.3 million units, a 61% increase y-o-y. Within the total, electric passenger car sales were 788 000 units, an increase of 68% y-o-y. Plug-in hybrid passenger vehicles sales reached 265 000 units, up 140% y-o-y. Electric commercial vehicles sales rose 6% y-o-y. The electric vehicle industry is a national priority under the government's *Made in China 2025* industrial policy. It is estimated that the share of electric vehicles in total sales will reach 4% in 2020. The goal of deploying 5 million electric vehicles by the end of 2020 could therefore be achieved. In our forecast we assume that, by 2024, electric passenger cars should displace roughly 160 kb/d of gasoline. Consumers, however, are very sensitive to prices and the reduction in 2017 of subsidies by 20% had a strong impact on sales. Subsidies are set to be further reduced, by 40% in 2019 and eliminated in 2021. The subsidy cuts will be partially offset by enabling electric vehicle makers to sell carbon credit quotas. Sales of electric buses are also booming and the fleet reached an estimated 490 000 at the end of 2018. Electric and plug-in hybrid buses accounted for 22% of total bus sales in

2017. The city of Shenzhen has electrified 100% of its bus fleet and estimates that about 7 kb/d of diesel consumption has been replaced. In addition, 62% of the city's taxi fleet is comprised of electric vehicles and it is hoped to reach 100% by 2020. Other Chinese cities are following the same path.

Table 1.17 Chinese electric bus sales

units	2011	2012	2013	2014	2015	2016	2017	2018	Total
Fully Electric	1 136	1 904	1 672	12 760	94 260	115 700	89 546	96 240	413 218
Plug-In Hybrid	1 478	313	2 637	16 500	23 051	19 376	9 785	5 666	78 806
Total	2 614	2 217	4 309	29 260	117 311	135 076	99 331	101 906	492 024

Source: cvworld, Press reports.

The increasing number of electric buses could have a bigger impact on China's oil demand than electric cars. The very strong growth of the electric bus fleet only started in 2015 and it is estimated to have displaced 20 to 25 kb/d of diesel per year (a cumulative total of 110 kb/d in 2018). In the early years of the forecast, it is assumed that the growth in electric buses will continue at around 100 000 units per year, displacing at least an additional 20 kb/d of diesel demand each year. Growth may slow thereafter and we assume a displacement of roughly 15 kb/d of diesel demand after 2022.

Table 1.18 Chinese natural gas vehicles fleet

Thousands	1996	2000	2004	2008	2012	2016	2017	2018
China NGVs	2	6	69	400	1 561	5 296	5 645	5 994
% World	0.2%	0.5%	1.8%	4.2%	9.4%	21.5%	21.9%	23.2%

Note: NGV = natural gas vehicle.
Source: NGV Global, IEA calculations.

China also has the largest number of compressed natural gas (CNG) cars in the world. Roughly 80% of CNG passenger vehicles have been converted from gasoline. In provinces where gas is easily available and CNG refuelling infrastructure developed, a large proportion of cars have switched. Using the same methodology as for electric vehicles, it is assumed that the 6 million natural gas vehicles operational in 2018 are saving some 85 kb/d of oil.

While CNG is fine for passenger vehicles, for trucks, liquefied natural gas (LNG) is more appropriate. The storage capacity and driving range is much higher, even though the initial cost is greater. China has an estimated fleet of 340 000 LNG trucks, accounting for around 4% of the 6 million large trucks. Sales jumped in 2017, following the imposition of a ban on the use of diesel trucks to transport coal in ports in Shandong, Hebei and Tianjin. The restriction placed on thousands of factories in northern China using diesel trucks during the winter of 2017 also provided a boost to LNG vehicles.

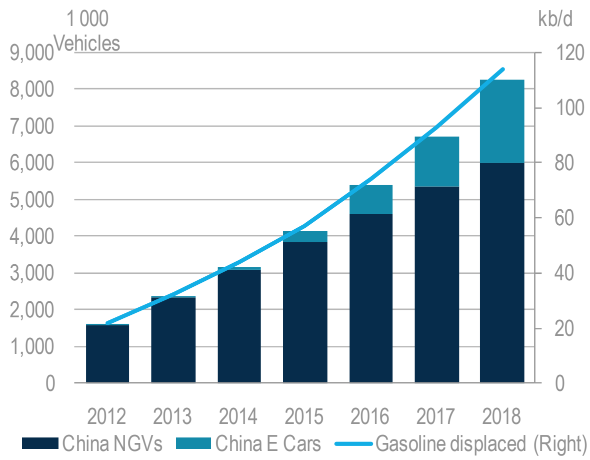
Table 1.19 Chinese LNG trucks

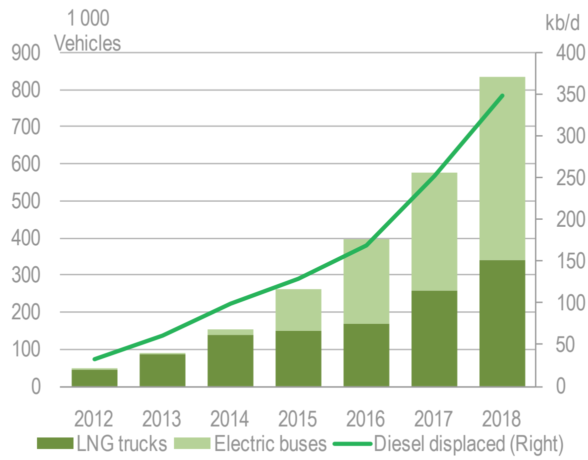
	2010	2011	2012	2013	2014	2015	2016	2017	2018
LNG truck sales	4 000	22 925	16 091	38 576	50 105	16 000	19 601	85 000	86 240
LNG truck fleet est. (1 000)	7	30	46	85	135	151	170	255	342

Source: Sichuan Clean Energy Vehicle Association, cvworld.

In the forecast, it is assumed that LNG trucks will displace roughly 20 kb/d of diesel demand per year, and there are reportedly plans for the further replacement of heavy duty diesel trucks in northern China by alternative-fuelled vehicles using LNG, electricity or a higher grade of diesel. The new policy will apply from 2020.

Figure 1.19 China alternative fuel impact





Together, the major shifts underway in China's transport sector are having a significant impact on oil demand. CNG and electric cars could displace at least 20 kb/d of gasoline demand every year; LNG trucks and electric buses could replace at least 40 kb/d of diesel; and the electrification of railways, greater penetration of electric two or three wheelers, bike-sharing schemes and impressive targets for car efficiency standards are expected to further slow the pace of China's oil demand growth.

Other Asia

India's oil demand rose strongly from 2007 to 2018, with average demand growth close to 160 kb/d per year. Gasoline demand grew by 40 kb/d per year while gasoil demand increased by 65 kb/d.

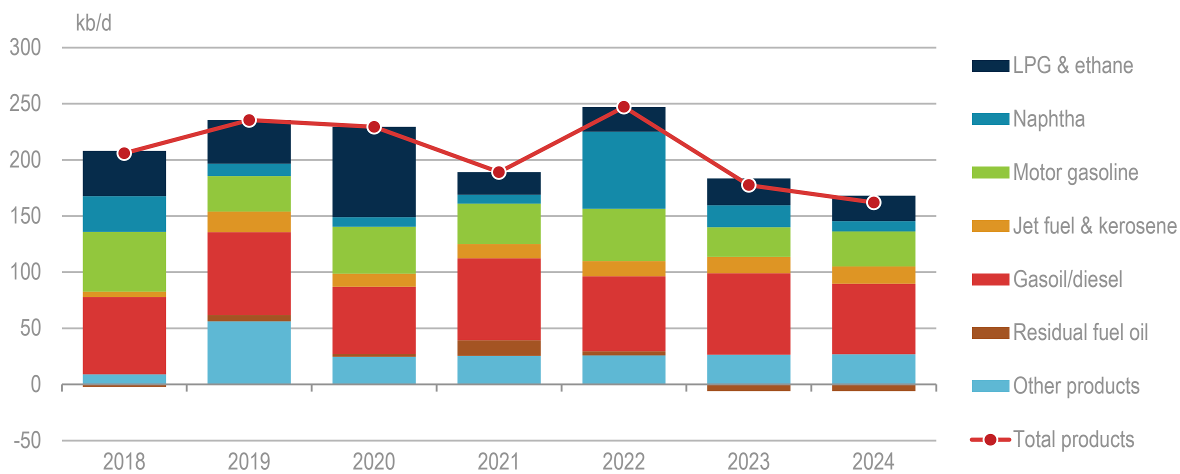
Table 1.20 Indian oil demand (kb/d)

	2018	2019	2020	2021	2022	2023	2024	2018 - 2024 Growth rate
LPG & ethane	781	820	900	920	943	967	989	4.0%
Naphtha	315	326	335	342	411	431	440	5.7%
Motor gasoline	668	700	742	778	824	851	882	4.7%
Jet/Kerosene	246	265	276	289	302	317	332	5.1%
Gas/Diesel Oil	1 673	1 747	1 807	1 880	1 947	2 019	2 082	3.7%
Residual fuel oil	143	148	151	165	169	163	157	1.5%
Other products	947	1 004	1 028	1 054	1 079	1 106	1 133	3.0%
Total Products	**4 774**	**5 009**	**5 239**	**5 428**	**5 675**	**5 852**	**6 014**	**3.9%**

India posted very strong growth in 2018, in comparison to a mediocre 2017, when demand was penalised by the implementation of the Goods and Service Tax and the demonetisation episode. However, a sharp increase in US dollar oil prices amplified by a currency devaluation of 12% contributed to slower growth in the second half of the year. If prices follow the path shown in our forward curve, demand growth should remain strong.

Rapid industrialisation and the fast pace of growth in vehicle fleets has caused severe air quality problems. Strong policies are being put in place to try to tackle this. India wants the market share of electric vehicles to reach 30% of total sales by 2030. Ahead of the 2019 election, the government has offered tax incentives for the purchase of hybrid vehicles if it is re-elected.

Figure 1.20 Indian oil demand, year-on-year change



The government requires an improvement of 1.6% per year in fuel economy between 2012 and 2022. The passenger car CO_2 emissions target for 2022 is 113 g/km, which is equivalent to gasoline consumption of 4.9 l/100 km.

In August 2017, India introduced regulations aimed at reducing the fuel consumption of heavy duty vehicles weighing more than 12 tonnes. This impacts roughly 60% of total fuel use from the haulage fleet. Between 2018 and 2021, rigid trucks must reduce their consumption by 5% to 13%, tractors, trucks and trailers by 7% to 10% and buses by 15%. The fleet wide fuel-consumption reduction by 2021 is estimated at 10%.

We expect Indian growth in oil demand to average 205 kb/d in 2019-24, on strong gasoil and gasoline demand, which increase by 70 kb/d and 35 kb/d per year, respectively.

Table 1.21 Non-OECD Asia (excluding China) demand by product (kb/d)

	2018	2019	2020	2021	2022	2023	2024	2018 - 2024 Growth rate
LPG & ethane	1 731	1 789	1 892	1 929	1 965	2 000	2 035	2.7%
Naphtha	1 251	1 277	1 363	1 398	1 476	1 546	1 615	4.4%
Motor gasoline	2 564	2 646	2 740	2 832	2 937	3 019	3 105	3.2%
Jet/kerosene	1 105	1 153	1 184	1 225	1 265	1 306	1 350	3.4%
Gasoil/diesel	4 108	4 246	4 682	4 813	4 942	5 085	5 217	4.1%
Residual fuel oil	1 601	1 575	1 278	1 368	1 420	1 447	1 474	-1.4%
Other products	1 455	1 527	1 561	1 593	1 628	1 663	1 700	2.6%
Total products	**13 815**	**14 214**	**14 700**	**15 158**	**15 632**	**16 067**	**16 497**	**3.0%**

Pakistan's oil demand dropped sharply in 2018, as more gas and coal was used at the expense of fuel oil, for which demand declined by 80 kb/d. In 2015, Pakistan built an LNG Floating Storage Regasification Unit (FSRU), initially receiving 1 mt, rising to 3.4 mt in 2016, and 6 mt in 2017. A second FSRU started operations in 2018 and a third should start up in 2019. By 2022, seven FSRU's will allow the import of 30 million tonnes per year (mt/y) of LNG. At the same time, Pakistan is developing 8 GW of coal fired power generation capacity, of which 1.3 GW was commissioned in 2017.

Table 1.22 Non-OECD Asia: oil demand in selected countries (kb/d)

	2018	2019	2020	2021	2022	2023	2024	2018 - 2024 Growth rate
Non-OECD Asia*	**13 815**	**14 214**	**14 700**	**15 158**	**15 632**	**16 067**	**16 497**	**3.0%**
India	4 774	5 009	5 239	5 428	5 675	5 852	6 014	3.9%
Indonesia	1 789	1 787	1 827	1 874	1 917	2 008	2 107	2.8%
Malaysia	766	771	846	888	908	924	944	3.5%
Singapore	1 401	1 420	1 423	1 460	1 488	1 514	1 534	1.5%
Thailand	1 437	1 476	1 531	1 564	1 593	1 607	1 621	2.0%
Annual change	369	399	487	458	474	435	430	

*excluding China.

Indonesia experienced a significant drop in gasoil demand in 2014-16, partly as the result of its displacement by natural gas and coal in the power sector. In 2018, there was a return to subsidies to offset the sharp increase in oil prices. The government also extended the use of biodiesel, expanding its blending in regular diesel to 20%.

Singapore is the world's largest bunkering port, with bunker sales reaching 0.9 mb/d in 2017. The port is preparing for the IMO 2020 switch by looking at issues such as compliant fuel availability, infrastructure for scrubber residues and enforcement measures. As Singapore has decided to ban ships with open-loop scrubbers, vessels with this equipment will have to use compliant fuel to access the port from January 2020. The port will provide a list of suppliers able to deliver compliant fuels to shippers in advance.

Overall, we expect oil demand in non-OECD Asia (excluding mainland China) to increase by 3% per year on average between 2018 and 2024. This group of countries will add 2.7 mb/d to global oil demand.

Non-OECD Europe

Table 1.23 Non-OECD Europe oil demand (kb/d)

	2018	2019	2020	2021	2022	2023	2024	2018 - 2024 Growth rate
LPG & ethane	60	61	62	64	66	67	69	2.3%
Naphtha	10	10	10	10	11	11	11	2.6%
Motor gasoline	93	96	98	100	101	104	105	2.0%
Jet/kerosene	28	29	30	31	32	32	33	2.6%
Gasoil/diesel	337	345	371	377	382	388	395	2.7%
Residual fuel oil	139	141	123	125	129	132	136	-0.4%
Other products	92	94	96	98	99	101	103	1.8%
Total products	**759**	**776**	**790**	**805**	**820**	**836**	**852**	**1.9%**

Oil demand in non-OECD Europe, the smallest of our regions, is forecast to grow much faster than in OECD Europe because underlying economic growth is stronger. There is scope for growth in vehicle fleets and some countries have yet to introduce fuel economy standards. The group's oil demand is expected to grow by 1.9% per year between 2018 and 2024, adding 95 kb/d to our global demand forecast.

Table 1.24 Non-OECD Europe oil demand in selected countries (kb/d)

	2018	2019	2020	2021	2022	2023	2024	2018 - 2024 Growth rate
Non-OECD Europe	**759**	**776**	**790**	**805**	**820**	**836**	**852**	**1.9%**
Bulgaria	101	104	107	109	112	115	118	2.5%
Croatia	72	73	75	76	78	79	81	2.0%
Romania	214	219	216	215	213	212	211	-0.3%
Serbia	81	83	86	89	93	96	99	3.5%
Annual change	12	17	13	15	15	16	16	

Former Soviet Union

Russia's demand comprised 73% of the FSU total in 2018. After three years of decline, gasoline demand rose slightly in 2018 (10 kb/d). Car sales were up 12.8% in 2018 but could slow in 2019, as consumer taxes will increase and US sanctions could tighten. Kerosene demand rose by 10 kb/d in 2018 on strong air traffic as domestic RPK rose by 9% y-o-y. Fuel oil demand will temporarily increase in 2021 and 2022 due to the IMO regulations, as some of its excess HSFO is expected to be used in the power or district heating sectors. Demand will also be supported by petrochemical projects in 2020, with LPG and ethane growing at an average rate of 3.9% in 2019-24. On the back of economic growth running at 1.4% in the next six years, oil demand will grow by 30 kb/d per year to 2024.

Table 1.25 FSU oil demand by product (kb/d)

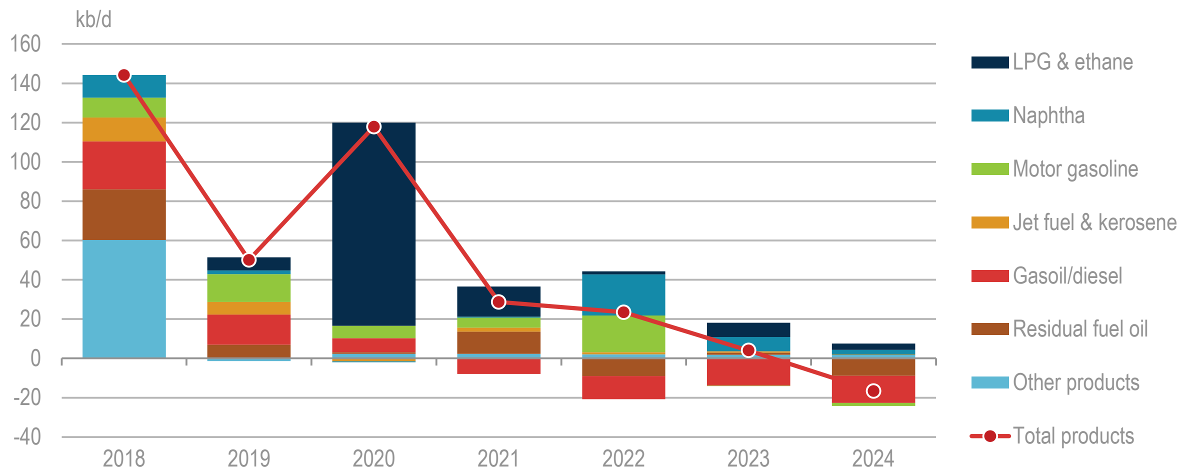
	2018	2019	2020	2021	2022	2023	2024	2018 - 2024 Growth rate
LPG & ethane	694	704	809	832	839	851	859	3.6%
Naphtha	166	168	168	169	190	197	199	3.1%
Motor gasoline	1 142	1 165	1 185	1 201	1 232	1 244	1 256	1.6%
Jet/kerosene	287	295	297	300	303	306	309	1.2%
Gasoil/diesel	1 276	1 303	1 325	1 332	1 336	1 338	1 341	0.8%
Residual fuel oil	202	212	216	230	224	229	224	1.7%
Other products	950	954	960	969	977	984	992	0.7%
Total products	**4 717**	**4 802**	**4 961**	**5 033**	**5 100**	**5 150**	**5 181**	**1.6%**

Other significant oil consumers in the group include Kazakhstan (350 kb/d), Turkmenistan (165 kb/d), and Ukraine (255 kb/d). Most of these countries will experience economic growth of 4% to 5% per year in the forecast period. Overall, we expect total FSU oil demand to increase by 1.6% per year on average to 2024, adding 465 kb/d to global demand over the forecast period.

Table 1.26 FSU oil demand in selected countries (kb/d)

	2018	2019	2020	2021	2022	2023	2024	2018 - 2024 Growth rate
FSU	**4 717**	**4 802**	**4 961**	**5 033**	**5 100**	**5 150**	**5 181**	**1.6%**
Kazakhstan	347	355	365	376	388	399	411	2.9%
Russia	3 466	3 516	3 634	3 663	3 686	3 690	3 674	1.0%
Turkmenistan	165	172	180	189	199	209	220	4.9%
Ukraine	256	262	269	277	285	293	302	2.8%
Uzbekistan	55	57	60	63	66	70	74	5.1%
Annual change	182	85	159	72	67	50	31	

Figure 1.21 Russian oil demand, year-on-year change



Latin America

Latin America's oil demand is expected to grow by 1.2% per year to 2024, with Argentina and Brazil, the largest consumers, expected to see progressive economic recovery over the forecast period.

Table 1.27 Latin America oil demand by product (kb/d)

	2018	2019	2020	2021	2022	2023	2024	2018 - 2024 Growth rate
LPG & ethane	650	655	662	668	675	681	688	1.0%
Naphtha	183	185	185	186	187	188	189	0.5%
Motor gasoline	1 847	1 803	1 840	1 891	1 918	1 959	1 985	1.2%
Jet/kerosene	316	324	333	344	355	366	377	3.0%
Gasoil/diesel	2 087	2 066	2 161	2 198	2 224	2 256	2 297	1.6%
Residual fuel oil	571	570	529	548	550	561	573	0.1%
Other products	740	733	733	736	742	745	748	0.2%
Total products	**6 395**	**6 336**	**6 443**	**6 571**	**6 649**	**6 756**	**6 857**	**1.2%**

Table 1.28 Latin America oil demand in selected countries (kb/d)

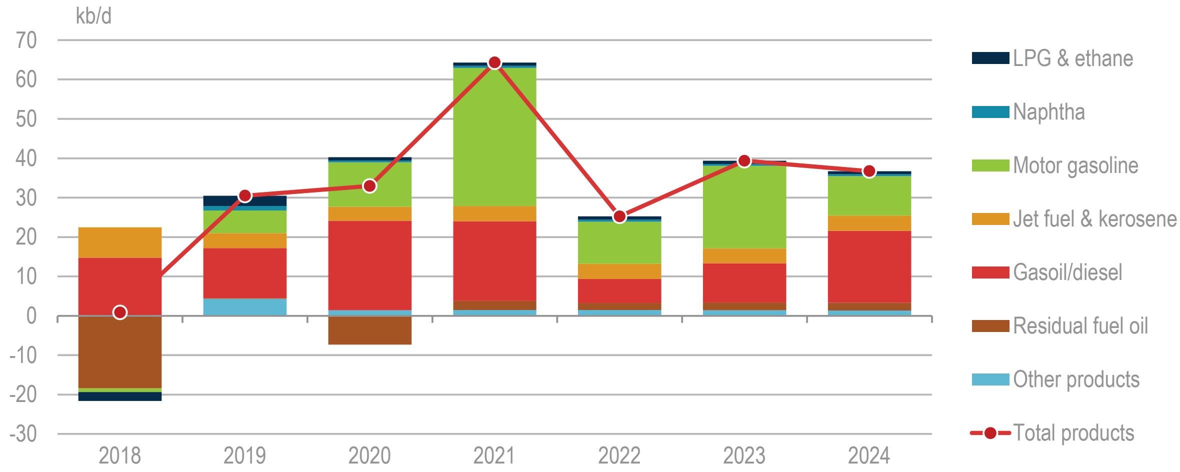
	2018	2019	2020	2021	2022	2023	2024	2018 - 2024 Growth rate
Latin America	**6 395**	**6 336**	**6 443**	**6 571**	**6 649**	**6 756**	**6 857**	**1.2%**
Argentina	733	714	733	740	750	766	777	1.0%
Brazil	3 003	3 033	3 066	3 131	3 156	3 195	3 232	1.2%
Colombia	361	370	376	382	388	395	402	1.8%
Ecuador	266	268	271	275	280	284	289	1.4%
Panama	167	176	186	195	205	215	225	5.1%
Peru	256	263	267	271	276	281	286	1.8%
Venezuela	443	328	334	341	329	326	323	-5.1%
Annual change	- 60	- 59	107	128	78	107	101	

After two years of steady decline, **Brazil**'s oil demand returned to growth in 2017 as the economy emerged from a deep recession. GDP grew by 1.3 % in 2018 and it is expected to hover around 2.3% in the next few years. Oil demand posted modest growth in 2017 and 2018 and further economic recovery should see it grow by 40 kb/d per year to 2024.

Argentina's oil demand collapsed in 2018 as GDP fell by 2.6% and in 2019 it is expected to contract again, by 1.6%. In 2020, a return to economic growth should see oil demand rise by 10 kb/d per year to 2024.

According to IMF data**, Venezuela's** GDP has fallen by 60% since 2016. This is one of the most dramatic collapses in modern history. Oil demand has also declined although accurate data is difficult to verify. At the time of writing, the uncertainties surrounding the economic and political situation are such that it is impossible to provide a viable forecast. As a scenario, we have assumed that oil demand remains stable through 2024 after a sharp drop in 2019.

Figure 1.22 Brazilian oil demand, year-on-year change



Overall, Latin America will add 460 kb/d to our demand forecast by 2024, with jet fuel showing the fastest growth.

Middle East

The Middle East's oil demand is expected to grow at an average annual rate of 1.6% over the forecast period, adding 0.9 mb/d to our global forecast by 2024 with naphtha, fuel oil, and gasoil being the fastest growing components. The economic health of the region remains dependent on the level of oil prices and so suffered from their collapse in 2015-16. Brent prices rose by 22% in 2017 and more than 30% in 2018, helping regional economies to recover.

Table 1.29 Middle East oil demand by product (kb/d)

	2018	2019	2020	2021	2022	2023	2024	2018 - 2024 Growth rate
LPG & ethane	1 690	1 704	1 732	1 741	1 812	1 837	1 903	2.0%
Naphtha	106	102	103	104	140	148	151	6.1%
Motor gasoline	1 647	1 659	1 686	1 789	1 808	1 824	1 839	1.9%
Jet/kerosene	516	538	545	556	566	576	585	2.1%
Gasoil/diesel	1 841	1 909	2 061	2 078	2 098	2 109	2 118	2.4%
Residual fuel oil	1 579	1 620	1 643	1 789	1 789	1 823	1 837	2.6%
Other products	1 012	920	850	815	800	807	814	-3.6%
Total products	**8 391**	**8 452**	**8 620**	**8 872**	**9 013**	**9 125**	**9 247**	**1.6%**

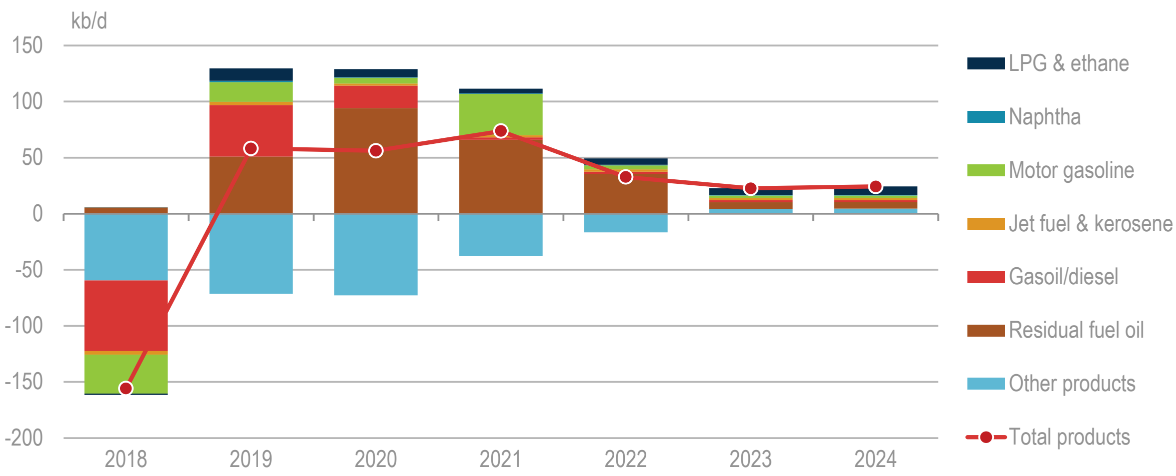
Table 1.30 Middle East oil demand in selected countries (kb/d)

	2018	2019	2020	2021	2022	2023	2024	2018 - 2024 Growth rate
Middle East	**8 391**	**8 452**	**8 620**	**8 872**	**9 013**	**9 125**	**9 247**	**1.6%**
Iran	2 033	1 985	2 016	2 084	2 109	2 134	2 189	1.2%
Iraq	924	917	944	974	960	963	966	0.7%
Saudi Arabia	3 118	3 176	3 232	3 306	3 339	3 361	3 386	1.4%
Annual change	- 116	61	168	252	141	111	123	

In **Saudi Arabia,** following the strong oil price recovery in 2018, the IMF expects economic growth to be 2.1% in 2019-24. The pattern of oil demand changed significantly between 2016 and 2018. On one hand, there was a strong increase in fuel oil demand to replace crude oil in the power sector (40 kb/d per year), while gasoil demand fell by 85 kb/d per year. For gasoil, switching to fuel oil in the power sector, large-scale emigration by foreign workers, and a slowdown in construction activity were largely responsible for the decline. Fuel oil demand will likely be boosted by the implementation of the IMO marine fuel regulations in 2020 as large volumes of discounted material become available.

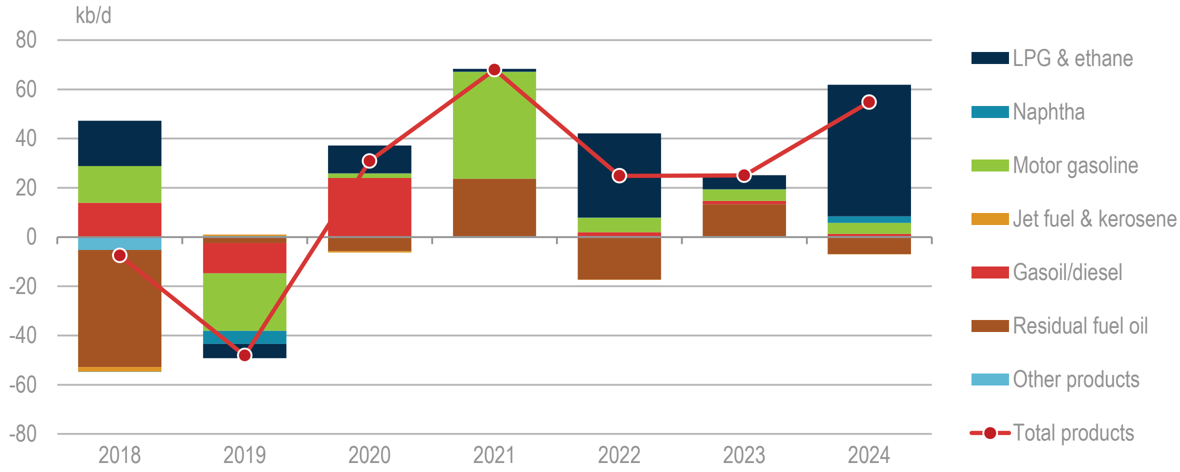
In January 2018, the government increased the price of gasoline by 127%, to bring prices towards international levels, albeit still well below European or US prices. Even so, they have increased by enough to have an impact on gasoline demand growth. The price of 91 octane gasoline rose to $0.37/litre (+83%) while the price of 95 octane gasoline rose to $0.55/litre (+127%). The price increases run alongside a new vehicle fuel economy target of 17 km/l (5.9 l/100 km) for 2020. Diesel and kerosene prices were unchanged. Overall, we expect an increase of 45 kb/d per year on average in Saudi oil demand from 2019 to 2024.

Figure 1.23 Saudi Arabian oil demand, year-on-year change



Since 2014, **Iran** has seen a very large decline in gasoil and fuel oil use in the power sector. The switch to natural gas was responsible for a drop of 65 kb/d per year in diesel demand in 2014-16 and a drop of 35 kb/d per year in 2014-18 for fuel oil. It is nevertheless assumed that Iran will be using some additional fuel oil if US sanctions are maintained.

Figure 1.24 Iranian oil demand, year-on-year change



Iraq is another Middle Eastern country using more natural gas in the power sector. Direct crude use in power generation has been in decline from 210 kb/d in June 2017 to negligible volumes at the end of 2018, replaced by gas and fuel oil. Iraq has developed its domestic gas resources and has also started to import gas from Iran to feed its power sector. It has also used more fuel oil in 2018 and we expect some further increases from 2020, if HSFO prices collapse following the implementation of the new IMO regulations.

2. SUPPLY

Highlights

- Global oil production capacity is set to rise by 5.9 million barrels per day (mb/d) by 2024, with the United States by far the dominant country. Growth plunges to just 0.2 mb/d this year, however, as US sanctions erode Islamic Republic of Iran's ("Iran") effective capacity[1] and Venezuela declines further. In 2020, capacity in the Organization of the Petroleum Exporting Countries (OPEC) returns to growth. Towards the end of the forecast, the global expansion stalls as the United States slows down.
- Apart from the United States, significant growth will also come from Brazil, Iraq, Norway and newcomer Guyana. Total non-OPEC production rises by 6.1 mb/d to 68.7 mb/d by 2024.
- Iraq drives OPEC's capacity-building effort, with the United Arab Emirates (UAE) also posting solid growth. However, a sharp reduction in Iranian production due to sanctions and further losses in Venezuela mean that crude oil capacity in OPEC *falls* by 380 thousand barrels per day (kb/d) to 34.5 mb/d by 2024.
- A new round of OPEC/non-OPEC supply cuts that took effect in January 2019 is expected to go some way towards restoring market balance. However, robust non-OPEC production growth in the early part of the forecast period suggests that some form of market management might stay in place.
- The call on OPEC crude initially drops from 31.1 mb/d in 2018 to 30.1 mb/d in 2020. As non-OPEC supply growth moderates, the call rises to 32 mb/d by 2024. This implies that effective spare OPEC capacity as a percentage of global demand falls to 2.4% in 2024. An additional 2 mb/d of capacity is currently shut in for various reasons.
- Following an increase of 6% in 2018, global upstream spending is expected to rise by 4% this year. For the first time since the 2014 peak, investment in conventional resources is set to increase at a stronger pace than US shale where investors prioritise capital discipline and shareholder returns.
- Global natural gas liquids (NGL) and condensate production is set to expand by 1.9 mb/d by 2024, representing 29% of total oil capacity growth. Non-OPEC countries contribute most of the expansion, led by the United States. Globally, NGL output rises by 1.35 mb/d to 12.1 mb/d and condensates increase by 510 kb/d to 6.5 mb/d.
- Permian takeaway pipeline capacity reaches 8 mb/d by the end of 2024, up from just 3.5 mb/d in 2018, after billions of dollars of investment in new lines. The United States could have the capacity to export as much as 5.1 mb/d of crude by 2024, making it one of the world's largest *gross* crude exporters. A further 3.2 mb/d of crude export capacity could be added if all projects under consideration were completed.
- Global biofuels production is set to reach 3.1 mb/d by 2024, an increase of 0.5 mb/d from 2018. Growth mainly occurs in Latin America and Asia.

[1] In this report, effective capacity is defined as volumes available to the market. It excludes production estimated to be shut in due to sanctions on Iran and political turmoil in Venezuela

Global overview

The world of oil supply in 2018 was extraordinary with explosive growth in the United States, unprecedented production from Saudi Arabia, the Russian Federation ("Russia") and Iraq as well as record declines in Venezuela. Our forecast to 2024 is equally remarkable. The big picture is that the United States continues to dominate an expansion that boosts the world's oil production capacity by 5.9 mb/d. This year, however, growth in global supply plunges to 0.2 mb/d from a massive 2.6 mb/d in 2018 as US sanctions erode the Islamic Republic of Iran's (Iran) effective capacity and Venezuela declines further. In 2020, capacity surges as non-OPEC gains pace and OPEC posts a modest rebound. Momentum slows in the United States towards the end of the period and in 2024 the global capacity expansion is only 0.4 mb/d.

Figure 2.1 Global liquids capacity growth

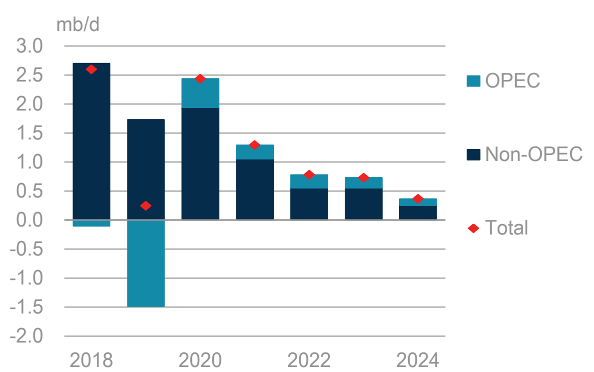
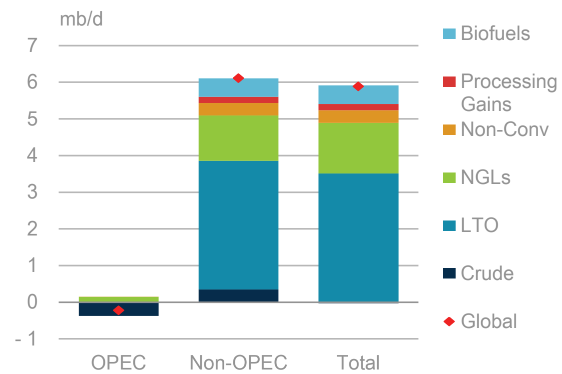


Figure 2.2 Global capacity growth 2018-24



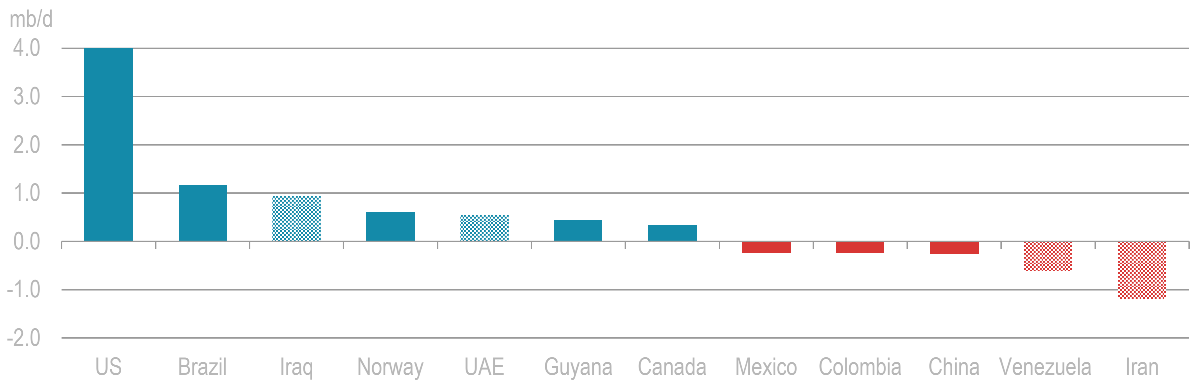
The United States is joined by Brazil, Iraq, Norway, the UAE and Guyana as the biggest sources of supply growth. Iran, hemmed in by sanctions, and Venezuela, in the throes of economic and political upheaval, post the deepest losses. In both countries, the outlook could change dramatically if political problems were to be resolved. Despite ambitious government targets to increase output, the People's Republic of China ("China") and Mexico are set for further declines to 2024. Production from the two plunged nearly 1 mb/d over the past three years due to losses at mature fields. In all, total non-OPEC oil supply rises by 6.1 mb/d to reach 68.7 mb/d by 2024. As for OPEC, effective crude oil capacity falls by 380 kb/d to 34.5 mb/d.

Annual gains will boost the United States to levels never seen in any country, in excess of maximum capacity in both Russia and Saudi Arabia. Given its huge resource potential, estimates of which are regularly increased, the United States could produce still more if prices were higher than assumed in the futures curve used for our analysis. Even with growth slowing, the United States is poised to double its gross crude exports to more than 4 mb/d by 2024. This is still a long way behind Saudi Arabia and Russia, who in 2018 exported 7.3 mb/d and 5 mb/d, respectively. Rising US exports will, however, provide healthy competition, especially in the Asian market.

With the United States and other non-OPEC countries seeing continued growth throughout the forecast period, Saudi Arabia will almost certainly have to play its traditional role as swing producer when the market is unbalanced. Currently, Saudi Arabia and Russia lead a 24-country group that accounts for nearly 60% of global supply in cutting output by 1.2 mb/d in an effort to return the market to balance and to stabilise prices.

Market management by producers is likely to remain necessary for some time given the outlook for the call on OPEC crude. From 31.1 mb/d in 2018, it falls to 30.1 mb/d in 2020. As non-OPEC supply growth moderates thereafter, the call rises again to 32 mb/d in 2024. Based on our estimates for global oil demand and non-OPEC supply, this implies that effective spare OPEC crude capacity as a percentage of global demand falls to 2.4% in 2024. However, there is an additional 2 mb/d of capacity, including 500 kb/d from the Neutral Zone, that is currently shut in.

Figure 2.3 Highs and Lows: Change in total oil supply 2018-24



Note: Shaded columns are OPEC members.

Upstream investment

For a third consecutive year, upstream investment is set to rise in 2019. The pace of growth drops to nearly half the 2018 level, however, as US spending hikes come to an abrupt halt. In fact, for the first time since the 2015 downturn, investment on conventional assets could increase slightly faster than North American shale. While global upstream spending, of around $500 billion (United States dollars), remains nearly $300 billion lower than the peak of 2014, a decrease in costs of between 30% to 40% means that the industry is able to do significantly more with less than only a few years ago.

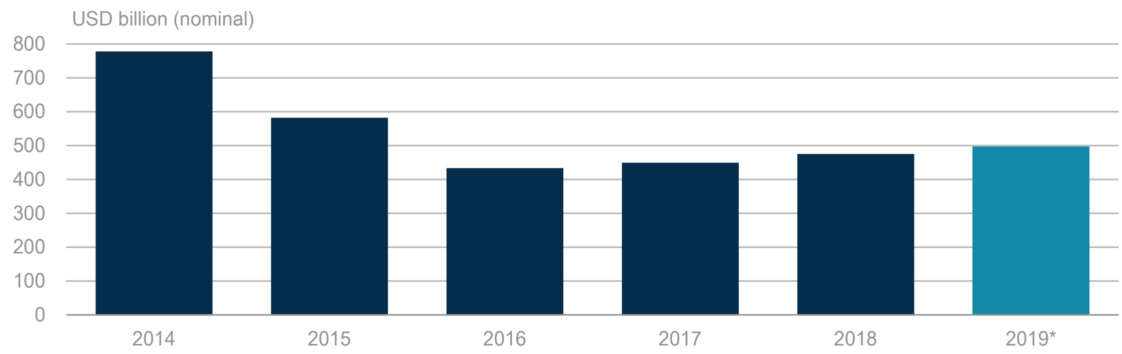
Based on preliminary company announcements, global upstream capital expenditure (capex) for oil and gas is expected to increase by 4% in 2019. Gains will be led by the Middle East, where large national oil companies such as Saudi Aramco, Abu Dhabi National Oil Co (Adnoc), Qatar Petroleum (QP) and Kuwait Petroleum Corp are spending more to address rising domestic gas needs. This includes gas injection to support or boost oil production. Investment is also expected to pick up in Brazil and Guyana as new offshore developments pick up steam.

Increased demands for capital discipline and investor returns are putting a cap on US expansions. Following the drop in oil prices at the end of 2018, a number of shale operators announced that they are planning to reduce spending in 2019 to below the levels planned and realised in 2018. Pioneer, Continental, WPX Energy, Parsley Energy, Centennial Resource Developments, Apache and Noble all cut spending this year, while maintaining robust growth projections. Many companies left room for upward adjustments should prices recover, however, as was seen during 2018 when the actual spend was significantly higher than planned at the start of the year.

In contrast, international oil companies (IOCs), including ExxonMobil, Shell, BP and Total have announced higher upstream budgets, with Exxon planning the biggest boost. Moreover, the IOCs continue to gear investments towards shorter-cycle developments to reduce long-term exposure.

Exxon and Chevron have made the Permian a centrepiece of their strategies, while Shell and BP are increasing their positions. Exxon boosted its total 2019 capex to $30 billion from $25.9 billion spent last year, in large part to pay for increased activity in the Permian. That, and similar moves by Chevron, Shell and BP, will give the majors a much greater role in US supply. Also, for conventional projects, companies continue to favour projects that can generate cash flow quickly.

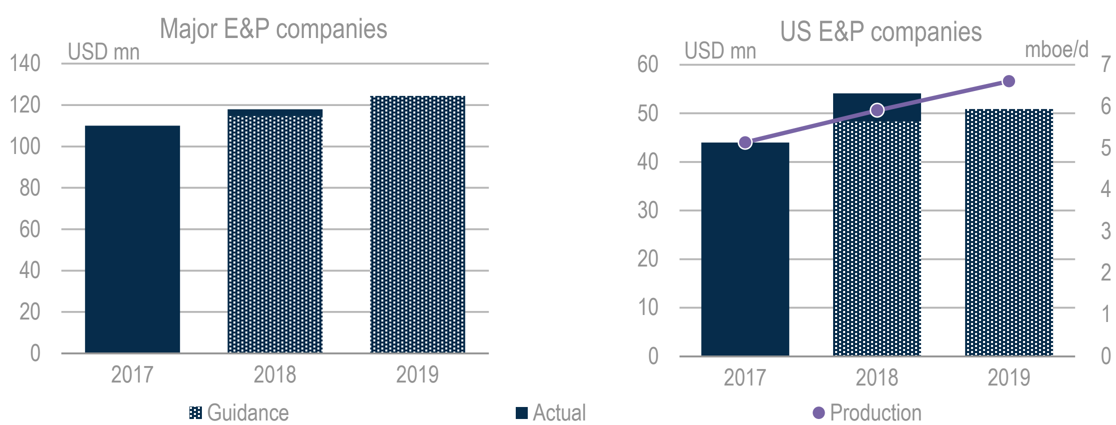
Figure 2.4 Global oil and gas upstream capital spending 2014-19



*Preliminary based on company reports.

As a result, 2019 might be the first year where investment growth in shale assets passes from independents to big oil companies. This is a remarkable change for a sector which has hitherto been dominated by smaller operators. The growing footprint of large players means that investments might become less volatile. Larger players make longer-term strategic plans and, given the strength of their balance sheets and diversified portfolios, can continue to invest and grow output during a downturn.

Figure 2.5 Selected company oil and gas upstream capital spending



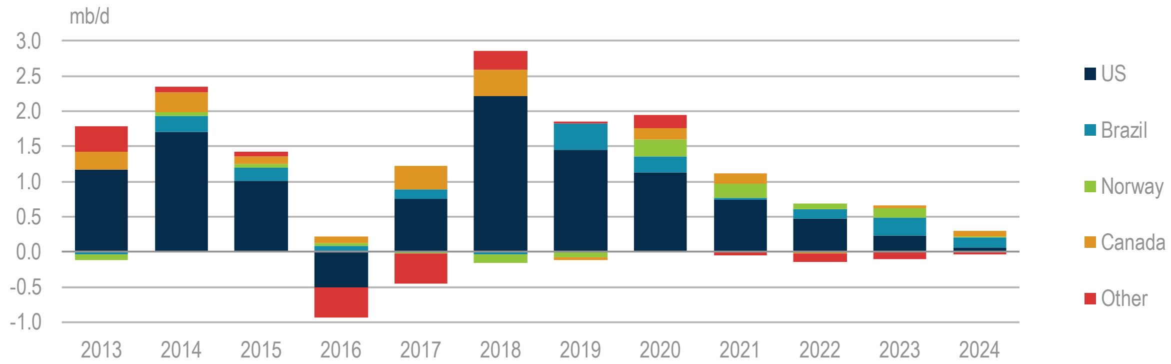
Notes: Majors include Exxon, Shell, Chevron, Total, BP, Eni and Conoco. US E&Ps include EOG, Anadarko, Occidental, Pioneer, Apache, Continental, Chesapeake, Marathon, Noble Energy, Whiting, Concho, Devon Energy, Murphy oil Co. Diamondback, Parsley, Carrizo, Ladero, EQT Corp., WPX Energy, Centennial Resources, Antero Resources, Cimarex and SM Energy.

So far, there are few indications of overheating and significant inflation in the upstream sector. Costs remain between 30 to 40% lower than the 2014 peak. Companies maintain that a significant share of the cost deflation seen over the past four years is structural and here to stay due to great efforts to improve operational efficiency, including digitilisation. The IEA's upcoming *World Energy Investment 2019* will address this issue in more detail.

Non-OPEC oil supply

The spectacular growth of 2.7 mb/d in non-OPEC supply in 2018, driven by the United States, will be difficult to sustain. However, heady gains of nearly 2 mb/d are still expected in the near term. In 2019, growth will slow as Canada, Russia and other Vienna Agreement producers cut supply and the rate of US expansion cools. The start-up of a number of new projects keeps growth at robust levels through 2020. Thereafter, the pace could ease considerably unless higher prices unlock further US expansions and/or field developments elsewhere are sanctioned. Even so, non-OPEC oil supply is forecast to expand by 6.1 mb/d by 2024 to reach 68.7 mb/d.

Figure 2.6 Non-OPEC supply growth



The United States will continue to lead supply gains, adding 4.1 mb/d of new output over the period. Significant increases will also come from Brazil, Norway, Canada and new oil producer Guyana. The biggest declines are expected in China, Colombia and Mexico.

Table 2.1 Non-OPEC supply (mb/d)

	2018	2019	2020	2021	2022	2023	2024	2018-24
North America	22.8	24.0	25.2	26.1	26.5	26.8	26.9	4.18
Central and South America	4.5	4.9	5.1	5.1	5.3	5.6	5.9	1.38
Europe	3.6	3.6	3.8	4.0	4.0	4.0	4.0	0.41
Africa	1.4	1.5	1.5	1.5	1.5	1.5	1.5	0.06
Middle East	3.3	3.3	3.3	3.3	3.3	3.3	3.3	0.06
Eurasia	14.5	14.6	14.7	14.7	14.7	14.6	14.5	0.00
Asia Pacific	7.6	7.5	7.4	7.4	7.2	7.1	6.9	-0.67
Non-OPEC Oil Production	**57.6**	**59.3**	**61.0**	**62.0**	**62.5**	**62.9**	**63.1**	**5.4**
Processing Gains	2.3	2.3	2.4	2.4	2.4	2.5	2.5	0.17
Global Biofuels	2.6	2.7	2.8	2.9	3.0	3.1	3.1	0.50
Total-Non-OPEC Supply	**62.6**	**64.3**	**66.3**	**67.3**	**67.9**	**68.4**	**68.7**	**6.10**
Annual Change	2.7	1.7	1.9	1.1	0.6	0.6	0.3	0.9

United States sets new records, but needs higher price to maintain pace

The United States will dominate non-OPEC supply growth to 2024. Production is expected to expand by 4.1 mb/d, accounting for more than two thirds of the total increase. US crude oil production rises 2.8 mb/d to 13.7 mb/d, led by higher light tight oil (LTO) output, primarily in the Permian Basin. Rapid growth in natural gas production and new petrochemical capacity underpins gains of an additional 1.3 mb/d of natural gas liquids.

The outlook for US supply to 2024 is by no means certain, however. Future price levels, investment strategies, infrastructure capacity, the size of recoverable resources and technological advances will all play a part in determining the pace of growth. In the past, onshore spending has proven to be highly reactive to prices and a 30% crude oil price increase in 2018 compared with 2017 led to more upstream spending than initially budgeted. At roughly $54 billion, exploration and production investment for a selection of 23 large and midsize independents was nearly $6 billion above company guidance and 23% above 2017 levels. This increased spending, along with continuous technological and efficiency improvements and efforts to overcome infrastructure constraints saw the United States set records in 2018, with total oil supply rising 2.2 mb/d year-on-year (y-o-y).

Figure 2.7 US total oil supply

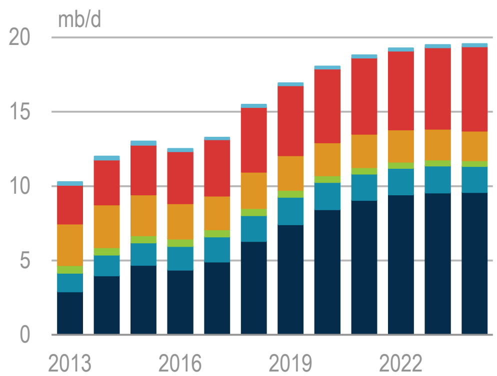
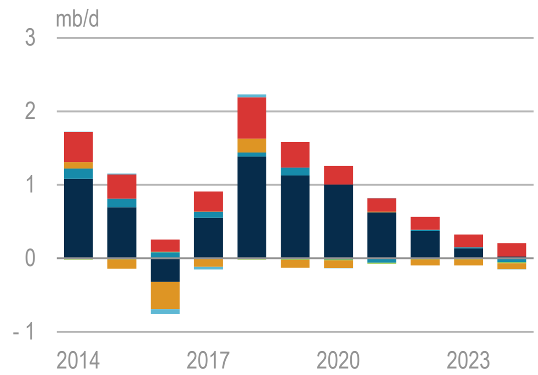


Figure 2.8 US supply growth



Even though current capex guidance suggests US spending by this group of companies could drop by 6% this year, and the number of rigs have been falling, production is likely to grow strongly given the momentum from existing drilling programmes. The independents have set 2019 production growth targets of 12% and the majors continue to raise US investment. Moreover, the number of drilled but uncompleted horizontal wells (DUCs) targeting oil rose by 12% last year to more than 5 000 wells at the end of the year, providing operators with an inventory of wells that could provide a significant output boost at lower levels of investment.

While the current $50-55/barrel (bbl) West Texas Intermediate (WTI) price environment is not a major impediment for US shale activity, growth is expected to slow markedly. According to *Rystad Energy*, WTI breakeven prices[2] for prime shale acreage generally lie in the range of $30-40/bbl with the best locations coming in below $20/bbl. Taking into account all wells, *Rystad* estimates that full cost WTI breakeven prices rose marginally during 2018, to between $45/bbl for the Permian Delaware and $63/bbl for Eagle Ford. Wellhead breakeven prices[3] were on average, $12/bbl lower.

Without a material increase in spending, growth will slow as an increasing number of new wells are needed to offset the steep decline from the existing production base. Tight oil wells decline very rapidly after completion, often by as much as 70% within the first year. Given the rapid rise in activity over the course of 2018, the number of wells needed to offset declines rose to 900 per month at the start of 2019 compared with 650 a year earlier.

[2] Including drilling and completion costs, lease operating expenses, production taxes and royalties, transportation costs, price differentials, overheads and a 10% discount rate.

[3] The wellhead breakeven price captures drilling and completion costs, lease operating expenses, production taxes and royalties.

Figure 2.9 US LTO breakeven prices (WTI)

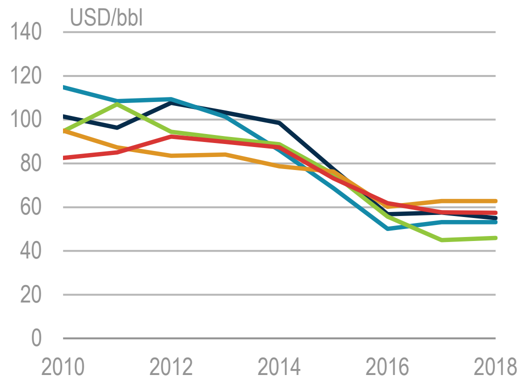
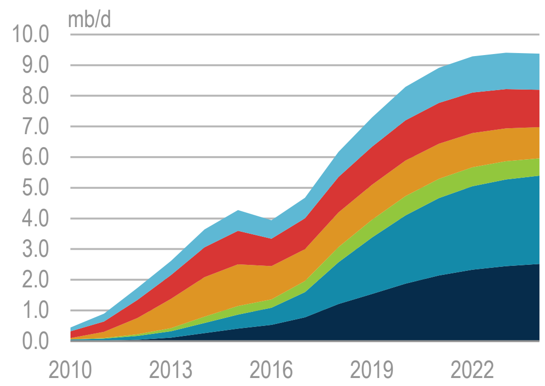


Figure 2.10 US LTO production



Source: Rystad Energy, IEA.

Technological advances are unlocking new resources and allowing companies to better target core locations. The estimated resource potential is subject to regular reassessment. A recent update by the United States Geological Survey of Permian resources upgraded the estimate by 20 billion barrels. In this report, tight oil resources, assumed at 155 billion barrels, are nearly 35% greater than a year ago. Production towards the end of the forecast period is likely to be more than 1.5 mb/d higher than assumed in *Oil 2018*.

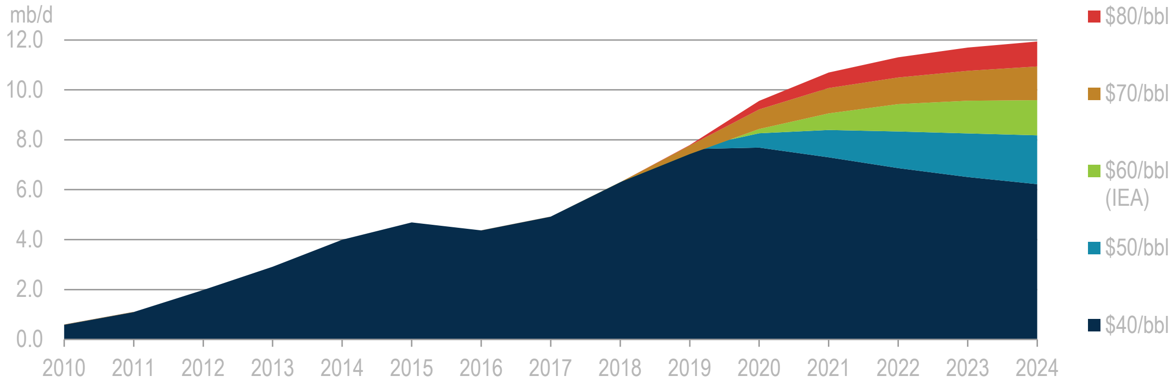
Even with continued innovation, many of the most productive areas in the United States are expected to show signs of depletion by the mid-2020s, given the current recoverable resource potential. This means that the average well drilled in 2024 will be less productive than today and so a larger number of wells must be completed to maintain or increase production.

US LTO price sensitivities

While resource potential and further technological advances are key determinants of future US supply, prices will impact growth the most. This report derives its price assumptions for modelling purposes from the futures curve. At the time of writing, prompt month Brent futures were trading at just over $60/bbl with the curve staying close to this level through to 2024. The futures curve is not a price forecast and it is an imperfect modelling tool. It nevertheless represents the level at which market participants can hedge production today and, as such, influences investment and business decisions, at least in the near term.

The relatively steady price trajectory through 2024 suggests that market participants expect plentiful US LTO supplies coupled with continued OPEC market management to maintain prices in a narrow range. In reality, they will be volatile. The response of shale production to different prices is therefore critical, as it will play a key role in balancing the market over the medium term. If prices remain steady at around $60/bbl as seen in the futures curve, we expect growth to slow towards the end of the forecast period. Over the whole period, LTO output will rise by 3.3 mb/d to around 9.6 mb/d in 2024.

Figure 2.11 US LTO price sensitivities



Should prices for any extended period veer away from this level, however, LTO production is expected to respond accordingly. As an illustration, a price of $80/bbl throughout our forecast period could result in output rising by as much as 5.5 mb/d over the same period. Alternatively, a price of $40/bbl would cause LTO output to decline from 2020 onwards.

Permian prepares for higher output

Given the huge uncertainties about future production levels, it is very difficult to assess the adequacy of planned investments in pipeline and export capacity. What is clear is that an unprecedented buildout of pipeline capacity is underway, with a number of projects in the planning stage that could be brought on line if needed.

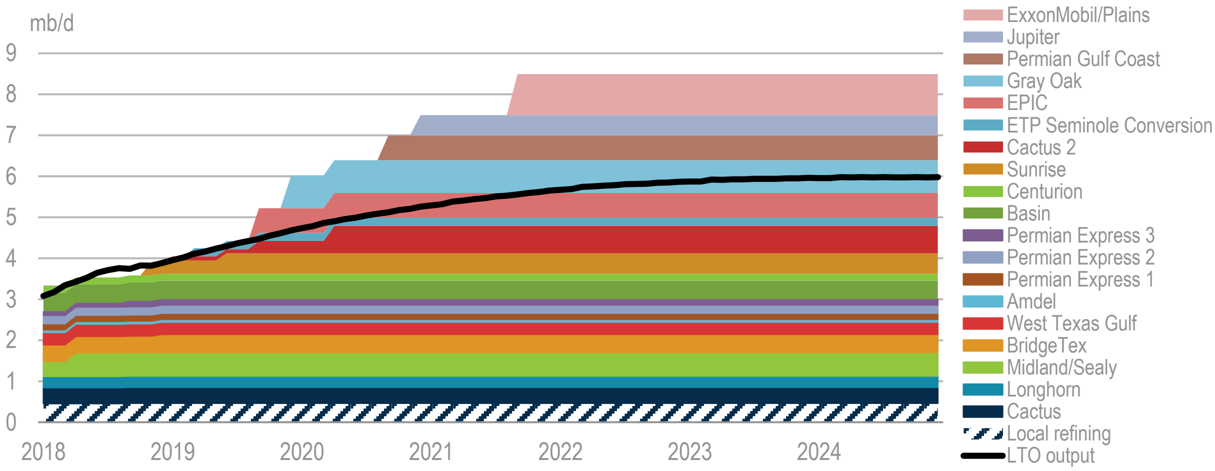
Crude oil pipeline capacity in the Permian became a key operational factor during 2018. Bottlenecks emerged, forcing operators to stockpile crude locally and widening price spreads versus other locations. WTI for delivery in Midland, Texas, the main Permian hub, traded at an average $7.28/bbl discount to WTI for delivery in Cushing, Oklahoma in 2018, compared to $0.38/bbl in 2017. In last year's report*,* we forecast that takeaway capacity would become fully utilised in May 2018 as LTO production increased. With production rising strongly, the shortage was worse than anticipated, averaging 180 kb/d for the year. Total takeaway capacity stood at 3.5 mb/d at the end of the year, up 610 kb/d versus end-2017. Crude production, meanwhile, was up 780 kb/d. Producers found ways to cope and major lines ran near full capacity thanks to the use of drag reducing agents and with no major unplanned shutdowns. A combination of luck and technology was thus able to limit the impact on production.

In 2019, we expect a year of two halves, with an average deficit of 110 kb/d in the first six months and a return to overcapacity sometime in third quarter 2019 (3Q19), helped by the construction of new infrastructure. The pipeline shortage in the first half of the year will be moderate, as midstream companies are able to bring new projects online quicker and with greater throughput than previously thought. For example, Plains All American Pipeline LP has commissioned a major 325 kb/d section of its Sunrise line nine months ahead of schedule. Epic Pipeline LP has raised the capacity of its new crude oil pipeline, due to come online in 3Q19, from 550 kb/d to 600 kb/d with the possibility of a further 300 kb/d expansion later. Enterprise confirmed the conversion of the Seminole NGL line to crude in first quarter 2019 (1Q19), more than a year earlier than it had originally announced.

We forecast the Permian pipeline shortage to turn into a surplus by the end of 2019 when EPIC's project is brought online. By the end of this year, the Permian is likely to have 5.6 mb/d of takeaway capacity, up 2.1 mb/d from 2018, the largest annual expansion recorded so far. Of this, we estimate that 780 kb/d could be unused, unless crude production increases by more than the 800 kb/d we currently expect. The 800 kb/d Gray Oak pipeline, due online at year-end, has received strong interest, suggesting that some producers are betting on a significant increase in output.

Beyond this year, several lines have the potential to ramp up throughput if needed, such as EPIC (300 kb/d), Gray Oak (300 kb/d), Cactus (200 kb/d) and Midland to Sealy (100 kb/d). These upgrades are often quicker and more economic to undertake than the building of new infrastructure as they only require the installation of additional pumps or the injection of chemicals. Three new pipelines have also been lined up, including the 500 kb/d Jupiter, a 1 mb/d "Wink to Webster" line developed by ExxonMobil and the 600 kb/d Permian to Gulf Coast, but they were either unconfirmed or had just been recently given the go-ahead at the time of publication (See Appendix, Table 6.6).

Figure 2.12 Planned Permian/Eagle Ford nameplate pipeline capacity and LTO production

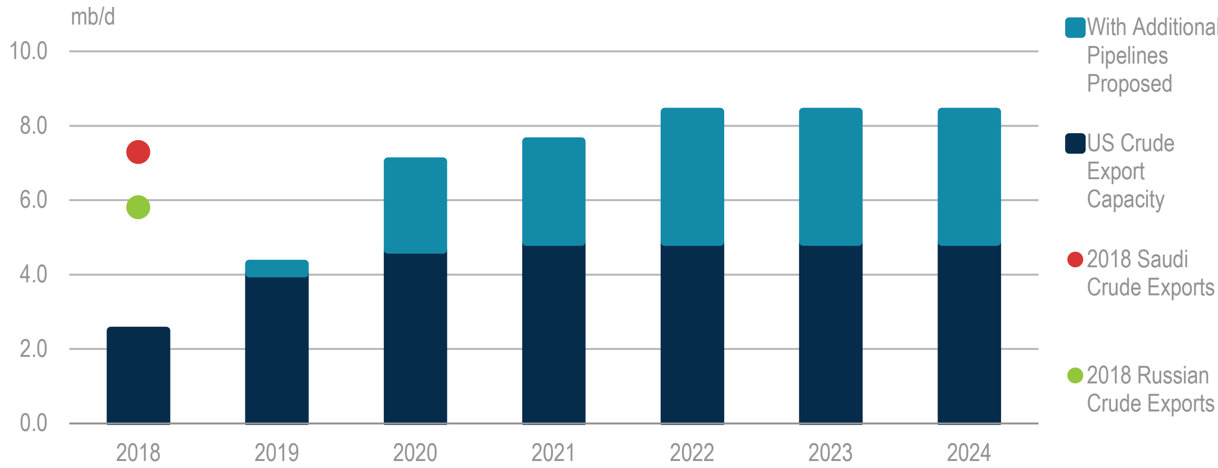


US Gulf Coast export capacity could reach 8 mb/d by 2024

Most new Permian pipelines on the drawing board are attached to storage and export terminal projects, as Gulf Coast refineries have largely run out of LTO intake capacity. In the past year, at least five new terminals have been announced, in addition to those we listed in *Oil 2018*. Details remain scant for some of these projects, however many share the same characteristic: the ability to load very large crude carriers in order to gain economies of scale and bring down the cost of exporting US crude. At the time of writing, Trafigura's 500 kb/d Texas Gulf terminal, located 15 miles from Corpus Christi, and Enterprise's Texas Offshore Port System, located offshore Freeport, are the only projects to have applied for formal approval. Five competing projects from Jupiter (Brownsville), Enbridge (Freeport), Buckeye, Carlyle and Magellan (Corpus Christi) have also been mentioned.

We expect US Gulf Coast crude export capacity to reach 5.1 mb/d by 2024, up from last year's forecast of 4.9 mb/d, following the decision to increase throughput on several Permian lines. This is based on the projects we deem *likely* to go ahead. If all the new projects that have been announced are actually commissioned, then the United States could have the capacity to export as much as 8.4 mb/d of crude oil by 2024. This would make it one of the largest *gross* crude exporters in capacity terms, on a par with Saudi Arabia and ahead of Russia, even if net exports remain well behind those countries.

Figure 2.13 Forecast US crude export capacity based on pipeline buildout



Notes: Based on forecast pipeline additions to the US Gulf Coast. Pipelines going to Houston and Beaumont only export half their volume.

A Bakken takeaway crunch?

North Dakota's Bakken takeaway capacity showed signs of strain in the fourth quarter of 2018 (4Q18) for the first time since Energy Transfer Partners' Dakota Access Pipeline came online in mid-2017. Ironically, the situation was partly caused by the Permian's takeaway issues, which incentivised some producers to move rigs to the Bakken. This contributed to a significant output increase during the year, which coincided with Canada's pipelines being fully utilised, making it impossible for some spot Bakken volumes to leave the region. A more immediate factor was the planned maintenance shutdown during October-November 2018 of refineries that normally take crude from Bakken, which meant more crude than usual was available for export. This caused Bakken differentials to drop $14.22/bbl below WTI Cushing in November, their lowest level since 2012, even if it was largely temporary.

Over the medium term, we expect shortages to worsen. Midstream companies have not invested substantial sums in the Bakken in the past two years. There are only three major projects in the works. The Dakota Access line expanded by 45 kb/d in 1Q19 and Phillips 66 sought nominations in November 2018 for a new 350 kb/d Liberty pipeline with a tentative launch date of December 2020. In early 2019, Kinder Morgan said it may expand its Double H line, without specifying a date or volume. Unlike the Permian, however, the Bakken benefits from substantial rail export capacity of around 1.5 mb/d following investments made in the 2010-13 period. This should allow some of the surplus production to escape the region, albeit at a higher cost.

Gulf of Mexico production gets boost from new start-ups

Offshore production in the Gulf of Mexico is often overlooked due to the focus on LTO. However, there is plenty of activity. After a 50 kb/d boost in 2018, offshore output is set to rise by 110 kb/d this year as a number of new fields are set to ramp up and as companies boost output at already producing fields. Of note, the 80 kb/d Hess-operated Stampede field came on line in February 2018. Last May, Shell produced first oil at the Kaikias project a year ahead of schedule and at 30% below the original development cost ($30/bbl breakeven). In October, BP started up the Thunder Horse Northwest Expansion project, four months ahead of schedule and 15% under budget. In January, BP announced that it had discovered an additional 1 billion barrels of oil at the field and sanctioned phase 3 of its Atlantis project. Finally, in November, Chevron reported first oil from its deep water Big Foot project that is designed for a capacity of 75 kb/d of oil and 25 million cubic feet of natural gas per day. Shell will launch its 175 thousand barrels of oil equivalents per day (kboe/d) Appomattox project in 2020. Shell and partner Equinor announced they would move forward the Vito development, which will have capacity to produce 100 kb/d after its start-up in 2021, when BP's 140 kb/d Mad Dog Phase 2 platform will also start up. Offset by declines at other fields, Gulf of Mexico production is expected to hold relatively steady over the forecast period at around 1.8 mb/d.

Table 2.2 US oil supply forecast (kb/d)

	2018	2019	2020	2021	2022	2023	2024	2018-24
LTO	**6 301**	**7 428**	**8 432**	**9 057**	**9 429**	**9 565**	**9 588**	**3 287**
Permian	2 624	3 440	4 168	4 739	5 128	5 367	5 547	2 923
Bakken	1 181	1 263	1 334	1 352	1 342	1 300	1 236	55
Eagle Ford	1 154	1 161	1 180	1 163	1 133	1 087	1 035	-120
Niobrara	506	590	641	639	629	605	574	69
Other	836	973	1 110	1 164	1 198	1 205	1 196	360
Gulf of Mexico	**1 735**	**1 845**	**1 830**	**1 771**	**1 789**	**1 805**	**1 750**	**15**
Alaska	478	458	446	431	417	404	391	-87
Other crude	2 449	2 339	2 231	2 243	2 160	2 076	1 995	-454
Total crude	**10 963**	**12 070**	**12 939**	**13 502**	**13 795**	**13 849**	**13 724**	**2 761**
NGLs	4 346	4 693	4 948	5 130	5 304	5 476	5 661	1 315
Other hydrocarbons	173	173	172	173	173	173	**172**	**0**
Total US	**15 482**	**16 936**	**18 060**	**18 805**	**19 272**	**19 498**	**19 557**	**4 075**

Brazil rebound around the corner

After a rather disappointing 2018, when steep declines at mature fields, heavier than anticipated maintenance shutdowns and delays in the commissioning of new production units derailed expected output growth, Brazilian oil supply is set to increase strongly over the medium term. In fact, Brazil will be the second-largest source of non-OPEC production growth to 2024, adding nearly 1.2 mb/d to world oil production.

Expansions are frontloaded, with 0.4 mb/d of growth expected in 2019 and an additional 0.3 mb/d in 2020, when as many as nine new production systems ramp up. Petrobras and international partners commissioned four new floating production, storage and offloading (FPSO) vessels during 2018 and another four are set to start up in 2019. While only one new unit is due on stream in 2020, nine are planned for the 2021-23 period and additional developments could be sanctioned for the years that follow. Though not included in this forecast, the Libra consortium is considering deploying additional units at the Mero field while Equinor's Caracara discovery could start-up of by 2024.

In the near term, growth will come from the Lula and Búzios fields. At Búzios, three FPSOs have started up since April 2018, each with the capacity to produce 150 kb/d. The fourth and fifth units are due on line later in 2019 and 2021, respectively, taking total production capacity to 750 kb/d. At Lula, one additional FPSO was added in 2018, while a second one was delayed to early 2019.

Later, growth will be dominated by the start-up of the Mero field located in the Libra pre-salt block in the Santos basin, which is estimated to hold recoverable reserves of 3.3 billion barrels of oil. Petrobras, which holds a 40% interest in Mero, in partnership with Shell (20%), Total (20%), China National Petroleum Corporation (CNPC) (10%) and China National Offshore Oil Corporation (CNOOC)

(10%) is currently tendering for two FPSOs, each with 180 kb/d of capacity. Full field development will likely include additional units. Other gains will come from the start-up of the Berbigao field (2019), Atapu (2020), Sepia (2021) and Itapu (2023).

Figure 2.14 Brazil total oil supply

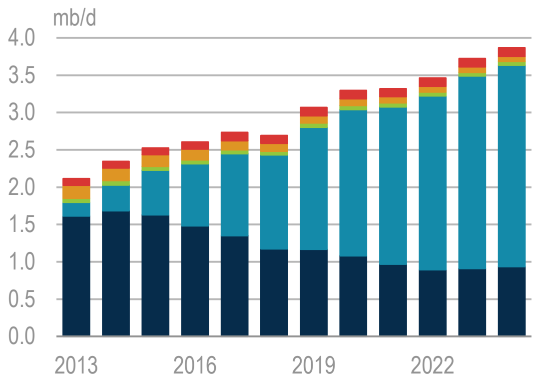
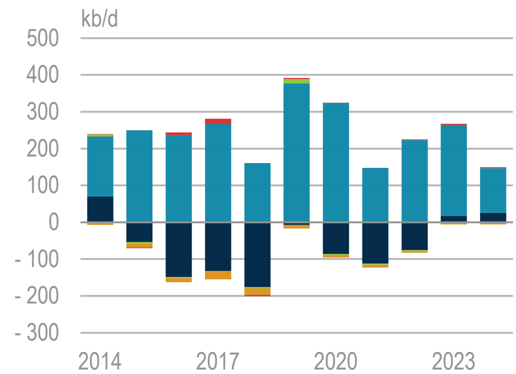


Figure 2.15 Brazil oil supply growth



Petrobras is also taking measures to stem declines in the Campos Basin, which historically was the bedrock of Brazil's oil production. Not only does it plan to add four new production systems by 2023, including the Tartaruga Verde that started up last year and units planned to revitalise the Marlim fields, it has also signed a number of partnerships with IOCs. Notably, Equinor took a 25% stake in the Roncador field for $2.9 billion and signed a strategic agreement with Petrobras for technical cooperation in order to increase recovery rates. Petrobras has signed similar deals with Total and BP. In all, Brazilian production is expected to reach 3.9 mb/d in 2024, compared with 2.7 mb/d in 2018.

Table 2.3 Brazilian oil supply forecast (kb/d)

	2018	2019	2020	2021	2022	2023	2024	2018-24
Onshore	106	97	89	83	77	72	67	-39
Campos basin	1 174	1 167	1 081	968	893	910	935	-239
Lula	863	982	1036	994	942	900	868	4
Búzios	33	253	430	543	641	712	704	671
Lara	0	41	135	209	238	238	255	255
Other Santos basin	363	359	358	362	510	728	873	510
Other offshore	46	57	55	52	50	50	49	3
Crude	**2 585**	**2 956**	**3 184**	**3 211**	**3 351**	**3 609**	**3 751**	**1 166**
NGLs	107	111	111	109	111	114	116	9
Total Brazil	**2 698**	**3 073**	**3 301**	**3 326**	**3 468**	**3 729**	**3 873**	**1 175**

Tight oil developments boost Argentina

Despite challenging economic conditions, Argentina's government announced in mid-2018 an ambitious goal of doubling the country's oil production to 1 mb/d by 2023 in order to become a major oil exporter. The new energy secretary and the industry are being more cautious. Even so, we have revised up our forecast for Argentina's oil production. Total output is now seen reaching 660 kb/d by 2024 from 580 kb/d in 2018.

Argentina holds the world's fourth-largest technically-recoverable LTO resources, most of which sit in the Vaca Muerta play in southwestern Neuquén province. LTO production is expected to grow from around 70 kb/d at the end of 2018 to 250 kb/d by 2024, as more projects targeting the Vaca Muerta play move to large-scale development. Although this increase is significant, and more than offsets the decline in conventional production, the ramp-up falls short of the government's ambitions as the country struggles to attract the level of investments that would unlock its full potential.

The Loma Campana field was the first major shale project developed in Argentina. It has served as a testing ground for state-owned YPF and Chevron to build the technical capacities needed to develop the play and to progressively reduce costs, bringing them close to similar levels in the United States. Development costs have fallen from $29/barrels of oil equivalents (boe) in 2015 to around $11/boe in third quarter 2018 (3Q18), with operating costs falling from $16/boe to around $7/boe during the same period. Additional reductions would be unlocked by addressing infrastructure bottlenecks and high logistics and material costs. As of December 2018, Loma Campana produced 40 kb/d of LTO, more than 60% of the country's total unconventional output, making it the second-largest oil producing area, and it is expected to increase during a second phase of development.

In 2018, despite challenging macroeconomic conditions, local and foreign players announced new investments in Vaca Muerta. Several pilot projects are planned for the area as well as the beginning of large-scale developments in several fields. This includes La Amarga Chica, where YPF and Petronas aim to produce 60 kboe/d by 2022. Total, Shell and Schlumberger are also moving ahead with tight oil developments.

Mexico shifts focus back to onshore and shallow water

Mexico's oil production continues to decline, but the new government plans to turn the tide. A boost to Pemex's budget and a shift in focus towards short cycle projects onshore and in shallow waters could provide some stimulus. However, in the longer term this might prove insufficient to offset losses from mature fields. A three-year moratorium on new block auctions, a ban on fracking and delays to new joint venture farm-outs between Pemex and private players risk further downside to the longer-term outlook.

Mexico's oil production fell by 160 kb/d in 2018, and at 1.9 mb/d, is roughly half the peak level reached in 2004. More recently, the decline has accelerated. President Andres Manuel Lopez Obrador is planning a massive push to reverse output declines, targeting an ambitious increase in domestic crude output of 40% to around 2.6 mb/d by the end of his term in 2024. Based on current plans, our forecast sees oil production *fall* to 1.8 mb/d by 2020 and then stabilise.

Oil supply was already expected to increase by the early 2020s, boosted by the energy reforms enacted in 2013 that ended Pemex's monopoly in the oil and gas sector. New entrants, including both national and international companies, have made several significant discoveries that will help stem output declines. However, the new government will not offer up any areas for auction for the next three years and is reviewing recently awarded infrastructure and energy contracts.

The new administration is proposing to increase Pemex's 2019 upstream budget by 24.5% from a year ago, to MXN 209.4 billion (Mexican peso, $10.45 billion). In addition, the 2019 budget of the Energy Ministry SENER includes another MXN 25 billion ($1.25 billion) earmarked for a "financial investment" into Pemex. The National Hydrocarbon Commission (CNH) said that Pemex needs to dedicate $20 billion each year to exploration and production activities to hit the new output target, about 70% more than this year's budget. The government's *New Oil and Gas Production Plan* sets out the strategy of speeding up oil production from shallow water and onshore fields. It aims to reduce lead times for project development from five years to just over one year. Pemex will invest half its budget in existing shallow projects such as Ku-Maloob-Zaap, Chuc, Crudo Ligero Marino, Cantarell, Yaxche and Ek-Balam and is targeting 20 discovered fields for swift development. In January, Pemex selected two consortia to develop two engineering, procurement and construction packages covering 13 platforms and worth up to a combined $775 million. Production from the fields could reach 73 kb/d by 2019 and an ultimate peak of 340 kb/d.

Figure 2.16 Mexico crude oil forecast

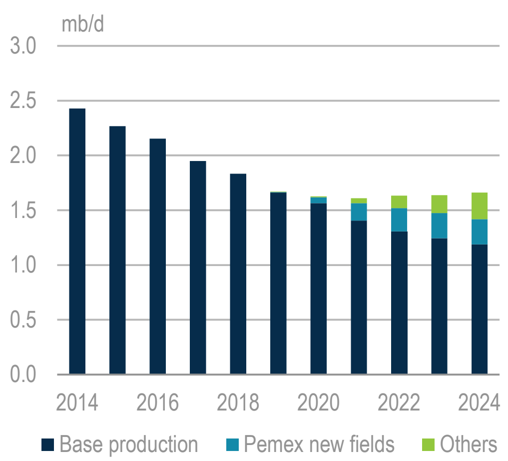
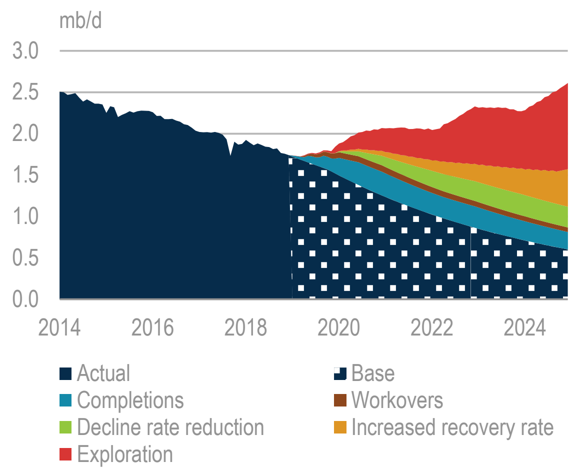


Figure 2.17 Mexico's oil production plan



Source (Figure 2.17): Pemex presentation, December 2018.

Within the abovementioned upstream budget, Pemex's 2019 exploration budget was doubled to MXN 50 billion. The new government said it further expects to increase this by 10% a year with the goal of achieving a reserve replacement rate of 200%. Exploration efforts have already borne fruit. Last October, Pemex announced that it discovered up to 180 mb of oil in the Gulf of Mexico's shallow waters. This follows discoveries in recent years in four nearby fields. New production from the Xikin, Esah, Kinbe, Koban, Mulach and Manik offshore fields could add up to 210 kb/d of crude by the second half of 2020. Pemex has also upped reserves estimates for its onshore Ixachi find to 1.3 billion barrels, making it the largest discovery in 25 years. Pemex expects field output to reach 80 kb/d of condensates and 720 mcf/d of gas by 2022.

Meanwhile, last spring CNH approved the first two plans by private operators to bring oil and gas discoveries to production. First, Eni's $7.49 billion plan to develop the Amoca, Mizton and Tecoalli fields (Area 1), that will start up later this year and ramp up to 90 kb/d by late 2020 was approved. Later, Pan American Energy received the go-ahead for its $2.5 billion plan for the Hokchi development (Area 2), with first oil in 2020 and peak production of 27 kb/d targeted by 2023. Talos's Zama discovery is expected to start up in 2022 and reach capacity of 115 kb/d by 2027, while Fieldwood Energy plans to launch Ichalkil (Area 4) in 2023. Meanwhile, first production from the Trion discovery is not expected until the mid-2020s at the earliest. BHP Billiton won the rights to operate Trion in late 2016, taking a 60% stake in the project valued at some $11 billion, while Pemex holds the remaining 40%. This marked the first-ever deep water joint venture partnership following the opening of the sector in 2013.

Guyana gears up for first oil

Prospects for Guyana's nascent oil sector continue to improve. ExxonMobil and its partners Hess and CNOOC announced two more discoveries in early February 2019 in the Strabroek block. The finds add to Stabroek's recently updated estimated resources of more than 5 billion barrels of oil equivalent. The most recent finds, Tilapia and Haimara, are the eleventh and twelfth made so far following on from Liza, Liza Deep, Hammerhead, Snoek, Longtail, Ranger, Turbot, Payara and Pacora and Pluma. The consortium has already received government approval for Liza phase one, which will start up in early 2020 via a 120 kb/d FPSO. The sanctioning of phase two has slipped from late 2018 to early 2019. The second FPSO will be able to handle 220 kb/d of oil and 400 million metric cubic feet of gas per day. A third FPSO with a capacity of around 180 kb/d is being considered for start-up by 2023. According to the consortium, at least five FPSOs could be producing more than 750 kb/d by 2025. Our forecast includes the first three phases that will bring output to around 500 kb/d by 2024.

Canada outlook deteriorates

The outlook for Canadian oil production has significantly deteriorated. In *Oil 2018*, we warned that rapid growth in Alberta's oil sands production would exceed available pipeline capacity, and thus increase the need to move oil by rail. With rail capacity unable to meet demand, the discount of Canadian heavy crudes to US grades widened to as much as $50/bbl in October 2018. This led the government of Alberta to order production cuts, which will be evaluated over the course of 2019. In the meantime, the government and private companies are lining up additional rail capacity.

Figure 2.18 Canada total oil supply

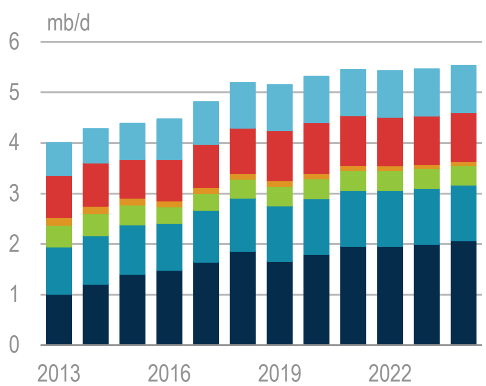
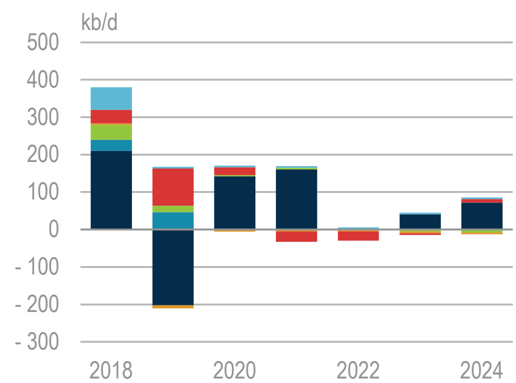


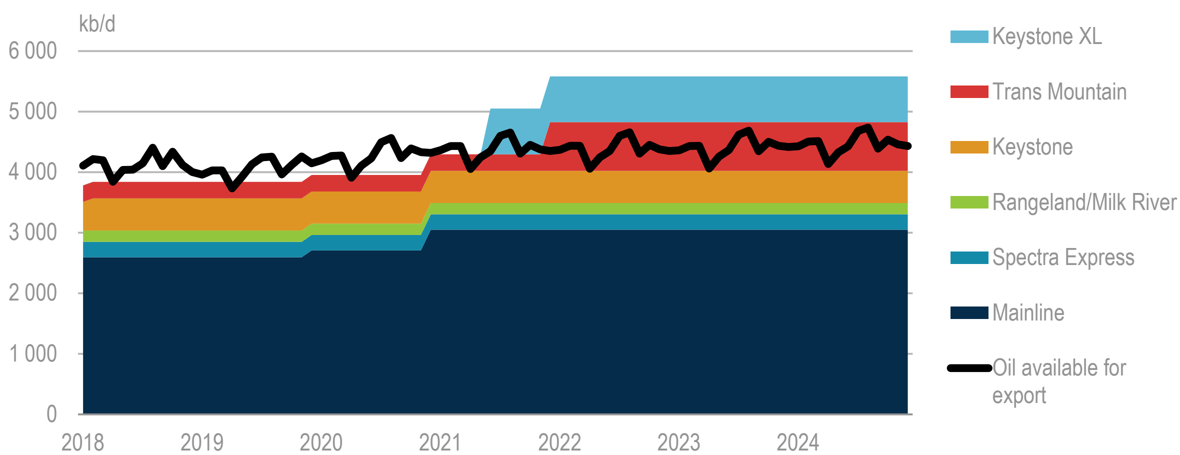
Figure 2.19 Canada total oil supply change



The longer-term outlook looks more precarious. During 2018 and 2019, three planned pipeline projects needed to accommodate further output gains faced renewed headwinds. First, Enbridge's Line 3 replacement project, which was scheduled to go online in the second half of 2019 and provide short-term relief to producers, was delayed by one year until the second half of 2020 due to permitting delays in the US State of Minnesota. Second, the Trans Mountain Expansion Project, which will raise the capacity of an existing line running from Alberta to British Columbia from 300 kb/d to 890 kb/d, was stalled, even after the federal government bought the line from Kinder Morgan to ensure its completion. Third, in early November, a US judge halted the construction of the 830 kb/d Keystone XL to the US Gulf Coast. At least two of these three projects are needed to accommodate higher production volumes. If approved, the new capacity will reduce the need for expensive rail shipments, typically costing around $15-20/bbl for Alberta to USGC deliveries (See Appendix, Table 6.7).

With Canadian oil prices under pressure and so much uncertainty regarding new takeaway capacity, companies have been reluctant to launch new projects. The exception is the Aspen oil sands project sanctioned last November. Imperial will invest CAD 2.6 billion (Canadian dollar) to produce 75 kb/d of bitumen starting in 2022. Suncor Energy's Fort Hills project was the last major oil sands project to be approved back in 2013. It is currently producing 150 kb/d versus a nameplate capacity of 194 kb/d. Over our forecast period to 2024, the pace of production expansion more than halves compared with the six-year period to 2018. By 2024, total Canadian oil supply is expected to reach 5.5 mb/d, only 0.3 mb/d higher than the 2018 average. Growth will primarily come from projects sanctioned years ago, including Cenovus's 50 kb/d Phase 2G Christina Lake expansion, Suncor's Meadow Creek and Canadian Natural Resources' Kirby North projects.

Figure 2.20 Planned pipeline capacity and crude production



Offshore production is also expected to increase. The Hebron field, discovered in 1980, is estimated to hold more than 700 mb of recoverable resources, and it will continue to ramp up towards its 150 kb/d capacity. Husky Energy and partners Suncor Energy and Nalcor Energy Oil and Gas have sanctioned the West White Rose project that is set to come on line in 2022 and reach peak output of 75 kb/d by 2025. Equinor, Husky Energy and Nalco are also moving ahead with the Bay du Nord project. Development activities are set to begin in 2020, with first oil targeted for 2025.

Norwegian giant fuels North Sea recovery

Norwegian oil production is on the cusp of a second expansionary phase. Output is set to grow by 0.6 mb/d by 2024 when it reaches 2.5 mb/d, the highest since 2008. As many as 20 development projects are under way on the Norwegian Shelf, and others could well be sanctioned and start up within the timeframe of this report.

The largest contribution to Norway's growth will come from the massive Johan Sverdrup field, one of the largest discoveries ever made on the Shelf. The first phase, expected to produce as much as 440 kb/d, is on track to start up by the end of 2019. The second phase, set to come on line by 2022, will raise output to 660 kb/d. Other key developments include the Johan Castberg field in the Arctic Barents Sea and the Snorre Expansion Project. Numerous smaller developments help underpin the reversal of the long decline since the all-time high production level of 3.4 mb/d was hit in 2001.

Equinor and other operators are introducing new measures to improve the recovery rate and extend the life of existing fields. Equinor plans to drill as many as 3 000 production and exploration wells by 2040, almost as many as it has managed since its establishment close to 50 years ago. By doing so, it hopes to achieve recovery rates of 60% and 85%, respectively, at oil and gas fields. This is an improvement on the current recovery rate for oil of 50% and almost twice the average global rate of 35%. Plans call for a lifetime extension of more than 20 fields. The lifetime of Equinor's fields is already 2-3 times longer than assumed in the original development plans.

Figure 2.21 North Sea total oil supply

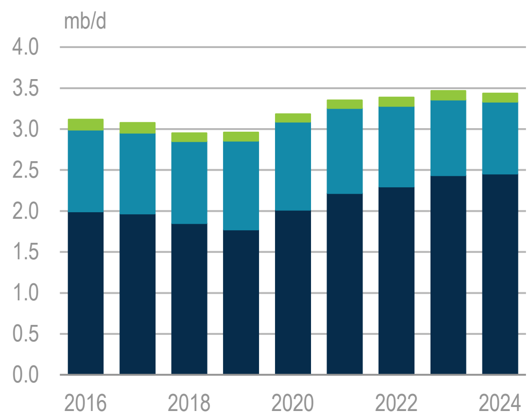
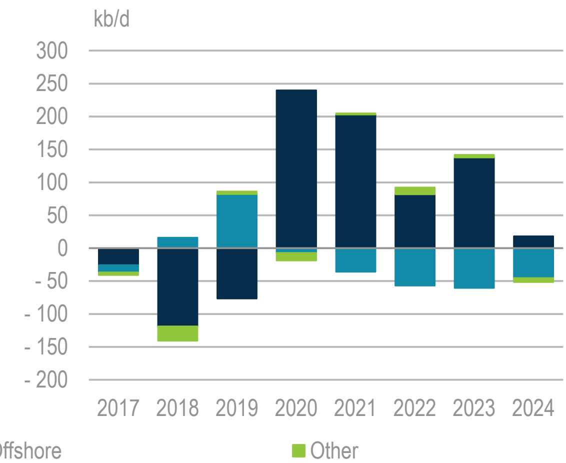


Figure 2.22 North Sea annual supply change



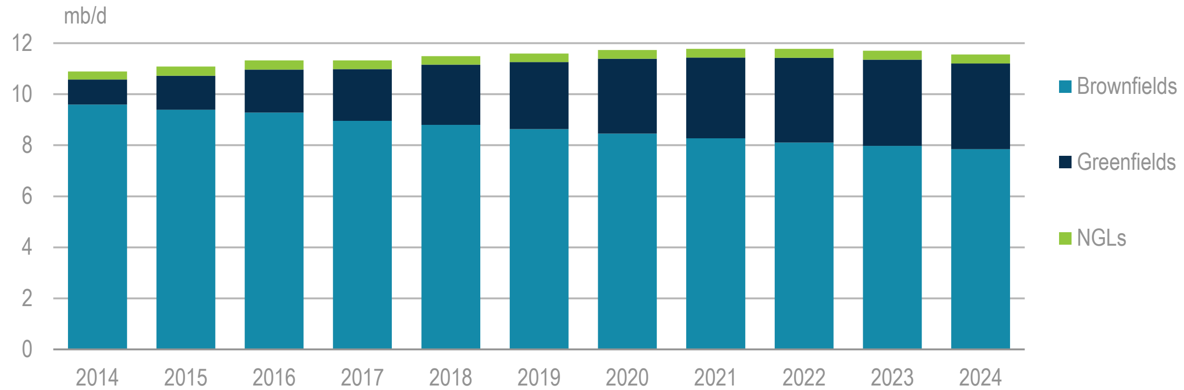
In contrast, oil production in the **United Kingdom** is set for further declines. After a temporary boost in 2019 when BP's Quad 204 and Clair Ridge ramp up towards capacity, output resumes its long-term decline from 2020. The Clair Ridge project saw first oil last November and is expected to produce 120 kb/d at its peak. The Equinor-operated Mariner field is set to start up in 2019. In all, production will decline by around 130 kb/d over the forecast period to 900 kb/d by 2024. **Denmark's** oil output falls during the early part of the forecast before the redevelopment of the Tyra field takes output back to 2018 levels of around 110 kb/d.

Russia demonstrates its capability with record output

Russian oil production rebounded sharply last year, after Vienna Agreement output cuts were unwound. Crude and condensate output surged 450 kb/d in only five months from May, to a new record high of 11.4 mb/d in October. With another round of supply cuts agreed in early December, and new energy sanctions imposed, the outlook for 2019 and beyond is becoming cloudier. Russia agreed to cut supplies by 230 kb/d from October 2018's high, for an initial period of six months. As a scenario for this report, we assume that the deal will not be extended, allowing Russian production to recover in the second half of 2019.

On that assumption, and on the basis that the commissioning and ramping up of new greenfields will not be materially delayed, Russian production is set to rise to 11.8 mb/d by 2021. Natural gas liquids from processing plants accounts for roughly 300 kb/d. Key development projects include; condensate volumes from Gazprom's and Novatek's Messoyakha, Kuymumba, Yamal liquefied natural gas (LNG) projects as well as new output from Rosneft's Russkoye, Erginskoye, Yurubcheno-Tokhomskoye and Suzun/Tagul fields. After these additions come on stream, we expect to see a gradual fall in production due to accelerating declines at mature fields. Total supplies will be 11.6 mb/d by 2024.

Figure 2.23 Russia total oil supply



Caspian production holds steady

Following two years of gains, **Kazakhstan**'s oil production is set to stabilise and then resume modest declines before recovering from 2023. The Caspian region's largest producer saw output expand by 175 kb/d in 2017 and a further 85 kb/d last year, as the Kashagan oil field ramped up. Kashagan is expected to reach its initial 370 kb/d output target in 2019. Partners in the international consortium managing the field, the North Caspian Operating Company (NCOC), are studying options for further developments. The government has already approved a scheme to expand phase 1 capacity to 450 kb/d by installing new gas compression and injection capacity. The initial development plans for Kashagan included three development phases, with phases two and three pushing up the plateau beyond 1 mb/d. However, none of the four Western majors represented in NCOC - Exxon Mobil, Shell, Eni and Total - has expressed a desire to bring on any new phases. By 2022, output will get a boost from the start-up of the Tengiz Future Growth Project that increases daily crude production by 260 kb/d. The Chevron-led project, which is Kazakhstan's largest producer, pumped roughly 590 kb/d in 2018. An international consortium, consisting of Shell, Eni, Chevron, Lukoil and KazMunaiGaz, agreed a $1.1 billion investment in the giant Karachaganak field last October, aimed at extending the duration of the production plateau. As part of the Vienna Agreement, Kazakhstan agreed to reduce production by 40 kb/d from the November 2018 level of more than 2 mb/d.

In **Azerbaijan**, output is expected to see modest declines over the period, even as international companies push ahead with new projects. Equinor recently signed agreements to develop the Karabagh oil field and a Production Sharing Agreement (PSA) for the Ashrafi, Dan Ulduzi, Aypara area. Likewise, BP signed a new PSA, dubbed D230, comparing it to the Azeri Chirag Deepwater Gunashli (ACG) PSA it signed in 1994. BP and its partners are discussing building an additional platform at the ACG complex to add to the six already in place, to help maintain production. According to BP, a decision to build the Azeri Central East platform will be made with its partners, including state oil company Socar, early in 2019 and the facility could be ready around 2022-23. ACG output has mostly been in decline in this decade, but in 2018 it was marginally higher than the year earlier when production cuts were in place. Under the new Vienna Agreement, Azerbaijan agreed to cut output by 20 kb/d from January 2019. This might be challenging as BP recently launched its Shah Deniz 2 project, which is intended to raise condensate output from 55 kb/d to around 120 kb/d.

Asian output slumps further

Oil production in Asia is heading down. Over the past three years, total output, including Australia, has fallen by more than 0.7 mb/d, to 7.6 mb/d in 2018. The biggest declines have come from **China**, which saw its domestic crude oil supply slide by 660 kb/d from its 2015 peak. Following the recent rebound in international oil prices and calls by the government to boost production to improve energy security, Chinese oil companies are taking steps to stem losses. Even so, production is expected to continue to fall through to 2024 as mature fields decline and few new projects are in the pipeline. Some additional output will come from new coal to liquids plants.

Figure 2.24 Asia total oil supply

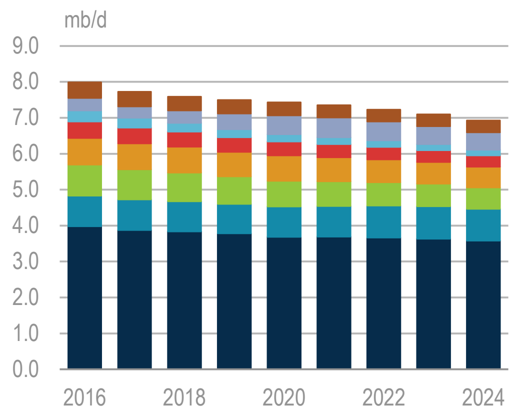
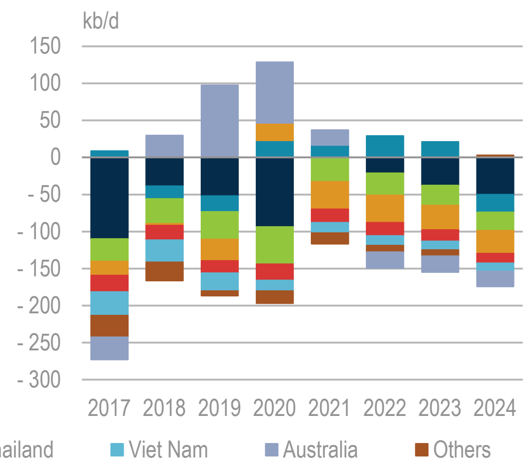


Figure 2.25 Asia annual supply change



Production will also fall in other countries such as **Indonesia, Malaysia and Viet Nam**. In contrast, output in **India** is expected to increase marginally. Growth will primarily come from state-owned Oil and Natural Gas Corp's (ONGC) $5-billion KG-DWN-98/2 deep water oil and gas development. ONGC expects the project to produce 80 kb/d of oil at its peak with output starting up in 2020. **Australian** output will also rise, with additional condensate and NGLs production from new LNG projects. In all, Asian oil supply is set to fall by another 660 kb/d by 2024, to 6.9 mb/d.

New producers gear up in non-OPEC Africa

Non-OPEC African oil production will hold steady over the medium term at just under 1.5 mb/d, with Uganda, Kenya and Senegal gearing up to tap their resources and further gains from Ghana. Tullow Oil and its partners are making good progress on their **Kenya** development project, targeting a final investment decision in late 2019 with the possibility of production starting in 2022. Woodside Petroleum, Cairn and junior partner FAR Ltd are also moving forward with developments in **Senegal**. Last October, the trio submitted a development plan for the SNE project targeting up to 100 kb/d of crude oil production from 2022.

The timeline for Tullow, Total and CNOOC's Lake Albert project in **Uganda** has once again slipped, however. Construction of the pipeline that will run from Uganda to Tanzania has been postponed, delaying oil production from a planned start in 2020, to late 2021 or 2022. A further boost could come from the restart of some oilfields in northern Unity state in South Sudan after a five-year shutdown following its declaration of independence from Sudan and the subsequent civil war.

South Sudan's production averaged 130 kb/d in 2018 and while the government hopes to restore it towards pre-civil war levels of 350 kb/d, we have kept production flat for the time being. Output from **Egypt**, Africa's largest non-OPEC producer, has been in steady decline since 2014, and with investments increasingly geared towards newly discovered gas resources, output is set to fall further.

Figure 2.26 Non-OPEC Africa total oil supply

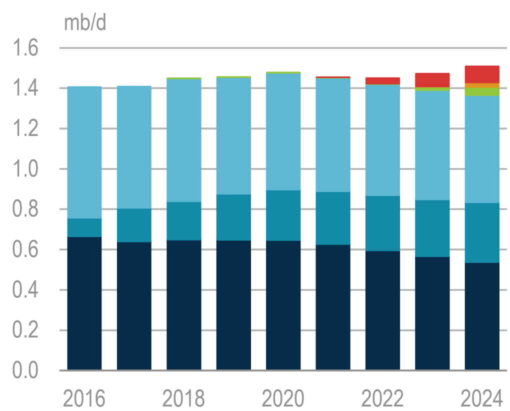
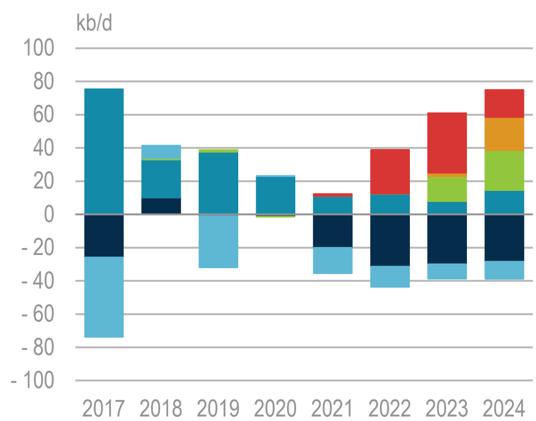


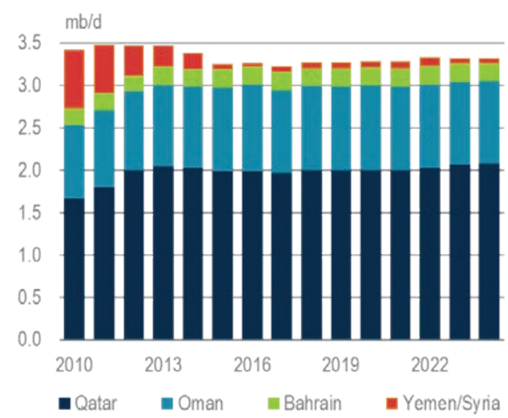
Figure 2.27 Non-OPEC Africa annual change



Qatar lifts Middle East

Qatar's early 2019 arrival in non-OPEC will push Middle East oil production a touch higher over the forecast period. Qatar is expected to see a 75 kb/d increase in total oil supply by 2024 thanks to further development of condensates from the North Field. QP, the world's second-largest LNG supplier after Australia, is adding a fourth train to raise North Field capacity by over 40% to 110 million tonnes a year. This is expected to be online by early 2024 and it will also boost supply of NGLs. In April 2017, Qatar lifted a self-imposed ban on development of the North Field, the world's biggest gas field that it shares with Iran, where it is known as South Pars. Qatar's crude output of around 600 kb/d is expected to stay broadly steady over the next six years.

Figure 2.28 Non-OPEC Middle East supply

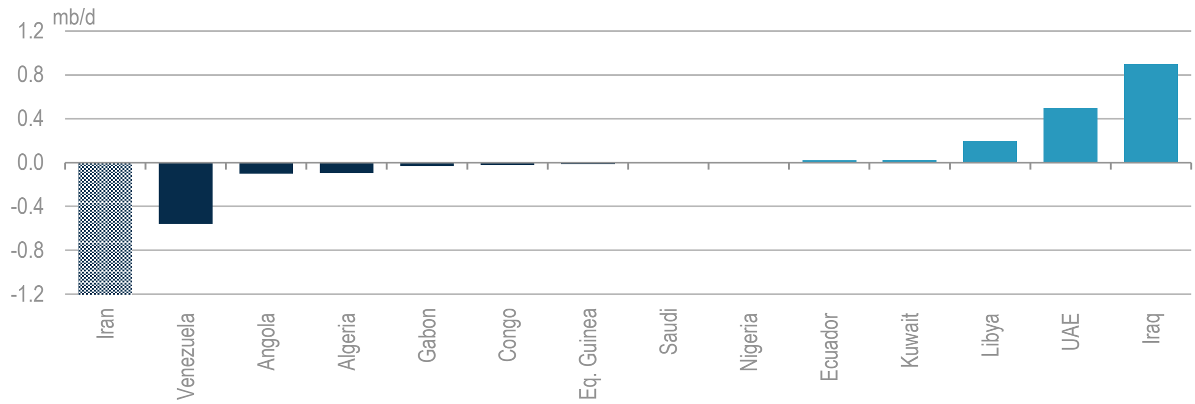


Oman, which agreed to cut crude and condensates by 25 kb/d to 980 kb/d in first half 2019 (1H19), is expected to see relatively steady output through 2024. Condensate supply got a boost late in 2017 after the early start-up of BP's Khazzan tight gas field, which is producing 35 kb/d of liquids. A further phase of development, the $4 billion Ghazeer project, was approved last April. Due onstream in 2021, it is expected to boost condensate output to 50 kb/d. We have assumed there will be no change to supply in **Yemen** and **Syrian Arab Republic** ("Syria"), where conflict continues.

OPEC crude oil capacity

OPEC's effective capacity this year could plunge by more than 1.5 mb/d as the US embargo hits Iran hard and Venezuela, in the midst of a political crisis, sees production decline further. Capacity starts to grow again from 2020, albeit modestly. As a scenario, we assume that US sanctions against Iran remain in place throughout the six-year period.

Figure 2.29 Change in effective OPEC crude capacity 2018-24



Within OPEC, Iraq expands the most by far, with the UAE also set to deliver solid growth. Iraq's increase bolsters its rank as OPEC's second-largest crude producer. Gains in the UAE allow it to hold onto the number three slot assuming Iran remains under sanctions. The continuation of sanctions on Iran and further losses in Venezuela would offset capacity increases from elsewhere and cut OPEC's effective capacity by 380 kb/d by 2024.

Table 2.4 Estimated sustainable OPEC crude production capacity (mb/d)

	2018	2019	2020	2021	2022	2023	2024	2018-24
Algeria	1.07	1.05	1.03	1.01	1.00	0.99	0.98	-0.10
Angola	1.52	1.57	1.54	1.51	1.48	1.46	1.42	-0.10
Congo	0.34	0.35	0.34	0.33	0.32	0.32	0.31	-0.02
Ecuador	0.54	0.55	0.55	0.55	0.56	0.56	0.56	0.02
Equatorial Guinea	0.13	0.12	0.12	0.11	0.11	0.11	0.11	-0.02
Gabon	0.19	0.19	0.18	0.18	0.17	0.17	0.16	-0.03
Iran	3.85	3.85	3.85	3.85	3.85	3.85	3.85	0.00
Iran w/sanctions	3.85	2.65	2.65	2.65	2.65	2.65	2.65	-1.20
Iraq	4.90	5.00	5.29	5.45	5.58	5.70	5.80	0.90
Kuwait	2.92	2.95	2.95	2.95	2.95	2.95	2.95	0.03
Libya	1.07	1.00	1.10	1.16	1.21	1.24	1.27	0.20
Nigeria	1.70	1.78	1.81	1.77	1.76	1.74	1.70	0.00
Saudi Arabia	12.02	12.02	12.02	12.02	12.02	12.02	12.02	0.00
UAE	3.35	3.42	3.53	3.63	3.72	3.80	3.85	0.50
Venezuela	1.31	0.75	0.75	0.75	0.75	0.75	0.75	-0.56
Total OPEC	**34.91**	**34.59**	**35.04**	**35.27**	**35.49**	**35.63**	**35.73**	**0.82**
OPEC/sanctions	**34.91**	**33.39**	**33.84**	**34.07**	**34.29**	**34.43**	**34.53**	**-0.38**

Notes: Capacity levels can be reached within 90 days and sustained for an extended period. Neutral Zone excluded.

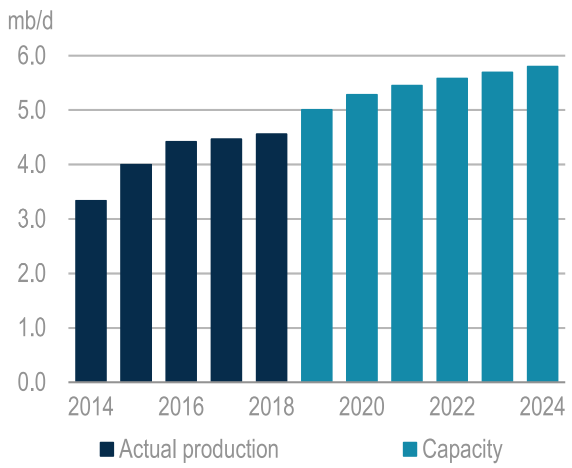
Iraq fuels OPEC growth

With its vast, low-cost reserves and strong economic incentives to raise production, **Iraq's** capacity expansion will be the largest within OPEC. Capacity is projected to reach 5.8 mb/d in 2024, growing at an average annual rate of 150 kb/d. The Basra oil heartland in the south, where IOCs are managing mega-projects, will dominate the effort. The northern Kirkuk oil fields and the capacity that is controlled by the Kurdistan Regional Government (KRG) are expected to deliver a modest amount of growth.

The new oil minister, Thamir Ghadhban, has vowed to press on with capacity building. Prospects would improve if the ministry were to move ahead with a crucial water injection project which could take up to four years to complete. This would help raise output from the southern fields of West Qurna-1 and West Qurna-2, Zubair and Rumaila, operated by ExxonMobil, Lukoil, Eni and BP, respectively. These fields, along with Halfaya, have been ramping up to support robust exports of Basra crude.

Halfaya is driving much of the near-term growth in the south. Output from the CNPC-operated field has recently ramped up by 100 kb/d to roughly 350 kb/d and is set to add a further 50 kb/d. Majnoon, now operated by Basra Oil Co following Shell's departure, is also expected to pump more. Shell has pulled out of oil projects in Iraq but remains committed to the gas sector as operator of the Basra Gas Co. So-called "national effort" fields in the south such as Nassiriya are also set for higher output, with ambitions to raise production from 90 kb/d to 200 kb/d.

Figure 2.30 Iraq builds up



Export capacity in the south of roughly 4 mb/d should be enough to handle the anticipated increase in supply. In early 2019, shipments of Basra crude were running just below 3.6 mb/d.

To underpin the expansion, a substantial drilling effort is gathering pace. Schlumberger and the Basra Oil Co are each expected to drill 40 wells in the Majnoon field, now pumping 240 kb/d, and 30 wells at West Qurna-1, now producing 430 kb/d. In the Missan field, China National Offshore Oil Corp is striving to boost output by up to 140 kb/d by 2020. The fields of Fakka, Buzurgan and Abu Ghirab are now pumping about 200 kb/d in total. At the 400 kb/d West Qurna-2, Lukoil has awarded the second of two drilling contracts to China's Bohai Drilling Engineering Co, which will add 50 kb/d in two years.

The federal government has signed six preliminary deals with companies to explore for oil near the border with Iran and Kuwait. Blocks awarded in previous rounds are showing signs of promise. Rosneft unit Bashneft International announced an oil discovery in Block 12 in southern Iraq after completing its first exploration well.

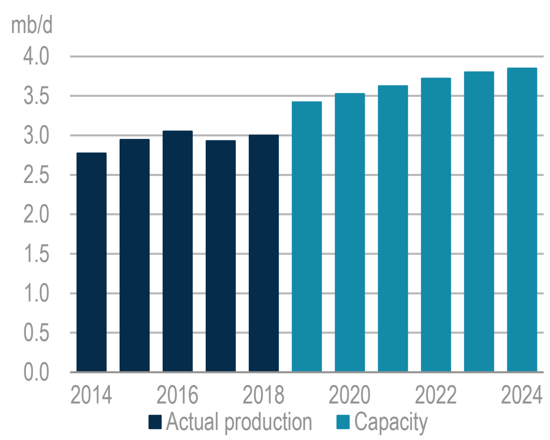
Baghdad is also striving to boost output in the north. The ministry of oil and BP have agreed to expand their agreement to develop Kirkuk to include the Kurdish-controlled Khurmala dome as well as the neighbouring fields of Bai Hassan, Jambour and Khabbaz. The aim is to raise Kirkuk production to 1 mb/d from 430 kb/d now, comprised of 130 kb/d at the Khurmala dome and 300 kb/d from elsewhere in the field. The nearby Qayara field, operated by Sonangol, has a near-term production target of 60 kb/d, double the current level.

Output has also risen from fields in Kurdistan such as Peshkabir and the Khurmala dome, with higher volumes flowing into a newly expanded 1 mb/d export pipeline. In mid-November, the North Oil Co (NOC) restarted exports of Kirkuk crude, halted for a year by a dispute between the KRG and the central government.

Its stable operating environment and relatively low-cost reserves will enable the **UAE** to post the biggest growth after Iraq. A gain of 500 kb/d is expected, with capacity reaching 3.85 mb/d, on a par with Iran's pre-sanctions capacity. In terms of actual supply, record output of 3.32 mb/d last November pushed the UAE past Iran to become OPEC's third largest producer behind Saudi Arabia and Iraq. To encourage growth, Adnoc has set new production targets of 4 mb/d by 2020 and 5 mb/d by 2030. Recent growth was underpinned by investment in the offshore Umm Lulu and Satah al-Razboot (Sarb) fields, which ramped up to 130 kb/d by end-2018 and will pump 200 kb/d by 2023.

To rise towards 4 mb/d, the expansion of the Exxon-operated Upper Zakum offshore field will be crucial. It is one of the world's largest, but is also technically challenging. Production is now around 750 kb/d and is expected to reach 1 mb/d by 2024. More near-term supply will come from offshore oil fields Ghasha, Dalma and Hail. To boost capacity to the 5 mb/d mark, Adnoc will have to rely on resources from six blocks on offer in its upstream licensing round and the development of a major new discovery that contains 1 billion barrels of oil.

Figure 2.31 UAE capacity catches up with Iran



The slow capacity build-up over the past 10 years was mostly down to a lack of agreement between Adnoc and its international partners over commercial terms for onshore and offshore concessions that were due to expire. With new partners in place at its major oil fields, the next hurdle will be for Adnoc to convince them to spend money on smaller oil fields and exploration.

On the offshore front, Adnoc finalised awards last year for its restructured 700 kb/d offshore oil concession that was split into three separate ventures: Lower Zakum, Umm Shaif and Nasr, and Sarb and Umm Lulu. Total secured a combined 25% stake in Lower Zakum (5%) and Umm Shaif/Nasr (20%), the largest share for any company, while OMV acquired the final 20% stake in Sarb and Umm Lulu. Adnoc will retain a 60% stake in each. OMV, owned 25% by Abu Dhabi, joins CNPC, Eni, ONGC and Cepsa as newcomers in the UAE's upstream industry.

For its onshore sector, which pumps around 1.6 mb/d, Abu Dhabi reworked commercial terms in 2017 to line up foreign partners for a 40% share of the concession that produces flagship Murban crude. The official target is 1.8 mb/d and, to that end, Adnoc plans to spend $1.4 billion to boost capacity by 100 kb/d at the Bu Hasa field to 650 kb/d by the end of 2020 and to lift the Bab field to

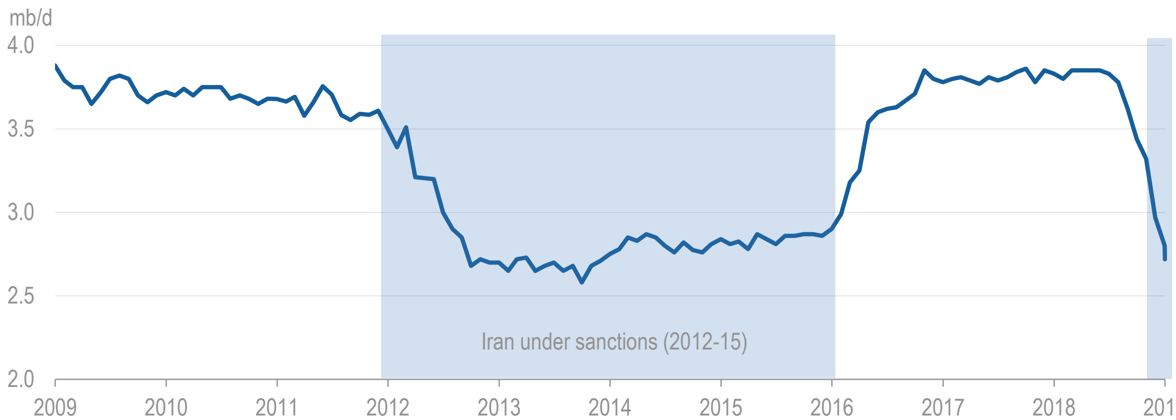
450 kb/d from 420 kb/d. Total and BP both hold 10% of Adnoc Onshore, with South Korea's GS, Inpex, CNPC and Zhenhua Oil securing minority stakes.

Adnoc is also pressing on with a 10-year plan to expand the commercial application of carbon capture, utilisation and storage technology to support enhanced oil recovery and reduce emissions. It is in the process of deciding whether to capture up to 2 million tonnes/yr of carbon dioxide (CO_2) from a gas processing facility at the onshore Habshan and Bab oil and gas fields, or from the Shah sour gas plant operated by Adnoc and Occidental. Adnoc now has the ability to capture 800 000 tonnes per year from Emirates Steel Industries through its Al-Reyadah venture.

US sanctions stymie Iran

US sanctions, assumed to remain in place throughout the forecast period, will frustrate **Iran's** expansion. Before sanctions were imposed, Iran was expected to see the fifth biggest capacity build-up in the world. Now capacity is likely to stay flat at 3.85 mb/d to 2024, but *effective* capacity will be around 2.65 mb/d.

Figure 2.32 Sanctions hit Iranian crude supply



Iran's production was 2.7 mb/d at the start of 2019, and exports of oil, including condensates, were around 1.3 mb/d, roughly half the pre-sanctions level. The National Iranian Oil Co (NIOC) is reportedly striving to keep production and exports fairly evenly split between Iranian Light and Heavy crude. As output sinks further, Iran is likely to shut in more and more wells and carry out maintenance at its ageing oil fields. In some respects, shutting in production is beneficial for mature reservoirs as it will allow pressure to rebuild and make it easier for the fields to restart.

Iran may have to put expansion plans on ice if it is unable, as seems likely, to attract investment and technology from IOCs. The re-imposition of US sanctions has already led firms such as Maersk Oil, Wintershall and OMW to withdraw from talks. Zarubezhneft has reportedly given up on plans to develop onshore oil fields.

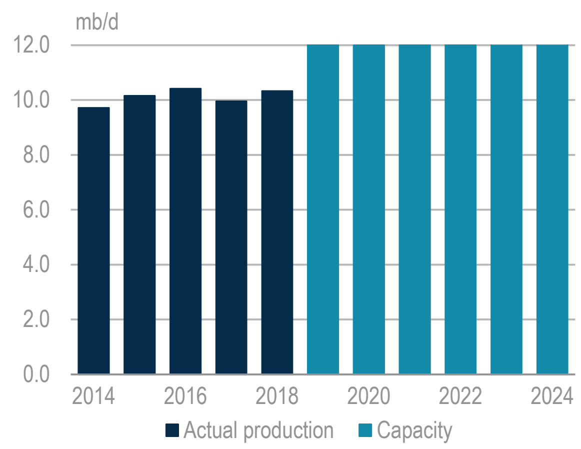
CNPC is one of the few foreign firms operating in Iran. It is developing the North Azadegan field, currently producing about 80 kb/d, from which it is repaid in equity oil. It has, however, suspended investment in the $4.8 billion Phase 11 of the South Pars gas field, where it was expected to replace Total as the foreign partner. Production capacity is 2 billion cubic feet per day of gas and, once operational, it is expected to deliver 70 kb/d of condensate. Total withdrew from the project to avoid breaking US sanctions.

Should sanctions be eased, Iran's capacity growth will be driven by the West Karun oil fields of Azadegan, Yadavaran and Yaran, which straddle the border with Iraq. Their development, along with the rehabilitation of older fields, is vital to sustaining output at 4 mb/d. Target output for West Karun is 1 mb/d versus current flows of 300 kb/d.

Saudi Arabia is the only country in the world with significant spare production capacity. In early 2019, it was about 1.8 mb/d. Billions of dollars are being invested to maintain current production capacity of 12 mb/d (excluding the Neutral Zone). The long-standing aim has been to stabilise, rather than add, capacity while developing natural gas. This will require investment of $150 billion over the next decade. Much of the gas will be used for chemicals. Saudi Aramco plans to invest as much as $100 billion in this this sector to benefit from booming Asian demand.

On the crude capacity front, Saudi Aramco is pressing ahead with its offshore expansion plans in order to make up for declining onshore output. To that end, the company has hired Baker Hughes to boost capacity at the Marjan field by 300 kb/d to 800 kb/d. It is the first of three major projects to raise offshore capacity by 1 mb/d by 2023 to offset declines elsewhere. The 800 kb/d Zuluf and 300 kb/d Berri fields are also set for expansion.

Figure 2.33 Saudi maintains capacity



Onshore, Saudi Aramco is continuing to fund the $3 billion Khurais project, which is due to reach capacity of 1.5 mb/d by June 2019. This expansion, together with a robust drilling programme, will help make up for natural declines, including at Ghawar, the world's biggest oil field. After an independent audit, the Kingdom's reported level of proven oil reserves has increased slightly to 268.5 billion barrels from the previous figure of 266.3 billion barrels. The audit was part of Saudi Aramco's preparation for its proposed initial public offering. Only Venezuela has more reserves, but they are mostly extra heavy and costly to extract. Saudi Arabia, by contrast, is one of the world's lowest-cost oil producers at an average of $4/bbl.

Our outlook for both Saudi Arabia and Kuwait assumes no restart to production from the Neutral Zone oil fields shared between them. **Kuwait** is pressing on with investment in its crude oil capacity, which edges up 30 kb/d to 2.95 mb/d in 2024. It plans to boost light crude oil production over the coming three years from around 180 kb/d to 250 kb/d. A new super light crude grade was launched in July 2018. To develop its geologically complex reserves, Kuwait has brought in IOCs for their technology and project management skills.

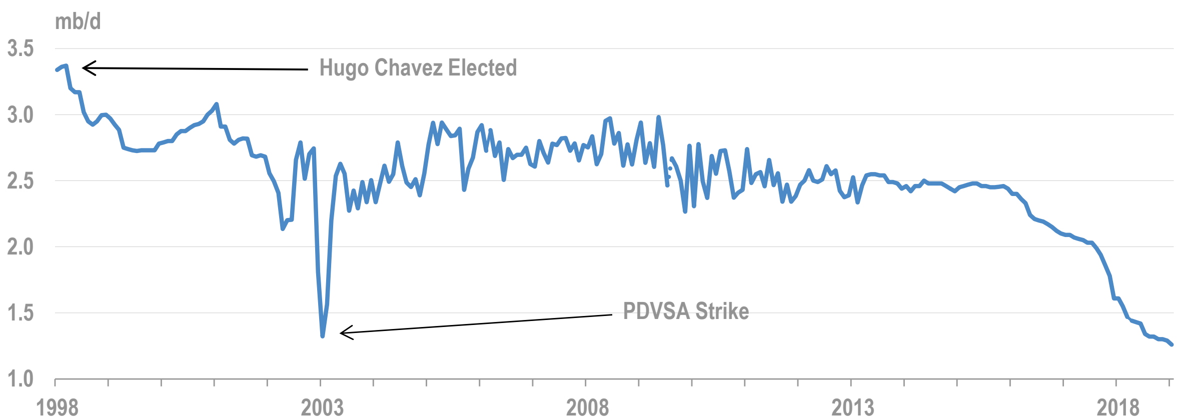
The northern Ratqa oil field near the border with Iraq is due to start up in early 2019 and produce about 60 kb/d of heavy crude by the end of the year. Shell will help double output at Ratqa and then boost it towards a target of 270 kb/d. It also won a deal for a water management project at onshore oil fields, which is intended to lift production. BP won a contract to tap the Burgan field which has the potential to produce 2 mb/d from roughly 1.7 mb/d now. For decades, Kuwait has struggled to develop upstream projects because its parliament has been critical of foreign involvement.

Political crisis clouds Venezuelan outlook

Having seen one of its biggest ever annual declines in 2018, production in **Venezuela** will continue to fall as its economy lurches deeper into crisis. The cash crunch at Petroleos de Venezuela (PDVSA) and poor reservoir management have already cut output by nearly 40% over the past two years. US financial sanctions enforced in January 2019 will compound the losses. The political situation is fast changing and forecasting output is more difficult than usual. In this report, we have assumed that following the 570 kb/d loss of actual production in 2018, annual declines this year may be as aggressive. Our assumption is that production capacity falls to 750 kb/d, which has been held through the remainder of the forecast.

Clearly the reality could be very different. An improvement in the political climate would give PDVSA the chance to repair the industry. If the situation worsens, the sector could collapse for an unknown period of time. Production has been trending down since President Chavez came to power in 1999. From a peak of nearly 3.4 mb/d just before he took office, supply now is less than half this level. Output from ageing conventional assets operated by PDVSA has plunged and upgraders operated by foreign joint venture partners in the vast Orinoco heavy oil belt have been malfunctioning due to the strain associated with sourcing equipment, late payments, corruption and security.

Figure 2.34 Venezuela declines



In the mid-1990s, PDVSA was planning to increase crude production capacity to 5.5 mb/d by 2005. This was to be achieved by a reorganisation of the company into one single integrated entity and by opening up (the "apertura") to foreign investment. Production did increase significantly by nearly 900 kb/d in the four years to 1997. Part of this was due to the early success of the apertura but also due to a disregard of the country's OPEC quota. Today, the resource base is significantly higher than in 1997 (300 billion barrels versus 80 bn barrels). Therefore, if conditions allow Venezuela's diaspora of skilled oil industry professionals to return and investment capital can be made available in time, the 20-year old production target could be achieved.

In the meantime, the Maduro government has looked to Russia and China to help revive the oil sector. Russia has become a major source of financial support and towards the end of 2018 pledged \$5 billion to raise output by 1 mb/d. China has also been a major backer of the Venezuelan government. It is thought that over the past decade, China has loaned Venezuela more than \$50 billion, repayable mainly in crude oil shipments. Recently, the China Development Bank said it plans to invest more than \$250 million to boost production. Additional investment has also been lined up with Erepla and France's Maurel & Prom. Erepla had plans to spend up to $500 million to boost output at three oil fields in exchange for crude. Maurel & Prom wants to invest $400 million to raise output at the Petroregional del Lago venture. The aim is to lift production at the field in Lake Maracaibo from around 15 kb/d to 70 kb/d. All of these investment plans must be treated with a degree of scepticism given the imposition of US sanctions and the collapse of the economy.

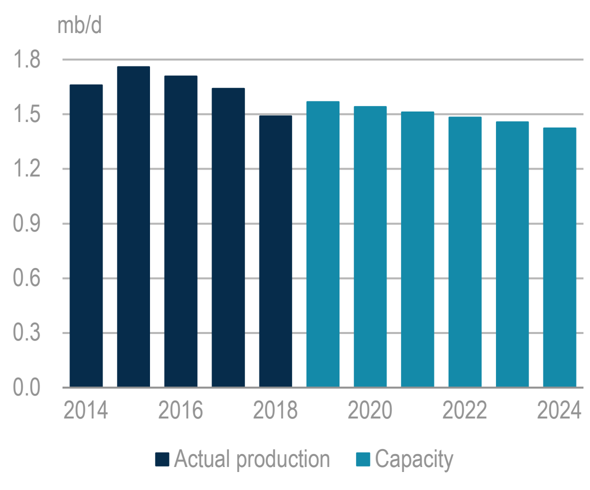
Civil unrest threatens African growth

Whether boiling over or simmering below the surface, conflict is taking a toll on capacity in OPEC's African producers, which make up half the group's membership. Their capacity is expected to decline by a net 60 kb/d during the forecast period, with growth in Libya helping to offset losses elsewhere. Capacity in Nigeria is expected to hold steady, while Algeria, Angola, Gabon, Congo and Equatorial Guinea will lose 260 kb/d between them by 2024.

The determination of **Angola's** new government to prevent a post-2020 oil sector collapse appears to be having some success. Its costly deep water oil fields need constant support. Offering more attractive upstream terms may have secured enough investment to see capacity decline by only 100 kb/d to 1.42 mb/d by 2024. That is modest compared to our outlook in *Oil 2018*, which foresaw a decline of nearly 400 kb/d. Output has fallen by more than 200 kb/d in the past two years to 1.49 mb/d in 2018 after operational and technical issues took a toll.

However, Total's $16 bn Kaombo project, which started up last July, is expected to help capacity recover in 2019 and mitigate declines going forward. At its peak, the ultra-deep water field is expected to pump 230 kb/d. Spurred by the more favourable fiscal framework, Total also took a final investment decision to press ahead with the $1.2 billion, 40 kb/d Zinia 2 deep water tie-back project in Block 17 that will sustain output from the Pazflor field that came online in 2011. It also intends to develop the 40 kb/d Clov 2 and the 30 kb/d Dalia 3, which should keep Block 17's output around 400 kb/d until 2023.

Figure 2.35 Angola fends off collapse



Eni was also swift to sign up for new projects. Its Ochigufu field in Block 15/06 reached plateau production of 24 kb/d in May 2018. The block's Vandumbu field started ahead of schedule and is feeding the N'Goma floating production storage and offloading (FPSO) vessel that serves the West Hub fields. Vandumu should lift output through the FPSO by 20 kb/d and the West Hub should be producing 170 kb/d in 1Q19. BP has also struck deals. Its production licence in deep water Block 18 has been extended to 2032, with Sonangol given an 8% equity stake. A final investment decision has yet to be taken on a new project to develop the Platina field, in the west of Block 18, as a tie-back to the *Greater Plutonio* FPSO, which produces Plutonio blend crude oil. The BP-operated development produced about 116 kb/d in 2017 and has suffered from frequent technical problems that have kept output well below its original 200 kb/d target.

In **Nigeria,** the launch of Total's 200 kb/d Egina project will give crude supply a near-term boost, although capacity is expected to slip after 2020 due to a lack of significant investment. A lull in militant attacks had already allowed output to recover from 30-year lows of just over 1 mb/d in 2016 to 1.6 mb/d in 2018. The start-up of Egina in early 2019 is expected to lift crude capacity towards 1.8 mb/d and provide a new source of medium sweet crude. Egina, which cost nearly 10% less than its original budget, is the first substantial deep water project to come online since 2012 when Total launched the Usan field. To take advantage of comparatively low service costs, Total aims to take a final investment decision in 2019 to develop Preowei as a tie-back to Egina.

The government has vowed to prevent violence, but the oil sector remains vulnerable to sabotage attacks in the Niger Delta oil heartland. Apart from Total's project, other major developments remain on the drawing board. Long-stalled deep water projects such as Shell's Bonga Southwest Aparo and Eni's Zabazaba have yet to get the final go-ahead. Upstream spending has also been drying up due to continued lack of progress on the Petroleum Industry Governance Bill, which aims to improve commercial terms and create a new national oil company.

Figure 2.36 Nigeria's near-term boost

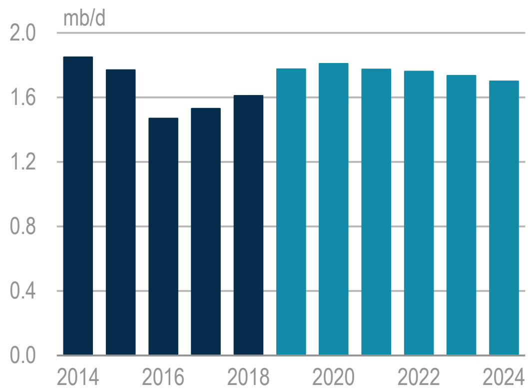
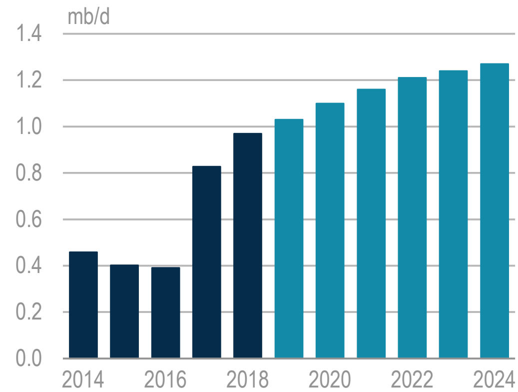


Figure 2.37 Libya rebounds



Actual production Capacity

Libya's production rebound continued into 2018, but a dip is expected in 2019 due to ongoing unrest. Growth returns from 2020 and there will be a gain of 200 kb/d over the medium term. This is dependent on a return to political stability and a steady stream of revenue to pay for infrastructure repairs. Towards the end of 2018, Libya's oil fields were briefly producing at 1.2 mb/d, the highest level in five years. The largest oil field, El Sharara, was pumping close to capacity at roughly 300 kb/d, and the nearby El Feel had also ramped up to around 70 kb/d. However, production remains vulnerable to armed groups and security breaches. Stable conditions at Libya's remote southwestern fields are crucial to sustaining higher production levels.

The Waha Oil Co, located in the Sirte basin in the northeast, is crucial to further growth. Some of its infrastructure, producing around 300 kb/d, has suffered extensive damage from militant attacks. Total has acquired a 16.33% stake in the Waha Oil Co from Marathon for $450 million. Other stakeholders are Libya's National Oil Corp (59.18%), ConocoPhillips (16.33%) and Hess (8.16%). Crude from Waha is delivered to the Es Sider terminal for export. A top priority is to repair damage to the Es Sider and Ras Lanuf export outlets caused by militia attacks. Libya also hopes for higher production from National Oil Corp unit Agoco, whose biggest asset is the Sarir oil field in the southeast.

There is some hope that international oil companies will take encouragement from Libya's doubling of production in the past two years and return to the country. Eni and BP intend to restart exploration and Repsol and OMV are hoping to expand their upstream presence. Libya's sustainable capacity in the medium term is unlikely to reach the 1.6 mb/d that was achieved prior to the 2011 overthrow of Muammar Gaddafi. The wider threat to the oil sector comes from a simmering feud between competing institutions and rival groups based in the east and west of the country.

Algeria's crude output has been on a downward trend since peaking at 1.4 mb/d in 2007. For years, there has been a struggle to attract foreign investment, with companies grumbling about tough commercial terms and mountains of red tape.

Capacity in 2018 was 1.07 mb/d and is expected to fall to 980 kb/d by the end of the forecast period. For its part, Sonatrach intends to invest close to $45 billion on a drilling programme through 2022. It is also courting foreign investors and is meeting some success. Eni expanded its portfolio with three onshore oil blocks in the North Berkine basin in the east of the country. It will also explore Algeria's deep water prospects with Total. The three oil licences, in which Eni holds a 49% share and Sonatrach the remainder, are estimated to hold 145 mb of oil equivalent. The aim is for first production by the end of 2020. Sonatrach also agreed with Cepsa to spend $1.2 billion to boost output from 11 kb/d to 24 kb/d at Rhourde el Krouf.

Production capacity in **Gabon** is expected to drift down to 160 kb/d by 2024, continuing a decline from a peak of just under 400 kb/d in 1997. A lack of exploration and development has taken a toll on mature oil fields and a failed coup attempt in early 2019 is adding to instability. Additionally, the lower price environment convinced long-standing investors Shell and Total to sell off some of their assets. Total Gabon sold its 32.9% share in the Rabi-Kounga field for around $100 million to Assala Upstream Gabon last July. Having farmed out its entire onshore portfolio in 2017, Shell, involved in Gabon for more than five decades, may reduce its offshore position. In a bid to drum up investment, Gabon is proposing to remove a corporate tax rate of 35% and offer flexibility in negotiations. A new licensing round, which includes 23 deep water blocks, is expected to close in April.

In **Equatorial Guinea**, President Teodoro Obiang claims to have thwarted a coup at the end of 2018. Crude oil output in OPEC's smallest member is on a gradual decline after peaking above 300 kb/d in 2004. With production dropping at most fields, capacity is expected to slip to 110 kb/d by the end of 2024. In an attempt to breathe life into the upstream, a new oil and gas exploration round will be launched in 2019 that covers acreage both onshore and in ultra-deep waters.

The rejection of an expected opposition election victory in **Congo** could inflame violence in OPEC's latest recruit. Capacity is expected to peak at 350 kb/d in 2019 before easing to around 310 kb/d in 2024. The near-term boost is thanks to new deep water fields such as Total's Moho Bilondo and Moho Nord that are helping to compensate for losses from ageing fields.

Capacity in **Ecuador** is set to edge up to 560 kb/d by 2024, with the Ishpingo-Tambococha-Tiputini (ITT) block in the Amazon rain forest providing limited growth. After coming online in late 2016, production from ITT has reached only around 60 kb/d. Located in a UNESCO world biosphere reserve, the heavy crude-producing block holds about 20% of Ecuador's total reserves of 8 billion barrels. The government is also seeking to boost capacity by launching a bid round for eight onshore exploration blocks in the eastern Oriente area. It is hoped that the so-called "Intracampos Round" will lure investment of $1 billion that could lead to 20 kb/d of output.

Natural gas liquids

In recent years, exploration and production companies have focused increasingly on gas, production of which has boomed. Global investment in LNG facilities and the US shale revolution has had a profound impact on liquids markets as it has given rise to an increase in output of condensates and other natural gas liquids (NGL).

Figure 2.38 Global gas liquids supply

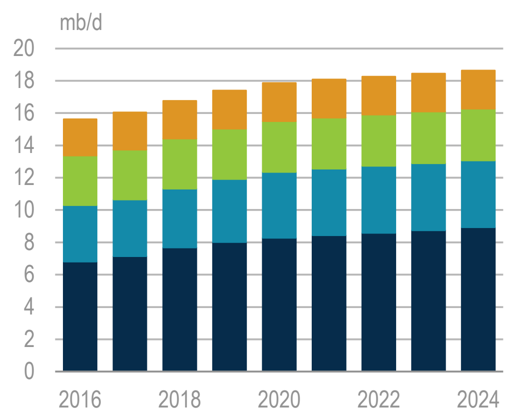
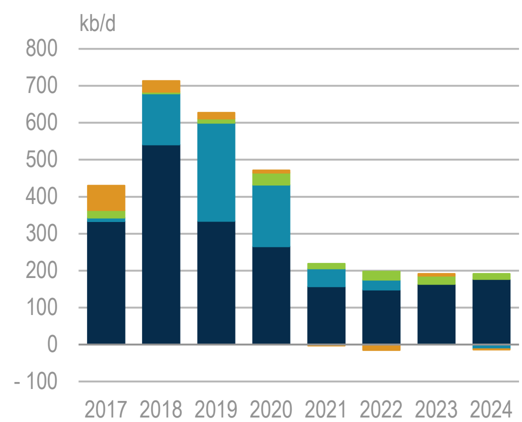


Figure 2.39 Global capacity growth



Non-OPEC NGLs | Non-OPEC Condensates | OPEC NGLs | OPEC Condensates

In 2018, total gas liquids output was 16.8 mb/d and accounted for 17% of total global liquids output. By 2024, gas liquids output will rise by a further 1.9 mb/d. The US leads the way, with strong growth also in Australia and Russia. On average, NGL and condensate production will increase by 1.8% per annum (p.a.), while natural gas output also gains 1.8% p.a. (IEA*, World Energy Outlook 2018, "*New Policies Scenario"). Consequently, the liquids ratio, defined as gas liquids in kb/d divided by dry gas in kboe/d, plateaus at 0.3, as producers turn to "dryer" gas sources. Furthermore, there has been a strong push to increase the utilisation of associated gas, which in the past was flared. This has, in turn, seen enhanced recovery of NGLs.

The main NGLs extracted at processing facilities are ethane, propane, butane, isobutane and pentanes. Field or lease condensate often has the same chemical composition as pentanes but is recovered at the field level. Most NGLs do not require refining; instead they are separated at fractionation plants and used directly by consumers for heating, cooking and transport or as feedstock for petrochemical plants. In some developing countries in Asia, e.g. India, Bangladesh, Thailand and Viet Nam, demand for LPG for residential use will grow at over 4% p.a. to 2024. Elsewhere, the start-up of new petrochemical plants in the United States, China and the Middle East will see consumption of ethane and LPG increase at least as fast. Condensate may be used to dilute bitumen for transportation or "spiked" into crude oil to make it lighter and sweeter. It is also used as feedstock for condensate splitters which can produce gasoline, naphtha, kerosene and gasoil.

The **United States** is by far the world's largest producer of NGLs and the boom in LTO and shale gas production has reinforced this position. The United States is also the largest natural gas producer, and its output of 811 billion cubic metres (14.0 million barrels a day of oil equivalent) in 2018 is set to grow by 2.9% p.a. over the forecast period. The output of NGLs will match this pace of growth, and exceed 5 mb/d in 2021, as two opposing influences play out. Over the last decade, the relative strength of liquids prices, compared to natural gas, has encouraged upstream producers to target liquids-rich gas plays. Therefore, the NGL-to-gas ratio for the United States increased from 0.18 to 0.31 between 2008 and 2018. This strategy, which enhances the economics of gas projects, has geological limitations and so upstream producers are expected to slowly shift to drier plays as sources of future gas production growth. Offsetting this, increased domestic demand for ethane, thanks to booming petrochemical demand at home and overseas, will see less ethane rejected into the gas stream. A number of new ethylene production units are expected to start up in the forecast period, requiring up to 665 kb/d of ethane as feedstock, and in total US ethane and LPG demand is expected to grow by 3.7% p.a. to 2024. Overall, these offsetting factors will see the US's NGL-to-gas ratio stabilise.

Figure 2.40 Shale oil and gas drive US NGLs

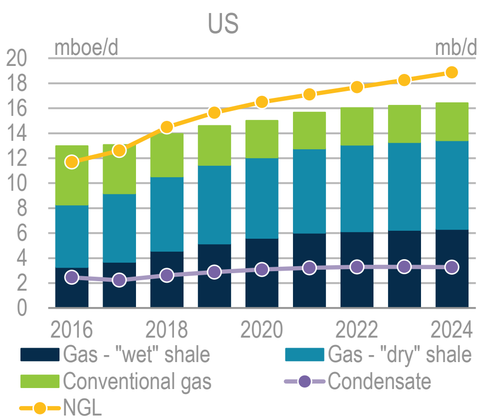
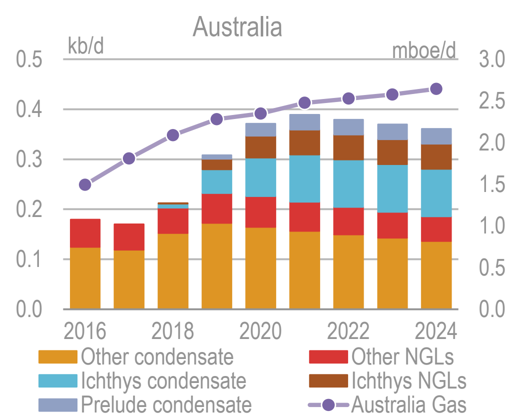


Figure 2.41 LNG projects lift Australia



In **Australia**, two new LNG projects have recently started up and gas liquids output will increase significantly. Condensate and NGL output climbs 100 kb/d (11% p.a.) and 45 kb/d (15% p.a.), respectively, over the forecast period. While gas production is also growing strongly, at 4.5% p.a., the "wetness" of the new projects will cause Australia's liquids ratio to increase to 0.15 in 2024, from 0.1 today. The first condensate cargoes departed from Inpex's Ichthys facility in September 2018, and the first LPG cargo followed two months later. When Ichthys is fully operational there is capacity for 150 kb/d of gas liquids to be shipped. Meanwhile, the first condensate cargo from Shell's Prelude floating LNG project should set sail in March. Prelude will add an estimated 30 kb/d to liquids output by the end of 2020. While further growth in gas liquids may come from the second phase of Cooper Energy's Sole project, Woodside's Browse LNG and Western Gas' Equus LNG projects remain unsanctioned and have not been included in the forecast.

Russia is the world's second-largest natural gas producer, with output of 663 billion cubic metres (bcm) in 2018. Growth of 2.2% p.a. is expected over the forecast period as several new projects come on stream. The ramp-up of Gazprom's giant Bovanenkovskoye field, which supplies gas for Yamal LNG, and production from Rospan's East-Urengoy field, underpin gains of 2.4% p.a. in condensate output. Meanwhile, development of Gazprom's Chayandinskoye and Kovyktinskoye fields will support NGL production growth of 1.3% p.a. as ethane, propane and hexane-pentane are extracted at the Amur gas processing plant. The facility is expected to reach nameplate capacity of 40 kb/d of NGLs production by 2024. These projects will support Russia's ambitions to double its petrochemicals output by 2030. Beyond 2024, expansions at the Arctic and Sakhalin LNG facilities could provide a further boost to associated gas liquids production. Final investment decisions for these projects are expected in 2019. It should be noted that the Ministry of Energy reports crude and condensate production only. Estimates for NGL output are based on data from Sibur, a petrochemicals company that processes the majority of Russia's associated gas and raw NGLs and other secondary sources. In 2018, output of condensate is estimated at 745 kb/d and NGLs at 335 kb/d.

Figure 2.42 New facilities in Russia

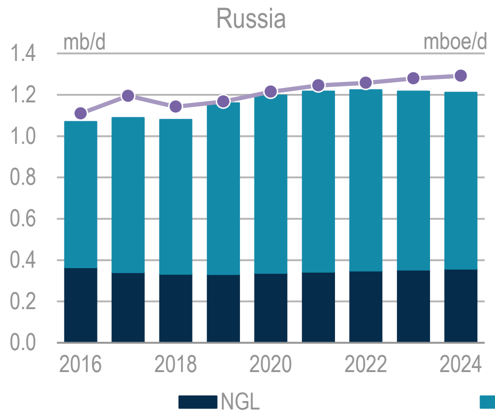
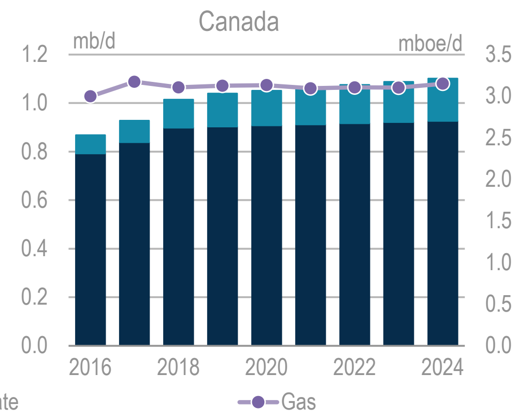


Figure 2.43 Diluent demand boosts Canada



In **Canada**, condensate output has more than doubled in four years to reach 115 kb/d in 2018. Strong demand for condensate as a diluent for bitumen production has seen operators target liquids-rich gas plays, such as the Montney and Duvernay shale formation, output from which underpins 9% p.a. average growth in condensate supplies to 2024. Continued investment in gas liquids gathering and processing facilities, such as the Wapiti gas plant, Simonette gas plant and Keylink NGL gathering system will allow Canada to reduce its dependence on imports from the United States of bitumen diluent. Meanwhile, in line with modest expectations for Canadian gas output, ethane, butane and propane production growth slows to 1% p.a. on average over the forecast period.

Qatar supplies 26% of globally-traded LNG and it has announced plans to expand its production capacity by 40% to 110 million tonnes per annum (mtpa). Supplies are set to come from the North Field, Qatar's share of the world's largest gas field which straddles the border with Iran. However, with no additional LNG projects sanctioned to date, substantial volumes are not expected online until after 2024. In the medium term, gas output will grow 1.2% p.a. and NGL and condensate 1.1% p.a.

In recent history, OPEC gas production growth has been driven by Qatar and Iran. However, Qatar has now left the group and US sanctions will hamper activity in Iran. Expansion in Iraq and Saudi Arabia will underpin growth of 1.4% p.a. for OPEC to 2024. In 2018, **Iraqi** gas production was 9 bcm (150 kboe/d). Most of this is associated with its southern oil fields, and, incredibly, a further 18 bcm (310 kboe/d) was flared. In a bid to reduce flaring and a dependence on imports, investments in processing infrastructure will see gas production increase by 17.3% p.a. This, in turn, will see higher recovery of gas liquids, and capacity is forecast to grow by 7.9% p.a. to 140 kb/d in 2024.

In **Saudi Arabia**, despite a government push to boost gas production to diversify from oil, and with strong domestic demand expected, output will grow only modestly to 2024 at 1.3% p.a. Nevertheless, Saudi Arabia is OPEC's largest producer of gas liquids and the gradual ramp-up of the Hawiyah and Shaybah NGL developments will add 56 kb/d to capacity.

Iran is the largest gas producer in OPEC, and, indeed, the third biggest in the world, but our growth forecast has been slashed following the imposition of US sanctions. In late 2018, Total exited the development of the giant South Pars field having failed to secure a waiver. The project, which was expected to produce an additional 240 kb/d of NGLs and condensates, is on hold for now.

Figure 2.44 Awaiting Qatar LNG expansion

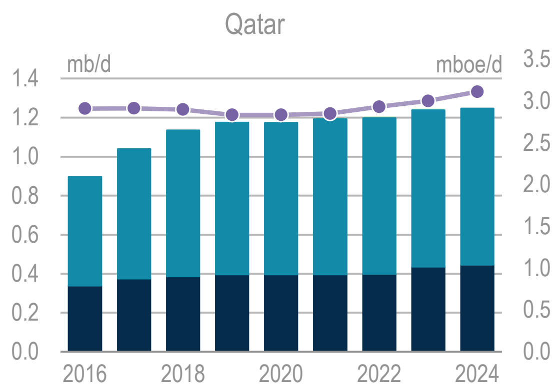


Figure 2.45 Iraq monetises gas liquids

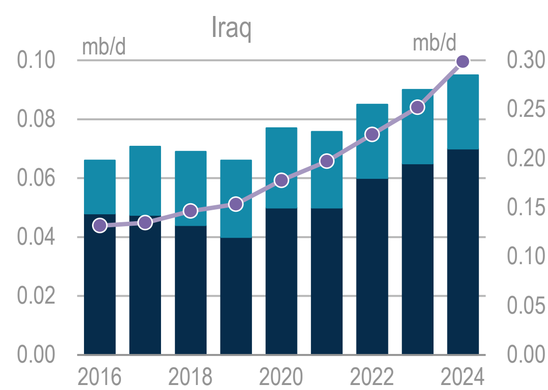


Table 2.5 Estimated OPEC condensate and NGL production (kb/d)

	2018	2019	2020	2021	2022	2023	2024	2018-24
Algeria	481	475	477	479	471	473	466	-16
Angola	78	77	75	74	75	76	78	0
Congo	7	7	7	7	7	7	7	0
Equatorial Guinea	86	86	85	85	84	84	83	-3
Iran	1,010	1,020	1,020	1,020	1,020	1,020	1,020	10
Iraq	95	100	110	120	130	140	140	45
Kuwait	305	305	308	308	308	311	311	6
Libya	58	65	68	70	73	75	77	19
Nigeria	444	454	457	453	450	452	453	9
Saudi Arabia	1,944	1,948	1,971	1,975	1,978	1,987	2,000	56
UAE	803	817	820	825	835	842	852	49
Venezuela	136	122	118	110	102	95	86	-50
Total NGLs*	**5,448**	**5,476**	**5,515**	**5,526**	**5,533**	**5,561**	**5,573**	**147**
Non-Conventional**	98	98	98	98	98	101	105	7
Total OPEC	**5,546**	**5,574**	**5,613**	**5,624**	**5,631**	**5,662**	**5,678**	**149**

* Includes ethane.

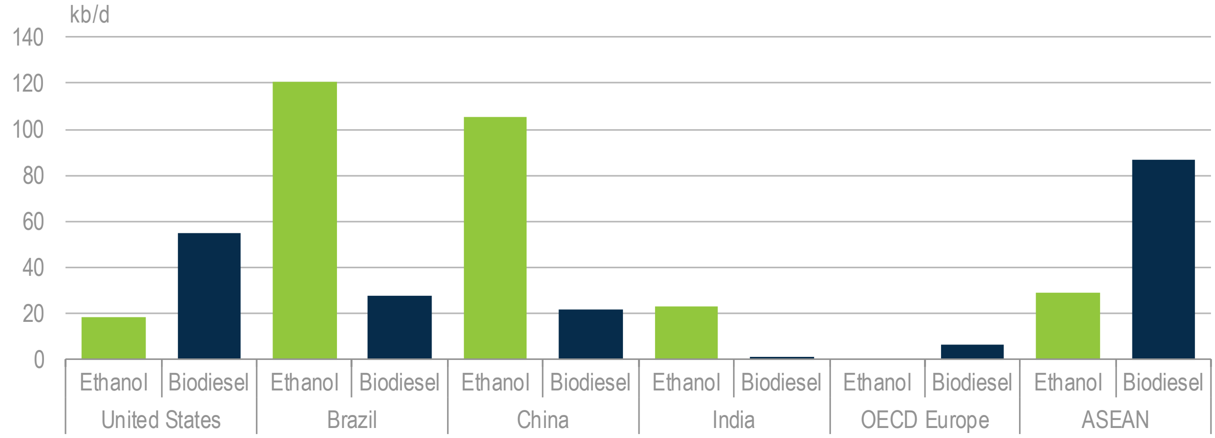
** Includes gas-to-liquids (GTLs).

The expansion in global liquefaction capacity of 30% over the medium term will be supported by the approval in second half 2018 of a number of new LNG projects. These include BP's Tortue FLNG project offshore Mauritania and Senegal and Shell's LNG Canada. LNG demand continues to grow, and in 2019 major projects in the United States, Russia and Mozambique are expected to face their final investment decision. Should they proceed, more associated gas liquids are likely, although given lengthy project lead times this will be seen beyond our forecast period. Some other high profile sources of gas production growth are Egypt's super-giant Zohr field, which ramped up to 2 billion cubic feet per day (bcm/d) over 2018, and China, where output will grow by 6.6% p.a. However, these are dry gas developments so will not contribute to gas liquids growth.

Biofuel supply

Global conventional biofuels production in 2018 was 2.6 mb/d, up 7% on the 2017 level. The forecast has been revised upwards since last year's report, with production expected to grow by 20% to 2024 to reach 3.1 mb/d. Biofuels are anticipated to account for just over 4.5% of road transport energy demand by the end of the forecast. This more optimistic outlook is primarily due to robust growth prospects in emerging economies in Asia and Brazil.

Figure 2.46 Biofuel production growth by country and region, 2019-24



Notes: ASEAN = Association of Southeast Asian Nations. In the United States, OECD Europe and ASEAN, biodiesel output growth includes hydro-treated vegetable oil.

China, India and Association of Southeast Asian Nations (ASEAN) countries provide half of forecast production growth. Rising gasoline and diesel demand in these markets means domestically produced biofuels are a means of offsetting some crude oil and petroleum product imports, thereby reinforcing security of supply. Consequently, a range of policy initiatives have been introduced, giving impetus to production to 2024.

Brazil, with the biggest increase in output of any individual country, accounts for almost 30% of global biofuel production growth in the forecast period. The prime driver is the new flagship RenovaBio policy framework, which is anticipated to strengthen the economics of biofuel production, boosting investment in new capacity and output from existing plants.

World fuel ethanol production in 2018 grew 7% y-o-y to 1.9 mb/d. Average annual growth of 2.5% will see output reach just over 2.2 mb/d by 2024. Growth is principally driven by Brazil and China. However, in 2024 the United States will still dominate the fuel ethanol market, accounting for almost 50% of global production.

Biodiesel and hydro-treated vegetable oil (HVO) production increased 5.5% in 2018 versus 2017 levels, to 710 kb/d. Over the next five years, average annual growth of 4% is anticipated, with production reaching around 900 kb/d in 2024. Market expansion is driven by supportive policies in the United States, Brazil and some ASEAN countries, as well as increased HVO capacity from the expansion of existing facilities and new plants coming online in Europe, Singapore and the United States.

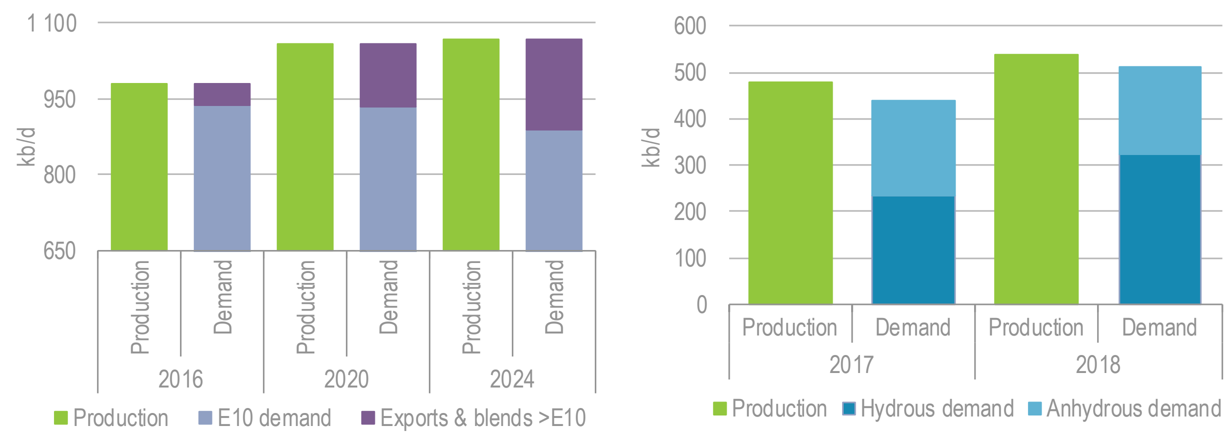
Biofuel demand in the aviation sector is growing and should accelerate with new policy initiatives in the United States and Europe. The number of flights using aviation biofuels reached 150 000 at the end of

2018. However, aviation biofuel production capacity remains low, which, along with costs currently higher than fossil-based jet fuel, dampens significant market penetration over the forecast period.

Key ethanol market developments

In the **United States**, ethanol production rose by around 1.5% y-o-y to 1.05 mb/d in 2018. Growth was supported by an abundant corn crop and high capacity utilisation by ethanol facilities. Output is forecast to stabilise around this level over the forecast as the allowable limit for corn ethanol under the Renewable Fuel Standard (RFS2) has been reached.[4] This represents an upward revision from the forecast published in *Oil 2018* as a result of a smaller reduction in gasoline demand than anticipated, record ethanol exports in 2018, and the prospect of year-round sales of E15[5] ethanol blends. In addition, ongoing improvements and technical modifications at existing plants will increase capacity.

Figure 2.47 United States (left) and Brazil (right) production and consumption overview



Notes: E10 demand for 2020 and 2024 calculated as 10% of forecast gasoline demand. For 2020 and 2024 "production" refers to forecast production. Blends >E10 principally refers to E15 and E85. Hydrous ethanol is consumed directly by flex fuel vehicles, which can run on gasoline or unblended ethanol. Anhydrous ethanol is blended with gasoline at a rate of 27% in Brazil.

Sources: Unica (2019), Unicadata, January 2019, http://www.unicadata.com.br/; US EIA (2019), Monthly Energy Review, https://www.eia.gov/totalenergy/data/monthly/index.php#renewable.

Gasoline is blended with 10% ethanol (known as E10) as standard. The 4% contraction in gasoline demand anticipated over the forecast period is expected to lower domestic ethanol consumption. For the ethanol production volumes within the forecast to be met, increased exports and more consumption in higher blend shares than E10 is needed.

In 2018, Brazil and Canada underpinned US ethanol exports. Over 2019-24, growth of exports to other markets is anticipated. For example, recent regulatory changes in Japan and Mexico support increased imports. Higher consumption of E15 is also anticipated with the approval of its sale year-round expected to be formally adopted in 2019. However, E15 is currently only available in around 1% of service stations and demand growth is tied to the rate at which new sites supply the blend and its price competitiveness at the pump versus E10.

[4] The RFS2 is currently established up to 2022; however, because of the its importance to the agricultural sector and ethanol's octane value, this forecast assumes that the policy remains in place over the forecast period. This assumption also applies to the biodiesel and HVO forecast.

[5] Gasoline blended with 15% fuel ethanol by volume. E85 refers to gasoline blended with up to 85% fuel ethanol by volume.

Ethanol output in **Brazil** increased significantly in 2018, growing 14.5% y-o-y to a record level of 545 kb/d. This increase was due to two key factors. Firstly, mills maximised ethanol production at the expense of sugar due to low international sugar prices. Secondly, there was higher hydrous ethanol demand as a result of its price competitiveness at the pump versus gasoline. This was explained by lower levels of federal taxation on ethanol and higher crude oil prices for most of the year.

Ethanol production is anticipated to increase at an average annual rate of 3% to around 655 kb/d by 2024. This is driven by the improved economics of biofuel production under the RenovaBio scheme, which is due to commence in 2020 and is a key mechanism to meet the recently established national target to reduce greenhouse gas emissions by 10% by 2028. RenovaBio will establish emissions reduction targets for fuel distributors, as well as a tradeable credit system to demonstrate they are met. Biofuel producers will generate emissions reductions certificates which can subsequently be used for compliance, strengthening the economics of biofuel production.

RenovaBio is expected to provide a supportive framework for further ethanol production capacity investment. This is anticipated from the expansion of existing sugar mills, idle mills coming back into use and greenfield investments. Ethanol production from corn feedstock is currently relatively small compared to that derived from sugar cane, but it is expected to grow over the forecast period with a number of distilleries in development.

In 2018, **China** increased ethanol output by 24% y-o-y to 70 kb/d. Production is forecast to more than double to 175 kb/d by 2024 as a result of plans to roll out E10 blends of ethanol nationwide by 2020. Key drivers for this policy are offsetting crude oil imports and utilising accumulated corn stocks no longer fit for human consumption.

The expansion of fuel ethanol consumption from 11 to 15 provinces is already underway. Significant new capacity is under construction to meet this higher demand, with further plants in development. New facilities are mostly located in northeast China, due to abundant corn resources and processing subsidies. Cassava-based refineries in southern China will also contribute to increased output.

Nevertheless, domestic ethanol output is not anticipated to reach the levels required to meet 10% of nationwide demand during the forecast period, which, accounting for average annual gasoline demand growth of 3% per year, equates to around 350 kb/d by 2024. Whether ethanol imports will be permitted to make up any shortfall in demand is unclear.

Ethanol production in **India** rebounded in 2018 to reach a record level of 25 kb/d. Increased production was underpinned by a large supply of molasses combined with higher oil prices that boosted ethanol demand from national oil marketing companies.

Over the forecast period, annual production is anticipated to double to 50 kb/d, an upward revision from last year's forecast. This level of production is expected to be sufficient to meet the national 5% blending mandate.[6] Long-term drivers for ethanol industry expansion remain strong. With average annual gasoline demand growth of 5% over 2019-24, using domestically produced ethanol is viewed as a means to offset oil demand, in line with the aim to reduce crude oil imports by 10% by 2022.

India's new national biofuels policy, introduced in 2018, is expected to support growth. Whereas only molasses from the sugar industry was previously permitted for ethanol production, the new policy widens the range of allowed feedstocks. Production capacity is also set to increase over the first half of the forecast period as a result of the high number of applications for subsidised government loans.

[6] A 10% blending target in place for the major ethanol-producing states.

Key biodiesel and HVO market developments

Biodiesel and HVO production in **OECD Europe** decreased 5% in 2018, to 250 kb/d. France, Germany and the Netherlands combined were responsible for half of the total. The removal of anti-dumping duties on biodiesel imports from Argentina and Indonesia led to the restart of shipments. This constrained output of the least competitive European biodiesel.

Production is anticipated to grow by around 15% to 2020 due to progressively increasing mandated biofuel shares in various member states. For example in Finland, France, Italy, Poland and Spain, mandates will increase to meet the Renewable Energy Directive (RED) 10% target for renewable energy in transport for 2020. After 2020, output is anticipated to gradually decline to around 260 kb/d in 2024. This is primarily as diesel consumption contracts by 10% over the forecast period, reducing mandated demand. Conversely, HVO production will grow in France, Italy and some Nordic Countries over 2019-24 as new facilities come online.

Under the updated RED, after 2020 member states may increase the contribution of conventional biofuels to renewable energy in transport by up to 1 percentage point only from 2020 levels,[7] with the absolute cap of a 7% maximum contribution to renewable energy targets remaining in place. In this context, strengthened policy support for conventional biofuels is not expected. For the 2030 target of 14% renewable energy in transport to be met, the remainder will need to come from advanced biofuels, which do not use crop-based feedstocks, and renewable electricity.

In 2018, biodiesel and HVO production increased 15% y-o-y in the **United States**, reaching a record 120 kb/d. Production was boosted by a bumper soybean crop, demand from the RFS2 and anti-dumping duties on biodiesel imports from Indonesia and Argentina that rendered them uneconomic.

Output is expected to increase to 175 kb/d by 2024. Growth is underpinned by demand from the RFS2, as biodiesel and HVO will benefit from increased renewable fuel demand from the scheme given that corn ethanol has already reached its maximum contribution. Demand for low carbon biodiesel and HVO from waste and residue feedstocks from California's Low Carbon Fuel Standard is also anticipated to remain robust as annual carbon intensity requirements are tightened to 2030.

Biodiesel production in **Brazil** rose by 25% in 2018, to a record 90 kb/d, supported by a good soybean harvest and higher demand from the increase in the blending mandate to 10% in March 2018.

Average annual production growth of 5% is forecast to 2024, with output scaling up to just under 120 kb/d and consequently reducing current biodiesel plant overcapacity. The primary driver is the proposed staged increase in the mandate towards 15% in 2023. Incremental increases will be dependent on automotive industry testing to assess the effects of using higher blend levels, representing a downside risk on the forecast if mandate increases are not delivered.

In **Indonesia** the biodiesel market is in transition from an export-driven focus towards higher domestic consumption. A 30% y-o-y increase in production to 70 kb/d was delivered in 2018. Output is anticipated to grow at an average annual rate of 9% over the forecast period, reaching 115 kb/d.

Growth is delivered by new plants coming online, complemented by a ramp-up in production from under-utilised capacity. Demand is ensured by new regulations that extend the B20 mandate to new market segments. Biodiesel consumption under the mandate is augmented by average annual diesel demand growth of 1.5%. Due to higher domestic consumption the share of production exported is anticipated to decrease over the forecast period.

[7] Or two percentage points if a country's share is zero in 2020.

3. REFINING AND TRADE

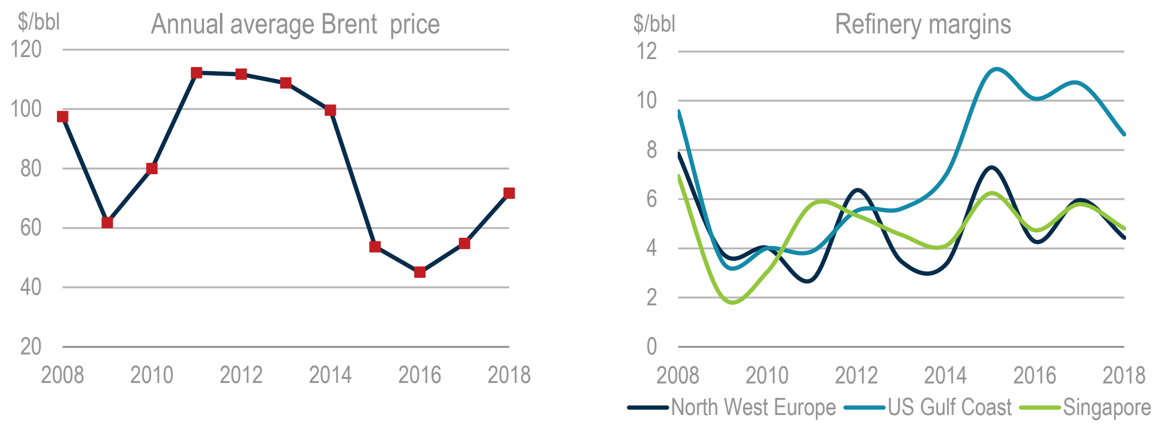
Highlights

- The downstream oil industry is facing a huge wave of capacity additions with as much as 9.1 million barrels per day (mb/d) coming online by the end of our forecast period in 2024. This is twice the size of growth in demand for refined products, and it signifies major competition ahead. Almost two thirds of the new capacity, as well as two thirds of refined products demand growth, will be in Asia.
- While the United States will remain the largest refiner and products exporter, People's Republic of China ("China") is expected to become the world leader in terms of installed refinery capacity by 2024. Chinese utilisation rates are currently below the global average, and will remain so, barring government-mandated or voluntary shutdowns. New projects are primarily driven by petrochemical feedstocks requirements. However, transport fuels production is expected to grow, resulting in even larger volumes of products exports. A US Gulf Coast-type refining hub is emerging along China's northeast coast.
- Structural changes in global oil products demand and crude supply will have a profound impact on refining margins and crude and product differentials. These include: a gasoline demand slowdown in the Atlantic Basin; the implementation in 2020 of the International Maritime Organisation's (IMO) marine fuel regulations; booming petrochemical feedstock demand in Asia; US light tight oil (LTO) production growth; and declines in the supply of medium-heavy crude oil.
- Oil markets will go through transformational changes, as the United States becomes a net oil exporter and doubles its *gross* crude exports to 4.2 mb/d by 2024. Its symbiotic relationship with Canada means that the United States's reliance on international seaborne markets for crude imports falls to the minimum levels required to sustain the northeast and west-coast refiners, while the Gulf Coast becomes a net crude export hub. Asia, meanwhile, increases net crude imports by 3.4 mb/d, with the bulk of the incremental barrels coming from the United States, Latin America and the Middle East.
- The largest growth in interregional product trade comes from natural gas liquids: ethane and liquefied petroleum gas (LPG). Asian diesel exports to the West all but cease as the region retains its excess fuel to meet demand resulting from the IMO bunker rules. However, the United States and the Middle East increase diesel exports to Europe. Africa remains a major product importer, despite bringing online 0.8 mb/d of new refining capacity.

Global overview

Benchmark Brent crude oil prices increased for a second consecutive year in 2018, rising by $17 (United States dollars)/ barrel (bbl) on average. This started to overwhelm refining margins, which fell year-on-year, as demand growth for refined products slowed dramatically to just 0.6 mb/d and refining capacity additions reached 1 mb/d. Record US and Chinese refining runs were offset by deteriorating performance in Mexico, Latin America and, to a certain extent, Europe. In the near-future, most of the factors that played out in 2018 will continue to determine the fate of regional refining hubs: slowing demand, growing capacity and competition from regions with access to cheaper feedstock.

Figure 3.1 Oil prices and refining margins



Supplies from non-refinery sources, will continue growing and further reducing refiners' market share, albeit not as fast as in the recent past. In the forecast period, while the supply of coal-to-liquids, gas-to-liquids and biofuels will accelerate, direct use of crude oil will decline. The growth in natural gas liquids is also expected to slow. In 2018, refiners' market share, or the "call on refineries" was estimated at 85%, but by 2024 it will decline to 83.7%.

Figure 3.2 Global liquid fuel supply in 2018 (mb/d)

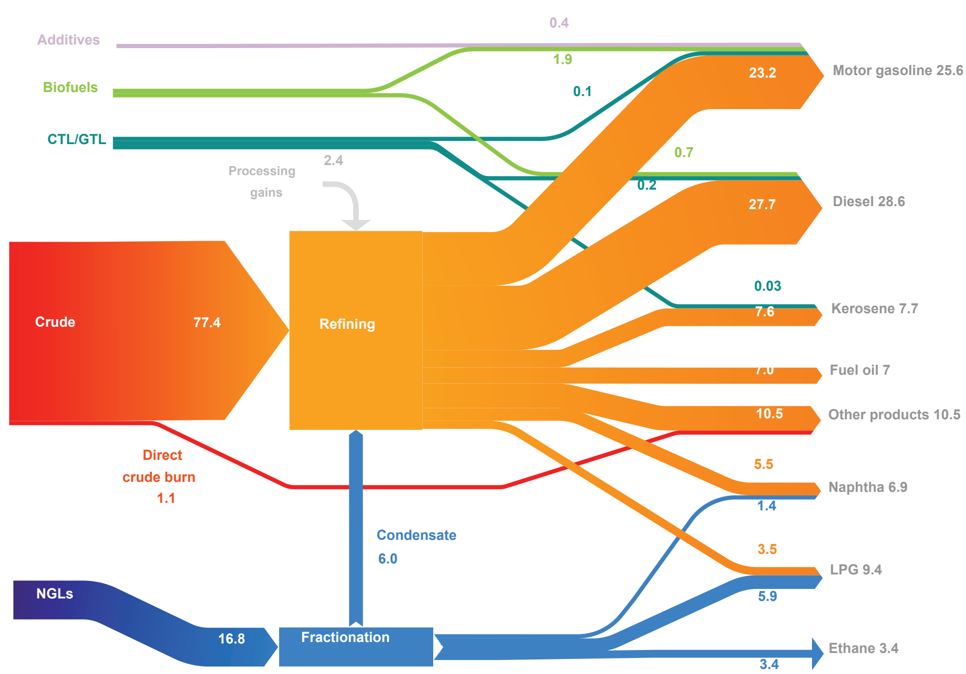


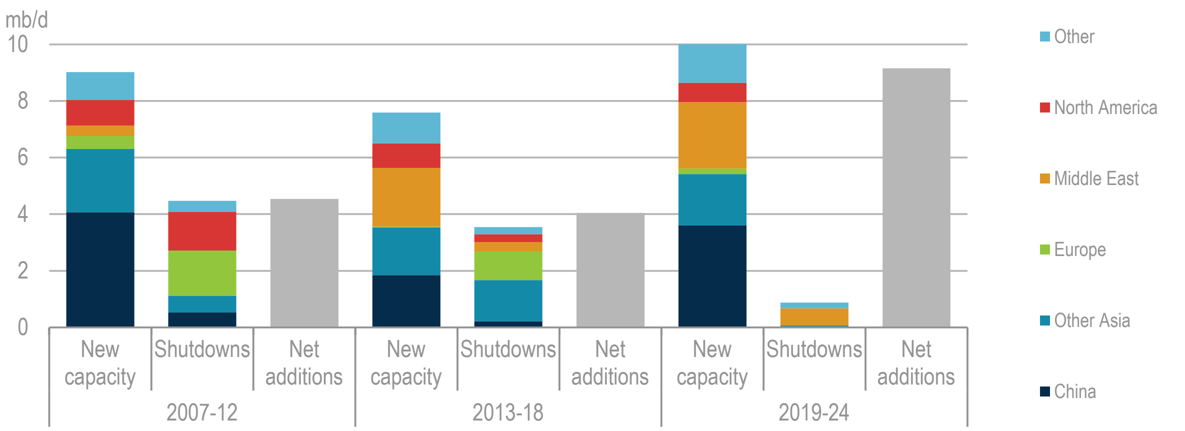
Table 3.1 Total oil demand and call on refined products

	2018	2019	2020	2021	2022	2023	2024	2018-24
Total liquids demand	99.2	100.6	102.0	103.3	104.5	105.4	106.4	7.2
of which biofuels	2.5	2.6	2.7	2.7	2.8	2.8	3.1	0.7
Total oil demand	96.7	98.0	99.3	100.5	101.7	102.6	103.3	6.5
of which CTL/GTL*/additives	0.8	0.8	0.8	0.9	1.0	1.0	1.1	0.3
direct use of crude oil	1.1	1.0	0.9	0.9	0.8	0.8	0.8	-0.3
Total oil product demand	94.9	96.2	97.5	98.8	99.9	100.8	101.4	6.5
of which fractionation products	10.5	10.9	11.3	11.6	11.8	12.1	12.3	1.8
Refinery products demand	84.4	85.3	86.2	87.2	88.1	88.7	89.1	4.7
Refinery market share, %	85.0	84.8	84.5	84.5	84.3	84.1	83.7	-1.3%

*CTL/GTL: Coal-to-liquids and gas-to-liquids.

Our forecast of refining capacity additions has been revised up in this report due to a more aggressive Chinese expansion, with net global additions now 1.9 mb/d higher than outlined in *Oil 2018*. The gross capacity additions now total 10 mb/d in 2019-24. In our forecast, we do not model or nominate refineries as shutdown candidates, only taking into account known shutdown projects. Usually, plans are announced only for imminent closures which is why our current list of capacity shutdowns amounts to just 0.9 mb/d, mostly at sites where new units are being built to replace old equipment, for example, in Bahrain and Islamic Republic of Iran ("Iran"). The resulting net additions of 9.1 mb/d are well above oil-based demand growth of 6.5 mb/d (excluding biofuels), and even more so in relation to the expected growth in refined products demand of 4.7 mb/d.

Figure 3.3 Capacity expansion requires shutdowns to balance

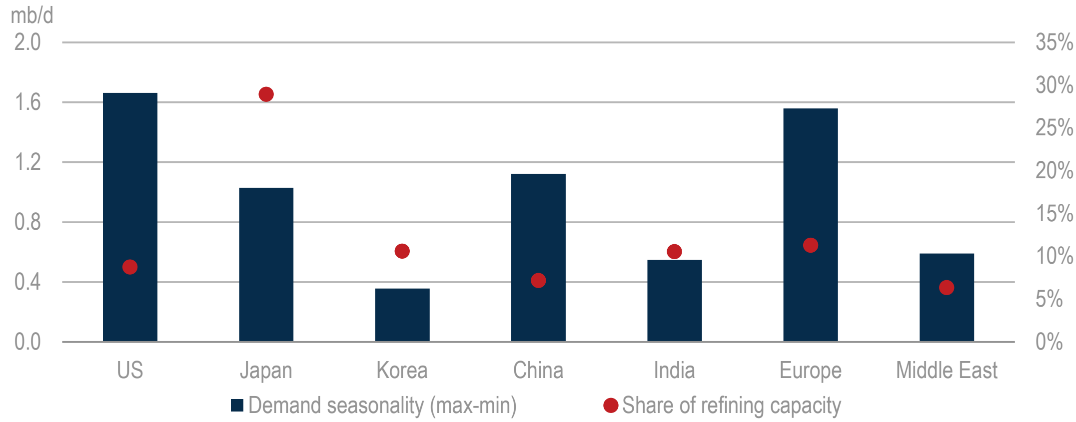


Since 2007, 16.5 mb/d of new capacity has come online globally, but almost half as much was shut down. Previous shutdowns were usually voluntary business decisions by integrated oil companies. Exceptions to this include the European refiner Petroplus's bankruptcy in 2012 and government-mandated capacity reductions in Japan. If net capacity additions are not to exceed refined products demand growth, another 4.3 mb/d of capacity should theoretically be closed by 2024. This could be in regions where unused capacity is relatively large. However, identifying excess capacity is not a straightforward process.

What is excess refining capacity?

When comparing annual average refining throughput to installed crude distillation unit (CDU) capacity, there is already more than 15 mb/d of unused capacity globally. This will grow, unless the refining system adjusts by closing idle or under-utilised units. China leads in terms of unused capacity, with idle units amounting to close to 4 mb/d, a quarter of the global total. This is a structural issue and also reflects the highly regulated nature of China's oil trade. Next is the United States, where about 2 mb/d of capacity is unused on an annual average basis. However, given the strong seasonality of throughput, the unused capacity at seasonal peak run rates is lower. Combining the highest weekly run rates of the five Petroleum Administration for Defence Districts (PADD) observed in 2018, the excess capacity at the peak shrinks to only 400 thousand barrels per day (kb/d). Japan faces a similar issue of a large gap between winter and summer demand and capacity utilisation. Of course, oil products are regularly stored for peak seasonal withdrawals, but stock holding comes at a cost, so it would not be an economic solution to balance refinery throughputs throughout the year.

Figure 3.4 Seasonal demand variation and share of refining capacity



Mexico and Venezuela each contribute almost 1 mb/d to global spare capacity. In Mexico, refinery utilisation rates have dropped in the last three years due to operational issues. In Venezuela, the cause is the general turmoil in the economy and the petroleum industry. The Russian Federation ("Russia") is the next largest source, with 900 kb/d of under-utilised capacity. It is a large net exporter of refined products and recent fiscal changes may encourage crude exports at the expense of refining. In both Iraq and Libya, conflict-related equipment damage and an overall lack of security prevent higher capacity utilisation. The refining industries of Ukraine and Nigeria have also long suffered from general neglect and 550 kb/d and 400 kb/d of capacity, in these countries, respectively, has been idled for years.

The reality is that excess crude distillation capacity is not necessarily the main issue. If refineries are not equipped with the optimum setup of secondary processing equipment, the spare distillation capacity is "phantom". It is unused, but not actually usable. As such, the global system may continue carrying large chunks of idle crude distillation capacity without making much effort to optimise.

Refining outlook

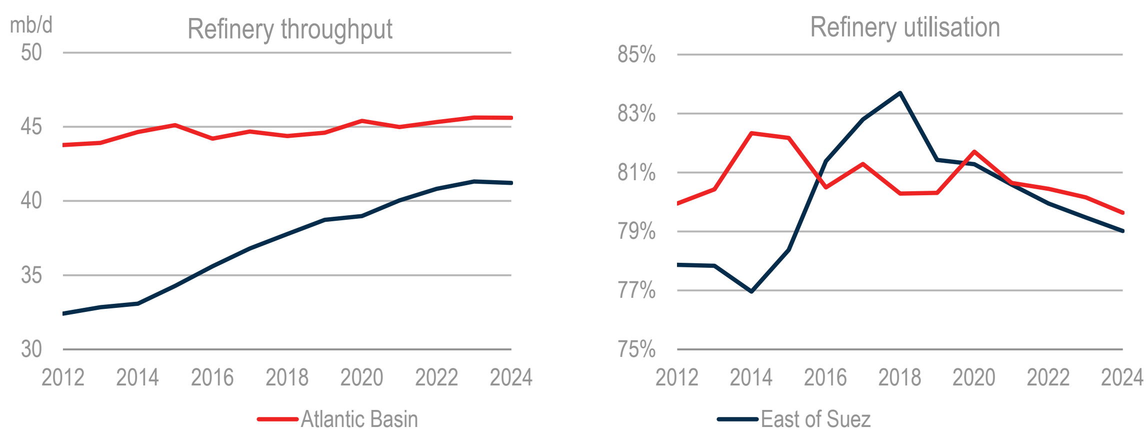
New refining capacity East of Suez (Middle East and Asia) accounts for 78% of global additions, similar to its share in the growth in global refinery intake (72%). Capacity utilisation rates spike in 2020 to balance global middle distillate markets in the first year of the new IMO rules, but decline afterwards. Post-2020, declines are more pronounced in the East of Suez, where utilisation rates are expected to fall to 79%, to avoid product oversupply even as the demand growth for refined products is heavily concentrated in this region. Atlantic Basin demand for refined products grows by only 0.7 mb/d, compared to 4.2 mb/d East of Suez. Utilisation rates in Latin America and Africa are expected to improve only marginally. India's refining industry will remain one of the most efficient, with utilisation rates holding between 95-99%.

Table 3.2 Regional developments in refining capacity and throughput

	Total capacity (mb/d)			Refinery throughput (mb/d)			Utilisation rates	
	2018	**2024**	**Change**	**2018**	**2024**	**Change**	**2018**	**2024**
North America	22.7	23.3	0.7	19.2	20.7	1.4	85%	88%
Europe	15.1	15.3	0.2	13.1	12.2	-0.9	87%	80%
FSU*	8.7	9.1	0.4	6.8	6.5	-0.4	78%	71%
China	15.7	19.3	3.6	12.0	14.1	2.0	77%	73%
India	5.2	5.7	0.5	5.1	5.5	0.3	99%	95%
Other Asia	14.3	15.5	1.2	12.2	12.3	0.1	85%	79%
Middle East	9.3	11.0	1.7	7.9	9.0	1.0	85%	82%
Latin America	6.0	6.0	0.0	3.7	4.0	0.2	62%	66%
Africa	3.5	4.3	0.8	2.0	2.8	0.7	58%	65%
World	**100.4**	**109.4**	**9.0**	**82.1**	**86.8**	**4.7**	**82%**	**79%**
Atlantic Basin	*55.3*	*57.3*	*2.0*	*44.4*	*45.6*	*1.2*	*80%*	*80%*
East of Suez	*45.1*	*52.2*	*7.0*	*37.8*	*41.2*	*3.4*	*84%*	*79%*

*FSU: Former Soviet Union.

Figure 3.5 Atlantic Basin vs East of Suez



Note: Only announced capacity closures are included in the forecast.

Atlantic Basin

Americas

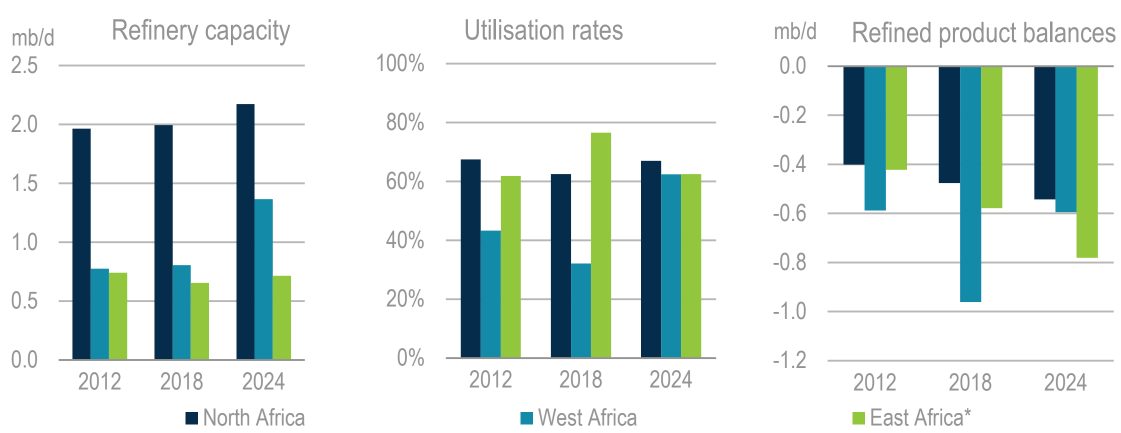
Two major projects are expected to be completed in North America by 2024. ExxonMobil is planning a 350 kb/d addition to its Beaumont, **Texas**, plant, geared to processing domestic light crude grades, and a 250 kb/d new refinery will be built in **Mexico**. US refiners are expected to increase the processing of local light crude grades, while also trying to adjust yields away from increasingly oversupplied gasoline to diesel. US gasoline yields are about 46%, in line with the share of the product in local demand (Figure 3.7). More than half of gasoline output comes from secondary units, rather than straight-run (or reformed) naphtha. This means that a significant portion of atmospheric residue is used to make gasoline, instead of diesel, for example. It is possible to further increase distillate yields by minimising the use of atmospheric and vacuum gasoil in fluid catalytic crackers (FCC). We expect US refiners to become a major part of the global effort to increase middle distillate yields to meet the new IMO specifications. Also, by increasing the utilisation of domestic light sweet grades, and possibly, redirecting the FCC feed, they will increase output of 0.5% sulphur fuel oil.

In Latin America, refining throughput declined again in 2018, by 200 kb/d. Most of this was due to the collapse of **Venezuela's** industry. The refinery at **Curaçao**, operated by Petroleos de Venezuela S.A, was shut down due to legal disputes and supply issues. **Trinidad** announced the shutdown of its sole 170 kb/d refinery at the end of 2018. However, in early 2019 the governments of both Trinidad and Curaçao announced their intention to re-open the plants subject to viable bids being received. A mothballed refinery in the **US Virgin Islands** may see a temporary comeback as a private-equity firm is considering rehabilitating one of the smaller CDUs and associated units to cater for the marine bunker fuel market in 2020.

Africa

Africa is the world's largest net importer of refined products, as its own output covers less than half of its needs. Over the last few years the continent has quietly overtaken the United States to become the world's largest gasoline importer. It is also the world's second-largest diesel/gasoil importer.

Figure 3.6 Refining situation in Africa's subcontinents



*East Africa includes the Republic of South Africa.

The situation is slightly better in North Africa, which accounts for about 60% of the continent's refining capacity and over 60% of its crude runs. Utilisation rates could have been higher in the last few years if not for the shutdown of **Morocco's** relatively modern 200 kb/d refinery in 2015, and the conflict in **Libya**. **Egypt** has engaged in a modernisation programme to increase fuel quality, along with a small capacity expansion of 60 kb/d coming online by 2023. A total of 120 kb/d of capacity additions is forecast for **Algeria**. In 2018, Sonatrach acquired ExxonMobil's 200 kb/d Augusta refinery in Italy, which it plans to use to supply its domestic market. In West Africa, only 32% of capacity is being utilised and three quarters of its products demand is supplied from imports. **Nigeria's** 650 kb/d Dangote project is expected to come on stream in 2022, but we are less optimistic about the revival of its existing refineries, which have a total capacity of 450 kb/d. In 2018, utilisation rates in Nigeria averaged just 9%. **Angola's** 60 kb/d Cabinda project is the only other refinery expected to materialise over the forecast period. East Africa, where we include South Africa for trade modelling purposes, also depends on imports for about half of its demand. We expect only 85 kb/d of additions in the region, comprised of the commissioning of **Uganda's** first refinery in 2022 and a project in **South Sudan**.

African refiners in general suffer from a lack of funds to invest in maintenance and upgrades. Also, there are the distorting impacts of subsidies as well as widespread smuggling. In addition, the region sits between the gasoline-long Atlantic Basin and the diesel-long Middle East/India, which means that external suppliers are keen on gaining market shares in Africa. Thus, despite robust demand growth, the continent's refining development may be constrained by growing competition from other regions.

Europe

Europe faces similar issues in terms of increasing competition from global markets. Local demand is skewed towards middle distillates (diesel and kerosene), with gasoline accounting for a much smaller share. Gasoline export markets have been getting increasingly competitive, as the United States has become a net exporter. At the same time, while boasting reasonably high middle distillate yields, Europe has to import every fifth barrel consumed, as it is not practically possible for refiners to achieve the required yields of over 50%.

Figure 3.7 Structure of regional demand in 2018

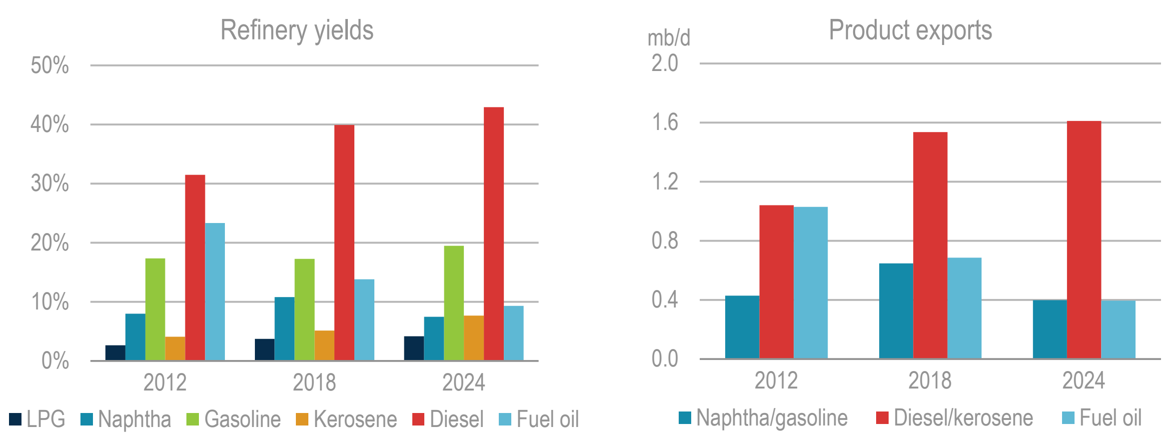
No new refining capacity is expected in the region, after **Turkey's** 200 kb/d Star refinery in Aliaga, built by the State Oil Company of Azerbaijan Republic (SOCAR) was completed in 2018. However, refiners have either already brought online, or are constructing, several upgrading units to deal with the fuel oil/gasoil imbalance resulting from the IMO 2020 regulations. Cokers, hydrocrackers and solvent de-asphalting units have been announced at several refineries. Nevertheless, the overall impact of the IMO change and increased competition from exporters in the United States, Middle East and Asia is expected to be utilisation rates falling from the current 87% to 80% in 2024, with imports of middle distillates products increasing.

Former Soviet Union

Ongoing adjustments to **Russia's** oil industry tax system are based on a gradual rise in the mineral extraction tax, offset by the phasing out of crude oil and products export duties from 30% in 2019 to zero in 2024 for crude oil and products. These changes, which are having a considerable impact on oil product trade and investment decisions by Russian refiners, will be accompanied from 2019 by a complex new system of tariffs and rebates to boost state revenues while seeking to shelter the downstream sector from oil price volatility.

Subsidies remain a critical component of the tax scheme. They extend lifelines to many Russian refineries that are either remote from inland demand centres or export outlets, and thus subject to higher transport costs, or are experiencing low to negative margins. In the future, subsidies via an excise refund will be offered to a subset of refiners. Qualifying refiners are those that fall under Western sanctions, provide the minimum designated amount of Euro-5 fuels or naphtha to the domestic market and for the petrochemicals industry, or are engaged in continued modernisation works through 2024. Following the eventual completion of Russia's long-running refinery modernisation programme to raise high-quality product yields, we expect fuel oil yields to fall to 9.3% in 2024 from 13.8% in 2018 and overall light and middle distillate product yields to increase to 77.6% from 73.2%.

Figure 3.8 Russian product yields and exports



On the eve of the implementation of the 2020 IMO regulations, Russia remains the world's largest fuel oil exporter. The rules will make life even more difficult than it already is for less complex or otherwise struggling refineries. This is why we see throughput declining from 5.7 mb/d in 2018 to 5.4 mb/d in 2024. Higher diesel yields and modest domestic demand growth means that total diesel exports will remain between 1.4-1.5 mb/d, while fuel oil exports decline to 0.4 mb/d from 0.7 mb/d in 2018.

The fiscal changes in Russia are having far-reaching consequences across the FSU. Russia supplies **Belarus** with duty-free oil products and crude, but with the implementation of fiscal changes in Russia, the duty-free advantage of Belarus refiners will effectively disappear. Negotiations are underway for compensation from Russia, but, depending on the outcome, some consideration may be given to the sale or privatisation of Belarusian refineries. In **Kazakhstan**, the refineries upgrade programme has been completed, and the availability of higher quality gasoline and diesel is increasing. We do not expect any major refinery projects to come online in the next five years.

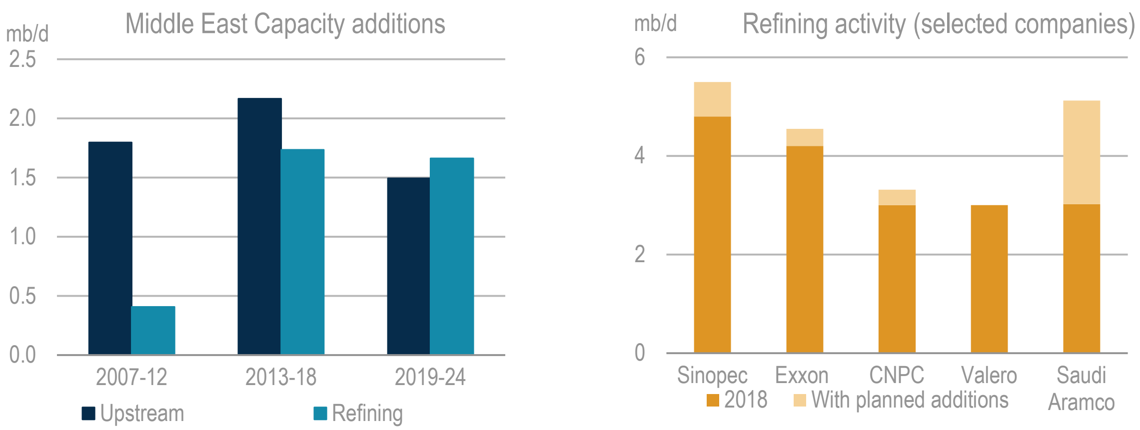
East of Suez

Middle East

The region will add 2.3 mb/d of new capacity, while 0.6 mb/d of existing capacity will be shut down. With a net increase of 1.7 mb/d, the Middle East's capacity growth will be exceeded only by China. At the same time, regional demand for refined products (excluding ethane and LPG) will increase by just half the rate of capacity expansion, even as the direct crude burn declines by 230 kb/d and fuel oil use in power generation increases. Planned refining capacity additions, in terms of volumes, also exceed upstream projects for the first time in several decades.

The largest additions will come from **Kuwait**: these are the 615 kb/d Al-Zour refinery scheduled for 2021, and the 200 kb/d capacity addition at Mina Abdulla, which will also involve a 112 kb/d shutdown at the Mina al-Ahmadi site. **Saudi Arabia** remains the largest refiner in the region, but expansion is limited to the final phase of the Jazan project which will come online in 2019. **Iran** has finished the construction of its 360 kb/d Persian Gulf Star condensate splitter complex. Beyond that, it is only expected to build a new 200 kb/d crude distillation unit at the Abadan complex, which, however, will merely replace existing equipment. **Iraq's** additions will total 225 kb/d, including the Kerbala greenfield project and the restoration of war damaged facilities. **Bahrain's** 260 kb/d Sitra refinery will be replaced by a new, 355 kb/d site in 2022. **Oman's** extension at the Sohar refinery and the 230 kb/d Duqm project are expected to come online in 2020 and 2023, respectively.

Figure 3.9 Downstream ambitions



In the **United Arab Emirates** (UAE), apart from a 65 kb/d expansion at the Jebel Ali condensate splitter, there will be no new greenfield projects coming online before 2024. While intensifying efforts for international expansion, Adnoc opened its domestic refining business to foreign participation, selling 15% and 20% stakes to OMV and Eni, respectively. The three companies will also jointly establish a global oil trading business. This follows closely Saudi Aramco's model of downstream joint ventures both at home and abroad.

In **Saudi Arabia**, plans for international expansion gained new momentum in 2018. While we do not expect most of Saudi Aramco's projects to come online within our forecast period, the diversity of regions and companies involved confirms the seriousness of the company's intentions. In China, Saudi Aramco has partnered a state-owned industrial conglomerate, Norinco, to build a 300 kb/d refining and petrochemical complex in Liaoning. In India, it reached an agreement to build a 1.2 mb/d refinery in Rajasthan. It also announced intentions to build a 300-500 kb/d refinery in Pakistan's Gwadar port and a 300 kb/d refinery in South Africa. Furthermore, Saudi Aramco also reached an agreement to purchase a 19.9% stake in Hyundai Oilbank, a 560 kb/d refining company in Korea. If all the current projects materialise, Saudi Aramco may be able to overtake ExxonMobil, the world's second-largest refiner, in terms of throughput, but will remain well behind Chinese refining giant Sinopec.

Table 3.3 Saudi Aramco's refining capacity and expansion plans

Name	Location	Capacity (kb/d)	Saudi share (%)	Aramco capacity	JV partners	Year
Various	Saudi Arabia	924	100%	924	-	Existing
Petro Rabigh	Saudi Arabia	400	38%	150	Sumitomo	Existing
Yasref	Saudi Arabia	400	63%	250	Sinopec	Existing
Satorp	Saudi Arabia	400	63%	250	Total	Existing
Sasref	Saudi Arabia	305	50%	153	Shell	Existing
Samref	Saudi Arabia	400	50%	200	ExxonMobil	Existing
Showa Shell	Japan	255	15%	38	Idemitsu Kosan	Existing
S-Oil	Korea	620	63%	393	-	Existing
Fujian	China	280	23%	63	Sinopec, ExxonMobil	Existing
Motiva	US	600	100%	600	-	Existing
Total existing		**4 584**		**3 021**		
Jazan	Saudi Arabia	400	100%	400	-	2019
RAPID	Malaysia	300	50%	150	Petronas	2019
Hyundai Oilbank	Korea	560	20%	111	Hyundai Heavy Industries	2019
Zhejiang	China	800	9%	72	Rongsheng	2022
Cilacap	Indonesia	400	45%	180	Pertamina	2022
With confirmed		**7 044**		**3 934**		
Crude to Chemicals	Saudi Arabia	400	100%	400	Sabic	After 2024
Ratnagiri	India	1200	25%	300	IOC, Adnoc, etc	After 2024
Panjin	China	300	50%	150	Norinco	After 2024
NA	South Africa	300	50%	150	NA	After 2024
NA	Pakistan	500	50%	250	NA	After 2024
Total		**9 744**		**5 184**		

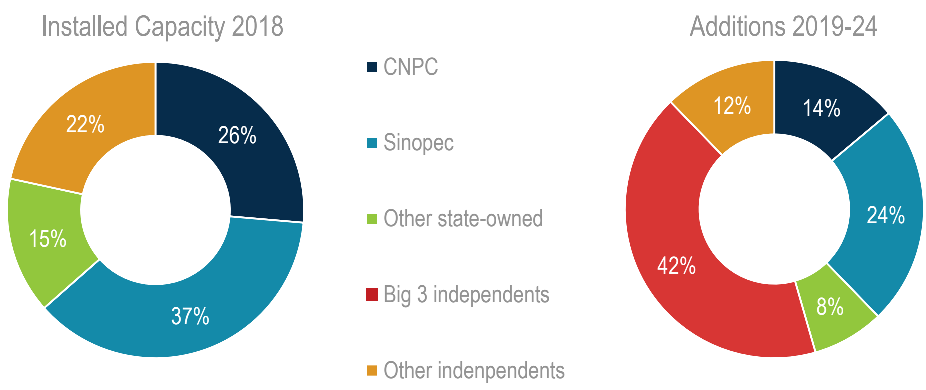
In *Oil 2018*, we noted that Saudi Aramco's petrochemical integration was somewhat limited, compared to its peers. Over the course of 2018, however, the company revealed several major joint venture petrochemical projects both at home and abroad. In addition, Saudi Aramco announced a merger plan with Sabic, one of the largest petrochemical companies in the world. The two companies had earlier agreed to jointly develop a 400 kb/d crude-to-chemicals project in Yanbu on the Red Sea Coast, but we do not expect it to come online in our forecast period.

China

China's refining industry is undergoing major changes, which will have a sweeping impact on the global refining industry. The country is once again leading the capacity-building race in the medium term, adding 3.6 mb/d to 2024. The additions to 2023 are about 2 mb/d higher than what we anticipated in *Oil 2018*. Against a background of relatively low utilisation rates, and with oil demand growth set to slow, several mega-projects are expected to materialise in the next five years. State-owned majors, China National Petroleum Corporation (CNPC) and Sinopec, which account for two thirds of installed capacity today, will see relatively modest additions, accounting for just over one third of the new capacity.

In this forecast we include three projects from the two state companies that we previously did not expect to materialise in the medium term. CNPC revived the 400 kb/d Jieyang project, in Guangdong, that was originally to be developed with Petroleos de Venezuela S.A. The refinery is expected to come online in 2023, and it will be the company's first major site on the southern coast. Most of CNPC's refineries are landlocked and are usually close to oil producing regions. Its only existing major coastal refinery is located in the northern Liaoning province. Sinopec's plans for relocating and expanding the Shanghai Gaoqiao refinery seem to have been put on hold. However, two 300 kb/d projects, in Zhejiang and Fujian provinces, respectively, appear in our forecast for the first time, with both expected to start up in 2021.

Figure 3.10 Independents drive China's capacity expansion



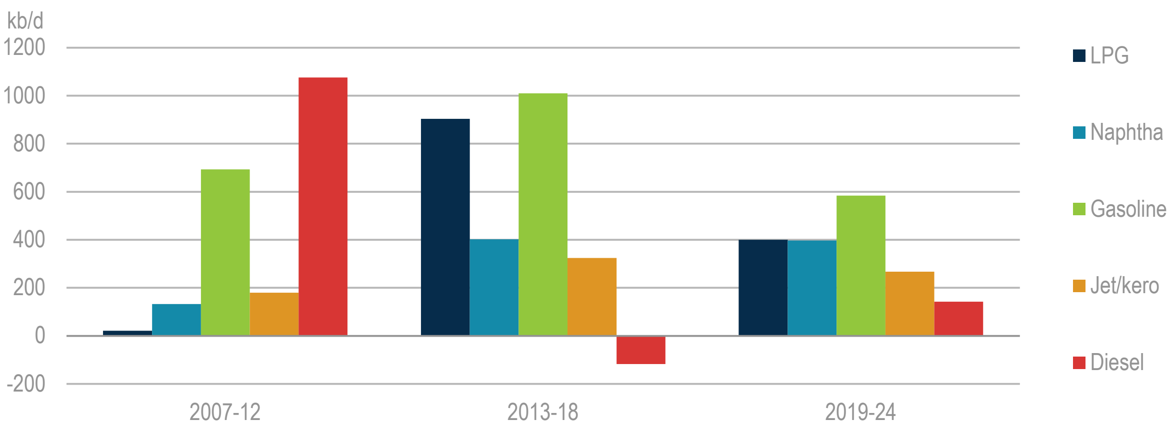
Two other state-owned refiners, CNOOC and Sinochem, account for a relatively small volume of capacity expansion at their existing sites. The joint venture of Norinco, a state-owned industrial and trade conglomerate, and Saudi Aramco, for a 300 kb/d greenfield refinery in Liaoning, is not included in our forecast, as we assume it will start up after 2024. Independent refineries in Shandong are expected to add only 240 kb/d of new capacity, with another 100 kb/d coming online in Guangdong.

It is the arrival of the three large independent players that signifies a major change in China's refining landscape. The Hengli, Rongsheng and Shenghong Groups are building large petrochemical-oriented refineries in coastal Liaoning, Zhejiang and Jiangsu provinces, respectively. These are the most striking examples, on a global scale, of "reverse integration" along the petrochemical value chain. The companies have their origins in textile manufacturing and are major suppliers to the global clothing industry. They gradually moved up the value chain, to synthetic fibre manufacturing, and now plan to also produce the petrochemical feedstock in-house. Rongsheng will have the largest base, with a total capacity of 800 kb/d, as much as the two others put together. This will be the largest single-site complex in China once the second phase comes online in 2022.

For many years, rapid oil demand growth spurred capacity expansion plans, helping the country become self-sufficient in transport fuels almost a decade ago. China is a major refined products exporter now, regularly shipping between 10-20% of its domestic diesel, gasoline and kerosene output, with cargoes reaching as far as North America and Europe. In the environment of regulated oil trade, with crude imports and product exports subject to quotas, the drivers for capacity additions have changed too.

China now aspires to become self-sufficient in key petrochemicals. Despite growing production, it still depends on imports for almost half of key olefins and aromatics supply, ethylene and paraxylene, respectively. China's refining-petrochemical integration is amongst the highest levels globally. In the absence of visible volumes of domestic natural gas liquids, most olefins production is naphtha-based and integrated with refineries. Coal-to-olefins technology has been heavily promoted but remains localised in inland coal-producing regions and is uncompetitive at lower oil prices. Several ethane cracker projects, targeting US imports for feedstock, as well as standalone propane de-hydrogenation (PDH) plants, are also going ahead, but most of the demand growth is still expected to be met through refinery-based naphtha supply. Refinery-integrated projects account for 75% of new olefins capacity in the next five years, including not only conventional naphtha and LPG crackers but also PDH units.

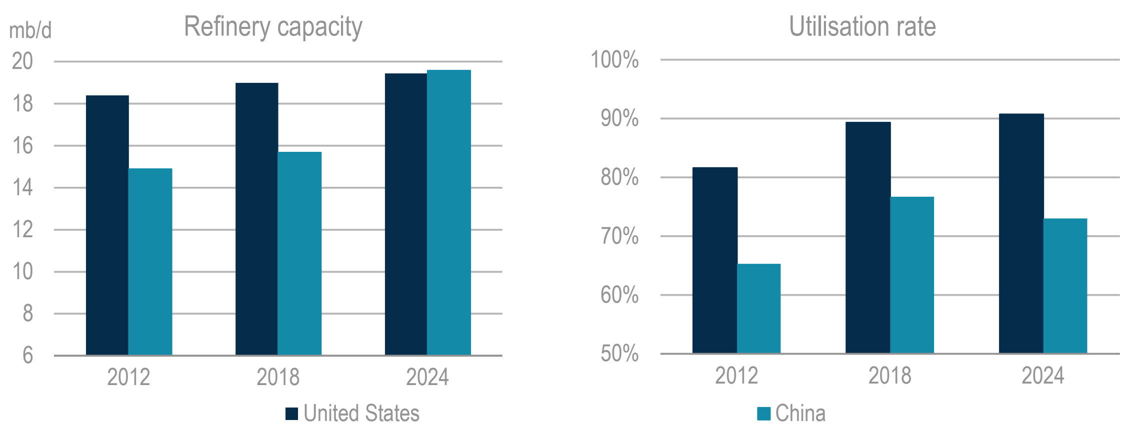
Figure 3.11 Strong growth in petrochemical feedstock demand relative to other products



The three large independent complexes target unusually high yields of olefins and aromatics of between 45-60%, compared to global averages of about 5%-10%. This will be achieved at the expense of reduced transport fuel yields and thanks to integrated crackers and aromatics recovery units. However, transport fuels will still be produced in significant volumes, given the size of the refineries, adding to the oversupply in the domestic market, at a time when demand growth is set to slow. Overall, China's refining capacity additions will be almost double the size of total demand growth.

This will further exacerbate the problem of overcapacity. By 2024, installed capacity will reach the level of the United States at 19 mb/d, barring voluntary or government-mandated shutdowns. Refinery runs are expected to reach only 14 mb/d, however, with excess capacity growing to 5 mb/d from the current 4 mb/d. The government has been trying to address the overcapacity issue by requiring independent refineries to shut down smaller units as part of their crude import quota application. However, no large-scale measures, similar to the ones implemented in the steel or coal industries have been proposed. The government of the Shandong province, which is home to the largest volume of refining capacity, announced a reorganisation and optimisation plan for the sector in November 2018. The plan targets the shutdown of refineries in two stages. By 2022 refineries under 60 kb/d, which altogether account for some 1 mb/d, or a quarter of the province's total capacity, are expected to close permanently. By 2025, refineries under 100 kb/d of capacity, representing a combined 800 kb/d in total, should close permanently. At the same time, the plan includes possibly restoring the closed capacity by building two 600 kb/d and one 400 kb/d petrochemical-oriented refineries. Neither the shutdowns nor the new plans are currently included in our forecast.

Figure 3.12 US and China refining activity



Shandong's refining industry has its roots in the development of the Shengli oil field in the 1960s, currently the fourth-largest producing basin in China. However, its multitude of independent refiners increasingly depend on crude imports. Several ports on the peninsula's southern coast have undergone major expansion to accommodate very large crude carriers (VLCC). Pipelines have been built to connect these ports to the clusters of independent refineries located further inland.

Infrastructure developments in Shandong are the epitome of how China's refining industry is gradually concentrating on the coast. Coastal provinces, including the cities of Shanghai and Tianjin, account for only 16% of China's territory, but 45% of its population, and 73% of its installed refining capacity. All new capacity in our forecast period will be located in the coastal provinces. Given that some 75% of new additions are in the southern coastal provinces of Jiangsu, Zhejiang, Fujian and Guangdong, it is evident that a balancing between the north and south is also being targeted. Currently, the northern provinces, even when coastal capacity is taken separately, account for the larger part of China's total capacity.

Nevertheless, the more established northern part of the country is likely to first see the development of a world-scale downstream hub, similar to Europe's Amsterdam-Rotterdam-Antwerp, or the US Gulf Coast. This could be around the Bohai Bay Rim, which skirts the peninsulas of Shandong and Liaoning, and the coastline of Hebei, including the Tianjin mega-city.

In many ways, the Bohai Bay Rim could become the equivalent of the US Gulf Coast, given the concentration of downstream infrastructure. The two regions command similar levels of importance for their respective countries' downstream infrastructure. The share of the Bohai Bay Rim in total Chinese refining capacity is about 43%, and will increase to 48% in 2024, compared to the US Gulf Coast's 49%. Both areas are relatively compact, with similar land and maritime distances between the marginal points.

The key differences are, of course, in the drivers of the expansion. The US Gulf Coast owes its existence to its proximity to crude import flows from Latin America and the Middle East. Its recent dynamism lies in domestic oil supply growth: its refining and petrochemical sector benefits from local crude oil and natural gas liquids (NGL), and exports products to domestic and international markets. Bohai Bay Rim, while accounting for a third of total oil production in China, is 75% dependent on imported crude oil. While low on local resources, the area boasts a key factor for future growth: compared to the US Gulf Coast's 33 million inhabitants, China's Bohai Bay Rim has a population of 235 million. Per capita oil consumption in the United States is higher than China's by a factor of six, but the growth prospects are far more certain in China.

Table 3.4 Two of the world's largest refining hubs: Bohai Bay Rim vs US Gulf Coast

	Bohai Bay Rim	US Gulf Coast
Country	China	US
Regions	Liaoning, Hebei, Tianjin, Shandong	Texas, Louisiana
Land stretch, km	1 300	900
Maritime stretch	2 days	2 days
Population, million	235	33
as % of country total	17%	10%
2018 refining capacity, mb/d	6.8	9.2
as % of country total	43%	49%
2018 refining throughput, mb/d	4.9	8.6
as % of country total	40%	51%
2024 refining capacity, mb/d	7.9	9.6
2018 crude oil production, mb/d	1.3	6.2
NGL production, mb/d	-	2.1
Natural gas production, bcf/d	0.5	25.4
Crude storage capacity, mb	469	1 388
Trade restrictions	Crude import and product export quota system	Jones Act

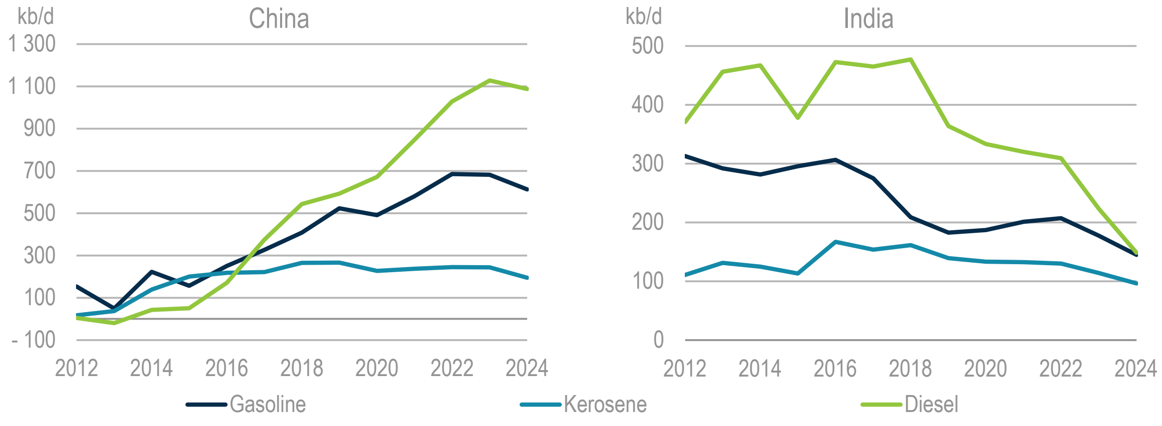
Other Asia

Elsewhere in Asia, the only major new refineries coming online before 2024 are **Malaysia's** 300 kb/d RAPID complex, and **Brunei's** petrochemical refinery operated by the Chinese Hengyi Group, which is expected to start the 150 kb/d first phase in 2019 and add another 280 kb/d in 2023. Expansion projects at existing refineries are under way in Indonesia, Philippines, Viet Nam, Thailand and India, amounting to 1 mb/d. No capacity changes have been announced in OECD Asia.

India's capacity expansion of 0.5 mb/d amounts to only half of its expected demand growth, even when excluding demand for ethane and LPG, the incremental consumption of which is mostly met through increasing imports. This means that in the medium term India's product exports will decrease. Diesel net exports, in particular, will decline from 0.5 mb/d in 2018 to 150 kb/d. However, this slowdown could be temporary and products exports will rebound if and when the 1.2 mb/d Ratnagiri mega-project is complete. It is a joint venture between Indian Oil, Bharat Petroleum and Hindustan Petroleum and international partners Saudi Aramco and Adnoc. We do not expect the refinery to be ready before 2025.

Demand growth is also strong in other developing Asian countries, amounting to 1.3 mb/d. In aggregate, they do not produce enough of almost every single oil product. They have a strong incentive for further refining growth to replace imports, especially as they are mostly located along the crude trade flow from the Middle East or other regions to Northeast Asia. However, the question is whether China intends to increase its refining utilisation rate and become a major oil products exporter. It has already overtaken India in terms of diesel, gasoline and kerosene exports, and has the potential to increase shipments more. If China decides to increase exports, this would put further pressure on the region's refiners.

Figure 3.13 China and India product exports

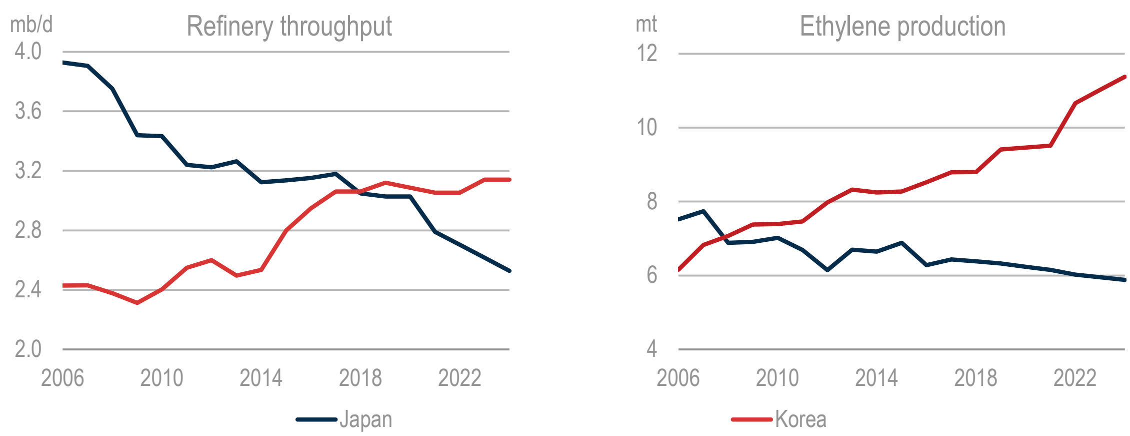


In OECD Asia, developments will diverge between the two largest refiners: Japan and Korea. **Japanese** refiners are more exposed to negative developments at home and in international markets. First, refined products demand will continue to decline, losing another 200 kb/d by 2024. Second, the highly seasonal domestic demand dictates a variable refining activity, with Japanese refiners effectively forced to carry a certain amount of excess capacity that is utilised for only part of the year. While this phenomenon exists everywhere, it is most extreme in Japan, where the ratio of seasonal variation in demand amounts to almost 30% of installed refining capacity (Figure 3.4).

Furthermore, Japan is located further from the growing markets of Asia, compared to **Korea**, which has capitalised on transport fuel exports and is now relying on petrochemical expansion to support activity growth.

This explains why our model's response to the growing competition in Asian markets is to redistribute refining activity towards regions with strong demand and petrochemical industry growth. Japanese refinery throughputs could be reduced by 500 kb/d in the highly competitive market, while Korean refiners see a marginal increase. The role of petrochemical developments is hard to overstate. Not only do they offset the inherent demand seasonality from other sectors, but they also support refinery margins with the more profitable petrochemical operations.

Figure 3.14 Japan and Korea refining and petrochemical developments



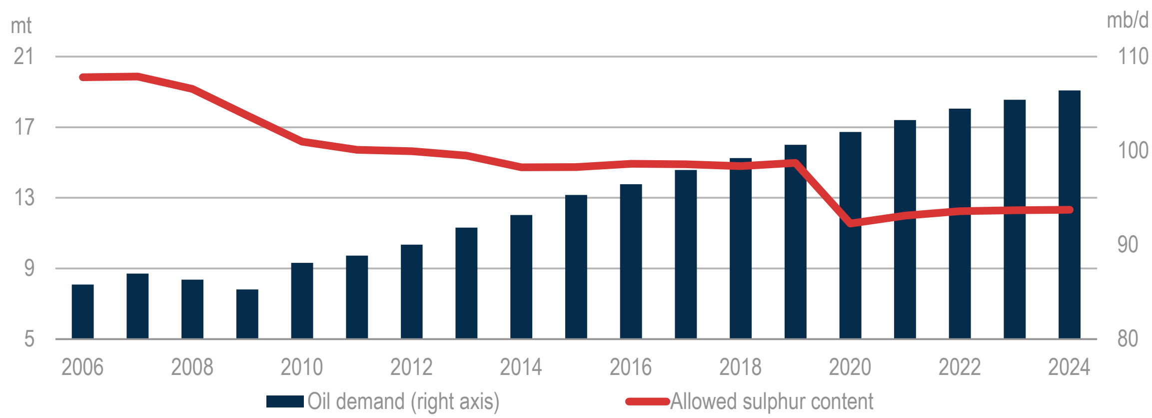
Crude and product quality developments

Since the implementation of ultra-low sulphur transport and heating fuel rules in the developed economies in the early to mid-2000s, progress has slowed somewhat. Consequently, the debate about their impact on global product and crude markets has moved to the background. The 2015 introduction of Northern Europe's Sulphur Emission Control Area (SECA), which limited the sulphur content of bunker fuel to just 0.1%, was practically a non-event, when compared to past specification changes.

In the next few years, several key standards will be introduced, and quality issues have returned to the fore. The United States is expected to fully switch to the Tier 3 regulations, reducing allowed sulphur content in transport fuels to 10 parts per million (ppm). In 2019, China started the nationwide switch to 10 ppm diesel and gasoline. India is expected to do so in 2020. China has also introduced its own emission control areas (ECA) in its coastal waters, where only fuel with a sulphur content of 0.5% can be used. For inland navigation, the bunker fuel sulphur content will be capped at 0.1% from 2020.

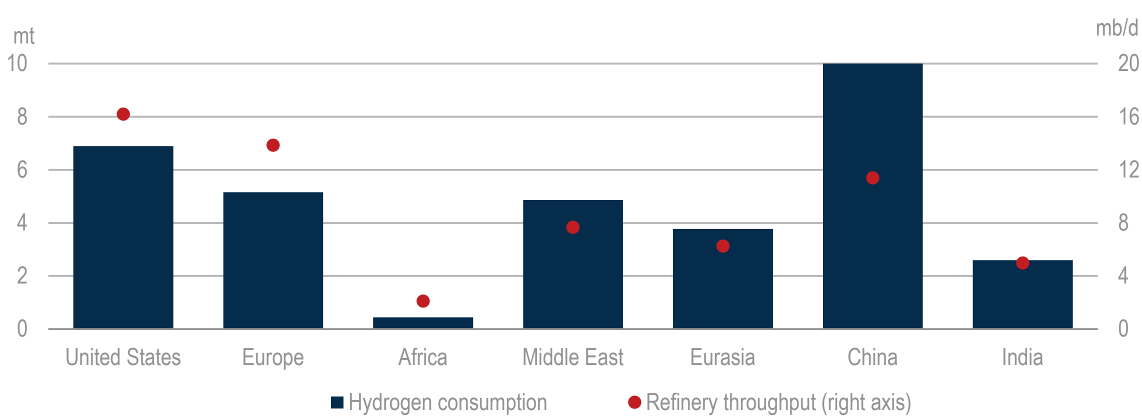
Several African nations have attempted to introduce ultra-low sulphur transport fuels standards, but import logistics have so far frustrated these efforts. The sulphur content in transport fuels can be as high as 500 ppm or even close to 3 500 ppm. Almost every country on the continent needs to import oil products from other regions. For these long voyages, larger product carriers are used, while purchases from individual countries are relatively small. This means that the cargo is usually offloaded in several countries to save on transport costs, which limits the scope for the enforcement of new fuel standards. In July 2018, members of the Economic Community of Western African States decided to jointly implement fuel and vehicle efficiency standards, which is a significant step towards ensuring the enforcement of new specifications. In the meantime, rapid urbanisation means that air quality issues have become a serious problem.

Figure 3.15 Sulphur rejection – as oil demand grows, sulphur tolerance decreases



In 2020, one of the most significant changes to fuel quality standards ever made will be implemented. IMO's new bunker fuel regulations are a major challenge for two industries – oil refining and shipping. The issue is analysed in detail in *Special Feature: IMO: Calm after the storm*. The dramatic step change in 2020 to the allowed sulphur levels in oil products, based on the weighted average of different products, is shown in Figure 3.15. Currently, bunker material is one of the most polluting fuels, with sulphur levels reaching as high as 3.5%, although the average is closer to 2.5%. Only some grades of petroleum coke, used in industrial applications, have higher sulphur levels, of up to 8%. Road transport fuels in developed economies and some major developing countries are typically below 50 ppm (0.005%). This compares to a sulphur content of 1.3% in the average global oil barrel. Refineries have to remove close to 70-75% of the sulphur from crude oil. To meet the requirements of the IMO specification change, this rises to 80%.

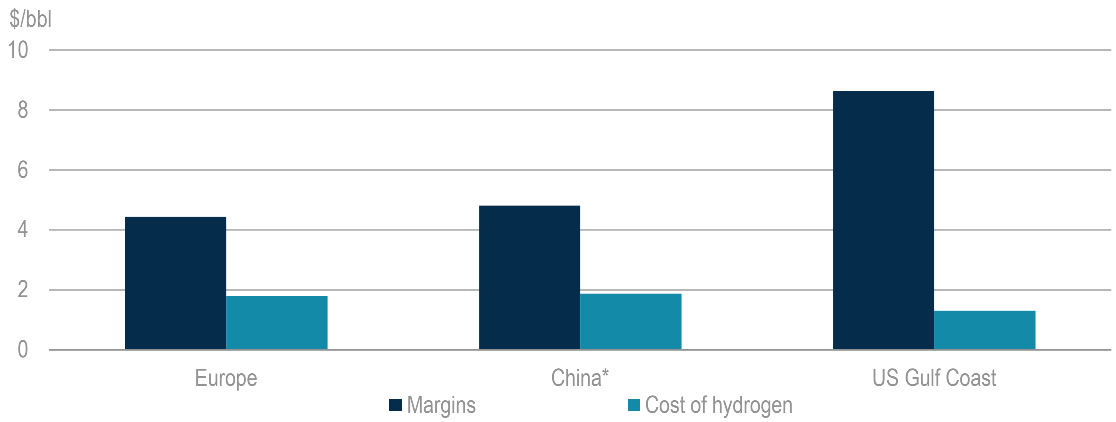
Figure 3.16 Refinery hydrogen requirements by region



Removing sulphur requires expensive equipment e.g. hydrotreatment or hydrocracking installations. Hydrotreatment is not conducted solely for desulphurisation purposes, and in fact it is not a selective process. Denitrification (removal of nitrogen compounds), deoxygenation, demetalation, and aromatics and olefins saturations are other key reactions necessary to improve fuel quality or protect catalysts in downstream processing units. Hydrotreatment requires the presence of hydrogen, which is in part supplied by the refinery's catalytic reformer that produces gasoline blendstocks from naphtha. As a process by-product, this portion of hydrogen comes at a relatively low cost. However, reformer hydrogen yields can typically satisfy only a third of the refinery's demand in hydrogen. The gap has to be filled by hydrogen generation on site, or by purchases from merchant suppliers of industrial gases. The latter is usually only an option in large industrial hubs, e.g. the US Gulf Coast or the Amsterdam-Rotterdam-Antwerp area.

Both on-site generation and merchant hydrogen supplies are typically based on steam reforming of methane, which uses natural gas as feedstock to produce hydrogen and carbon dioxide (CO_2). In China, given the deficit of natural gas, coal gasification or partial oxidation of petroleum coke is more widespread, as well as the reforming of lighter hydrocarbon fractions.

Figure 3.17 Hydrogen costs compared to refining margins

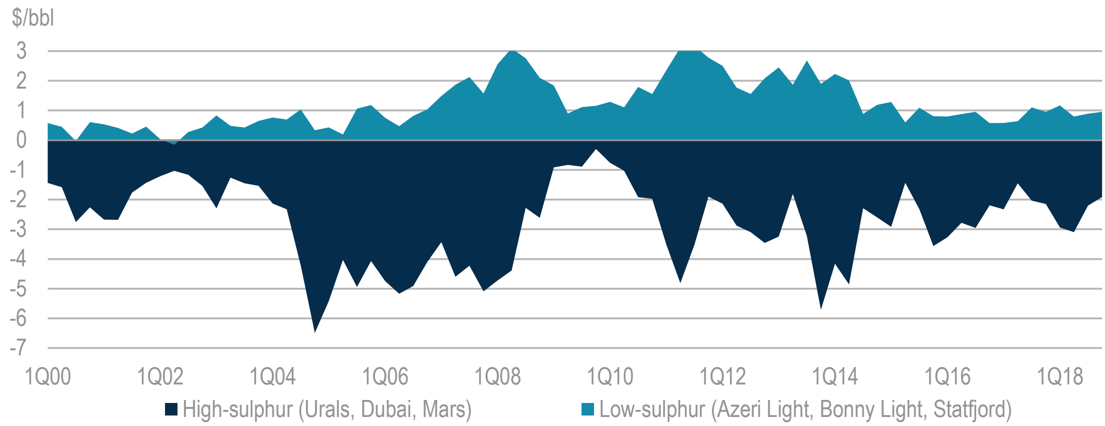


*Singapore margins are used for indicative Chinese refinery economics.

Desulphurisation/hydrotreatment is one area where the tightening fuel specifications affect refining margins, unless end-product prices reflect the costs. Apart from the capital investments required for hydrotreatment and hydrocracking equipment, desulphurisation also means an increase in operating expenses, i.e. energy costs. Natural gas prices vary by region and so does the impact that hydrogen acquisition costs can have on refining margins. US Gulf Coast refiners benefit not only from discounted crude feedstock, but also from an abundance of natural gas, and thus see the lowest hydrogen costs per barrel of oil refined. In Europe, even though refineries use less hydrogen per barrel of oil refined than their US counterparts, higher natural gas prices mean that overall hydrogen costs are higher.

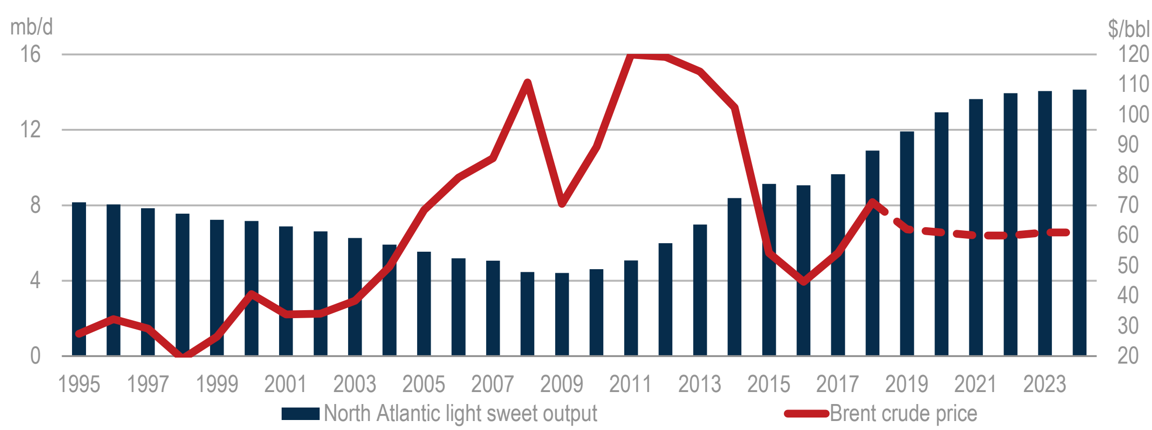
Lack of hydrotreatment capacity and/or high natural gas prices can affect refineries' crude selection. In the oil price cycle of 2004-08, light, sweet oil differentials surged, while heavy, sour crude discounts widened. This was caused by refineries looking to process lower sulphur crude oils to meet the newly introduced ultra-low sulphur transport fuel specifications, particularly in Europe. Higher natural gas prices also played a role. In the United States, in 2007-08, average Henry Hub benchmark was close to $8/ millions British thermal units (mmbtu), more than double than the 2017-18 average of $3/mmbtu.

Figure 3.18 Crude differentials to Brent price



Crude oil markets in that period were not undersupplied. There is anecdotal evidence that heavy/high-sulphur oil grades were being offered on the market with little interest from refiners. Instead, faced with hydrotreatment constraints and high hydrogen costs, refiners were chasing light and low-sulphur barrels. And since the two most important futures contracts, WTI and Brent, are based on light and low-sulphur crudes, eventually the benchmark crude prices were forced to move higher. A strong correlation can be observed between Brent futures and North Atlantic light sweet crude output, which includes US and North Sea conventional and shale crudes. The ramping up of shale output has clearly capped crude oil prices in the last five years. While the forthcoming sulphur specification changes are more significant than ever seen before, one substantial difference is that today it is light, sweet crude oil output that sees most growth.

Figure 3.19 Light sweet crude output and Brent futures

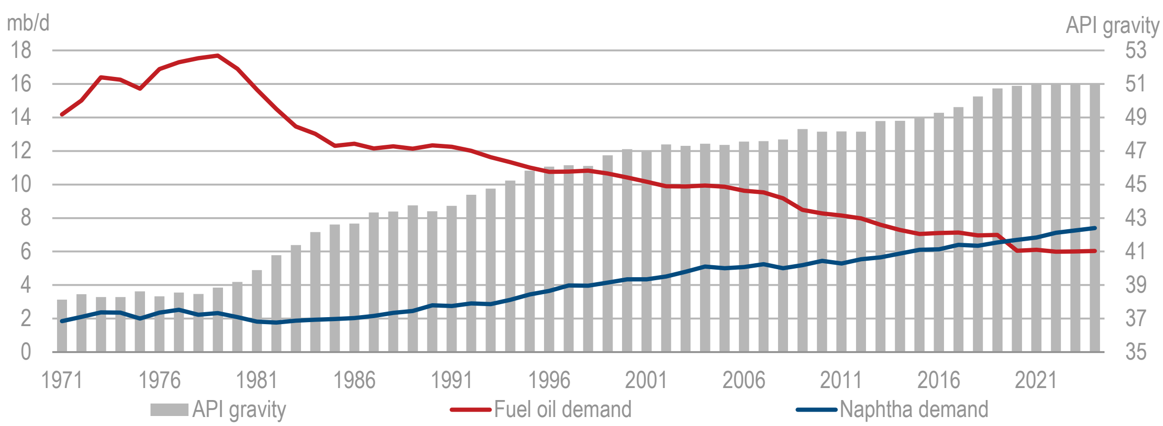


While sulphur is a major quality parameter for both crude oil and products, crude density does not have a direct equivalent for individual oil products. Instead, it is the makeup of the global oil products barrel that defines the density inherently required by the market. World product demand has been getting lighter as fuel oil demand has declined. The weighted average demand gravity is now about 48 API (American Petroleum Institute), while the average gravity of crude oil produced is 33 API. What the end-users eventually consume is closer to the condensate spectrum of the crude oils, than to the prevailing crude output.

In the past, the lightening of the oil demand barrel required investments in cracking capacity to destroy fuel oil and produce lighter products. Now, it is the lighter spectrum of crude oils that is seeing most output growth. The output of heavy and medium crude oils varies for a number of reasons: natural decline, the political situation e.g. Venezuela and Iran, and the Vienna Agreement.

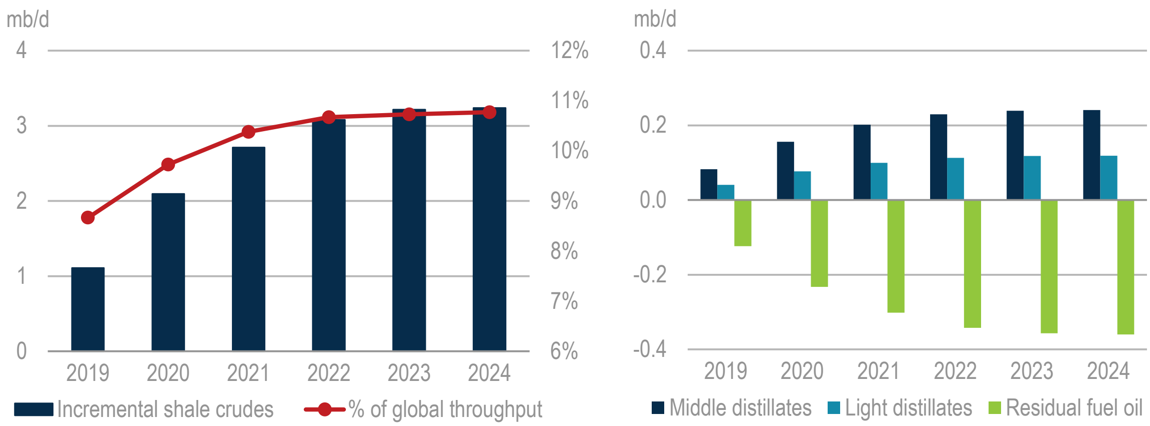
Intuitively, developments in crude grades correspond with the direction of product barrel density. However, this is not welcome news for refiners who have invested in cokers, hydrocrackers or FCC units, even if most of these investments have already been paid back. Eventually, refineries only prefer heavy/sour grades if running them makes more money than running light sweet grades. In the United States, processing discounted light sweet grades was more profitable for refiners, even if it meant that upgrading units were not fully utilised. Now they account for a third of the US Gulf Coast's crude slate. A major independent refiner, Valero, said that more than half of its intake in 2018 was light crude oil.

Figure 3.20 Weighted average density of refined product demand



US shale crude is not a homogenous stream and has different quality grades. Some are very light, closer to condensate, such as Eagle Ford, while others are very similar to conventional WTI, such as Bakken and some Permian grades. Their straight-run yields of middle distillates can actually be higher than that of heavy crudes, while their residual oil yields are lower. Moreover, the sulphur content is much lower, compared to heavier crudes, and in some instances the straight-run residual oil can meet the upcoming 0.5% bunker specification without additional processing. Thus, for simple refiners operating to meet the 2020 IMO rules, the processing of shale grades can actually increase distillate yields and reduce the yield of loss-making high sulphur fuel oil. Of course, what shale grades lack in terms of atmospheric residue yield, compared to an average medium barrel, they make up in terms of light distillate yields. A higher yield of naphtha is what makes shale grades less attractive in the structurally long Atlantic Basin.

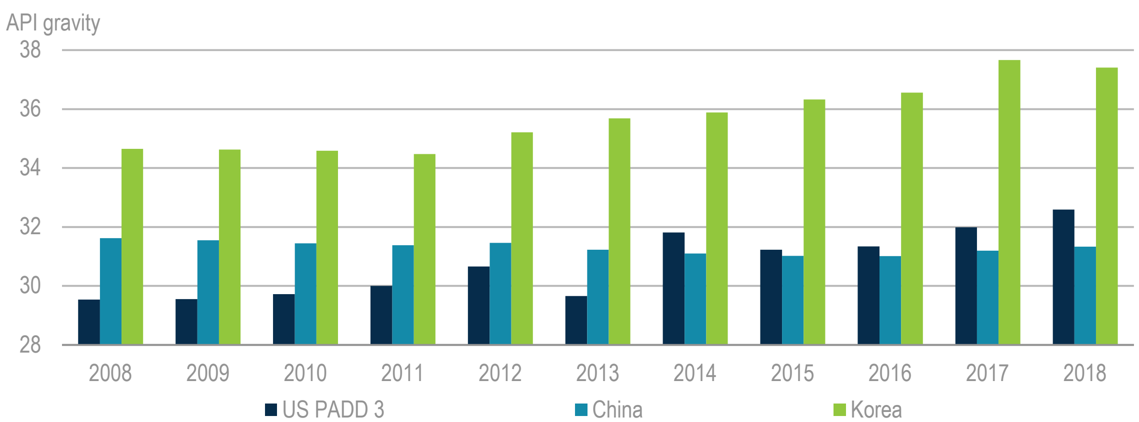
Figure 3.21 The impact of incremental shale crude intake on distillation yields (vs 2018)



Note: Charts show incremental shale crude intake over the forecast period, but the red line on the left chart shows the share of total shale crude in global refining intake.

The situation is different in Asia, though, where naphtha sees the fastest growing demand after ethane. Imports of naphtha will have to increase from 1.6 mb/d in 2018 to 2.3 mb/d in 2024. In general, Asia is structurally short of light ends. The region's total demand for ethane, LPG and naphtha amounted to 8.5 mb/d in 2018, while the production of NGLs, including condensates, was only 1.1 mb/d. The 7.4 mb/d gap has to be covered by imports or by LPG and naphtha from the local refining sector. Refinery naphtha yields in Asia are over 9%, twice as high as in the Atlantic Basin. By 2024, demand for light ends grows to almost 10 mb/d, while local NGL supply stays flat. In addition to this, gasoline demand is also increasing, compared to a decline in the Atlantic Basin.

Figure 3.22 Average API gravity of refinery crude intake

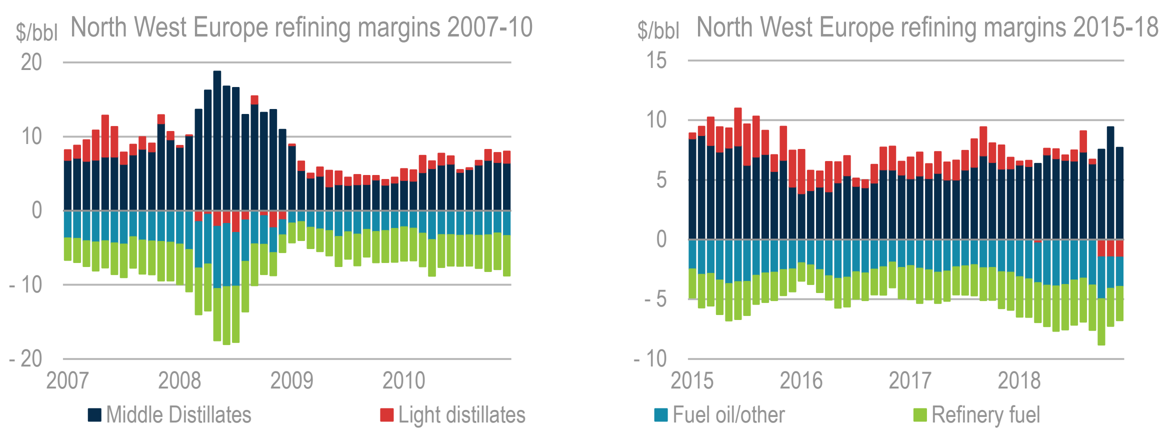


Asian refiners have already become the largest export market for US crude, even as Chinese buying stopped in the second half of 2018. This is despite the voyage length from the United States being twice as long as from the Middle East. Asian refiners have traditionally favoured Middle Eastern grades due to their relative proximity, large volumes of production and the security of long-term contracts. However, Asian buyers are becoming used to operating in a more flexible way. US light crudes are expected to become a key feedstock for Asia's growing refining activity, to provide them with marginal flexibility to increase the yields of light ends, destined for the booming petrochemical industry. A case in point is Korea, where the average gravity of crude intake has increased over the last ten years as petrochemical expansion has become a key priority (Figure 3.14). This is similar to the evolution of the US PADD 3 (primarily Texas and Louisiana) refinery crude slate as it went from refining heavier barrels than China, to a lighter barrel, helped by a large share of gasoline in local demand (Figure 3.7). Overall, the lightening and sweetening of the global demand barrel is going to be accompanied by far less extreme pricing in the benchmark crude oil prices and product differentials, thanks to the growth of light sweet crudes, than in the past.

Structural imbalances in light and middle distillates markets

While Asian demand for ethane, LPG and light distillates, including naphtha and gasoline, is forecast to grow robustly, in the Atlantic Basin light distillates demand is struggling. In 2018, demand for refinery-produced gasoline (excluding blended ethanol), declined by 130 kb/d year-on-year (y-o-y), and is forecast to decline by another 130 kb/d by 2024. The 2018 fall coincided with record high US refinery throughput that is heavily geared towards gasoline production, with yields amounting to 46-48%. While increased processing of shale oil has not had a major impact on US refinery yields, the sheer volume of incremental refinery production began to weigh heavily on light distillate cracks at the end of 2018. This imbalance was further exacerbated by seasonal factors e.g. lower winter demand. In addition, there are also fears of a cyclical slowdown in demand. Even when seasonal and cyclical factors disappear, the structural issue is long-term.

Figure 3.23 Diesel remains the only support for margins when light distillates are weak



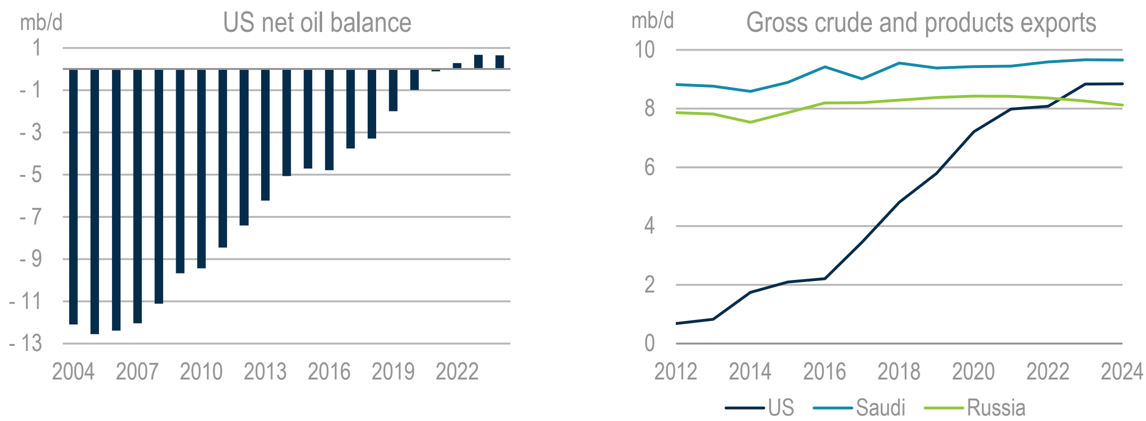
We expect that in 2020, in response to the IMO regulations, US refiners will mobilise and further switch yields between gasoline and diesel, or between gasoline and low-sulphur marine bunkers, through redirecting secondary unit feedstocks to the bunker blending pool. However, increased processing of shale oil may offset some of the yield switch effect. Atlantic Basin light ends will have to be priced competitively to allow exports to East of Suez. This means that the recently observed negative naphtha and even gasoline cracks are likely to persist for some time. This, in turn, implies that middle distillate cracks again will become the sole support for refineries. This was the case in 2008-09, when refineries, in a push to produce more diesel, found themselves with too much gasoline in a stagnating market.

Crude and products trade

One of the most important developments in our forecast to 2024 is that the United States will become a net oil exporter, ending its 75-year import dependency, only about a decade since the start of the shale revolution, and two decades after its net imports reached a record high of 12 mb/d. This would not have been possible without the shale developments. Combined output from the shale (LTO and NGLs) was just under 10 mb/d in 2018 and is expected to approach 15 mb/d in 2024. Were it an independent jurisdiction, US shale could overtake Russia and Saud Arabia total liquids production in 2020.

From 2021, US exports of crude oil *and* products will outweigh imports of crude oil. In 2024, US net product exports will increase by 1.9 mb/d to 4.7 mb/d, while net crude oil imports will decline by 2 mb/d to just under 4 mb/d, resulting in a net surplus of 0.8 mb/d. While this may look relatively modest, in terms of *gross* export outflows, the United States will overtake Russia in 2023, and will be less than 1 mb/d behind the world's top exporter Saudi Arabia.

Figure 3.24 US becomes a net oil exporter and the second-largest gross exporter

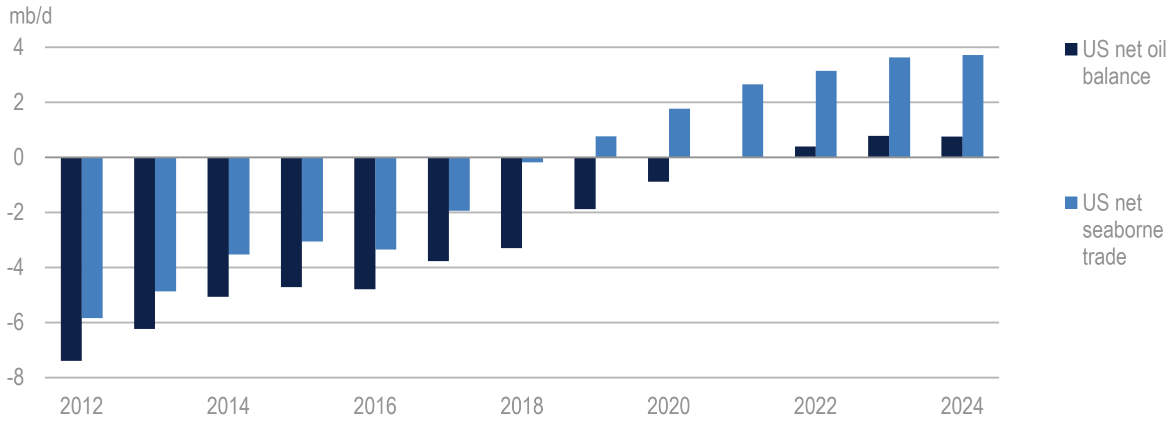


The United States-Canada double act

Developments in US seaborne oil trade (crude and products combined) are even more striking than achieving a net oil exporter status. In addition to the growth in LTO, Canadian oil supplies have played a major role in reducing the United States's dependence on seaborne imports. Canada's crude oil is essentially landlocked due to the absence of major pipeline infrastructure to either the Atlantic or Pacific seaborne markets, and flows to the US Midcontinent and Gulf Coast refining centres instead.

Since 2010, Canadian crude oil shipments to the United States have almost doubled, accounting for half of the total US crude imports in 2018. Consequently, the United States had to source only 4 mb/d out of its 8 mb/d import requirement from seaborne markets. At the same time, the United States exported almost as much in products and crude oil to global markets, which means that its trade with the rest of the world (i.e. excluding landlocked Canadian supplies) was balanced. From 2019, United States will become a net supplier to seaborne markets, ahead of achieving net oil exporter status. In 2024, the United States will be exporting close to 4 mb/d more of oil and products than it will import from seaborne markets, placing it amongst the major net suppliers to international seaborne markets.

Figure 3.25 US oil trade flows



Barrel for barrel

As for crude oil exports, our man view is driven by considerations about the US refinery crude slate. We assume a 0.7 mb/d increase in the volume of LTO processed. Were refiners to replace more of their intake by domestic grades and process all the forecast growth in oil output, leaving no incremental volumes to export, US trade in international markets would slow to just 2 mb/d each for exports and imports. In the absence of a reform of the Jones Act, 2 mb/d of import flows are necessary to supply East Coast (PADD 1) and West Coast (PADD 5) refineries, as inland infrastructure for transporting domestic grades to these refining centres is not expected to develop in the forecast period.

As a consequence of our forecast of US crude output, refinery throughput and Canadian flows, US crude exports and imports to/from seaborne markets will have to be balanced. Therefore, an interesting question arises as to how the global crude trading system is going to accommodate this development. Of course, other countries import and export crude oil, e.g. the UK, Brazil, Australia and several Asian countries, but volumes are lower than in the United States.

In 2018, the US Gulf Coast imported about 2.9 mb/d of crude from seaborne markets and exported 1.8 mb/d. There were 1.3 mb/d of short-haul imports from around the Caribbean, including Mexico, Colombia, Ecuador, and Venezuela. In some cases, short-haul freight can be cheaper than pipeline and rail transport costs for domestic US production, as Gulf Coast refiners operate 7 mb/d of capacity that is mostly well connected to import terminals. Other determinants of crude oil imports for refiners are crude slate optimisation, and specific corporate strategies to integrate upstream and downstream assets, such as for example, the 600 kb/d Motiva refinery, owned by Saudi Aramco.

US Gulf Coast crude exports are expected to double to 3.5 mb/d by 2024 and imports to fall below 2 mb/d. This means that very soon the US Gulf Coast will become a net crude oil export hub. To simultaneously price such large export and import flows is an interesting challenge. Several price indices have been launched recently by various organisations, including Argus, Platts, ICE and CME, and in time a major regional crude price benchmark may emerge in the region.

The logic of simultaneous imports and exports is supported by so-called triangle arbitrage, when vessels are laden on two out of three legs: for instance, they transport crude from the US Gulf Coast to Asia, then ballast to the Middle East and finally, sail fully laden from the Middle East to the US Gulf

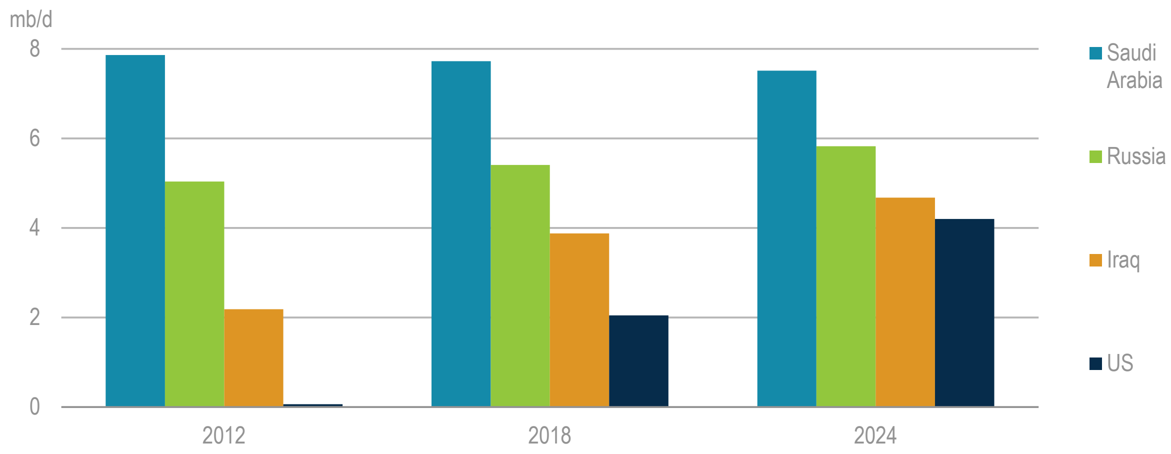
Coast. This could in time make global physical trade flows more interconnected and more similar to product trade, where the same region imports and exports different types of products (for example, Europe importing diesel and exporting gasoline).

Crude trade developments

Export flows

In 2018, the United States exported 2.1 mb/d of crude oil. This was more than any non-Middle Eastern OPEC member. During our forecast period, crude exports will double to 4.2 mb/d, turning the country into the fourth-largest supplier of crude oil to international markets, behind Saudi Arabia, Russia and Iraq. There is the potential to add infrastructure to enable even more exports if higher prices allow domestic crude output to grow faster than our base case, given the already higher utilisation rates of domestic refineries and longer lead times needed for refinery expansions.

Figure 3.26 Top four gross crude exporters between 2012 and 2024

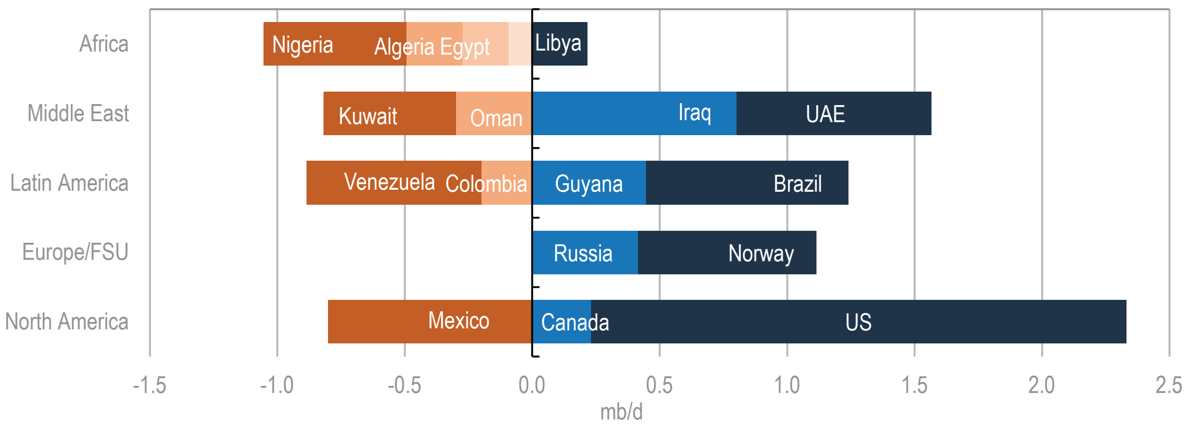


While the United States is growing impressively, Canadian export growth slows and Mexico's declines. After rising by an impressive 1.5 mb/d in the past six years, Canada's exports will increase by only 0.3 mb/d to 2024 as a result of takeaway capacity constraints. Mexico's exports will decline by 0.8 mb/d as output growth lags behind the recovery in refining activity. The North American region's combined net crude oil balance, currently in deficit by 1.6 mb/d, will be neutral in 2024.

The second-largest source of growth of exports is Brazil with an incremental 0.8 mb/d of crude. Other Latin American countries, e.g. Venezuela, Colombia and Ecuador, experience declines, but these are offset by Brazil's incremental volumes. A rapid ramp-up in Guyana's offshore developments means that the region will see a net growth of 0.5 mb/d in crude exports.

The third largest export volume growth comes from Norway, the only net crude exporter in Europe, which will see growth of 0.7 mb/d. With volumes reaching 1.9 mb/d in 2024, Norway will overtake Kazakhstan, Kuwait and Brazil and export more crude oil than any African producer. In Africa, exports will decline by 1 mb/d, driven by increased refinery intake (0.7 mb/d). FSU crude exports will increase by a relatively modest 0.3 mb/d.

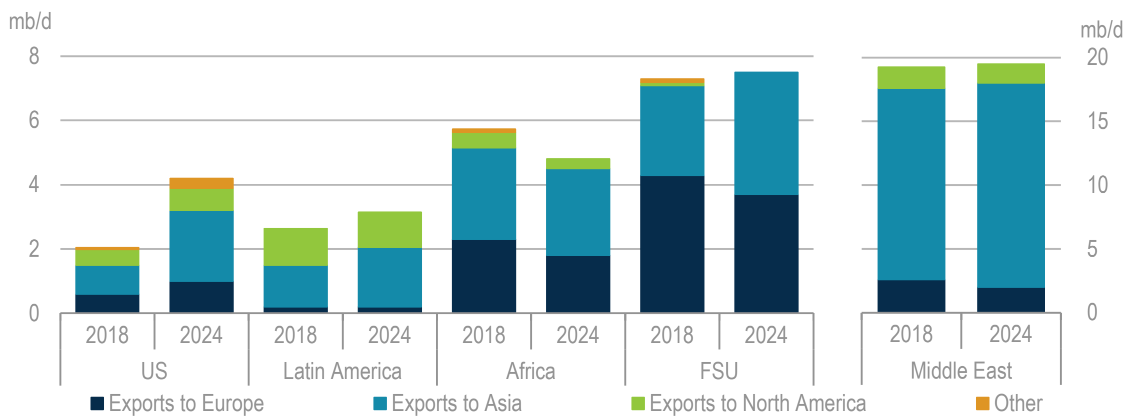
Figure 3.27 Largest changes in crude exports, 2018-24



West to East

All major crude exporters, except those in Africa, are expected to increase flows to Asia. Asia was already the largest market for US crude exports in 2018, having taken 0.9 mb/d, and volumes are expected to more than double to 2.2 mb/d. European refiners will increase purchases of US crudes by 0.4 mb/d, reaching 1 mb/d, while exports to Canada and Mexico will rise too.

Figure 3.28 Crude flows by source and destination



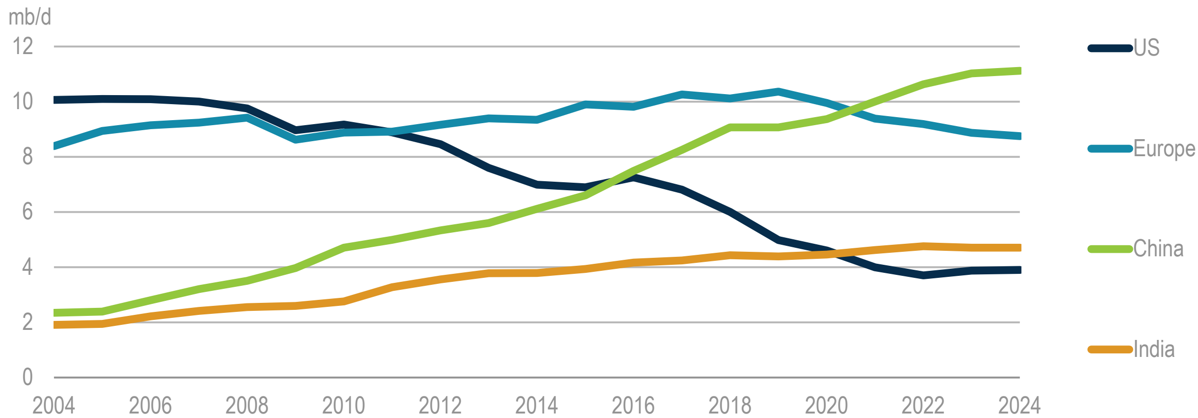
Note: US is both an exporter and importer of crude oil. The green bar for North America as an export destination mostly represents US imports from the regions shown.

Growing shares of both Latin American and FSU exports will be directed towards Asian markets, at the expense of flows to North America and Europe. Africa's exports to Asia decline somewhat and even more so shipments to Europe. The Middle East will reduce shipments to Europe and, marginally, to the United States, but increase exports to Asia.

Import flows

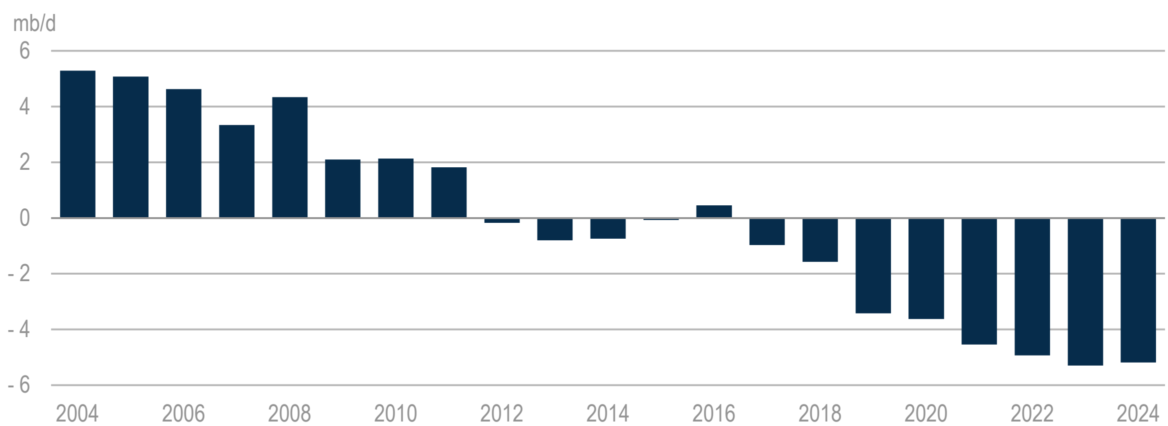
The ranking of crude importers will soon see some interesting changes. China, having overtaken the United States as the world's largest net crude importer in 2017, is on track to overtake Europe in 2022. In the same year, US net crude imports will fall below India's. Europe's dependency declines to 8.7 mb/d in 2024 from 10 mb/d in 2018 thanks to higher Norwegian production, but also due to lower refining activity. Asia's net crude shortage surges 3.4 mb/d to 26 mb/d. Import requirements increase primarily for China, up by 2.6 mb/d, and also for Indonesia, Malaysia and India, which increase by 0.3-0.4 mb/d each.

Figure 3.29 Largest net crude oil importers



China enters uncharted territory in 2024 when import requirements based on our local supply and refinery throughput forecast exceed 11 mb/d. The United States has never imported as much on an annual basis, and Europe's net imports were close to 12 mb/d for only a couple of years in the late 1970s. However, not all of China's crude imports are for domestic consumption: net exports of refined products increase by 1.1 mb/d to 1.7 mb/d.

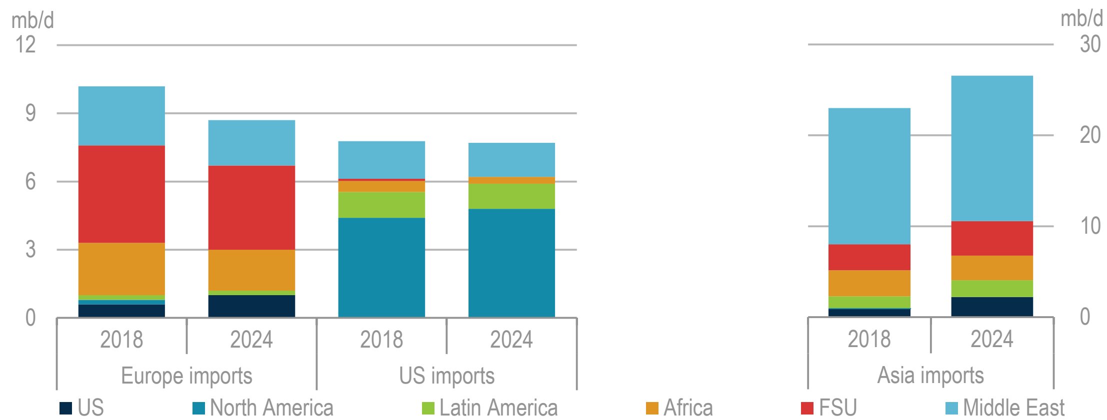
Figure 3.30 East of Suez crude oil balance



Growing Chinese net imports are a major factor in the East of Suez crude balances (Middle East and Asia combined), which are short by 6 mb/d at the end of our forecast. This means that even if Middle East producers direct all their exports to Asian refiners, the latter would need to source another 6 mb/d from other regions. Diversification of crude supplies outside the Middle East is no longer a choice, but a necessity to fill the growing Asian need for crude.

With increased flows of US, Latin American and FSU supplies, Asian importers nominally reduce their reliance on Middle East producers from 65% to 60%. Even so, they import 1 mb/d more from the region in 2024 compared to 2018. The FSU remains Europe's largest crude source, accounting for 42% of the total, and its share remains stable. For the United States, it is Canadian and, to a smaller extent, Mexican imports that provide the bulk of its crude import requirements, close to 60%.

Figure 3.31 Crude flows by importer and by source



Note: US is both an exporter and importer of crude oil. North America as an import destination represents US imports from both Canada and Mexico and from other regions.

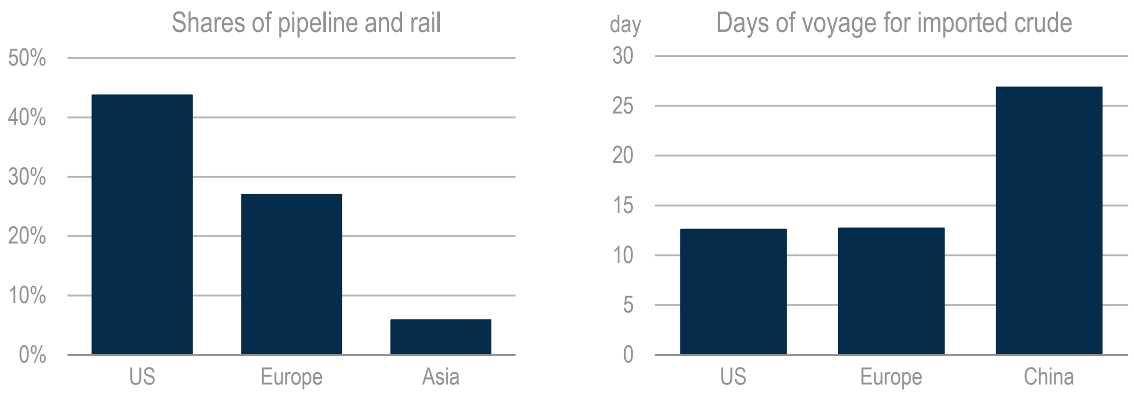
Will Asia ever have a working crude benchmark?

The two major crude futures benchmarks, WTI and Brent, were essentially developed to discover prices in important consuming regions, although they are explicitly tied to locally produced grades. In an importing region, there is always a significant degree of buying interest from consumers, which supports trading volume and market depth. As both the United States and Europe currently are net crude oil importers, these benchmarks define the attractiveness of the two regions for available export barrels. With growing US shale output and Canadian imports, the WTI Cushing market flipped into a discount to Brent and started pricing to export, which prompted seaborne US crude prices, such as Gulf of Mexico grades, to align themselves with Brent. The lack of pipeline infrastructure out of Cushing to the Gulf Coast refining districts was an important factor. Brent futures, have thus become the basis for Atlantic Basin seaborne crude grades, and are also gradually pricing in an excess crude market.

Asian imports are already close to 23 mb/d, more than Europe's 10 mb/d, and far above the US's levels. Why is no equivalent Asian benchmark emerging? Shanghai crude futures, priced in Chinese yuan, were launched in March 2018. However, despite the growth in trade volumes, they are still a long way from becoming an accepted benchmark for Asian crude trade. At the same time, it is unlikely that another benchmark can be introduced to take up the role. There are significant differences between Asian markets and North America and Europe:

- Consumer mentality: With no significant sources of local supplies, Asia imports 78% of its crude requirement. While Europe's import dependence is around the same level, Asian volumes are more than double Europe's. Security of supply is a major concern, and consumers are interested in long-term contracts, which narrow the scope for spot trading.
- Logistics: The nearest sources of crude oil are not close. A voyage from the Middle East to North Asia takes 27-30 days, longer than to Europe. Taking into account pipeline imports, the average number of days on water for imports into the United States and Europe was 12 days, compared to 27 days for China. This is another constraint for active spot trading, unless major regional storage hubs develop to support it. This also explains the viability of free on board (FOB) benchmarks such as Brent and Dubai.
- Currency: Brent and WTI are both priced in US dollars, while Shanghai futures are priced in Chinese yuan. Even if the yuan becomes fully convertible, or there is a new Asian contract proposed in US dollars, it would still face acceptance problems. Asian countries are far more diverse economically, politically and financially, than Europe and North America. The introduction of the euro in 2000 removed the issue of national exchange rates differences to the US dollar. In Asia, unsynchronised fluctuations in national currency exchange rates versus the contract currency may affect holdings of the contract, effectively becoming an additional risk factor on top of normal market fundamentals.

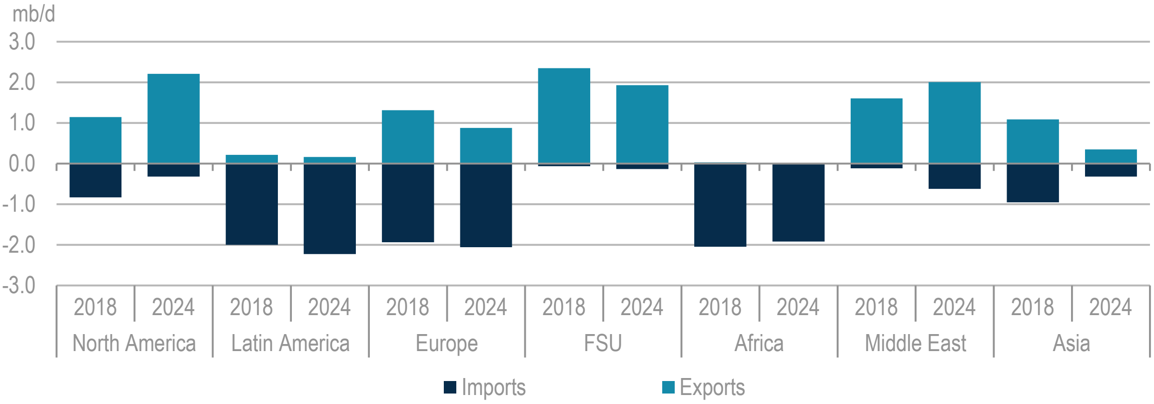
Figure 3.32 Crude logistics



Product trade developments

Africa has become the world's largest importer of refined products on a net basis, as demand growth has coincided with deteriorating refining activity. This is not expected to change materially over the forecast period. Despite 0.8 mb/d of new refining capacity coming online by 2024, African net product imports barely decline. The United States, the Middle East and China are the principal regions where exports of refined products are forecast to grow. The FSU's refined product exports will decline, and imports into Latin America and Europe will increase.

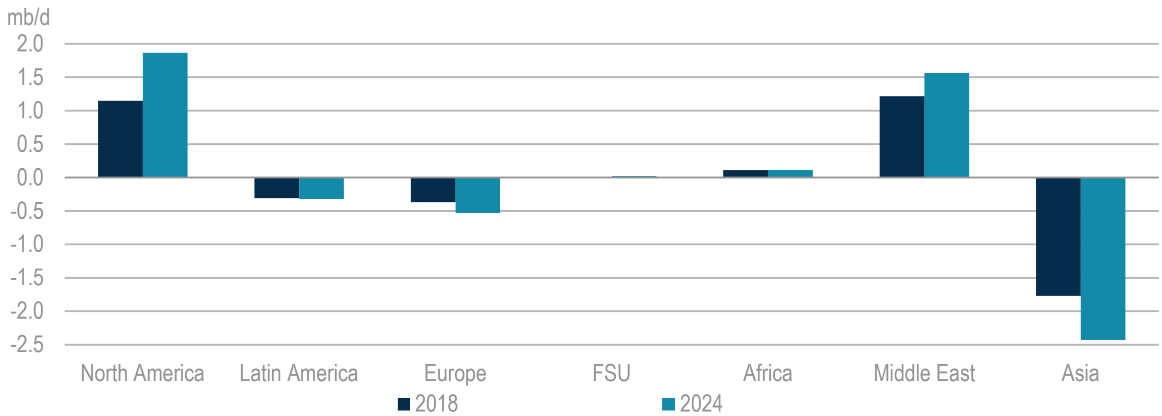
Figure 3.33 Refined product balances (excluding LPG/ethane)



Ethane/LPG: gas liquids lead oil products trade

Asian requirements for LPG and ethane imports, reaching 2.4 mb/d in 2024, overtake Europe's thirst for middle distillates in terms of volumes and top the league of products import markets. In 2024, the world's largest product flow will not be a refined product, but LPG. US LPG exports to Asian markets will likely represent the single largest directional product trade, rising from 0.8 mb/d in 2018 to 1.2 mb/d. In 2024, the United States is also expected to export 0.4 mb/d of ethane to consumers in Canada, Europe and Asia. LPG exports from the Middle East will also increase, by 0.4 mb/d, destined mostly for Asian consumers. China will start importing ethane in 2021, and reach 130 kb/d in 2024. Its LPG imports will increase by 300 kb/d, and India's will grow by 200 kb/d.

Figure 3.34 Ethane/LPG regional balances

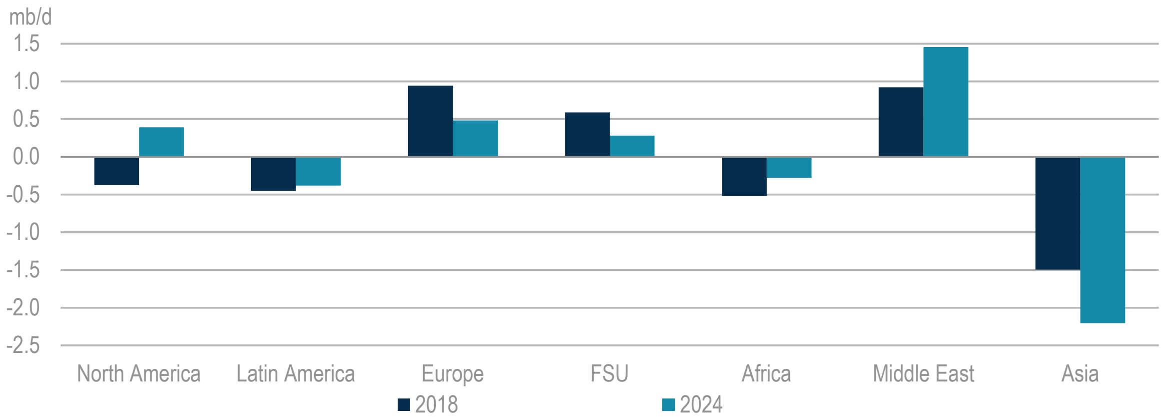


Gasoline/naphtha: petrochemicals drive naphtha demand, gasoline in the back seat

Asia's thirst for light hydrocarbons does not end with NGLs. The region already is the largest net importer of light distillates (primarily naphtha), and its shortage increases even more by 2024, reaching 2.2 mb/d from today's 1.5 mb/d. The largest exporter of light distillates, the Middle East, is currently sending mostly naphtha to Asian petrochemical producers. In the forecast period, however, thanks to refinery upgrades, gasoline net exports come into the equation and are mostly directed towards Africa. Asian consumers will have to fill the gap in naphtha supplies from the Atlantic Basin.

Africa's shortage of gasoline is expected to decrease as new refineries come online. Latin America becomes the largest regional importer of gasoline. At the same time, North America turns into a net exporter. The United States is already a net exporter of gasoline, but Mexico's shortages have so far kept the regional balance in the red. With expected improvements in Mexican refining, imports are expected to decline.

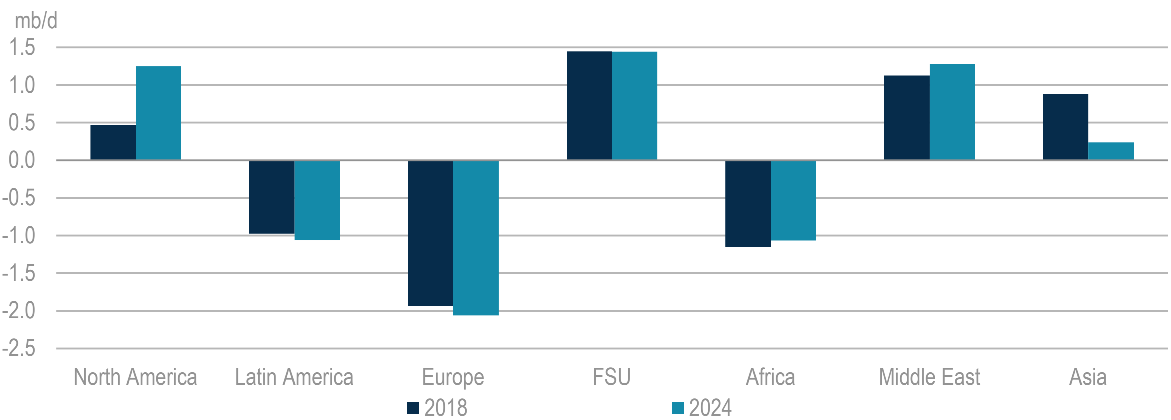
Figure 3.35 Gasoline/naphtha regioal balances



Diesel/kerosene: IMO accelerates US exports, culls Asian surplus

While marine distillates are expected to become one of the key solutions to the challenges posed by the IMO's new bunker fuel specifications coming into force in 2020, regional diesel/kerosene balances remain largely unchanged over the forecast period as refiners worldwide maximise middle distillates yields. In Europe, the net shortage will increase by only 150 kb/d, but this pushes the total beyond the 2 mb/d mark. A slowdown in the road transport sector helps minimise the impact of the bunker fuel switch. Latin America and Africa will both continue to see around 1 mb/d of net imports. Net exports from the FSU will not change despite a decline in refining volumes. The United States and the Middle East will increase diesel output and cement their role as key suppliers to the global market, especially when Asian diesel and kerosene exports to other regions are likely to decrease, being used instead to meet bunkering needs in the region's hubs.

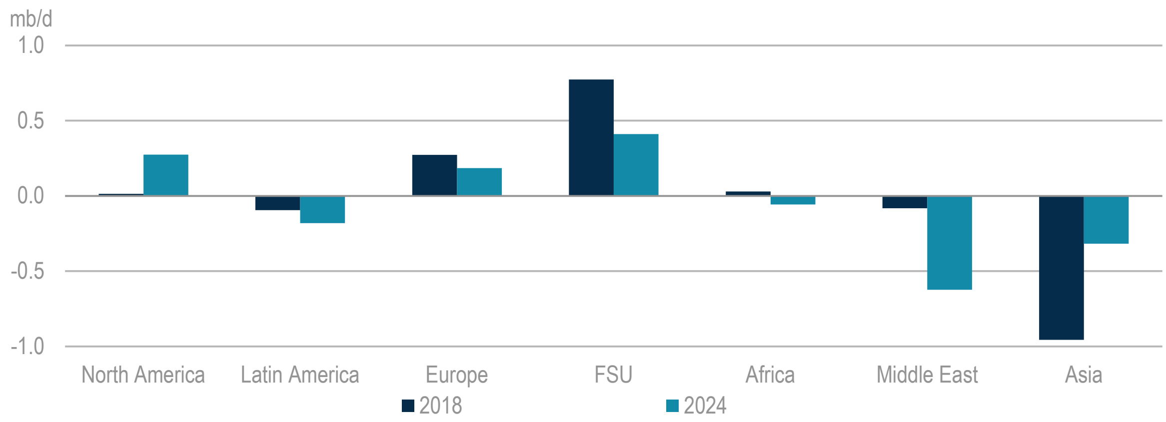
Figure 3.36 Diesel/kerosene regional balances



Fuel oil: a disappearing act?

While Russian refiners will further reduce their high-sulphur fuel oil yields, halving FSU exports as a result, we expect that North American refiners will start to offer very low sulphur fuel oil, derived from light domestic grades, to global markets. The Middle East's fuel oil imports will rise as the power generation sector soaks up large volumes of discounted fuel. Asian imports will be slashed as fuel oil loses market share to distillate bunkers. Europe's fuel oil excess will be both high sulphur, which can be exported for scrubber or power generation use elsewhere, and low sulphur, for bunkering needs, as crude intake remains relatively low sulphur in Northwest Europe in particular.

Figure 3.37 Fuel oil regional balances



4. SPECIAL FEATURE: IMO 2020, CALM AFTER THE STORM

Highlights

- The marine fuel landscape will alter dramatically in 2020 as new International Maritime Organisation (IMO) fuel quality rules are implemented. In our base case, demand for high sulphur fuel oil (HSFO), the main vessel fuel since the 1960’s, will fall from 3.5 million barrels/day (mb/d) to 1.4 mb/d. Demand for marine gasoil (MGO) increases from 900 thousand barrels per day (kb/d) to 2 mb/d. A new fuel called very low sulphur fuel oil (VLSFO) reaches 1 mb/d in 2020, but initial uptake is limited by the availability of blending material and compatibility issues.
- These challenges are overcome quickly. VLSFO is the fastest growing marine fuel in 2020-24, rising from 1 mb/d in 2020 to 1.8 mb/d, due to its price advantage versus gasoil. MGO demand reaches a peak in 2020 then eases to 1.8 mb/d by 2024, keeping a solid base of usage in smaller vessels and due to its wide availability.
- In 2020, some vessels will be non-compliant with the IMO rules due to lack of availability of VLSFO and higher costs. This represents about 700 kb/d of demand for HSFO (16% of bunker demand). However, non-compliance falls sharply to 300 kb/d in 2021 and 60 kb/d by 2024.
- Overall demand for bunker fuel stalls in 2020 before returning to growth at a rate of 1.8% per year. Demand growth for diesel and gasoil from inland consumers slows to its weakest pace in 20 years as prices increase. Slower growth, alongside higher prices, will help balance the gasoil market during 2019-24.
- Gasoil prices could increase by one fifth in 2020 under our base case. However, if compliance is strictly enforced in 2020, gasoil prices could more than double. Fuel oil prices fall sharply, triggering higher usage in the power and cement industries.
- Refiners raise gasoil output by 2.3 mb/d (+8%) between 2018 and 2024, thanks to investments in new units and yield changes, but the market remains tight throughout. Although fuel oil production falls by 900 kb/d (-14%), it remains in surplus until 2023.
- Demand for HSFO stays above 1 mb/d to 2024, helped by non-compliance and a rapid uptake in scrubber installations. The number of installed scrubbers reaches nearly 5 200 by end-2024. Scrubber retrofits slow markedly in 2021 as refiners increase gasoil output. Demand for HSFO from ships with scrubbers stabilises at around 1 mb/d in 2022.
- Liquefied natural gas (LNG) makes a small contribution to the bunker mix. In 2018, less than 10 kb/d was used in ships, and although this rises sharply by 2024 to 90 kb/d, it is still very modest. Most of the investment is in the cruise vessel and container segments.

Global overview

From January 2020, ships will have to use marine fuel with sulphur content below 0.5%, a big reduction from the current 3.5% limit. While the global average sulphur content in bunker fuel today is closer to 2.5%, this still implies a five-fold decrease in the effective sulphur dioxide emissions ceiling applied to ships sailing in international waters. Ship owners are free to choose how to comply. They can continue to use HSFO in conjunction with exhaust gas cleaning systems, known as scrubbers. Alternatively, they can burn oil products that contain less sulphur, e.g. marine gasoil (MGO), or a new product with a maximum sulphur level of 0.5% called very low sulphur fuel oil (VLSFO). Finally, they can use liquefied natural gas (LNG). Vessels sailing in the emission control areas (ECAs) of Northwest Europe and North America will continue to be subject to a 0.1% sulphur limit. We estimate that 3.5 mb/d of bunker fuel demand will be impacted by these changes in 2020, easily the largest ever transformation in the oil products market. The regulation will have a huge impact on the refining industry, which will need to adapt to a new demand landscape where fuel oil demand drops sharply by 60% in 2020 at the same time as marine gasoil consumption doubles and the new VLSFO is introduced. Gasoil prices will be higher and thus they will curb growth in marine bunker demand and demand from onshore users e.g. car and truck transportation, manufacturing, and heating.

Refiners will largely be able to produce the right oil products, helped by significant investments in new units and yield switches. However, there will be challenges. We currently expect an average 200 kb/d deficit in gasoil markets worldwide during 2020-24. This is small in the context of the 30 mb/d global gasoil market, although additional investments in new refining units are needed. Sourcing optimum crude oils as well as the 800-900 kb/d of low sulphur blending materials we have identified in our balances will no doubt prove a significant challenge. There is also the matter of finding enough storage to blend different marine fuel specifications and to store unwanted fuel oil. For shippers, availability will be their main concern, as certain fuels may not be found in specific locations. For those who have made the leap, the behaviour of scrubber equipment on large vessels remains largely untested at the time of writing. In the following section, we separate bunker fuels into three main groups: HSFO, MGO, and VLSFO, which itself includes straight-run fuel oil, hydrofined fuel oil, and MGO and HSFO.

Table 4.1 Summary of 2019-24 marine demand, refining forecasts (mb/d)

	2018	2019	2020	2021	2022	2023	2024
1. Demand							
(A) Marine high sulphur fuel oil	3.4	3.5	1.4	1.2	1.1	1.1	1.1
Of which: Scrubbers	0.2	0.3	0.7	0.9	1.0	1.0	1.0
Of which: Non-compliance	-	-	0.7	0.3	0.1	0.1	0.1
(B) Very low sulphur fuel oil	0.0	0.0	1.0	1.4	1.6	1.7	1.8
(C) Marine gasoil	0.9	0.9	2.0	1.9	1.9	1.8	1.8
(D) Inland fuel oil	3.6	3.5	3.8	4.0	4.0	4.0	4.0
(E) Inland gasoil	27.7	27.9	27.9	28.0	28.1	28.2	28.4
2. Refining/Supply							
(F) Gasoil supply	28.5	29.0	29.8	30.1	30.7	30.8	30.8
(G) Low sulphur fuel oil blended in VLSFO	0.0	0.0	0.9	0.9	0.9	0.9	0.9
(H) Fuel oil output	7.0	6.6	6.3	6.2	6.2	6.1	6.0
(I = F + G - B - C - E) Gasoil Balance	**-0.1**	**+0.2**	**-0.2**	**-0.3**	**-0.0**	**-0.0**	**-0.2**
(J = H - A - D - G) Fuel Oil Balance	**0.0**	**-0.4**	**+0.3**	**+0.1**	**+0.2**	**+0.0**	**-0.0**

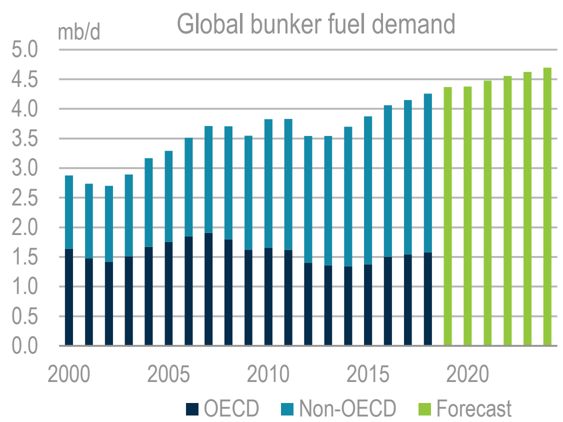
Note: Gasoil supply includes refinery output, biodiesel and gas-to-liquids output.

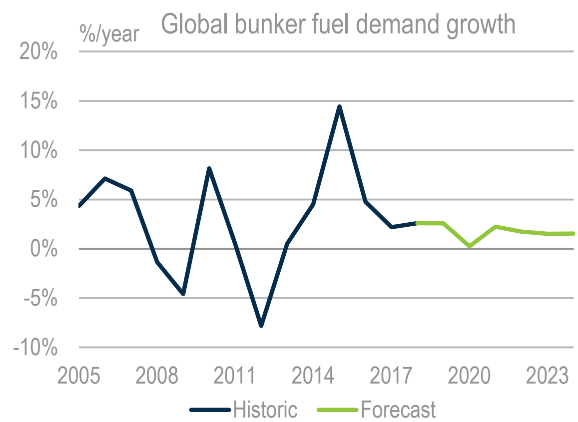
Bunker demand growth to slow

Demand for bunker fuel has grown by 2.5% per annum on average over the last ten years, reflecting expanding global trade. In 2019, demand will grow by 2.6% to a new record of 4.4 mb/d, unless trade disputes deepen. A slowdown is likely to materialise in 2020 when we expect growth of just 0.3%, the lowest since 2012, as vessel owners face rising fuel prices. For 2021-24, our central assumption is that bunker demand continues to grow, but at just 1.8% per year.

The new IMO regulations will force ship operators to adapt their modus operandi. They will have to choose between investments, in the form of scrubbers costing millions of dollars, or accept higher operational costs by switching to more expensive fuels such as MGO or VLSFO. Under most scenarios, unless the headline oil price falls sharply, and the Brent crude oil forward curve on which the research for *Oil 2019* is based remains close to $60 (United States dollars)/ barrel (bbl) until 2024, the industry's average fuel costs are likely to increase sharply in 2020. This is likely to impact demand for shipping by incentivising operators to cut activity. The marine fuel sector is often quick to reflect movements in the oil price as well as conditions in the overall economy. For example, bunker demand grew at a reduced pace of 1.2% during the high oil price era of 2010-14.

Figure 4.1 Historical, forecast bunker fuel demand





The adjustment to lower growth from 2020 will likely occur in all major trading regions, although the slowdown will be more marked in non-OECD countries. OECD countries, meanwhile, could see a fall-off in bunker activity during 2020 followed by strong growth in 2021-22.

Our 2020 fuel switching scenario

Demand for HSFO from the bunker sector is expected to fall from 3.5 mb/d in 2019 to 1.4 mb/d in 2020, a reduction of 2.1 mb/d in just one year. MGO demand, by contrast, will go up 1.1 mb/d to 2 mb/d while VLSFO, composed of both fuel oil and gasoil, will go from near zero consumption to about 1 mb/d in 2020. We have derived these figures by looking at fuel availability globally. In our model, we have split the world between OECD, non-OECD major and non-OECD small countries, based on 2019 demand estimates for each region, and made the following assumptions:

- In OECD countries, 40% of 2019's fuel oil demand switches to MGO in 2020, 30% to VLSFO and the remaining 30% stays in fuel oil.

- In non-OECD major countries, 40% of 2019's fuel oil demand remains as we expect more non-compliance with the IMO rules. In those countries, 30% of 2019's demand switches to MGO and 30% to VLSFO.
- In non-OECD small countries, half of 2019's demand stays in fuel oil and half switches to marine gasoil. We do not expect any demand for VLSFO from these countries initially.

Table 4.2 Our 2020 marine demand forecast split by fuel type (mb/d)

Fuel	2019	2020	2019-20 (mb/d)	2019-20 (%)
Fuel oil	3.5	1.4	-2.1	-60%
Of which: Scrubbers	0.3	0.7	+0.3	+99%
Of which: Non-compliance	-	0.7	+0.7	+100%
Very low sulphur fuel oil	0.0	1.0	+1.0	+100%
Marine gasoil	0.9	2.0	+1.1	+122%
Total	**4.4**	**4.4**	**+0.01**	**+0.3%**

The quantity of VLSFO produced will initially be limited by the availability of low sulphur blending materials, which we estimate at around 900 kb/d in 2020. Some shipping companies may be reluctant to adopt a new fuel immediately until they have confidence that it will be easily available in port. In addition, there is a risk that a new 0.5% sulphur bunker fuel resulting from blending may not be stable enough or compatible with similar grades produced in other locations. Therefore, in 2020, it is likely that many shipping companies will prefer to use MGO instead of VLSFO.

We estimate that there will be 4 000 scrubbers installed on large vessels by end-2020. They will consume 680 kb/d of fuel oil on average throughout the year, up from 340 kb/d in 2019. It is also likely that vessels operating in areas with less VLSFO availability, or where monitoring of ships is less stringent, will stick to HSFO even if they have not installed a scrubber. This phenomenon, known as non-compliance, could be significant in 2020 amounting to around 700 kb/d, equivalent to 16% of total bunker fuel demand. Outside the marine sector, we expect demand for fuel oil from power and cement facilities to increase (see *Demand Section*).

To meet higher demand, gasoil supply will increase by around 800 kb/d year-on-year in 2020 as refiners maximise output. Nonetheless, this will be insufficient to meet all of the demand growth, meaning gasoil stocks are likely to fall by 200 kb/d and that prices will rise as a result. Our research indicates that to reduce demand by an equivalent amount, prices would need to rise by one fifth versus what they would otherwise be. Market conditions could differ significantly if strict compliance is enforced in 2020. Under that scenario, suppliers would need to find an additional 700 kb/d of gasoil that we currently expect to go to HSFO, with gasoil prices possibly doubling versus business as usual conditions. The sharp drop in HSFO demand will initially trigger a significant market surplus, even if part of it will be recycled in the bunker pool as well as in the power and cement industries. Overall fuel costs for the marine industry (and subsequently total freight costs) are likely to significantly increase in 2020, as vessels will have to switch to a more expensive fuel (MGO or VLSFO).

VLSFO gathers pace during 2021-24

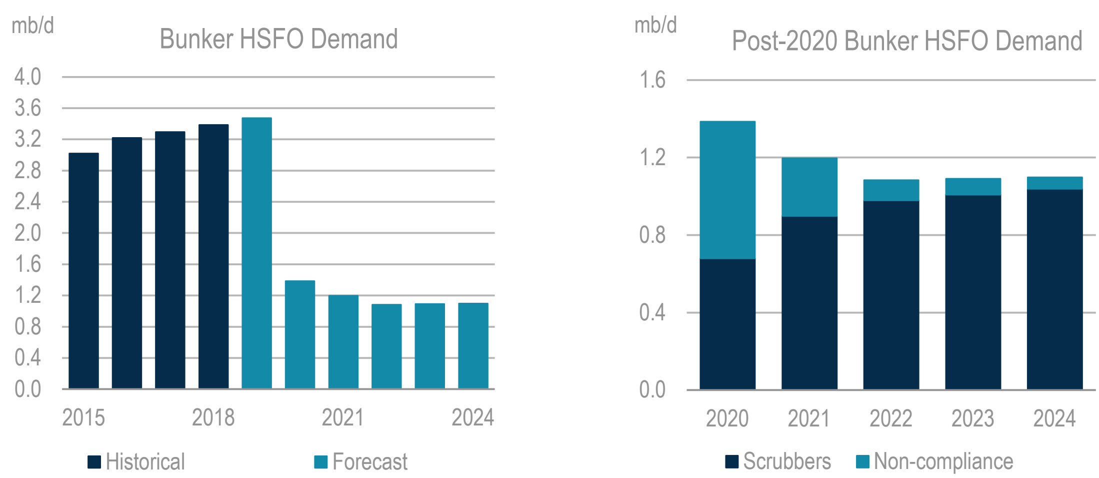
Under our central scenario, demand for VLSFO starts at 1 mb/d in 2020, rising sharply to 1.4 mb/d in 2021 and 1.8 mb/d by 2024, as ship operators become more familiar with the new fuel and issues of compatibility and stability are sorted out. There is little doubt that VLSFO will be cheaper than MGO as it will contain a certain volume of cheaper fuel oil. It is therefore likely to be increasingly favoured by large users. By 2024, we estimate that VLSFO and MGO consumption will be more or less equal.

Table 4.3 Our 2020-24 marine demand forecast split by fuel type (mb/d)

Fuel	2020	2021	2022	2023	2024
Fuel oil	1.4	1.2	1.1	1.1	1.1
Of which: Scrubbers	0.7	0.9	1.0	1.0	1.0
Of which: Non-compliance	0.7	0.3	0.1	0.1	0.1
Very low sulphur fuel oil	1.0	1.4	1.6	1.7	1.8
Marine gasoil	2.0	1.9	1.9	1.8	1.8
Total	**4.4**	**4.5**	**4.6**	**4.6**	**4.7**

We do not foresee a collapse in marine gasoil demand during the forecast period, for several reasons. First, it benefits from a solid demand base of circa 900 kb/d from smaller vessels and ships operating in the ECAs of Northwest Europe and North America. Second, we estimate that refiners will significantly increase gasoil production from 2020 thanks to investments made in the last few years and the increase in gasoil refining margins that is likely to occur. This will keep in check the price difference between MGO and VLSFO. Third, MGO is a more established fuel with known availability in many ports, especially smaller ones with less oil storage capacity and thus less flexibility to switch to a new fuel. It will take time for VLSFO to displace marine gasoil. In our forecast, MGO demand eases progressively from a record 2 mb/d in 2020 to 1.8 mb/d by 2024.

Figure 4.2 Bunker fuel oil demand before and after 2020



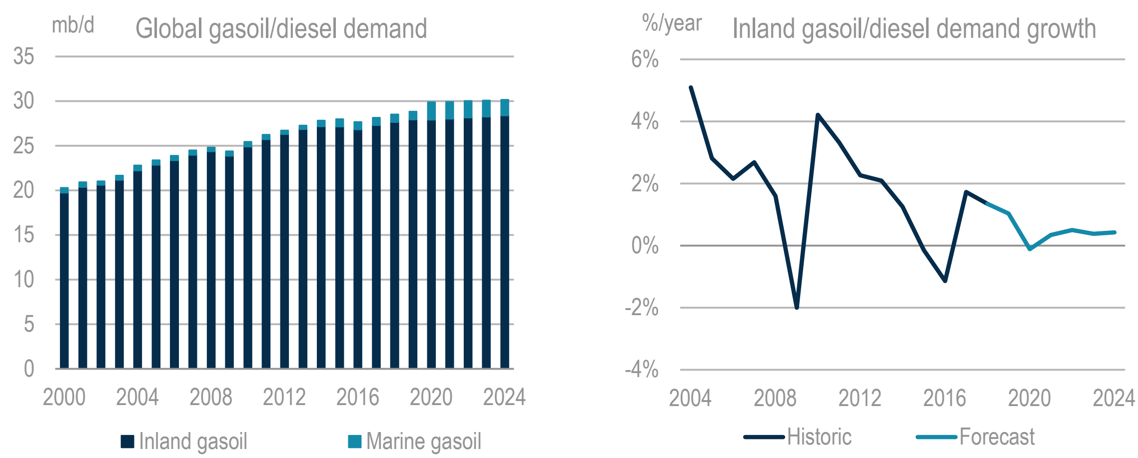
Demand for HSFO from the bunker sector, after collapsing in 2020, will ease during our forecast period with increased competition from VLSFO. However, it will be surprisingly resilient, staying above 1 mb/d all the way to 2024. Ships fitted with scrubbers will bolster demand, as we estimate that installed units will number 5 200 by end-2024. We assume that the business case for retrofitting existing ships with scrubbers largely disappears in 2021 as refiners increase gasoil output and amid competition for fuel oil from the power sector. Thus, demand from scrubbers stabilises after 2022.

Meanwhile, non-compliance is likely to fall away from 700 kb/d in 2020 to 300 kb/d by 2021 and just 60 kb/d by 2024, equivalent to 1% of total bunker fuel demand. This is because enforcement is likely to increase and HSFO will become scarcer over time. There will still be availability in the major ports for large ships with scrubbers, but fuel oil will have largely disappeared elsewhere.

Inland diesel demand growth slows

Few sectors are likely to be left untouched by the IMO regulations. We estimate that inland demand growth in the transportation, heating and industrial sectors, responsible for 97% of all gasoil/diesel consumed worldwide, will slow markedly over the forecast period.

Figure 4.3 Global gasoil/diesel demand growth and share of inland sector



Demand will increase by 1% in 2019, but will then fall in 2020 (-0.1%) with growth of just 0.4% on average in 2021-24, its slowest pace in at least 20 years. We expect middle distillate prices to rise relative to other oil products in 2020 due to higher marine demand, thus encouraging fuel switching and rationing in the inland sector. Onshore users with the highest marginal costs and/or most fuel switching options are likely to be most affected and ration their consumption. These include manufacturers with access to natural gas or customers using gasoil or kerosene for heating in parts of North America, Northwest Europe and Japan. All gasoil/diesel consumers worldwide will be affected by higher prices.

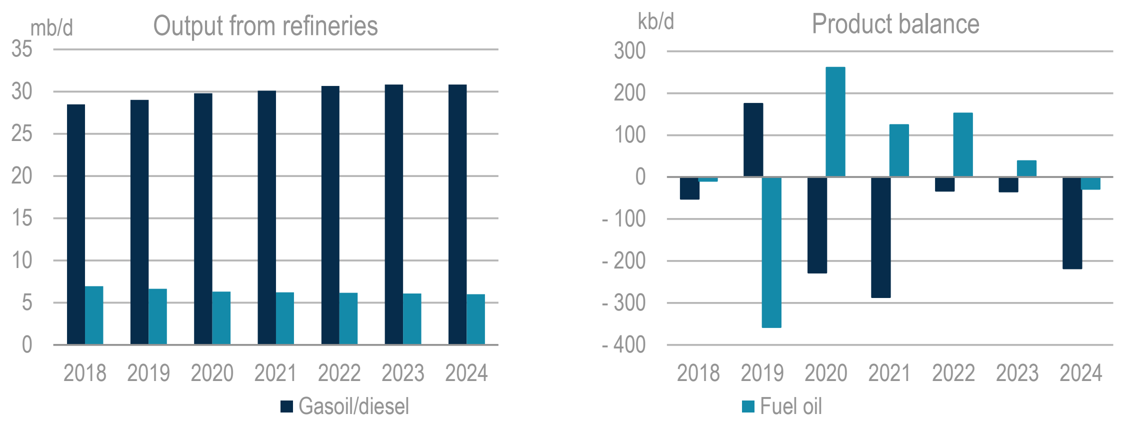
The marine sector, even if it accounts for a very small share of global gasoil and diesel demand, will be responsible for around 900 kb/d, or 56%, of total growth in demand over 2019-24. By the end of 2024, the marine sector's market share will have grown to 6%.

Refining sector targets gasoil

In 2020, refiners will face collapsing demand for fuel oil and a corresponding rise in demand for MGO gasoil and VLSFO. We expect refiners to supply 29.8 mb/d of gasoil and diesel in 2020, but most of it will be required by the transportation, heating and manufacturing sectors. This leaves around 1.9 mb/d of gasoil available for the marine segment versus demand of around 2 mb/d, implying a production shortfall of circa 200 kb/d. This is likely to push gasoil prices higher and incentivise higher gasoil yields at refineries. The production gap would be even greater if compliance with the IMO regulations is higher than we anticipate.

Over the next few years, we expect refiners to ramp up gasoil production significantly, from 28.5 mb/d in 2018 to 29.8 mb/d in 2020 and 30.8 mb/d in 2024. This is an increase of 2.3 mb/d (or 8%) in six years. This will help meet most of the increased demand for MGO over the forecast period, but will mean the gasoil market as a whole stays tight. Fuel oil production, meanwhile, will reach 6.3 mb/d in 2020, down 600 kb/d from 2018. With total fuel oil demand of 6 mb/d in that year, this means the market is likely to be in surplus and will remain so until 2023. These extra volumes will likely head into storage. There is enough spare storage capacity in Europe, North America and parts of Asia to accommodate this new flow.

Figure 4.4 Output of gasoil, fuel oil from refineries and market balances



Note: Balances represent the difference between product supply and consumption.

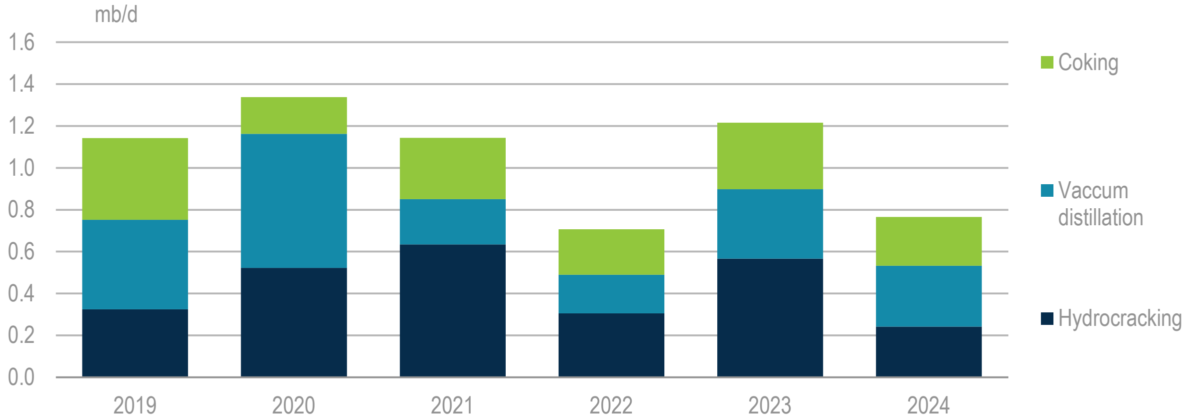
Refinery investments to increase

Refineries that have invested in new capacity will be able to increase gasoil and diesel production. We see a total of 8.9 mb/d of new crude distillation capacity (CDU) set to come online by 2024. While many new CDUs will cater to growing demand for oil products in the Middle East and Asia, they will also enable greater flexibility in the global refining system and allow refiners to produce additional gasoil for use in the bunker fuel market. Further downstream, there will also be investments in new cokers (+1.2 mb/d over 2019-24), hydrocrackers (+2.3 mb/d) and desulphurisation units (+5.3 mb/d), although average capacity additions will not necessarily increase compared with previous periods.

Second, we expect refiners to adjust their yields in favour of gasoil relative to gasoline. Most of the switching capacity is situated in the United States and People's Republic of China ("China"). With gasoline yields of nearly half, the highest in the world, US refiners can redirect some of the atmospheric gasoil and residue streams away from fluid catalytic crackers to target more gasoil production. In China, refiners have been trying to switch out of gasoil and into gasoline to meet rising demand. However, China's refiners are increasingly exposed to Asian and global products markets and are thus likely to reverse some of the yield switch and increase gasoil production. In our modelling, total gasoil exports from the largest producers; the United States, Russian Federation ("Russia"), China and the Middle East, increase by 700 kb/d year-on-year to 4.4 mb/d in 2020 and to almost 5 mb/d by 2024.

Another option for refineries is to produce very low sulphur fuel oil grades (compliant with the 0.5% IMO sulphur specification) which do not need to be blended with gasoil. We think there is at least 300 kb/d of 0.5% straight-run fuel oil that is currently absorbed by the market globally, but is likely to be redirected to the bunker pool starting from 2020. This is mostly available in countries where refiners use low sulphur crude oils, such as North Africa, Europe and the United States. In addition, refiners have the ability to hydrofine another 350 kb/d of fuel oil to produce 0.5% material. This is not being done currently due to the absence of a quality premium, but refiners will have the incentive in 2020. This capacity mostly exists in China and the Middle East. From 2020, refiners are widely expected to blend HSFO and gasoil to create the new VLSFO. Along with straight-run and hydrofined low-sulphur fuel oil, VLSFO production is likely to increase gradually from 1 mb/d in 2020 to 1.8 mb/d in 2024.

Figure 4.5 Forecast refinery capacity additions by unit type



Scrubbers boost fuel oil demand

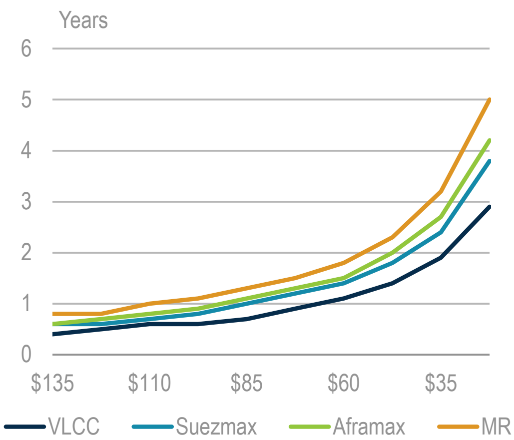
Orders of exhaust gas cleaning systems, more commonly known as scrubbers, increased substantially in 2018 as more ship owners made up their mind about compliance for the post-2020 period. Between 2 000-3 000 were ordered at the end of 2018, a significant increase from fewer than 400 at the end of 2017. The vast majority of orders (around three quarters) were for open-loop systems, which remove sulphur from exhaust fumes with the help of seawater and discharge the waste at sea. They are cheaper than closed-loop scrubbers, which store the waste in a tank and necessitate regular maintenance in port. We estimate that around 2 500 ships will be equipped with scrubbers at the end of 2019 in time to comply with the IMO regulations. This represents a leap of nearly 1 900 units from the 600 or so installed at the end of 2018.

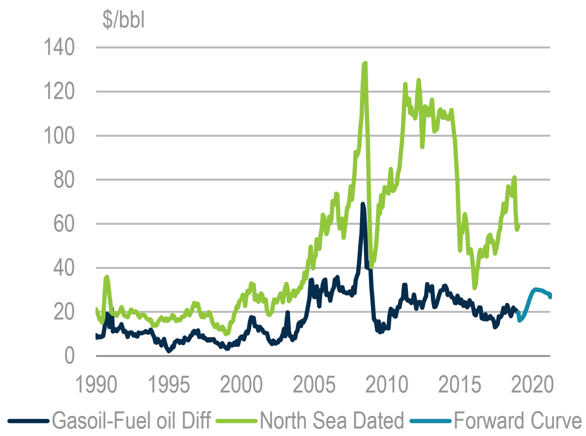
The differential between 0.5% gasoil and HSFO on the forward curve currently stands at $160/tonne, or $17-18/bbl, in 2020. We estimate that this is enough to cover the cost of retrofitting a scrubber on a Very Large Crude Carrier and earn a positive return within 1.5 years, making such investments very profitable for large ships. However, future oil prices will have a significant impact on this calculation.

Scrubber installations peak in 2019-20, fall afterwards

There will be a significant incentive to install scrubbers immediately before and after implementation of the IMO regulations. While some ports such as Antwerp, Fujairah, Shanghai and Singapore have moved to ban open-loop scrubbers from discharging waste water in their vicinity, we do not think this will have a significant impact on investment decisions. The reason is that large vessels spend most of their time at sea rather than in port. More scrubber bans are likely over the next few months, particularly in Europe and North America. Over time, this will mean that open-loop scrubbers are only used in international waters and that ships choose to burn MGO or VLSFO when sailing close to the coast. We have therefore assumed 90% availability from scrubbers to account for this phenomenon.

Figure 4.6 Years needed to pay back scrubber at different oil prices





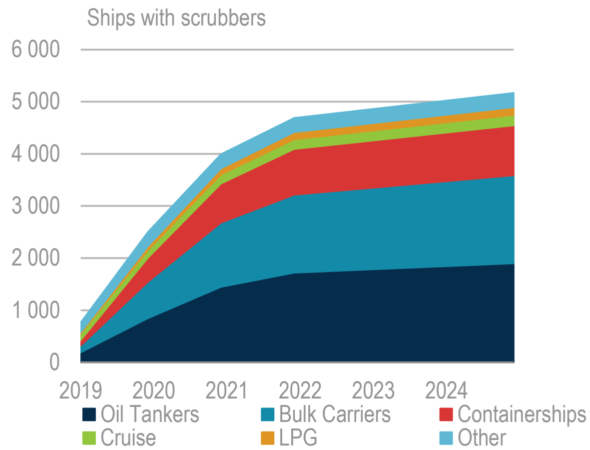
Note: The payback chart uses historical gasoil-fuel oil price spreads at different oil price levels. Differentials may differ significantly in 2020.
Source: Langh Tech (using IEA assumptions), Argus Media.

In our forecast, scrubber additions amount to 1 900 units in 2019 and a further 1 500 in 2020, as ship owners scramble to comply with the IMO rules. However, we expect installations to slow markedly to 700 in 2021, then to less than 200 in 2022 and in subsequent years. This is largely in keeping with our view that refiners will increase gasoil output significantly, thus providing more compliant fuel and helping to narrow the price spread between gasoil and fuel oil. It means that the burst of scrubber investments seen ahead of and after 2020 will end up being a short-lived phenomenon with just under 5 200 vessels equipped globally by end-2024, out of a fleet of 94 000 ships.

Initially, decisions to install scrubbers on existing vessels will represent the majority of installations; in the current order book, nearly two thirds of projects are retrofits. Over time, however, we expect scrubbers installed on new-build vessels to grow in importance, as they are less costly and can be easily added as part of the vessel's construction. From 2022, we expect new-build scrubbers to stand for all additional installations, as retrofits become less economic. By 2024, new-build scrubbers represent 43% of the total installed capacity versus 57% for retrofits.

While ships equipped with scrubbers only represent 5% of the global fleet by 2024, their share of total bunker fuel demand will be a much larger 22%. This is because we expect only the largest ships to install scrubbers owing to the significant one-off costs and onboard space required. We estimate that, overall, ships equipped with scrubbers will consume 510 kb/d of fuel oil by the end of 2019, up from just 140 kb/d at the end of 2018. In line with the installation of additional units in 2020, this is expected to grow quickly to 820 kb/d at the end of that year. Growth will slow down markedly afterwards as retrofits drop to zero. By end-2024, fuel oil demand from ships with scrubbers will reach 1.05 mb/d, a seven-fold increase versus the end of 2018.

Figure 4.7 Forecast scrubber installations by vessel category and type of investment



In our model, we have assumed that 75% of all installations happen in the oil and dry bulk tanker segments. This is because of the size of these fleets compared to other categories, with a high proportion of large ships with significant fuel consumption, and thus a high interest in using a low-cost feedstock such as high sulphur fuel oil.

Compliance issues unlikely to last

We expect non-compliance, the illegal use of fuel oil after 2020, to be relatively high at around 16% of total bunker demand in 2020, equivalent to around 700 kb/d. In some cases, ships may burn fuel oil to avoid paying for the more expensive VLSFO or MGO. In others, they may not be able to find compliant fuel and may therefore be “forced” to use fuel oil. It is also possible that enforcement by some governments will be patchy at the beginning.

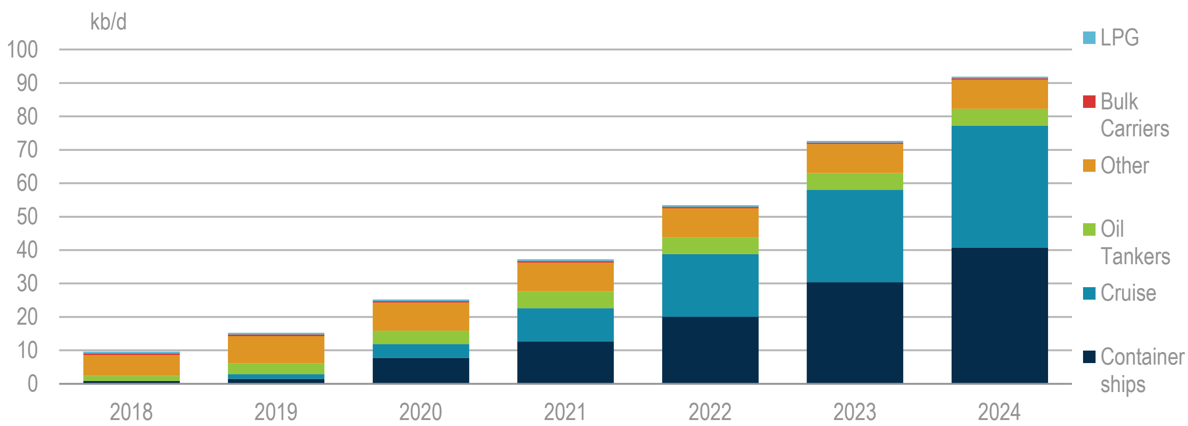
However, we do not think that non-compliance will be a lasting phenomenon. This is because the vast majority of commercial sea voyages typically occur between locations which are committed to enforce the IMO regulations, e.g. OECD countries, China, Chinese Taipei, Singapore and South Africa. In 2018, we estimate that 85% of oil flows, 93% of coal voyages and 94% of iron ore trips either originated or ended in these countries. Moreover, fuel oil availability in smaller ports, which are most likely to see non-compliance in 2020, will likely decrease sharply after 2020. We forecast non-compliance to fall away to 300 kb/b by 2021 and just 60 kb/d by 2024, equivalent to 1% of total bunker fuel demand in that year.

LNG makes small but growing contribution

Outside the liquefied natural gas carrier segment, demand for LNG as a bunker fuel is currently a niche market limited to parts of Northwest Europe, the Mediterranean and Central America. There were fewer than 200 vessels in operation at the end of 2018, of which the vast majority were small ships active in the passenger, car and container transportation business. Altogether, we estimate that demand was no more than 10 kb/d of equivalent fuel oil demand at the end of 2018, the same as 25 very large crude carriers. However, demand is likely to climb over the 2019-24 period thanks to several large new orders.

In 2019, Carnival Corporation will commission two new cruise ships running on LNG, while AET and Sovcomflot will start to operate between them six new LNG-powered Aframaxes in the Baltic and the North Sea. These vessels represent the beginning of a new wave of larger ships running on LNG. In 2020, CMA-CGM plans to commission seven containerships and Teekay and Rosneft have plans for several more Aframaxes and Suezmaxes, thus displacing 25 kb/d of equivalent fuel oil demand.

Figure 4.8 Bunker LNG demand split by ship segment



Note: Demand for bunker fuel from LNG tankers is not included in these figures.

We expect LNG bunker demand in 2019-24 to be supported by two key vessel segments: container ships and cruise liners. They are the most suitable because they operate largely fixed shipping lines. As LNG bunkering infrastructure remains minimal at the time of writing, vessels following fixed routes are more likely to use it. In our forecast, we expect four cruise liner additions in 2020, rising to 13 by 2024, or around two thirds of new cruise vessels commissioned in that year. Container ship additions number 10 in 2020, doubling by 2024 to cover around half of all new vessels built in that year. We do not factor in the potential for any retrofits as these are expensive to carry out. Instead, we assume that only new-build vessels use LNG bunker fuel.

LNG bunker fuel demand grows from 10 kb/d in 2018 to 25 kb/d in 2020, 55 kb/d in 2022 and 90 kb/d in 2024. While this represents just 2% of total global bunker demand in 2024, this is an almost ten-fold increase from the levels at end-2018. During the period, it is possible the IMO will publish a new strategy on greenhouse gas emissions, which could have an adverse impact on LNG as it offers just a 20-25% reduction in emissions versus oil.

5. Tables

Table 1
WORLD OIL SUPPLY AND DEMAND
(million barrels per day)

	1Q18	2Q18	3Q18	4Q18	2018	1Q19	2Q19	3Q19	4Q19	2019	2020	2021	2022	2023	2024
OECD DEMAND															
Americas	25.3	25.4	25.8	26.0	25.6	25.6	25.8	26.1	26.2	25.9	26.1	26.0	26.1	26.0	26.1
Europe	14.1	14.2	14.7	14.3	14.3	14.0	14.4	14.8	14.4	14.4	14.3	14.3	14.2	14.1	14.1
Asia Oceania	8.5	7.6	7.6	8.0	7.9	8.4	7.4	7.5	8.0	7.8	7.7	7.7	7.7	7.8	7.7
Total OECD	47.9	47.2	48.1	48.2	47.8	48.0	47.6	48.4	48.6	48.2	48.2	48.0	48.0	47.9	47.9
NON-OECD DEMAND															
FSU	4.5	4.6	4.9	4.8	4.7	4.5	4.7	5.0	5.0	4.8	5.0	5.0	5.1	5.1	5.2
Europe	0.7	0.7	0.8	0.8	0.8	0.8	0.8	0.8	0.8	0.8	0.8	0.8	0.8	0.8	0.9
China	12.7	13.0	13.2	13.1	13.0	13.1	13.5	13.6	13.7	13.5	13.8	14.2	14.5	14.8	14.9
Other Asia	13.8	14.0	13.5	14.0	13.8	14.2	14.4	13.9	14.4	14.2	14.7	15.2	15.6	16.1	16.5
Latin America	6.3	6.4	6.5	6.4	6.4	6.3	6.3	6.4	6.3	6.3	6.4	6.6	6.6	6.8	6.9
Middle East	8.1	8.5	8.7	8.3	8.4	8.1	8.6	8.9	8.2	8.5	8.6	8.9	9.0	9.1	9.2
Africa	4.3	4.3	4.2	4.4	4.3	4.5	4.4	4.3	4.4	4.4	4.5	4.6	4.7	4.8	4.9
Total Non-OECD	50.5	51.5	51.7	51.8	51.4	51.5	52.7	52.8	52.8	52.4	53.8	55.3	56.5	57.5	58.5
Total Demand[1]	**98.4**	**98.7**	**99.8**	**100.1**	**99.2**	**99.5**	**100.3**	**101.2**	**101.4**	**100.6**	**102.0**	**103.3**	**104.5**	**105.4**	**106.4**
OECD SUPPLY															
Americas	21.7	22.2	23.3	23.8	22.8	23.5	23.7	24.3	24.4	24.0	25.2	26.1	26.5	26.8	26.9
Europe	3.6	3.3	3.2	3.4	3.4	3.4	3.3	3.4	3.5	3.4	3.6	3.8	3.8	3.9	3.8
Asia Oceania	0.4	0.4	0.4	0.4	0.4	0.5	0.5	0.5	0.5	0.5	0.6	0.6	0.6	0.6	0.5
Total OECD	25.7	25.9	26.9	27.7	26.6	27.4	27.6	28.2	28.5	27.9	29.4	30.5	30.9	31.2	31.3
NON-OECD SUPPLY															
FSU	14.4	14.4	14.6	14.8	14.6	14.8	14.5	14.6	14.8	14.6	14.8	14.8	14.7	14.7	14.5
Europe	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1
China	3.8	3.9	3.8	3.9	3.8	3.8	3.8	3.8	3.7	3.8	3.7	3.7	3.7	3.6	3.6
Other Asia	3.4	3.3	3.3	3.3	3.3	3.2	3.2	3.2	3.2	3.2	3.2	3.1	3.0	2.9	2.8
Latin America	4.5	4.5	4.4	4.6	4.5	4.7	4.8	5.0	5.0	4.9	5.1	5.1	5.2	5.6	5.9
Middle East	3.2	3.3	3.3	3.3	3.3	3.3	3.3	3.3	3.3	3.3	3.3	3.3	3.3	3.3	3.3
Africa	1.4	1.5	1.5	1.4	1.4	1.5	1.5	1.5	1.5	1.5	1.5	1.5	1.5	1.5	1.5
Total Non-OECD	30.9	31.0	31.0	31.4	31.1	31.3	31.1	31.3	31.6	31.4	31.6	31.5	31.5	31.7	31.8
Processing Gains[2]	2.3	2.3	2.3	2.3	2.3	2.3	2.3	2.3	2.3	2.3	2.4	2.4	2.4	2.5	2.5
Global Biofuels	2.1	2.8	3.1	2.5	2.6	2.2	2.8	3.1	2.7	2.7	2.8	2.9	3.0	3.1	3.1
Total Non-OPEC[3]	61.0	62.0	63.3	64.0	62.6	63.3	63.8	64.9	65.1	64.3	66.3	67.3	67.9	68.4	68.7
OPEC															
Crude[3]	31.7	31.6	32.0	32.2	31.9										
OPEC NGLs	5.5	5.5	5.5	5.6	5.5	5.6	5.6	5.6	5.6	5.6	5.6	5.6	5.6	5.7	5.7
Total OPEC[3]	37.3	37.1	37.6	37.7	37.4										
Total Supply	98.3	99.1	100.9	101.7	100.0										
Memo items:															
Call on OPEC crude + Stock ch.[4]	31.8	31.1	30.9	30.6	31.1	30.6	30.9	30.7	30.7	30.7	30.1	30.3	31.0	31.3	32.0

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.

Table 1a

WORLD OIL SUPPLY AND DEMAND: CHANGES FROM OIL 2018

(million barrels per day)

	1Q17	2Q17	3Q17	4Q17	2017	1Q18	2Q18	3Q18	4Q18	2018	2019	2020	2021	2022	2023
OECD DEMAND															
Americas	-0.1	0.5	0.1	0.3	0.2	0.4	0.7	0.6	0.8	0.6	0.8	1.0	1.0	1.2	1.1
Europe	-0.2	-0.1	0.0	0.1	0.0	0.0	-0.2	-0.1	-0.1	-0.1	0.0	0.0	0.0	0.0	0.1
Asia Oceania	-0.2	0.0	-0.1	-0.1	-0.1	0.0	0.1	-0.1	-0.3	-0.1	-0.2	-0.2	-0.2	-0.2	-0.1
Total OECD	-0.5	0.4	0.0	0.3	0.1	0.4	0.5	0.4	0.4	0.4	0.6	0.8	0.8	1.0	1.0
NON-OECD DEMAND															
FSU	-0.2	-0.2	-0.3	-0.3	-0.3	-0.1	-0.2	-0.2	-0.1	-0.1	-0.1	-0.1	-0.1	-0.2	-0.2
Europe	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
China	0.3	0.5	-0.1	-0.2	0.1	0.3	0.2	0.4	-0.1	0.2	0.3	0.3	0.4	0.4	0.3
Other Asia	-0.1	0.1	0.3	0.1	0.1	-0.1	0.1	0.0	0.0	0.0	0.0	0.1	0.1	0.2	0.2
Latin America	0.0	-0.1	-0.1	-0.2	-0.1	-0.1	-0.3	-0.3	-0.4	-0.3	-0.4	-0.4	-0.3	-0.4	-0.3
Middle East	0.4	0.4	0.2	0.1	0.3	0.1	-0.1	-0.3	-0.1	-0.1	-0.1	-0.2	-0.2	-0.2	-0.2
Africa	0.0	0.0	0.0	-0.1	0.0	-0.1	-0.1	-0.1	0.0	-0.1	-0.1	-0.1	-0.1	-0.1	-0.2
Total Non-OECD	0.3	0.7	0.0	-0.6	0.1	-0.1	-0.2	-0.4	-0.7	-0.4	-0.4	-0.3	-0.2	-0.3	-0.4
Total Demand	**-0.2**	**1.1**	**0.0**	**-0.3**	**0.2**	**0.2**	**0.3**	**0.0**	**-0.4**	**0.0**	**0.2**	**0.5**	**0.6**	**0.8**	**0.7**
OECD SUPPLY															
Americas	0.0	0.0	0.1	0.2	0.1	0.4	0.6	1.3	1.3	0.9	1.0	1.7	2.2	2.3	2.4
Europe	0.0	0.0	0.0	0.0	0.0	0.0	-0.2	-0.2	-0.1	-0.1	0.0	0.1	0.1	0.0	0.1
Asia Oceania	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Total OECD	0.0	0.1	0.1	0.1	0.1	0.4	0.4	1.1	1.1	0.8	1.0	1.8	2.3	2.4	2.5
NON-OECD SUPPLY															
FSU	-0.1	-0.1	-0.1	0.0	-0.1	0.0	0.0	0.2	0.4	0.1	0.0	0.1	0.0	0.0	0.0
Europe	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
China	0.0	0.0	0.0	0.0	0.0	0.0	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.0	0.0
Other Asia	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Latin America	0.0	0.0	0.0	0.0	0.0	-0.1	-0.1	-0.2	-0.2	-0.2	-0.2	0.0	0.1	0.0	0.2
Middle East	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.1	0.1	0.1	0.1
Africa	0.0	0.0	0.0	0.0	0.0	0.0	0.1	0.1	0.0	0.0	0.1	0.1	0.2	0.2	0.2
Total Non-OECD	-0.1	-0.1	-0.1	-0.1	-0.1	-0.1	0.0	0.1	0.3	0.1	0.0	0.3	0.4	0.3	0.6
Processing Gains	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Global Biofuels	0.1	0.1	0.0	0.1	0.1	0.1	0.3	0.3	0.0	0.2	0.1	0.1	0.2	0.2	0.2
Total Non-OPEC	0.1	0.0	0.0	0.1	0.1	0.4	0.7	1.5	1.5	1.0	1.1	2.2	2.8	2.9	3.3
OPEC															
Crude	0.0	0.0	0.0	0.0	0.0										
OPEC NGLs	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	-0.1	-0.1	-0.2	-0.2	-0.2
Total OPEC	0.0	0.0	0.0	0.0	0.0										
Total Supply	**0.0**	**0.0**	**0.0**	**0.1**	**0.0**										
Memo items:															
Call on OPEC crude + Stock ch.	-0.2	1.1	0.0	-0.4	0.1	-0.2	-0.4	-1.5	-1.8	-1.0	-0.9	-1.6	-2.0	-2.0	-2.4

Table 1b
WORLD OIL SUPPLY AND DEMAND - WEO Regions
(million barrels per day)

	1Q18	2Q18	3Q18	4Q18	2018	1Q19	2Q19	3Q19	4Q19	2019	2020	2021	2022	2023	2024
DEMAND															
North America	24.9	25.0	25.5	25.6	25.2	25.2	25.4	25.8	25.8	25.6	25.7	25.6	25.7	25.6	25.7
Central and South America	6.7	6.7	6.8	6.8	6.8	6.6	6.7	6.8	6.7	6.7	6.8	7.0	7.0	7.1	7.2
Europe	15.5	15.7	16.2	15.8	15.8	15.5	15.9	16.3	16.0	15.9	15.9	15.8	15.8	15.8	15.7
Africa	4.3	4.3	4.2	4.4	4.3	4.5	4.4	4.3	4.4	4.4	4.5	4.6	4.7	4.8	4.9
Middle East	8.1	8.5	8.7	8.3	8.4	8.1	8.6	8.9	8.2	8.5	8.6	8.9	9.0	9.1	9.2
Eurasia	4.0	4.1	4.4	4.3	4.2	4.1	4.2	4.5	4.4	4.3	4.5	4.5	4.6	4.6	4.6
Asia Pacific	34.8	34.4	34.0	34.9	34.5	35.5	35.0	34.8	35.8	35.3	36.0	36.9	37.7	38.3	38.9
Total Demand[1]	**98.4**	**98.7**	**99.8**	**100.1**	**99.2**	**99.5**	**100.3**	**101.2**	**101.4**	**100.6**	**102.0**	**103.3**	**104.5**	**105.4**	**106.4**
NON-OPEC SUPPLY															
North America	21.7	22.2	23.3	23.8	22.8	23.5	23.7	24.3	24.4	24.0	25.2	26.1	26.5	26.8	26.9
Central and South America	4.5	4.5	4.4	4.6	4.5	4.7	4.8	5.0	5.1	4.9	5.1	5.1	5.3	5.6	5.9
Europe	3.8	3.6	3.4	3.6	3.6	3.6	3.5	3.6	3.7	3.6	3.8	4.0	4.0	4.0	4.0
Africa	1.4	1.5	1.5	1.4	1.4	1.5	1.5	1.5	1.5	1.5	1.5	1.5	1.5	1.5	1.5
Middle East	3.2	3.3	3.3	3.3	3.3	3.3	3.3	3.3	3.3	3.3	3.3	3.3	3.3	3.3	3.3
Eurasia	14.3	14.3	14.5	14.7	14.5	14.7	14.4	14.5	14.7	14.6	14.7	14.7	14.7	14.6	14.5
Asia Pacific	7.6	7.6	7.5	7.6	7.6	7.5	7.5	7.5	7.5	7.5	7.4	7.4	7.2	7.1	6.9
Total Non-OPEC	56.6	56.9	57.9	59.1	57.6	58.7	58.7	59.5	60.1	59.3	61.0	62.0	62.5	62.9	63.1
Processing Gains[2]	2.3	2.3	2.3	2.3	2.3	2.3	2.3	2.3	2.3	2.3	2.4	2.4	2.4	2.5	2.5
Global Biofuels	2.1	2.8	3.1	2.5	2.6	2.2	2.8	3.1	2.7	2.7	2.8	2.9	3.0	3.1	3.1
Total Non-OPEC[3]	61.0	62.0	63.3	64.0	62.6	63.3	63.8	64.9	65.1	64.3	66.3	67.3	67.9	68.4	68.7
OPEC SUPPLY															
Crude[3]	31.7	31.6	32.0	32.2	31.9										
OPEC NGLs	5.5	5.5	5.5	5.6	5.5	5.6	5.6	5.6	5.6	5.6	5.6	5.6	5.6	5.7	5.7
Total OPEC[3]	37.3	37.1	37.6	37.7	37.4										
Total Supply	**98.3**	**99.1**	**100.9**	**101.7**	**100.0**										
Memo items:															
Call on OPEC crude + Stock ch.[4]	31.8	31.1	30.9	30.6	31.1	30.6	30.9	30.7	30.7	30.7	30.1	30.3	31.0	31.3	32.0

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.

Table 2
SUMMARY OF GLOBAL OIL DEMAND

	1Q18	2Q18	3Q18	4Q18	2018	1Q19	2Q19	3Q19	4Q19	2019	2020	2021	2022	2023	2024
Demand (mb/d)															
Americas	25.3	25.4	25.8	26.0	25.6	25.6	25.8	26.1	26.2	25.9	26.1	26.0	26.1	26.0	26.1
Europe	14.1	14.2	14.7	14.3	14.3	14.0	14.4	14.8	14.4	14.4	14.3	14.3	14.2	14.1	14.1
Asia Oceania	8.5	7.6	7.6	8.0	7.9	8.4	7.4	7.5	8.0	7.8	7.7	7.7	7.7	7.8	7.7
Total OECD	47.9	47.2	48.1	48.2	47.8	48.0	47.6	48.4	48.6	48.2	48.2	48.0	48.0	47.9	47.9
Asia	26.5	27.0	26.7	27.1	26.8	27.4	27.8	27.5	28.0	27.7	28.5	29.4	30.2	30.8	31.4
Middle East	8.1	8.5	8.7	8.3	8.4	8.1	8.6	8.9	8.2	8.5	8.6	8.9	9.0	9.1	9.2
Latin America	6.3	6.4	6.5	6.4	6.4	6.3	6.3	6.4	6.3	6.3	6.4	6.6	6.6	6.8	6.9
FSU	4.5	4.6	4.9	4.8	4.7	4.5	4.7	5.0	5.0	4.8	5.0	5.0	5.1	5.1	5.2
Africa	4.3	4.3	4.2	4.4	4.3	4.5	4.4	4.3	4.4	4.4	4.5	4.6	4.7	4.8	4.9
Europe	0.7	0.7	0.8	0.8	0.8	0.8	0.8	0.8	0.8	0.8	0.8	0.8	0.8	0.8	0.9
Total Non-OECD	50.5	51.5	51.7	51.8	51.4	51.5	52.7	52.8	52.8	52.4	53.8	55.3	56.5	57.5	58.5
World	**98.4**	**98.7**	**99.8**	**100.1**	**99.2**	**99.5**	**100.3**	**101.2**	**101.4**	**100.6**	**102.0**	**103.3**	**104.5**	**105.4**	**106.4**
of which:															
US50	*20.2*	*20.3*	*20.6*	*20.8*	*20.5*	*20.5*	*20.7*	*20.9*	*20.9*	*20.8*	*20.9*	*20.8*	*20.9*	*20.7*	*20.8*
*Euro5**	*8.2*	*8.2*	*8.3*	*8.2*	*8.2*	*8.2*	*8.3*	*8.4*	*8.3*	*8.3*	*8.2*	*8.1*	*8.1*	*8.0*	*8.0*
China	*12.7*	*13.0*	*13.2*	*13.1*	*13.0*	*13.1*	*13.5*	*13.6*	*13.7*	*13.5*	*13.8*	*14.2*	*14.5*	*14.8*	*14.9*
Japan	*4.3*	*3.4*	*3.5*	*3.9*	*3.8*	*4.2*	*3.3*	*3.4*	*3.9*	*3.7*	*3.7*	*3.7*	*3.6*	*3.6*	*3.6*
India	*4.8*	*4.9*	*4.5*	*4.8*	*4.8*	*5.1*	*5.1*	*4.8*	*5.1*	*5.0*	*5.2*	*5.4*	*5.7*	*5.9*	*6.0*
Russia	*3.3*	*3.4*	*3.6*	*3.5*	*3.5*	*3.3*	*3.4*	*3.7*	*3.6*	*3.5*	*3.6*	*3.7*	*3.7*	*3.7*	*3.7*
Brazil	*2.9*	*2.9*	*3.1*	*3.1*	*3.0*	*2.9*	*3.0*	*3.1*	*3.1*	*3.0*	*3.1*	*3.1*	*3.2*	*3.2*	*3.2*
Saudi Arabia	*2.9*	*3.2*	*3.3*	*3.0*	*3.1*	*2.8*	*3.3*	*3.5*	*3.1*	*3.2*	*3.2*	*3.3*	*3.3*	*3.4*	*3.4*
Korea	*2.6*	*2.5*	*2.5*	*2.4*	*2.5*	*2.6*	*2.5*	*2.4*	*2.5*	*2.5*	*2.5*	*2.5*	*2.5*	*2.6*	*2.6*
Canada	*2.3*	*2.3*	*2.6*	*2.6*	*2.4*	*2.4*	*2.4*	*2.6*	*2.6*	*2.5*	*2.5*	*2.5*	*2.5*	*2.5*	*2.5*
Mexico	*2.0*	*2.0*	*2.0*	*2.0*	*2.0*	*2.0*	*2.0*	*2.0*	*2.0*	*2.0*	*2.0*	*2.0*	*2.0*	*2.0*	*2.1*
Iran	*2.0*	*2.0*	*2.0*	*2.1*	*2.0*	*2.1*	*2.0*	*2.0*	*1.9*	*2.0*	*2.0*	*2.1*	*2.1*	*2.1*	*2.2*
Total	*68.4*	*68.3*	*69.3*	*69.6*	*68.9*	*69.1*	*69.5*	*70.4*	*70.6*	*69.9*	*70.7*	*71.4*	*72.2*	*72.5*	*73.0*
% of World	*69.5*	*69.2*	*69.4*	*69.5*	*69.4*	*69.5*	*69.3*	*69.5*	*69.6*	*69.5*	*69.4*	*69.2*	*69.1*	*68.8*	*68.6*
Annual Change (% per annum)															
Americas	2.6	1.0	2.7	2.6	2.2	1.3	1.6	1.1	0.8	1.2	0.6	-0.3	0.3	-0.4	0.3
Europe	1.9	-0.4	-0.3	-1.0	0.0	-0.5	1.6	0.8	1.1	0.8	-0.5	-0.5	-0.5	-0.3	-0.5
Asia Oceania	0.4	-0.7	-2.3	-4.1	-1.7	-1.9	-2.2	-1.6	0.6	-1.3	-1.0	-0.4	0.4	0.1	-0.1
Total OECD	2.0	0.3	0.9	0.4	0.9	0.2	1.0	0.6	0.8	0.7	0.0	-0.4	0.1	-0.3	0.0
Asia	3.2	2.4	4.0	2.9	3.1	3.2	3.0	3.2	3.3	3.2	2.9	3.1	2.7	2.2	1.9
Middle East	-1.6	-2.6	-2.0	0.8	-1.4	0.4	1.8	1.9	-1.1	0.7	2.0	2.9	1.6	1.2	1.3
Latin America	-0.1	-1.6	-1.5	-0.4	-0.9	-1.0	-0.3	-1.2	-1.2	-0.9	1.7	2.0	1.2	1.6	1.5
FSU	4.3	2.8	3.8	5.1	4.0	1.0	1.7	1.4	3.0	1.8	3.3	1.5	1.3	1.0	0.6
Africa	-0.6	-0.2	-0.3	3.2	0.5	3.3	3.1	2.5	0.9	2.4	2.4	2.5	1.9	2.4	2.1
Europe	2.5	-0.9	1.4	4.0	1.7	2.3	3.1	2.7	0.8	2.2	1.7	1.9	1.9	1.9	1.9
Total Non-OECD	1.7	0.8	1.8	2.4	1.7	2.0	2.3	2.2	1.8	2.1	2.6	2.7	2.1	1.9	1.7
World	**1.9**	**0.6**	**1.4**	**1.4**	**1.7**	**1.1**	**1.7**	**1.4**	**1.3**	**1.4**	**1.4**	**1.3**	**1.2**	**0.9**	**0.9**
Annual Change (mb/d)															
Americas	0.6	0.3	0.7	0.7	0.6	0.3	0.4	0.3	0.2	0.3	0.2	-0.1	0.1	-0.1	0.1
Europe	0.3	-0.1	-0.1	-0.1	0.0	-0.1	0.2	0.1	0.2	0.1	-0.1	-0.1	-0.1	0.0	-0.1
Asia Oceania	0.0	-0.1	-0.2	-0.3	-0.1	-0.2	-0.2	-0.1	0.0	-0.1	-0.1	0.0	0.0	0.0	0.0
Total OECD	0.9	0.1	0.5	0.2	0.4	0.1	0.5	0.3	0.4	0.3	0.0	-0.2	0.0	-0.1	0.0
Asia	0.8	0.6	1.0	0.8	0.8	0.9	0.8	0.9	0.9	0.9	0.8	0.9	0.8	0.7	0.6
Middle East	-0.1	-0.2	-0.2	0.1	-0.1	0.0	0.1	0.2	-0.1	0.1	0.2	0.3	0.1	0.1	0.1
Latin America	0.0	-0.1	-0.1	0.0	-0.1	-0.1	0.0	-0.1	-0.1	-0.1	0.1	0.1	0.1	0.1	0.1
FSU	0.2	0.1	0.2	0.2	0.2	0.0	0.1	0.1	0.1	0.1	0.2	0.1	0.1	0.0	0.0
Africa	0.0	0.0	0.0	0.1	0.0	0.1	0.1	0.1	0.0	0.1	0.1	0.1	0.1	0.1	0.1
Europe	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Total Non-OECD	0.9	0.4	0.9	1.2	0.9	1.0	1.2	1.1	0.9	1.1	1.4	1.5	1.2	1.1	1.0
World	**1.8**	**0.6**	**1.4**	**1.4**	**1.3**	**1.1**	**1.6**	**1.4**	**1.3**	**1.4**	**1.4**	**1.3**	**1.2**	**0.9**	**1.0**
Revisions to Oil Demand from Last Medium Term Report (mb/d)															
Americas	0.4	0.7	0.6	0.8	0.6	0.6	1.0	0.8	0.8	0.8	1.0	1.0	1.2	1.1	
Europe	0.0	-0.2	-0.1	-0.1	-0.1	-0.1	0.0	0.1	0.1	0.0	0.0	0.0	0.0	0.1	
Asia Oceania	0.0	0.1	-0.1	-0.3	-0.1	-0.2	-0.1	-0.2	-0.3	-0.2	-0.2	-0.2	-0.2	-0.1	
Total OECD	0.4	0.5	0.4	0.4	0.4	0.3	0.9	0.6	0.6	0.6	0.8	0.8	1.0	1.0	
Asia	0.1	0.4	0.4	-0.1	0.2	0.2	0.4	0.5	0.0	0.3	0.4	0.5	0.6	0.6	
Middle East	0.1	-0.1	-0.3	-0.1	-0.1	0.0	0.0	-0.2	-0.3	-0.1	-0.2	-0.2	-0.2	-0.2	
Latin America	-0.1	-0.3	-0.3	-0.4	-0.3	-0.3	-0.4	-0.5	-0.5	-0.4	-0.4	-0.3	-0.4	-0.3	
FSU	-0.1	-0.2	-0.2	-0.1	-0.1	-0.1	-0.1	-0.2	0.0	-0.1	-0.1	-0.1	-0.2	-0.2	
Africa	-0.1	-0.1	-0.1	0.0	-0.1	-0.1	-0.1	-0.1	-0.1	-0.1	-0.1	-0.1	-0.1	-0.2	
Europe	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	
Total Non-OECD	-0.1	-0.2	-0.4	-0.7	-0.4	-0.2	-0.2	-0.4	-0.9	-0.4	-0.3	-0.2	-0.3	-0.4	
World	**0.2**	**0.3**	**0.0**	**-0.4**	**0.0**	**0.1**	**0.7**	**0.2**	**-0.3**	**0.2**	**0.5**	**0.6**	**0.8**	**0.7**	
Revisions to Oil Demand Growth from Last Medium Term Report (mb/d)															
World	0.4	-0.8	0.0	-0.1	-0.1	-0.1	0.4	0.2	0.1	0.1	0.3	0.2	0.1	-0.1	

* France, Germany, Italy, Spain and UK

Table 3
WORLD OIL PRODUCTION
(million barrels per day)

	1Q18	2Q18	3Q18	4Q18	2018	1Q19	2Q19	3Q19	4Q19	2019	2020	2021	2022	2023	2024
OPEC															
Crude Oil															
Saudi Arabia	9.95	10.14	10.43	10.78	10.33										
Iran	3.83	3.84	3.62	3.03	3.58										
Iraq	4.45	4.48	4.65	4.65	4.56										
UAE	2.84	2.88	3.00	3.26	3.00										
Kuwait	2.70	2.71	2.79	2.78	2.75										
Neutral Zone	0.00	0.00	0.00	0.00	0.00										
Angola	1.55	1.49	1.48	1.45	1.49										
Congo	0.32	0.34	0.34	0.34	0.33										
Gabon	0.20	0.19	0.19	0.18	0.19										
Nigeria	1.66	1.51	1.62	1.63	1.60										
Libya	1.01	0.89	0.90	1.08	0.97										
Algeria	1.01	1.03	1.06	1.07	1.04										
Equatorial Guinea	0.13	0.12	0.12	0.11	0.12										
Ecuador	0.52	0.53	0.53	0.52	0.52										
Venezuela	1.54	1.43	1.33	1.30	1.40										
Total Crude Oil	31.72	31.56	32.05	32.17	31.88										
Total NGLs[1]	5.54	5.53	5.55	5.57	5.55	5.57	5.57	5.58	5.58	5.57	5.61	5.62	5.63	5.66	5.68
Total OPEC[2]	**37.26**	**37.09**	**37.59**	**37.73**	**37.42**										
NON-OPEC[3]															
OECD															
Americas	21.74	22.16	23.28	23.83	22.76	23.48	23.75	24.30	24.45	24.00	25.23	26.09	26.54	26.79	26.94
United States	14.38	15.06	15.98	16.48	15.48	16.45	16.84	17.16	17.28	16.94	18.06	18.80	19.27	19.50	19.56
Mexico	2.16	2.12	2.07	1.95	2.08	1.90	1.92	1.90	1.89	1.90	1.85	1.82	1.83	1.83	1.84
Canada	5.19	4.97	5.23	5.39	5.20	5.12	4.98	5.23	5.28	5.15	5.32	5.45	5.43	5.46	5.53
Chile	0.01	0.01	0.01	0.01	0.01	0.01	0.01	0.01	0.01	0.01	0.01	0.01	0.01	0.01	0.01
Europe	3.56	3.35	3.23	3.43	3.39	3.43	3.31	3.39	3.49	3.41	3.63	3.78	3.81	3.88	3.83
UK	1.08	1.04	0.95	1.05	1.03	1.10	1.11	1.07	1.16	1.11	1.10	1.06	1.01	0.94	0.90
Norway	1.96	1.79	1.79	1.86	1.85	1.81	1.68	1.79	1.81	1.77	2.01	2.22	2.30	2.44	2.45
Others	0.52	0.52	0.49	0.52	0.51	0.52	0.52	0.53	0.53	0.52	0.51	0.50	0.50	0.50	0.48
Asia Oceania	0.40	0.39	0.42	0.45	0.41	0.48	0.49	0.51	0.53	0.50	0.58	0.60	0.58	0.56	0.54
Australia	0.33	0.31	0.35	0.38	0.34	0.41	0.43	0.45	0.47	0.44	0.52	0.54	0.52	0.50	0.48
Others	0.07	0.07	0.07	0.06	0.07	0.06	0.06	0.06	0.06	0.06	0.06	0.06	0.06	0.06	0.06
Total OECD	25.70	25.89	26.94	27.71	26.57	27.39	27.55	28.20	28.48	27.91	29.45	30.47	30.93	31.23	31.31
NON-OECD															
Former USSR	14.39	14.42	14.60	14.83	14.56	14.75	14.46	14.57	14.80	14.65	14.81	14.80	14.74	14.67	14.54
Russia	11.30	11.33	11.59	11.75	11.49	11.61	11.48	11.55	11.72	11.59	11.73	11.78	11.78	11.70	11.56
Others	3.09	3.09	3.00	3.08	3.07	3.14	2.98	3.02	3.08	3.05	3.08	3.02	2.97	2.97	2.98
Asia	7.21	7.21	7.10	7.17	7.17	7.05	7.03	6.96	6.94	6.99	6.85	6.75	6.65	6.54	6.39
China	3.80	3.86	3.81	3.86	3.83	3.81	3.81	3.76	3.75	3.78	3.69	3.69	3.67	3.63	3.58
Malaysia	0.74	0.72	0.69	0.71	0.72	0.68	0.69	0.68	0.70	0.69	0.71	0.67	0.64	0.60	0.57
India	0.85	0.85	0.83	0.82	0.84	0.82	0.82	0.82	0.82	0.82	0.84	0.86	0.89	0.91	0.88
Indonesia	0.81	0.81	0.80	0.79	0.80	0.77	0.77	0.76	0.76	0.77	0.72	0.68	0.65	0.63	0.60
Others	1.01	0.97	0.97	0.99	0.98	0.96	0.95	0.94	0.92	0.94	0.89	0.85	0.81	0.78	0.75
Europe	0.12	0.12	0.12	0.12	0.12	0.12	0.12	0.12	0.11	0.12	0.11	0.10	0.10	0.10	0.10
Latin America[2]	4.50	4.53	4.42	4.55	4.50	4.69	4.81	4.95	5.04	4.87	5.07	5.13	5.25	5.58	5.89
Brazil	2.71	2.72	2.63	2.73	2.70	2.87	3.00	3.16	3.26	3.07	3.30	3.33	3.47	3.73	3.87
Argentina	0.57	0.58	0.58	0.59	0.58	0.59	0.59	0.59	0.60	0.59	0.60	0.61	0.62	0.64	0.66
Colombia	0.86	0.87	0.87	0.89	0.87	0.89	0.88	0.87	0.86	0.87	0.83	0.77	0.72	0.67	0.63
Others	0.36	0.36	0.33	0.35	0.35	0.34	0.34	0.33	0.33	0.33	0.34	0.42	0.43	0.54	0.73
Middle East[2]	3.22	3.27	3.28	3.29	3.27	3.26	3.27	3.28	3.28	3.27	3.28	3.28	3.33	3.32	3.33
Oman	0.97	0.98	0.99	1.00	0.99	0.98	0.98	0.99	1.00	0.98	0.99	0.99	0.98	0.98	0.97
Qatar	2.00	2.01	2.01	2.01	2.01	2.01	2.01	2.01	2.01	2.01	2.01	2.01	2.04	2.08	2.08
Syria	0.02	0.02	0.02	0.02	0.02	0.02	0.02	0.02	0.02	0.02	0.02	0.04	0.06	0.02	0.02
Yemen	0.03	0.04	0.04	0.04	0.04	0.04	0.04	0.04	0.04	0.04	0.04	0.04	0.04	0.04	0.04
Others	0.18	0.22	0.22	0.21	0.21	0.21	0.21	0.21	0.21	0.21	0.21	0.21	0.21	0.21	0.21
Africa[2]	1.43	1.47	1.47	1.43	1.45	1.45	1.46	1.46	1.45	1.46	1.48	1.46	1.45	1.47	1.51
Egypt	0.65	0.65	0.65	0.65	0.65	0.65	0.65	0.65	0.65	0.65	0.65	0.63	0.60	0.57	0.54
Sudan	0.07	0.07	0.07	0.07	0.07	0.07	0.07	0.07	0.07	0.07	0.07	0.06	0.05	0.05	0.05
Others	0.71	0.75	0.75	0.70	0.73	0.73	0.74	0.74	0.74	0.74	0.77	0.77	0.80	0.86	0.93
Total Non-OECD	30.87	31.02	30.99	31.40	31.07	31.33	31.14	31.33	31.64	31.36	31.59	31.51	31.52	31.68	31.75
Processing Gains[4]	2.32	2.32	2.32	2.32	2.32	2.35	2.35	2.35	2.35	2.35	2.38	2.41	2.44	2.46	2.49
Global Biofuels	2.13	2.77	3.05	2.53	2.62	2.25	2.80	3.05	2.68	2.70	2.84	2.92	2.98	3.05	3.13
TOTAL NON-OPEC[2]	**61.03**	**62.01**	**63.30**	**63.96**	**62.58**	**63.31**	**63.85**	**64.94**	**65.15**	**64.32**	**66.26**	**67.32**	**67.87**	**68.43**	**68.68**
TOTAL SUPPLY	**98.29**	**99.10**	**100.90**	**101.69**	**100.01**										

1 Includes condensates reported by OPEC countries, oil from non-conventional sources, e.g. Venezuelan Orimulsion (but not Orinoco extra-heavy oil), and non-oil inputs to Saudi Arabian MTBE. Orimulsion production reportedly ceased from January 2007.
2 Total OPEC comprises all countries which are currently OPEC members. Total Non-OPEC excludes all countries that are current members of OPEC.
3 Comprises crude oil, condensates, NGLs and oil from non-conventional sources.
4 Net volumetric gains and losses in refining and marine transportation losses.

Table 3a
SELECTED NON-OPEC UPSTREAM PROJECT START-UPS

Country	Project	Peak Capacity (kbd)	Start Year	Country	Project	Peak Capacity (kbd)	Start Year
OECD Americas				***Asia***			
USA	Big Foot	75	2018	China	Caofeidian	40	2019
USA	Stampede (Knotty Head & Pony)	80	2018	India	KG-DWN-98/2	90	2021
USA	Kaikias	40	2018	***FSU***			
USA	Buckskin	30	2019	Russia	Novoportovskoye	160	2014
USA	Appomattox/Vicksburg	175	2020	Russia	East Messoyakha	130	2016
USA	Mad Dog Phase 2	140	2021	Russia	Suzun	90	2016
USA	Atlantis	35	2021	Russia	Tagul	90	2017
USA	Vito	100	2022	Russia	Yurubcheno-Tokhomskoe	100	2018
Mexico	Area 1 (Amoco, Tecoalli, Mizton)	100	2019	Russia	Taas-Yuriakh	75	2018
Mexico	Pemex Shallow water fields	350	2019	Russia	Erginskoye/Kondaneft	170	2019
Mexico	Zama	150	2022	Russia	Naulskoe	20	2019
Canada	Cenovus Christina Lake Ph G	50	2019	Russia	Russkoe	120	2019
Canada	Kirby North	40	2020	Russia	Kuyumba	65	2019
Canada	West White Rose	75	2022	Russia	Rospan	110	2019
Canada	Aspen ph 1	75	2023	Russia	Lodochnoe	40	2021
Canada	Suncor - Meadow Creek East ph 1	40	2023	Azerbaijan	Shah-Deniz 2	65	2018
OECD Europe				Kazakhstan	Tengizchevroil FGP	260	2022
Denmark	Tyra Future	25	2022	Azerbaijan	Absheron	35	2020
Italy	Tempa Rossa	50	2019	***Latin America***			
Norway	Martin Linge	40	2020	Brazil	Tartaruga Verde/Tartaruga Mestica	150	2018
Norway	Johan Sverdrup ph 1	440	2019	Brazil	Lula Ext. Sul (P-69)	150	2018
Norway	Johan Sverdrup ph 2	220	2022	Brazil	Buzios 1 & 2 (P-74, P-75)	300	2018
Norway	Johan Castberg	190	2022	Brazil	Buzios 3 & 4 (P-76,P-77)	300	2019
Norway	Snorre Expansion Project	100	2021	Brazil	Berbigào (P-68)	150	2019
Norway	Trestakk	35	2020	Brazil	P-67 (Lula Norte)	150	2019
Norway	Skarv	40	2021	Brazil	Atapu (P70)	150	2020
Norway	Oda	30	2019	Brazil	Sepia	180	2021
Norway	Njord/Bauge/Fenja	90	2021	Brazil	Libra ph 1	180	2021
Norway	Yme Redevelopment	30	2021	Brazil	Buzios 5	150	2021
UK	Clair Ridge	120	2018	Brazil	Parque das Baleeias	100	2021
UK	Mariner	55	2019	Brazil	Marlim redevelopment (Module 1)	80	2022
UK	Cheviot	20	2020	Brazil	Libra ph 2	180	2022
UK	Penguin	45	2021	Brazil	Marlim redevelopment (Module 2)	70	2023
OECD Asia Oceania				Brazil	Itapu	120	2023
Australia	Ichthys	130	2018	Guyana	Liza ph 1	120	2020
Australia	Prelude	40	2019	Guyana	Liza ph 2	220	2022
Australia	Greater Enfield	40	2020	Guyana	Liza ph 3	180	2023
Africa				***Middle East***			
Kenya	South Lokichar	50	2023	Oman	Ghazeer	50	2021
Uganda	Albert Basin (Kingfisher)	80	2022	Qatar	North Field Expansion	100	2024
Senegal	SNE Phase 1	100	2023				

Table 3b
Selected OPEC upstream project start-ups

Country	Project	Peak Capacity (kbd)	Start Year	Country	Project	Peak Capacity (kbd)	Start Year
Crude Oil Projects				***NGL & Condensate Projects***			
Angola	East Hub Development	80	2017	Iran	South Pars 20-21 (condensate)	75	2017
Angola	Kaombo	230	2018	Nigeria	Gbaran-Ubie Phase 2	20	2017
Angola	Zinia 2, Clov 2, Dalia 3	110	2020-21				
Kuwait	Ratqa	270	2019				
Nigeria	Egina	200	2019				
Saudi	Khurais Expansion	300	2018				
Saudi	Marjan Expansion	300	2019				
Saudi	Zuluf Expansion	600	2020				
Saudi	Berri Expansion	250	2020				
UAE	Sarb	100	2018				
UAE	Nasr	65	2018				
UAE	Upper Zakum (Phase 2)	1000	2019				

Table 3c
Non-OPEC supply - Oil Market Report and WEO definitions
(million barrels per day)

	Calculation	2010	2017	2018	2019	2020	2021	2022	2023	2024
Medium Term Oil Market Report definitions										
NON-OPEC SUPPLY		53.3	59.9	62.6	64.3	66.3	67.3	67.9	68.4	68.7
Processing gains		2.1	2.3	2.3	2.3	2.4	2.4	2.4	2.5	2.5
Global biofuels		1.8	2.5	2.6	2.7	2.8	2.9	3.0	3.1	3.1
NON-OPEC PRODUCTION (excl. processing gains and biofuels)	1	49.4	55.1	57.6	59.3	61.0	62.0	62.5	62.9	63.1
Crude	2	43.0	46.4	48.2	49.4	50.9	51.6	51.9	52.1	52.0
of which: Condensate	3	3.0	3.5	3.6	3.9	4.1	4.1	4.2	4.2	4.1
Tight oil	4	0.7	5.3	6.7	7.9	8.9	9.6	10.0	10.2	10.3
Un-upgraded bitumen	5	0.7	1.6	1.9	1.7	1.8	2.0	2.0	2.0	2.1
NGLs	6	5.1	7.1	7.7	8.0	8.3	8.4	8.6	8.7	8.9
Syncrude (Canada)	7	0.8	1.0	1.1	1.1	1.1	1.1	1.1	1.1	1.1
CTL, GTL, kerogen oil and additives[1]	8	0.5	0.6	0.7	0.7	0.8	0.8	0.9	1.0	1.0
World Energy Outlook definitions										
NON-OPEC PRODUCTION (excl. processing gains and biofuels)	=1	49.4	55.1	57.6	59.3	61.0	62.0	62.5	62.9	63.1
Conventional		46.7	46.6	47.3	47.9	48.4	48.5	48.5	48.6	48.6
Crude oil	=2-3-4-5	38.6	35.9	36.0	35.9	36.1	35.9	35.7	35.7	35.5
Natural gas liquids (total)	=3+6	8.1	10.6	11.3	12.0	12.4	12.6	12.7	12.9	13.1
Unconventional		2.7	8.5	10.3	11.4	12.6	13.5	14.0	14.3	14.5
EHOB (incl. syncrude)[2]	=5+7	1.5	2.7	2.9	2.8	2.9	3.1	3.1	3.1	3.2
Tight oil	=4	0.7	5.3	6.7	7.9	8.9	9.6	10.0	10.2	10.3
CTL, GTL, kerogen oil and additives[1]	=8	0.5	0.6	0.7	0.7	0.8	0.8	0.9	1.0	1.0

1 CTL = coal to liquids; GTL = gas to liquids.

2 Extra-heavy oil and bitumen

Table 4

WORLD REFINERY CAPACITY ADDITIONS

(thousand barrels per day)

	2018	2019	2020	2021	2022	2023	2024	Total
Refining Capacity Additions and Expansions[1]								
OECD Americas	160	20	20	50		350	250	690
OECD Europe		200						200
OECD Asia Oceania	90			-70				-70
FSU	124	230			30	100		360
Non-OECD Europe								
China	48	1,440	240	800	720	400		3,600
Other Asia	236	448	173	350	363	280	160	1,773
Latin America		-204		165	33			-6
Middle East	314	553	57	635	233	250		1,728
Africa	30	18			585	120	100	823
Total World	1,002	2,705	490	1,930	1,964	1,500	510	9,098
Upgrading Capacity Additions[2]								
OECD Americas	55			60		32		92
OECD Europe	223			43		20		63
OECD Asia Oceania	81	-38						-38
FSU	127	202	560	75	120	60	35	1,052
Non-OECD Europe		13	25		20			58
China	76	769	313	270	89	162		1,603
Other Asia	130	171	14	247	140	63	36	671
Latin America	100	-78			29			-49
Middle East	116	288	80		316	138		822
Africa	57		70	25	240			335
Total World	965	1,327	1,062	720	954	475	71	4,609
Desulphurisation Capacity Additions[3]								
OECD Americas	75							
OECD Europe	164	79						79
OECD Asia Oceania	57	-100	37					-63
FSU	73	29	238	20				287
Non-OECD Europe						20		20
China	62	850	376	194		296		1,716
Other Asia	276	255	269	253	90	70	150	1,087
Latin America		-217			64			-153
Middle East	180	527	343	658	312	10		1,850
Africa	42		4		200			204
Total World	929	1,424	1,267	1,125	666	396	150	5,027

1 Comprises new refinery projects or expansions to existing facilities including condensate splitter additions. Assumes zero capacity creep.

2 Comprises gross capacity additions to coking, hydrocracking, residue hydrocracking, visbreaking, FCC or RFCC capacity.

3 Comprises additions to hydrotreating and hydrodesulphurisation capacity.

Table 4a
WORLD REFINERY CAPACITY ADDITIONS:
Changes from Oil 2018
(thousand barrels per day)

	2017	2018	2019	2020	2021	2022	2023	Total
Refining Capacity Additions and Expansions[1]								
OECD Americas			-27		50			23
OECD Europe								
OECD Asia Oceania	40	90			-70			20
FSU		-189	140	-30		30		-49
Non-OECD Europe								
China	120	-152	990	40	400	720	50	2,048
Other Asia	4		210	-37	70	-361	-20	-138
Latin America			-204		165			-39
Middle East	-37	-16	153	-25	20	-60	-40	32
Africa			-42	-30	-500	555	20	3
Total World	127	-267	1,220	-82	135	884	10	1,900
Upgrading Capacity Additions[2]								
OECD Americas	-32				60		32	92
OECD Europe		96	-106					-10
OECD Asia Oceania		12	-67					-55
FSU		-10	-25	258	-105	-10	30	138
Non-OECD Europe			-20			20		
China		-153	505	-87	-252	89	-97	5
Other Asia		20	126	-86	167	43		271
Latin America			-78					-78
Middle East		138		69			138	345
Africa			-25		-215	240		
Total World	-32	103	310	154	-345	382	103	708
Desulphurisation Capacity Additions[3]								
OECD Americas								
OECD Europe			114	-35				79
OECD Asia Oceania			57	-100	37		213	206
FSU			-83	-220	28			-275
Non-OECD Europe							-65	-65
China		32	-94	730	-88	-552		28
Other Asia			37	205	110	123	-20	455
Latin America				-217				-217
Middle East		-39	10		95		159	225
Africa					4	-200	200	4
Total World		-7	41	364	186	-629	486	441

1 Comprises new refinery projects or expansions to existing facilities including condensate splitter additions. Assumes zero capacity creep.

2 Comprises stand-alone additions to coking, hydrocracking or FCC capacity. Excludes upgrading additions counted under 'Refinery Capacity Additions and Expansions' category.

3 Comprises stand-alone additions to hydrotreating and hydrodesulphurisation capacity. Excludes desulphurisation additions counted under 'Refinery Capacity Additions and Expansions' category.

Table 4b
SELECTED REFINERY CRUDE DISTILATION PROJECT LIST

Country	Project	Capacity (kbd)[1]	Start Year	Country	Project	Capacity (kbd)[1]	Start Year
OECD Americas				***China***			
Mexico	Petroleos Mexicanos - Dos Bocas	250	2024	China	Hengli Petrochemical - Dalian	400	2019
United States	ExxonMobil - Beaumont	350	2023	China	PetroChina/PDVSA - Jieyang	400	2023
United States	Meridian Resources - Davis North Dakota	50	2021	China	Rongsheng Petrochemical - Zhoushan island phase 1	400	2019
United States	Calumet Montana Refining - Great Falls	20	2020	China	Rongsheng Petrochemical - Zhoushan island phase 2	400	2022
United States	Valero - St. Charles	20	2019	China	Shenghong Petchem - Lianyungang	320	2022
OECD Europe				China	Sinopec/USI Taiw an(Gulei) - Zhangzhou	320	2021
Turkey	Socar - Aliaga/Izmir	200	2019	China	Sinopec - Zhenhai	300	2021
OECD Asia Oceania				China	Sinopec/KPC - Zhanjiang	200	2020
Japan	Cosmo Oil - Chiba	-70	2021	China	CNOOC - Ningbo Zhejiang	120	2021
Middle East			2018	China	PetroChina - Renqiu, Hebei	100	2019
Bahrain	Bahrain Petroleum Co. - Sitra	355	2022	China	CNOOC - Dongying	100	2019
Bahrain	Bahrain Petroleum Co. - Sitra	-262	2022	China	Zhuhai Huafeng - Zhuhai	100	2019
Iran	National Iranian Oil Co. - Abadan	195	2020	China	Dragon aromatics/Fuhaichuang - Zhangzhou	100	2019
Iran	National Iranian Oil Co. - Abadan	-233	2020	China	Shenchi Chemical - Dongying	100	2019
Iraq	INOC-ORA - Karbala	140	2022	China	Wudi Xinyue - Binzhou	70	2019
Iraq	South Refining Company - Basra	65	2019	China	Xintai Petrochemical - Zibo	70	2019
Iraq	Qaiw an - Bazian	20	2021	China	Sinochem - Quanzhou	60	2021
Jordan	Jordan Petroleum Refinery - Zarqa	20	2023	China	Sinopec Luoyang Sub - Luoyang	40	2020
Kuw ait	Kuw ait National Petroleum Co. - Al-Zour	615	2021	***Other Asia***			
Kuw ait	Kuw ait National Petroleum Co. - Mina Abdulla	200	2019	Bangladesh	BPC / KPI - Chittagong	60	2024
Kuw ait	Kuw ait National Petroleum Co. - Mina al-Ahmadi	-112	2019	Brunei	Zhejiang Hengyi Petrochemicals - Pulau Muara Besar	280	2023
Oman	Oman Refinery Co. - Duqm	230	2023	Brunei	Zhejiang Hengyi Petrochemicals - Pulau Muara Besar	148	2019
Oman	Sohar Bitumen Refinery - Sohar	30	2020	india	HPCL - Visakhapatnam	150	2021
Saudi Arabia	Saudi Aramco - Jizan	400	2019	India	Indian Oil - Koyali	100	2022
United Arab Emira	ENOC - Jebel Ali	65	2020	India	Indian Oil - Panipat	100	2022
FSU				India	HPCL - Mahul, Mumbai	60	2020
Azerbaijan	SOCAR - Heydar Aliev	30	2022	India	Indian Oil - Barauni	60	2021
Russia	Tatneft/Taneko - Nizhnekamsk	140	2019	india	BPCL - Mumbai	56	2020
Russia	Yayski - Irkutsk	60	2019	India	Bongaigaon Refinery & Petrochemicals Ltd. - Bongaigao	7	2020
Russia	Gazprom Neft - OMSK	30	2019	Indonesia	Pertamina - Balikpapan, Kalimantan	100	2024
Uzbekistan	Uzbekneftegaz - Jizzakh	100	2023	Indonesia	Pertamina/Saudi Aramco - Cilacap, Central Java	50	2021
Non-OECD Americas				Malaysia	Petronas - Rapid	300	2019
Brazil	Petrobras - COMPERJ	165	2021	Malaysia	Petron - Port Dickson	90	2021
Jamaica	Petrojam - Kingston	-36	2019	Philippines	Petron Corp. - Limay, Bataan	50	2020
Peru	Petroperu - Talara, Piura	33	2022	Thailand	Thai Oil - Sriracha	126	2022
Trinidad & Tobago	Petrotrin - Pointe-a-Pierre	-168	2019	Vietnam	Petro Vietnam/gazpromNeft - Quang Ngai/Dung Quat	37	2022
Africa							
Algeria	Naftec SPA - Tiaret	100	2024				
Algeria	Sonatrach - Algiers	18	2019				
Angola	Sonangol - Cabinda	60	2023				
Egypt	MIDOR - Alexandria	60	2023				
Nigeria	Dangote Oil Refining Company - Lekki	500	2022				
South Sudan	Trinity Energy - Paloich	25	2022				
Uganda	Total/Tullow /CNOOC - Albertine Graben	60	2022				

Table 5
World Ethanol Production[1]

(thousand barrels per day)

	2016	2017	2018	2019	2020	2021	2022	2023	2024
OECD North America	1,027	1,062	1,084	1,084	1,099	1,108	1,108	1,109	1,109
United States	997	1,032	1,050	1,046	1,060	1,068	1,068	1,068	1,068
Canada	29	30	32	35	35	35	35	35	35
OECD Europe	78	88	91	90	98	95	93	91	90
Austria	5	5	4	4	4	3	3	3	4
Belgium	5	6	6	6	6	6	6	6	6
France	12	13	16	14	14	13	13	13	12
Germany	15	14	17	16	18	17	17	17	16
Italy	0	0	0	0	1	0	0	0	0
Netherlands	2	6	6	6	7	7	7	6	6
Poland	4	4	4	4	6	7	6	6	6
Spain	6	7	6	6	8	7	7	7	7
UK	8	11	9	9	11	11	11	11	11
OECD Pacific	4	3	5	5	8	8	8	8	8
Australia	4	3	4	4	6	7	7	7	7
Total OECD	**1,109**	**1,153**	**1,180**	**1,179**	**1,205**	**1,211**	**1,210**	**1,209**	**1,208**
FSU	2	2	3	4	4	4	4	4	4
Non-OECD Europe	1	1	1	1	2	2	2	2	2
China	56	56	70	83	106	135	152	164	175
Other Asia	47	42	57	62	80	90	95	99	110
India	19	14	24	27	37	39	41	43	48
Indonesia	1	1	1	1	1	1	1	1	1
Malaysia	0	0	0	0	0	0	0	0	0
Philippines	4	4	4	5	6	7	7	7	8
Singapore	1	1	1	1	1	1	1	1	1
Thailand	21	21	26	27	31	35	37	39	45
Latin America	532	518	590	578	603	633	655	685	715
Argentina	15	19	20	20	20	20	20	21	21
Brazil	493	478	547	537	555	583	604	629	657
Colombia	7	7	8	8	9	10	10	10	10
Middle East	1	2	1	1	1	1	1	1	1
Africa	4	5	6	7	10	11	12	12	12
Total Non-OECD	644	626	729	738	806	875	921	966	1,020
Total World	**1,752**	**1,779**	**1,909**	**1,917**	**2,011**	**2,086**	**2,130**	**2,175**	**2,227**

1 Volumetric production; to convert to energy adjusted production, ethanol is assumed to have 2/3 energy content of conventional gasoline.

Table 5a

World Biodiesel Production

(thousand barrels per day)

	2016	2017	2018	2019	2020	2021	2022	2023	2024
OECD North America	109	111	127	143	150	156	164	175	184
United States	102	104	120	136	142	148	155	167	175
Canada	7	7	7	7	8	8	9	9	9
OECD Europe	231	265	251	275	293	277	264	259	257
Austria	6	5	6	6	5	5	5	5	5
Belgium	5	6	7	7	8	6	6	6	6
France	44	47	38	50	54	51	49	48	50
Germany	60	62	60	62	66	62	59	57	54
Italy	11	13	24	28	27	26	25	24	24
Netherlands	28	37	31	32	34	31	30	30	30
Poland	17	17	18	18	20	18	18	18	17
Spain	26	34	25	28	30	26	22	21	21
UK	7	9	9	9	9	9	9	9	9
OECD Pacific	11	14	14	15	14	14	14	14	14
Australia	1	1	1	1	1	1	1	1	1
Total OECD	**352**	**390**	**393**	**432**	**458**	**447**	**442**	**448**	**455**
FSU	4	4	4	4	4	4	4	4	4
Non-OECD Europe	4	5	5	6	6	6	5	5	4
China	15	15	18	21	25	28	33	36	40
Other Asia	123	114	133	149	171	181	202	214	221
India	3	3	3	3	3	4	4	4	4
Indonesia	63	53	69	86	92	98	102	108	114
Malaysia	15	11	14	15	18	20	20	21	21
Philippines	4	4	4	4	4	4	4	4	4
Singapore	18	19	16	15	20	20	36	41	41
Thailand	20	25	27	27	34	35	36	36	36
Latin America	132	145	155	163	162	165	164	168	171
Argentina	52	56	47	46	46	44	39	37	35
Brazil	65	74	92	94	98	103	107	112	118
Colombia	9	10	9	10	11	12	12	12	12
Middle East	0	1	1	1	1	1	1	1	1
Africa	3	3	4	4	5	5	5	6	6
Total Non-OECD	282	287	320	348	373	389	414	432	447
Total World	633	677	713	781	831	836	856	881	902

6. APPENDIX

Table 6.1. US petrochemical capacity addition

US projects	Location	Capacity ('000 t/y)	Feedstock	Maximum demand (kb/d)	Scheduled year
DowDupont	Orange, Texas	500	Ethane	29	2019
Formosa Plastics	Point Comfort, Texas	1 250	Ethane	72	2019
Indorama Ventures Olefins LLC	Westlake, Louisiana	420	Ethane/Propane	27	2019
Lotte Chemical, Axiall Corporation	Westlake, Louisiana	1 000	Ethane	58	2019
Sasol	Lake Charles, Louisiana	1 500	Ethane	87	2019
Shintech Inc.	Plaquemine, Louisiana	500	Ethane	29	2019
Bayport Polymers LLC	Port Arthur, Texas	1 000	Ethane	58	2020
Formosa Plastics	Point Comfort, Texas	750	Propane (PDH)	27	Possible 2020
Total Petrochemicals and Refining USA	Port Arthur, Texas	1 000	Ethane	58	2021
ExxonMobil SABIC	Corpus Christi, Texas	1 800	Ethane	104	2022
Shell Chemical Appalachia	Monaca, Pennsylvania	1 600	Ethane	92	2022
Formosa Petrochemicals	St. James, Louisiana	1 200	Ethane	69	2024
PTTGC America	Belmont County, Ohio	1 500	Ethane	87	2024
Total		**14 020**		**796**	

Source: Press reports, company reports.

Table 6.2. Chinese petrochemical capacity addition

Chinese projects	Location	Capacity ('000 t/y)	Feedstock	Maximum demand (kb/d)	Scheduled year
Hengli Petrochemicals	Dalian, Liaoning	1 500	Naphtha	121	2019
Oriental Energy	Caofedian, Hebei	660	Propane (PDH)	24	2019
SP Chemicals	Taixing, Jiangsu	650	Ethane/Propane /Butane	42	2019
Zhejiang Satellite Energy Co. PDH Phase II	Pinghu, Zhejiang	450	Propane (PDH)	16	2019
Dongguan Juzhengyuan	Dongguan, Guangdong	1 200	Propane (PDH)	44	2020
Sinopec-Kuwait Petroleum corp	Zhanjiang, Guangdong	800	Naphtha	64	2020
Rongsheng Petrochemical Co., Ltd.	Zhoushan, Zhejiang	600	Propane (PDH)	22	2020
Fujian Meide Petrochemical - Phase II	Fuzhou, Fujian	660	Propane (PDH)	24	Possible 2020
Haiwei Group Hengshui PDH II	Hengshui, Hebei	500	Propane (PDH)	18	Possible 2020

Chinese Projects *(continued Table 6.2)*	Location	Capacity ('000 t/y)	Feedstock	Maximum demand (kb/d)	Scheduled year
Haiwei Group Huanghua PDH I	Huanghua, Hebei	500	Propane (PDH)	18	Possible 2020
Ningbo Fortune Petrochemical - Phase II	Ningbo, Zhejiang	660	Propane (PDH)	24	Possible 2020
Oriental Energy	Tangshan, Hebei	660	Propane (PDH)	24	Possible 2020
Formosa Plastics	Ningbo, Zhejiang	600	Propane (PDH)	22	2021
Hengli Petrochemicals	Dalian, Liaoning	300	Propane (PDH)	11	2021
Sinochem Quanzhou Petrochemical	Quanzhou, Fujian	1 000	Naphtha	80	2021
Sinopec-SK Wuhan Petrochemical	Wuhan, Hubei	300	Naphtha	24	2021
Lianyungang Petrochemical Co. I	Lianyungang, Jiangsu	1 250	Ethane	72	2021
Lianyungang Petrochemical Co. II	Lianyungang, Jiangsu	1 250	Ethane	72	2021
Haiwei Group Huanghua PDH II	Huanghua, Hebei	500	Propane (PDH)	18	Possible 2021
Liaoning Bora Petrochemicals	Panjin, Liaoning	1 000	Naphtha	80	2022
Sinopec Gulei JV, Zhangzhou	Zhangzhou, Fujian	800	Naphtha	64	2022
Shenghong Petrochemical Group	Lianyungang, Jiangsu	1 100	Naphtha	88	Possible 2022
CNOOC Hainan ethylene project	Yangpu, Hainan	1 000	Propane/Butane	71	Possible 2023
Zhejiang Rongsheng Holding Group I	Zhoushan, Zhejiang	1 400	Naphtha	113	Possible 2023
Zhejiang Rongsheng Holding Group II	Zhoushan, Zhejiang	1 400	Naphtha	113	Possible 2023
China Petrochemical Development Corp (CPDC)	Ningbo, Zhejiang	600	Propane (PDH)	22	Possible 2024
Total		**21 340**		**1 292**	

Source: Press reports, company reports.

Table 6.3. Russian petrochemical capacity addition

Russian projects	Location	Capacity ('000 t/y)	Feedstock	Maximum demand (kb/d)	Scheduled year
Gazprom Cracker	Novy Urengoy	420	Ethane	24	2020
Sibur ZapSibNeftekhim Ethylene	Tobolsk	1 500	Ethane/Propane /Butane	96	2020
Nizhnekamskneftekhim (NKNC) Ethylene Complex	Tatarstan	600	Ethane/Naphtha	41	2022
Gazprom Neftekhim Salavat (GNS) All-Russia Gas Chemistry Center	Salavat	1 000	Ethane/Naphtha	69	Possible 2022
Total		**3 520**		**231**	

Source: Press reports, company reports.

Table 6.4. Iran's petrochemical capacity addition

Iranian projects	Location	Capacity ('000 t/y)	Feedstock	Maximum demand (kb/d)	Scheduled year
Ilam Petrochemical Company	Ilam	450	Ethane	26	Possible 2020
Gachsaran Petrochemical	Gachsaran	1 000	Ethane	58	Possible 2022
Mehr Petrokimiya Co PDH	South Pars	450	Propane (PDH)	16	2022
Salman-e-Farsi PC PDH	Bandar Imam	450	Propane (PDH)	16	2022
Total		**2 350**		**117**	

Source: Press reports, company reports.

Table 6.5. Petrochemical capacity addition in selected countries

Selected projects	Location	Capacity ('000 t/y)	Feedstock	Maximum demand (kb/d)	Scheduled year
LG Chemical (Expansion)	Daesan, Chungcheong, Korea	230	Naphtha	18	2019
Hanwha Total Petrochemicals	Daesan, Chungcheong, Korea	350	Propane	25	2019
Petronas Rapid Petrochemical Complex	Pengerang, Johor, Malaysia	1 200	Naphtha	96	2020
PTT Global Chemical	Map Ta Phut, Rayong, Thailand	500	Naphtha/LPG	38	2020
Oman Oil Refineries and Petroleum Industries Co.	Sohar, Liwa, Oman	900	Naphtha	72	2021
PTTGC Chandra Asri Expansion	Java, Indonesia	40	Naphtha	3	2021
JG Summit (Expansion)	Batangas City, Philippines	160	Naphtha	13	2021
SCG-Dow (MOC) (Expansion)	Map Ta Phut, Rayong, Thailand	250	Naphtha/LPG	19	2021
Borealis AG	Antwerp, Belgium	750	Propane (PDH)	27	2022
NOVA Chemicals	Corunna, ON, Canada	450	Ethane	26	2022
HPCL-Mittal Energy Ltd.	Bhatinda, Punjab, India	1 200	Naphtha /Kerosene	96	2022
Lotte Chemical Hyundai	Daesan, Chungcheong, Korea	750	Naphtha/LPG	57	2022
LG Chemical (Expansion)	Yeosu, South Jeolla, Korea	800	Naphtha	64	2022
Carbon Holding Tahrir Petrochemicals	Ain Sokhna, Egypt	1 500	Naphtha	121	2023
Lotte Chemical Titan Merak Banten Naphtha Cracker	Banten, Indonesia	1 000	Naphtha	80	2023
GS Caltex	Yeosu, South Jeolla, Korea	700	Naphtha/LPG	51	2023
INEOS AG	Antwerp, Belgium	750	Propane (PDH)	27	2023

Selected Projects (continued Table 6.5)	Location	Capacity ('000 t/y)	Feedstock	Maximum demand (kb/d)	Scheduled year
PTTGC Chandra Asri	Java, Indonesia	1 000	Naphtha	80	2024
Yeochun NCC	Yeosu, South Jeolla, Korea	335	Naphtha	27	Possible 2021
Kuwait Petrochemicals and Refining Company (KPRC)	Al-Zour, Kuwait	1 500	Ethane/Naphtha /Propane	104	Possible 2022
Oman Oil Duqm Petrochemical Complex Mixed Cracker	Duqm, Oman	1 100	Naphtha/Ethane	76	Possible 2023
INEOS Rafnes Cracker 2	Bamble, Norway	500	Ethane	29	Possible 2023
HPCL Rajasthan Refinery	Barmer, Rajasthan, India	820	Naphtha	66	Possible 2024
Total		**17 785**		**1 298**	

Source: Press reports, company reports.

Table 6.6. Planned investments in Permian/Eagle Ford crude and condensate pipelines

Project	Extra Capacity (kb/d)	Length (km)	Timeline	Operator	Type
Cactus 2	100	838	1Q19	Plains	New Build
Sunrise	175	950	2Q19	Plains	New Build/Conv
Seminole NGL Conversion	200	1 360	1Q19	Enterprise	Conversion
EPIC Pipeline	200	1 127	3Q19	TexStar	New Build
EPIC NGL Conversion	400	740	3Q19	TexStar	Conversion
Cactus 2	200	838	3Q19	Plains	Expansion
Gray Oak	800	843	4Q19	P66	New Build
EPIC Pipeline	400	1 127	1Q20	TexStar	New Build
EPIC NGL Conversion	-400	740	1Q20	TexStar	Conversion
Cactus 2	370	838	2Q20	Plains	Expansion
Jupiter	500	1 078	4Q20	Jupiter	New Build
Permian Gulf Coast	600	966	3Q20	ETP, Magellan, Delek, MPLX	New Build
Wink to Webster	1 000	988	3Q21	ExxonMobil, Plains	New Build
Total	**4 545**				

Source: Company reports.
Note: EPIC's NGL pipeline conversion will be temporary.

Table 6.7. Planned investments in Canadian crude and condensate pipelines

Project	Extra Capacity (kb/d)	Length (km)	Timeline	Operator	Type
Mainline Optimisation	100	-	4Q19	Enbridge	Expansion
Line 3 Replacement	175	1,659	4Q20	Enbridge	Expansion
Keystone XL	200	1,897	2Q21	TransCanada	New Build
Trans Mountain	200	980	4Q21	Canadian govt	New Build
Total	**1 920**				

Source: Company reports.

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Oil 2019, the International Energy Agency's annual outlook for global oil markets, examines the key issues in demand, supply, refining and trade to 2024. This year, the report covers the following themes:

- A changed supply picture led by the rise of the United States in world markets thanks to rapidly-growing shale oil production, as it becomes a net exporter of crude oil and products.

- Supply growth in the non-OPEC world, including Brazil, Canada, Norway and Guyana; and a falling capacity for the OPEC producers.

- Demand growth underpinned by China and India and by the growing importance of petrochemicals as the industry invests to meet rising consumer demand.

- And a detailed analysis of how the refining industry is grappling with the International Maritime Organisation's new marine fuel rules, growing excess capacity, and the changing patterns of global oil trade.

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