Upstream Oil & Gas Exploration And Production

October – 2021

The Al-Attiyah Foundation

The Al-Attiyah Foundation is proudly supported by:

INTRODUCTION

UPSTREAM OIL & GAS EXPLORATION AND PRODUCTION

The COVID-19 pandemic led to a major drop and rebound in global oil and gas prices. But uncertainty is growing about the direction for future hydrocarbon demand and pricing. The upstream oil and gas industry must think carefully about where it should allocate its capital, and transform their operations through portfolio restructuring and the introduction of new technologies and business models, in order to improve profitability.

How can oil and gas companies transform their upstream operations? How will long-term market trends change upstream production strategies? And what is the role for new oil and gas production in a carbon-constrained world?

Energy Industry Report

This research paper is part of a 12-month series published by The Al-Attiyah Foundation every year. Each in-depth research paper focuses on a prevalent energy topic that is of interest to The Foundation's members and partners. The 12 technical papers are distributed in hard copy to members, partners, and universities, as well as made available online to all Foundation members.

EXECUTIVE SUMMARY

- The oil and gas value chain must reconsider its upstream strategy and transform its portfolios through low-cost operations, reduce emissions footprint, and cut overall capital intensity. Additional free cashflow could either be invested in diversifying their operations away from oil and gas or returned to shareholders.
- In an uncertain global oil and gas market, investment trends in the upstream segment reflect a preference for low-cost, low-carbon resources through careful resource selection and capital discipline. The balance of investments is shifting from IOCs to NOCs.
- NOCs will lead the way in global oil and gas production, producing large volumes from their low-cost conventional onshore resources, with supermajors and large IOCs preferring core assets that provide small to modest growth, international independents focusing on growth opportunities through high-impact exploration projects, and US-independents focusing on unconventional shale oil and gas resource development and production across the United States.
- NOCs in the Middle East will dominate global oil production in the long-term, accounting for 55% of global oil production in 2050. Their dominance will be the result of their ability to produce the "cheapest barrel" rather than "more barrels", which will be supported by their abundant low-cost conventional and majority onshore oil resource base. And despite the expected long-term decline in global demand, the leading upstream operators in the Middle East will continue to expand output, with an increasing attention to unconventional gas.
- Global natural gas production is projected to increase by 1% / year to 4.4 Tcm in 2030, before declining by 1% / year to 3.9 Tcm in 2050. NOCs in Middle East and Russia, and US independents will jointly supply 69% of the global natural gas output in 2030, mainly through their existing operations on large onshore fields in Western Siberia in Russia, the North Field in Qatar, the South Pars field in Iran, and the major US shale/tight formations of the Marcellus and Permian Basin.
- Upstream operators have a key role to play mitigating climate change. There are various cost-effective technologies and opportunities that could be utilised to reduce the intensity of emissions from core upstream operations by minimising the deliberate and unintentional flaring of associated natural gas, tackling methane emissions, and integrating renewables in upstream operations.

TRANSFORMING UPSTREAM OPERATIONS

The COVID-19 pandemic produced a collapse in global oil prices in 2020 that slashed earnings, cashflows, and investor returns on global upstream portfolios. Despite a strong recovery in 2021 and projected into 2022, operators must reconsider their upstream strategy and think carefully about where they should allocate their capital.

Before the COVID-19 crisis started, the oil and gas value chain was already competing under different strategies, with some diversifying their operations by expanding into low-carbon growth areas, and others continuing to re-invest and expand their upstream portfolios.

A true test of an upstream leader is increasing investor returns on its exploration and production projects. And an effective upstream business strategy is one that begins with a transformation of operations to deliver robust investor returns, regardless of the uncertainty in global markets.

The financial results of the international upstream industry were poor from 2014-20. However, through disciplined risk management and capital allocation, cutting operational costs, and leveraging core capabilities, upstream operators can generate additional cashflow from their operations, essential whether the aim is to return cash to shareholders via dividends and buybacks, to reinvest in hydrocarbon growth projects, or to move into new energy businesses.

Weaker earnings and investor return from upstream projects, even at higher prices, have been a growing problem for petroleum companies. Following the global oil price crash in late 2014, the six supermajors spent

a total of ~US$ 615 billion on their upstream operations, which accounted for ~85% of their total capital employed[i]. Despite the large capital expenditure, their returns on capital employed (ROCE) had been slowly declining over the last decade.

When compared with oil prices in different years, the ROCE from upstream operations was strikingly different. In 2006 and 2019, Brent oil price was trading at US$ 65 / bl; however, the median ROCE on upstream projects for IOCs was 27% in 2006 and 3.5% in 2019. One of the reasons for the disparity is the composition of upstream portfolios. Since the 1970s, and again from the early 2000s, the resource-abundant NOCs have gradually reduced the access for IOCs to operate on low-cost upstream assets that produced good earnings. Those companies that invested heavily in US shale enjoyed production growth but rarely positive cashflow.

Over time, IOCs continued to operate a portfolio of conventional upstream assets, which consisted of onshore and shallow water projects under agreeable contractual terms. These assets provided proven returns over different price cycles. However, today these assets comprise less than ~50% their portfolio with most of them marked for divestment because of their declining contribution to production and reserves. This includes what were core assets in and around the North Sea, Alaska and parts of south-east Asia and Australia.

In an effort to increase upstream production, between 2005 to 2014, supermajors spent ~US$ 1 trillion on restructuring their portfolios, which consisted of technically challenging and carbon-intensive assets such as deepwater, remote LNG megaprojects, and unconventional resources projects in the United States and Canada.

As the pressure to grow upstream production increased, so did their portfolio capital intensity, which further added pressure to yield investor returns. The average capital employed per barrel by supermajors increased from US$ 47 in 2006 to US$ 111 in 2018, which in turn exposed these returns to volatile global prices.

Moreover, in the past, majors and supermajors took a view that the high cost of upstream production would eventually be absorbed by a rebound in global prices. This view does not hold any more, given views of "lower-for-longer" after the late 2014 price crash, the 2020 onset of the pandemic and, in the longer term, predictions of "peak oil demand". These companies re-strategised by shifting their capital expenditure from solely high-cost resource and frontier plays to a more diversified upstream portfolio, which consisted of various assets where they could achieve high productivity and reduced costs. They also re-organised their portfolios in terms of geography, the types of assets, levels of country risk, and opportunities for value chain integration.

Improving profitability and investor returns for an upstream portfolio is not an easy mission, mainly because the decisions on where to deploy their capital, is an almost existential choice. European IOCs are under the impression that the global oil demand is close to peaking or has already peaked, and the emergence of a low carbon energy landscape must be met with a re-allocation of capital into low-carbon energy businesses. At the same time, these companies continue to rely on earnings from their integrated operations (including their

large upstream portfolios, and increasingly important trading activities), which are used to finance new investments in renewables, bioenergy, hydrogen, and carbon capture. As Patrick Pouyanné, CEO of TotalEnergies, has said, "I'm proud to be black and green, because if I don't have the black part, which is delivering cash flows, I don't have the green part[ii]."

In contrast to the European IOCs, US-based IOCs such as ExxonMobil, Chevron and ConocoPhillips are continuing to re-invest in their traditional upstream businesses. Growth areas for them mainly consist of unconventional oil and gas projects, and a few select deepwater opportunities such as Guyana. For these companies, maintaining the dividend commitments to their shareholders is dependent on continued investment in new upstream assets and production growth.

Nonetheless, regardless of the strategic direction the upstream operators take, they must restructure or reorganise their upstream portfolios. They can achieve this through a strategy of low-cost operations combined with a reduced emissions footprint and reducing the overall capital intensity of their upstream portfolio.

DECLINING OIL MARKETS WILL PRESSURE UPSTREAM OPERATORS

Following the COVID-19 induced market shock of 2020, demand for oil has rebounded strongly, which may continue leading into 2023-30 after which, it is expected to gradually decline to ~50% of the 2018 demand levels by 2050[iii]. Given the disparity of the ongoing energy transition across different countries, the pace and nature of change in oil demand will be different across each geography. The speed of this transition depends on the robustness of global climate policy, and the pace of adoption of non-oil technologies, notably electric vehicles (EVs).

Demand for oil will continue to increase across most of the Asia-Pacific region and is expected to grow in South Asia till 2040, Middle East and Southeast Asia till the early 2030s, and China till the late 2020s. Collectively, these regions will account for 53% of global demand for oil in 2050, in contrast to 45% in 2020. The increase in demand in these regions will overtake the fall in demand across Europe and North America, which will collectively account for just 20% of the global demand in 2050.

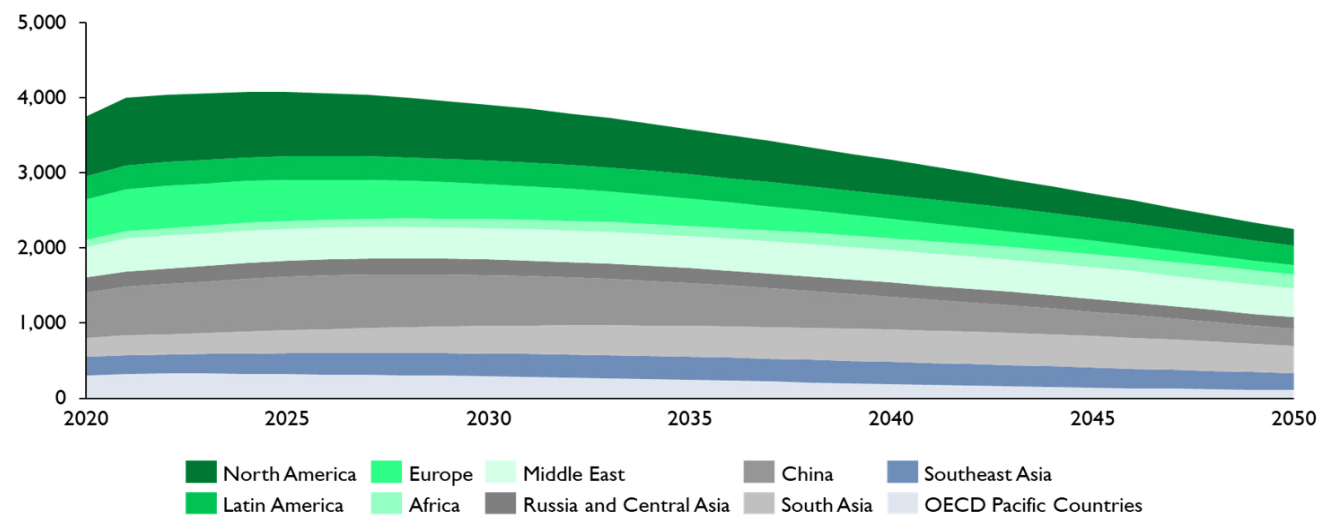
With the exception of China, across the Asia-Pacific region, and more so in South Asia, demand for oil will be driven by the transport sector, and particularly led by a significant increase in the vehicle fleet, which will continue to be dominated by internal combustion engine vehicles (ICEVs). In addition, the region's refining, processing, and the petrochemicals industry will grow to supply plastics consumption which typically outpaces GDP growth for middle-income countries.

In contrast to Asia-Pacific, the decline in oil demand across Europe and North America will be led by the transport sector's transition to battery-electric engine vehicles (BEEVs) and possibly hydrogen fuel cell vehicles (HFCVs), combined with a modal shift in commercial transport towards rail, and an increasing efficiency of new combustion engines.

In China, the transition away from oil is a mixed story. Demand for oil will increase gradually till the end of the decade, as the number of ICEVs increase, after which ICEVs will be increasingly replaced by BEEVs leading into 2050.

Figure 1. Demand for Oil by Region

Source: DNV, Energy Transition Outlook, 2021
Units: millions of tonnes



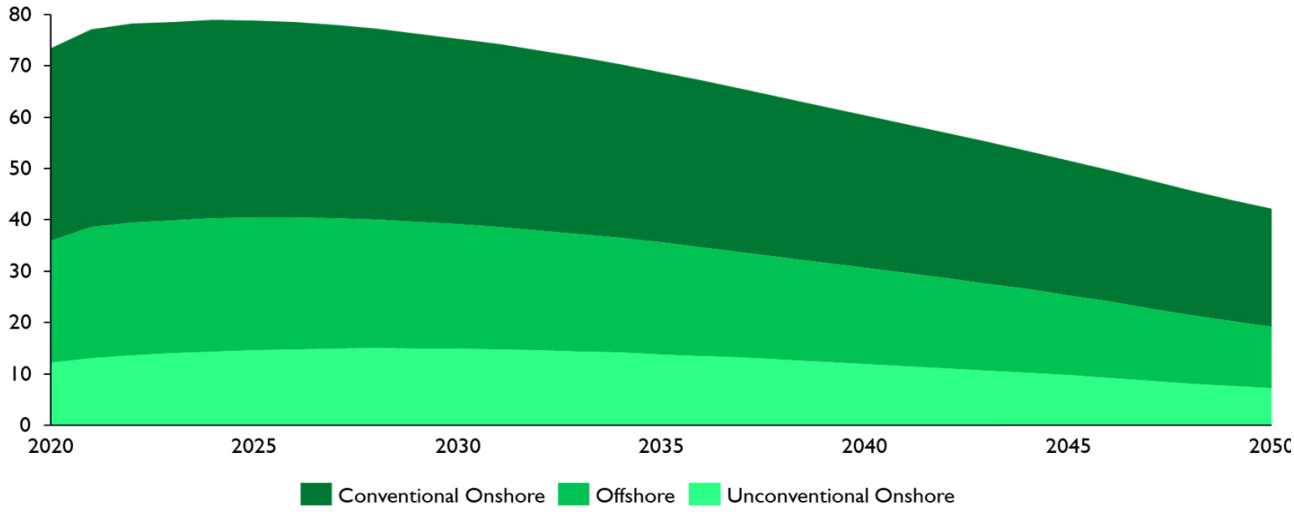
Despite the transport sector's continuing to be the largest consumer of oil, the decline in global demand will be led by the electrification of ground transport; followed by the use of natural gas, decarbonised fuel sources such as hydrogen and electricity, and biofuels, which will be important for road, maritime and aviation transport.

However, even in a declining oil market, continued investments will be needed to maintain production levels in order to meet the global demand. Amid the decline in oil production, conventional onshore oil resources will continue to contribute the largest share to global oil production.

In recent times, most of the oil production growth has been attributed to offshore (particularly deepwater) production, in addition to increasing supply from shale and oil sands sources in North America. Onshore conventional production has remained relatively stable for decades at around 40 Mb/d.

Figure 2. Global Crude Oil (exc. NGL) Production by Resource Type

Source: DNV, Energy Transition Outlook, 2021
Units: millions of barrels per day, Mb/d



The United States is the largest producer of unconventional oil, accounting for 82% of the global unconventional total[iv].

However, the Middle East will continue to benefit from conventional onshore production, and upstream operators in the region will continue to enjoy a competitive advantage over their counterparts in the United States, Russia, and Central Asia. Most of Middle East production comes from known reserves of light and medium crude from giant, high-quality conventional reservoirs with efficient extraction operations from existing wells, rather than the capital-intensive exploration and development of new fields. The Middle East produces 21 Mb/d from its conventional onshore, which accounts for 56% of the global conventional onshore production and is expected to increase to 77% by 2030.

The shift to low-cost conventional onshore production will put increasing pressure on expensive offshore and unconventional onshore resources. Offshore oil production currently stands at 25 Mb/d and accounts for 33% of the global total. However, unconventional onshore oil could be more

resilient than offshore oil in a volatile market, given its greater flexibility to pause production in periods of uncertainty.

Despite the large costs associated with developing offshore oil, it could remain cost competitive with unconventional oil. A recent example of this is Shell, which has achieved a breakeven cost of US$ 30 – US$ 35 / bbl[v]. If this trend continues, offshore oil could overtake many shale resources, but it won't be enough to make offshore assets competitive to the main onshore conventional assets.

However, the long-term outlook for growth in offshore oil is bleak. Offshore oil is exposed to societal and ESG pressure on IOCs to decarbonise their operations, particularly in Europe. As majors and large IOCs transition to "energy companies," offshore oil will be left to smaller IOCs to explore and develop. And these IOCs lack the resources and risk appetite to explore and develop the remaining resource, which is mainly found in deepwater and/or in technically challenging reservoirs. Currently, 74% of the deepwater resources are being developed by eight IOCs, and all of them have made commitments to lower or net-zero emissions[vi].

Therefore, upstream oil operators in the Middle East will dominate the global oil production in the long-term. These operators will jointly account for 55% of global oil production in 2050. Their dominance will be attributed to a global shift in producing the "cheapest barrel" rather than "more barrels," which will be supported by their abundant low cost conventional and primarily onshore oil resource base.

DISCIPLINED UPSTREAM OPERATORS

Natural gas is the least carbon intensive fossil fuel and will lead the energy mix by 2030 and 2050. The fuel source is projected to account for 27% of the global energy mix by 2030, and 23% by 2050. In addition to the power and utilities and industrial sectors, there will be new uses for natural gas, specifically in maritime transport and blue hydrogen production. The transport, commercial and residential sectors are projected to account for almost half of the demand for natural gas by 2030.

Following the global price crash of 2020, global natural gas capacity additions will decrease by 1% / year to 274 Bcm / year in 2030. Of the three resource types, offshore capacity additions will outperform conventional onshore and unconventional onshore capacity additions, with a 1% / year increase to 101 Bcm / year in 2030. This is partly because of continued strong demand that provides certainty to investments with longer time horizons, and also because of the price advantage from regional offshore supplies over pipelines and LNG imports, particularly in regions such as Southeast Asia.

China and South Asia currently account for 14% of world demand for natural gas and will jointly account for 19% of global demand by 2030, and 21% by 2050, as both regions see a strong policy support for natural gas consumption. Domestic production in both countries will account for a fraction of local consumption, and the deficit will be met by an increasing inter-regional trade and LNG imports mostly from Qatar, United States, Russia, and Australia, and possibly East Africa.

Over the next decade, global natural gas production is projected to increase by 1% / year to 4.6 Tcm in 2030, before declining by 1% / year to 3.9 Tcm in 2050. The Middle East, United

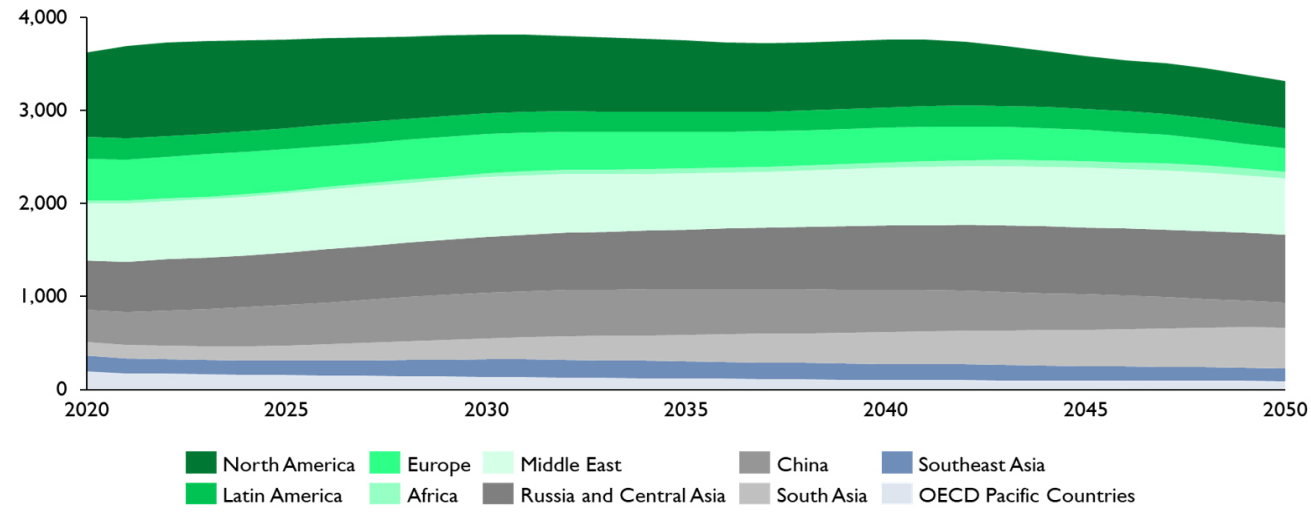
States, and Russia will jointly supply more than half of the global natural gas output in 2050, mainly from their unconventional onshore, conventional onshore, and offshore resources.

The United States will be the world's largest natural gas producer by 2050, accounting for 77% of the global unconventional onshore supply by 2030, and ultimately 50% by 2050. and the resource will continue to be a critical component of the country's energy domestic energy security, and an increasing export of LNG. In contrast to the United States, the Middle East and Russia will continue to dominate global exports through their conventional onshore and offshore resources. These regions will collectively account for 45% of the global supply by 2050, and 58% by 2050.

Along with the former Soviet Union, the Middle East dominates global conventional onshore gas supply, accounting for 28% of the global supply. The region's share is likely to remain unchanged by 2030.

Figure 3. Demand for Natural Gas by Region

Source: DNV, Energy Transition Outlook, 2021
Units: millions of tonnes oil equivalent, Mtoe



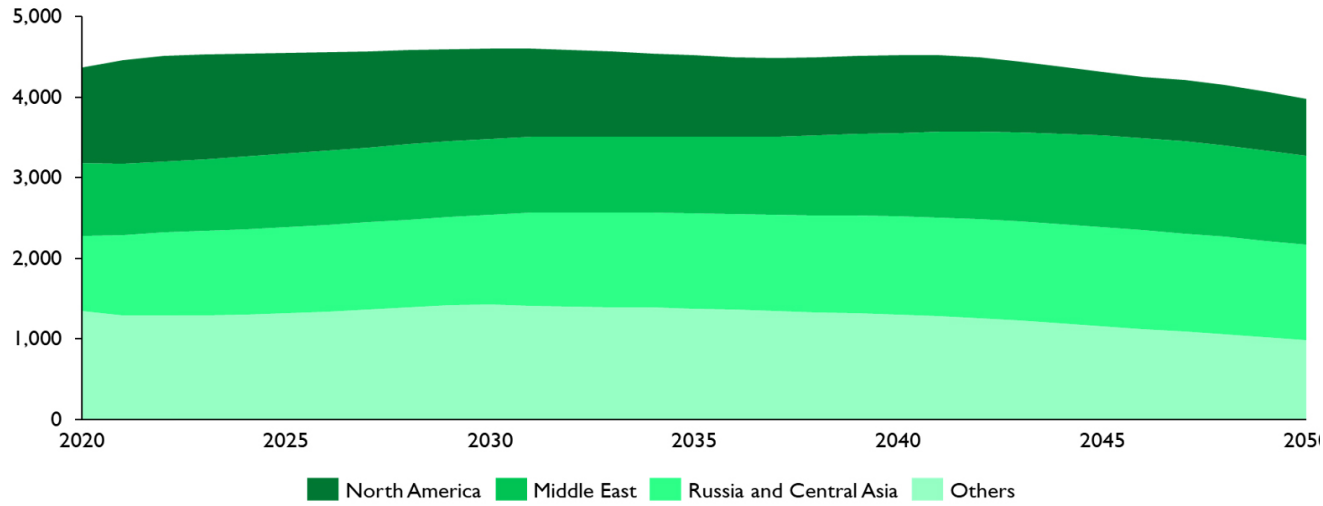
However, China and South Asia will benefit from an increasing supply of onshore gas. Currently, both regions jointly supply 10% of the global onshore gas, which is expected to increase to 13% by 2030. New conventional onshore capacity in South Asia and China will increase by 7% / year to 14 Bcm in 2030, as population, economic, and industrial growth will increase demand for domestic supply, in addition to pipeline and LNG imports.

The short-term recovery in demand for natural gas and the additional growth in emerging markets over the coming years will be accompanied by a 9% increase in supply between 2020 – 2024. The additional increase in global supply will come at a slower rate than 2020, and will almost exclusively come from projects that are already under development.

In 2021, unconventional onshore shale gas producers in the United States will keep their capital expenditure plans largely unchanged and will continue to focus on delivering investor returns as global prices continue their recovery. This financial caution of upstream producers in the United States is likely to contribute to lower growth over the coming years.

Figure 4. Global Supply of Natural Gas

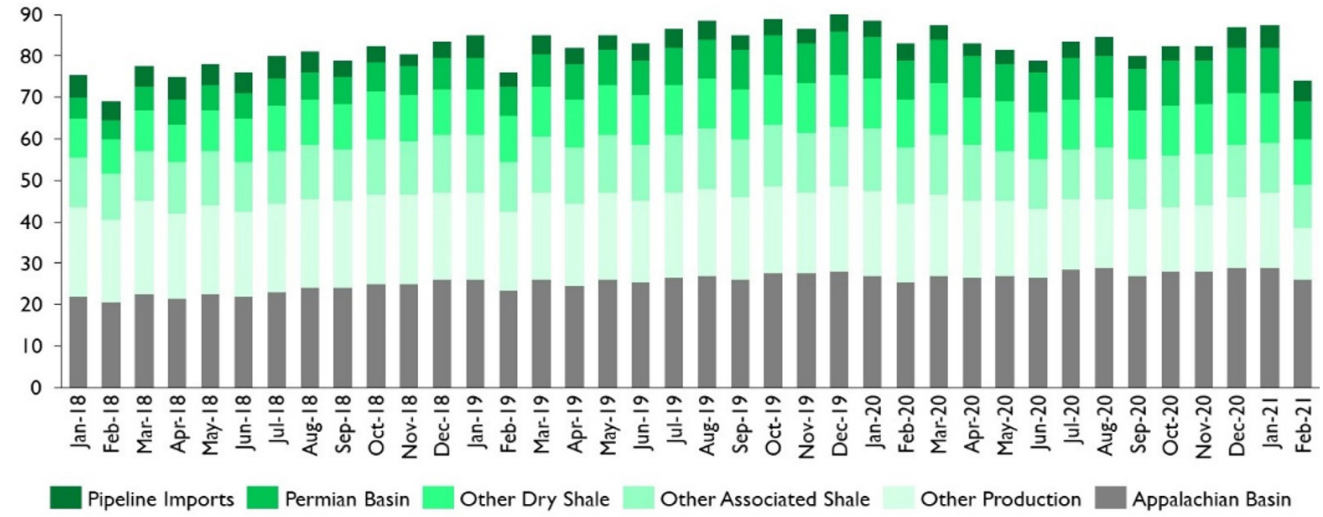
Source: DNV, Energy Transition Outlook, 2021
Units: billions of cubic meters, Bcm



Upstream producers across the Appalachian Basin, the United States' largest contributor to natural gas production, maintained their production level throughout the turbulent year of 2020, and even managed to increase production by 3% from the previous year, despite the 30% decline in monthly drilling activity[vii]. Production increased from previously drilled but uncompleted (DUC) wells, which provided a lower-cost alternative to new developments. Over the past six quarters, the Appalachian Basin's DUC count has declined by ~30%; however, this trend is less visible in other plays such as the Haynesville and Eagle Ford, where drilling activity remained stable throughout 2020[viii].

Figure 5. Supply of Natural Gas from the United States

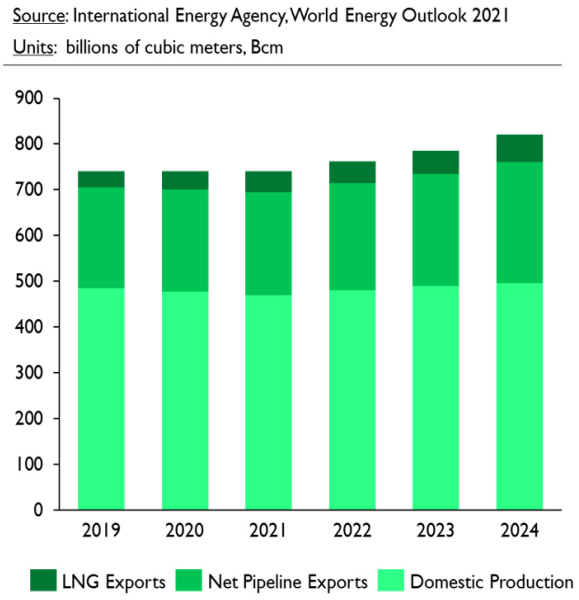
Source: International Energy Agency, World Energy Outlook 2021
Units: billions of cubic meters, Bcm



DISCIPLINED UPSTREAM OPERATORS

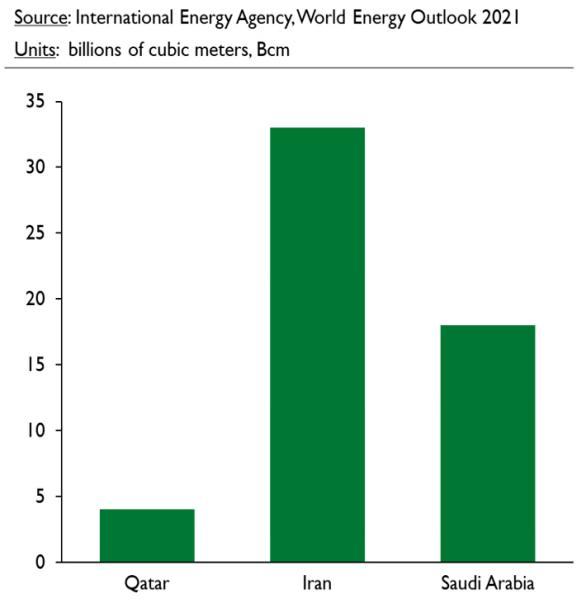
In addition to delivering returns to their investors, upstream shale gas producers in the United States are expected to face tougher environmental performance targets over the coming years, as the new US Administration puts climate considerations among its top priorities. Upstream producers will have to accelerate planned carbon mitigation operations by tackling natural gas flaring and methane emissions, and utilising carbon capture and sequestration technologies. As result of this, upstream producers in the United States are expected to focus more on environmental, social and corporate governance (ESG) issues, which were marginal until recent years.

Figure 6. Supply of Natural Gas from Russia



In Russia, natural gas production is set for a strong recovery in 2021. After steep decline in 2020, Russian supply is expected to increase by 12% to 80 Bcm as domestic consumption and exports rebound. The recovery in supply will be supported by Russia's large fields in Western Siberia that include Urengoyskoe, Yamburgskoye, and Zapolyarnoe. These fields produced well below their capacities in 2020, and are also becoming increasingly mature. Urengoy was affected by a fire in August 2021. In addition to this, the giant Bovanenkovo field is also expected to reach its full capacity level of 115 Bcm in 2022. Across the Eastern Siberia region, continued supplies to China through the Power of Siberia Pipeline is expected to result in an increase in production from the Chayandinskoe field by ~6 Bcm in 2021.

Figure 7. Growth in Natural Gas Production from Middle Eastern Markets, 2020 - 2024



Gazprom's production growth will be driven by the Yamal Peninsula, as the company's traditional resource base in Western Siberia continues to deplete. With the Bovanenkovo field achieving its full capacity, new fields such as Kharasavey are expected to achieve commercial operations by 2023. In addition to this, Rosneft is expected to continue its natural gas development programme in Western Siberia, which includes the phased commissioning of the Rospan fields and the launch of the Kharampur field.

The Middle East's natural gas supply is projected to expand by 9% to 64 Bcm between 2020 – 2024, which will be mainly driven by the region's strong demand growth from the electricity sector's oil-to-natural gas switching, particularly in Saudi Arabia, Iraq, Kuwait and Iran, and growing demand from industry. The shared North Field and South Pars field between Qatar and Iran is expected to account for ~50% of the region's natural gas production growth between 2020 and 2024. The increase in investments in South Pars Phases 13, 14, and 22-24 will add ~30 Bcm of additional production capacity by 2024. Drilling has started in late 2020 at South Pars Phase 11, which is expected to begin production in 2022, and will add ~21 Bcm of production capacity by 2024 Beyond 2024, the expected commissioning of the North Field East project in 2025 will increase Qatar's LNG export capacity by 45 Bcm.

Saudi Arabia's gas production growth will be driven by the expansion of the Hawiyah Gas Processing Project and growing associated gas production from existing fields; and the country's total supplies are estimated to increase by 20% to 18 Bcm between 2020 – 2024. In addition to this, Saudi Aramco also plans to increase its production from non-associated gas fields, such as the Jafurah unconventional gas field, the country's largest non-associated gas field spanning 17,000 km2[ix]. Last year, Saudi Aramco announced the regulatory approval for the development of the Jafurah resource, which is estimated at 200 Tcf. However, Saudi Aramco's recent capital expenditure cuts have delayed the commercial operation date of the Marjan Increment Programme and the 26 Bcm Tanajib Gas Processing Project to 2025.

Hence, upstream producers across the Middle East, United States, and Russia will collectively supply more than half of the global natural gas output in 2050. However, the short-term recovery in demand will be accompanied by a 9% increase in supply between 2020 – 2024, and will almost exclusively come from projects that are already under development.

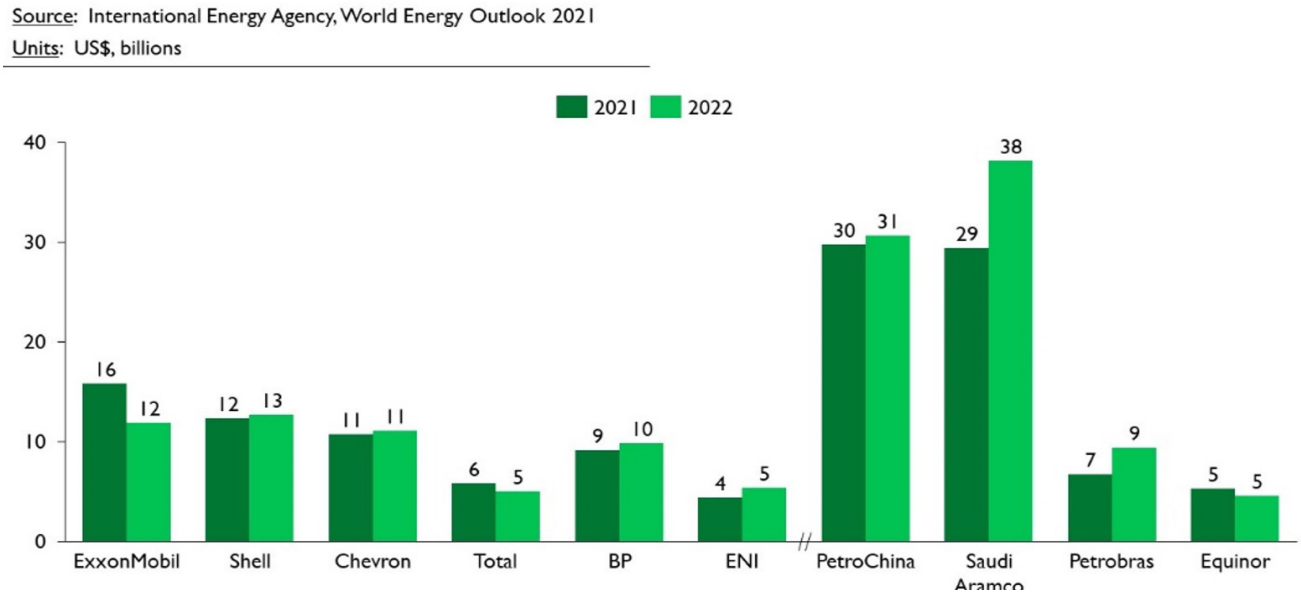
DISCIPLINED UPSTREAM OPERATORS

Investments in the upstream oil and gas segment are projected to increase by 8% to US$ 350 bn in 2021, as operators recover from the global oil price and financial shock of 2020[x]. However, the level of investment continues to be well below the pre-COVID-19 pandemic level. The recent increase in upstream capital expenditure has been triggered by recovering global prices and subsequent upstream revenues in 4Q2020 - 1Q2021, but upstream operators continue to face multiple uncertainties as they put together their future capital expenditure plans. These uncertainties relate to the length of the ongoing pandemic and global policy and regulatory announcements that could speed up the ongoing energy transitions; in addition to the large spare capacity held by OPEC+ countries and questions over the pace at which OPEC+ supply cuts will be relaxed.

Investment trends also reflect a renewed effort by upstream operators to keep costs under control through careful resource selection and capital discipline. Companies are facing demands from their stakeholders to focus on improving their free cashflow and pay off debts. The recent increase in upstream activity has also increased the pressure on costs. The higher cost of oil and gas production has been explored in much of the economic literature as one of the primary reasons for structurally higher oil prices.

However, a combination of continued extension in the market for some services and equipment, consolidation in the oil field services industry, and an increasing uptake of digital technologies to improve productivity has limited the cost inflation in the upstream segment. These technological developments have improved the planning and forecasting

Figure 8. Upstream Spending by Selected Majors and National Oil Companies



of long-term project economics in the upstream, which are exposed to cost shocks as result of project complexity risk.

Nevertheless, the upstream investment environment is changing. And the direction of change varies significantly across various geographies. One particular trend that stands out is that the balance of investments in the upstream segment is shifting from IOCs to NOCs. The overall expectation is that upstream investments by NOCs is estimated to increase by 10% in 2021[xi]. As ever before, their investment strategies and capital allocation is determined by national priorities.

However, these investments cover a range of spending plans, strategies, and financial pressures. While many NOCs still face severe revenue and spending constraints, some are stepping up their counter-cyclical investments. Chinese NOCs, PetroChina, China National Offshore Oil (CNOOC), and Sinopec have announced large capital expenditure plans in 2021, with PetroChina leading globally in the upstream segment. The company is projected to spend US$ 28 bn in 2021[xii]. This is in response to Chinese government concerns about energy security and import dependence.

Middle Eastern NOCs are also increasing their capital expenditure, as Saudi Aramco and ADNOC look to expand their current production capacity by around 1 Mb/d each by 2027 for Aramco and 2030 for ADNOC. ADNOC has announced a US$ 120 bn spending plan for 2021 – 2025, and Saudi Aramco is looking to increase spending by 30% to US$ 35 bn in 2021[xiii].

In contrast to the NOCs, supermajors and independents continue to be conservative on their upstream capital expenditure plans, which are likely to remain unchanged or decline in 2021. This is because of continued pressure by their shareholders to diversify into low carbon energy and/or to reduce debt and return cash to shareholders.

DISCIPLINED UPSTREAM OPERATORS

Furthermore, the exploration and production strategies of NOCs, supermajors, independents, US-independents are largely determined by the scalability, scope, costs, and running room of their portfolio.

NOCs, such as Saudi Aramco, ADNOC, and Kuwait Oil Company will continue to operate a large portfolio of upstream operations that include producing large volumes from conventional onshore and / or shallow-water projects. Their upstream business divisions run a near-monopoly over their domestic resource development, and they have significant running room for decades, at current production rates.

The challenge for many NOCs is managing costs, mainly relating to operational and political issues such as fuel subsidies and fiscal regimes. In some cases, the host countries of these NOCs face deficit challenges even at US$ 80 oil prices, despite the fact that well-level (or production-level) breakeven cost can be less than US$ 10[xiv]. This has put upstream operators in a difficult position of balancing investment in their operations and other domestic priorities. After the fall in global oil prices in 2014, many Middle Eastern countries used the opportunity to reduce domestic fossil fuel subsidies. However, as global oil prices increase, so does the tendency to increase these subsidies, which will likely reduce the cashflow that NOCs could otherwise spend on expanding their future production and reserves.

Nevertheless, the strongest NOCs have advantages they can leverage when global oil prices increase. Given their low-cost production and reserves from already-discovered conventional resources, and additional investments in new drilling campaigns and enhanced oil recovery (EOR) programmes, they can increase production with relatively short lead times and lower costs than their global peers. Partnering with experienced IOCs on developing their unconventional and (in some cases) deepwater resources could provide exposure to advanced technologies and operational strategies.

Table 1. Budget Breakeven Oil Prices for MENA Oil Exporters in US$ / bbl[xv]

Country	2019	2020	2021
Saudi Arabia	82	77	82
UAE	62	62	69
Kuwait	54	68	66
Oman	68	88	71
Iraq	52	55	64
Iran	198	246	361
Bahrain	99	118	105
Algeria	106	84	142
Libya	36	142	55

Supermajors and large IOCs are likely to prefer core assets that provide small to modest growth and generate significant cashflow. Legacy assets or those with limited prospects for growth, and a declining contribution to cashflow will be earmarked for divestments. However, the IOCs' challenges stem not from the scale of operations but from the diverse geographical scope of upstream operations. To maintain their running room and to grow their reserves, these operators often maintain a large portfolio of assets, which sometimes involves large areas of exploration acreage in multiple geographies requiring several years assessing the technical and economic viability of major capital projects. At times, it can also involve holding onto legacy assets well past their economic value.

This problem is exacerbated by a shortage of buyers for such assets. NOCs have generally chosen to invest at home or in highly strategic international assets. Majors are unlikely to buy tail-end assets from each other. US and Canadian independents have largely focused on domestic unconventional resources. Smaller firms have been starved of capital because of a lengthy history of poor returns, and unwillingness from environmentally-focused investors. NOCs, including the Chinese and Russian ones, have been cautious on international upstream in recent years due to some unprofitable investments, political challenges and domestic imperatives.

That leaves the most likely buyers for assets outside North America as private or private equity-backed companies, such as Neptune and Harbour Energy (the result of the merger of private equity-backed Chrysaor with listed Premier Oil). Another option is to spin off these assets into joint ventures and/or to list minority stakes, as ENI and BP have done in Norway (with Vår Energi and Aker-BP respectively), and as BP is considering in Angola, Algeria (both potential JVs with Eni) and Iraq (Rumaila Operating Company). A third option is consolidation, an approach taken in Australia with the merger of Santos and Oil Search, and the purchase by Woodside of BHP's oil and gas portfolio.

1- How much oil & gas the company is producing from different fields and regions.

2- How many different types of projects (e.g. fields, pipelines, processing plants, etc.) and resource (e.g., oil sands, shale, deepwater, etc.) the company operates.

3- What is the capital and operating cost structure, are projects short or long cycle, and do they require continuous or upfront investments?

4- How efficient and sensitive is new production capacity to costs?

DISCIPLINED UPSTREAM OPERATORS

International independents will focus on growth opportunities through a handful high-impact exploration projects. These operators may find it difficult to expand their resource base and add cost-effective incremental capacity because of their narrow scope and risk averse approach. With many operating in borderline basins and fields, there are two clear options for growth, either by balancing the traditional exploration focus with sustainable cashflow growth or by expanding their resource base through inorganic growth.

As oil and gas prices increase, the conventional strategy for these companies is to farmout interest in stages during the exploration process, then to sell part or all of a large discovery that the company cannot develop itself. This has become increasingly difficult given the shrinking pool of likely partners, particularly for frontier exploration. A long-term partnership of a skilled explorer with a NOC or Asian industrial player could provide a more stable source of capital.

In contrast to international independents, United States-based independents are continuing to devote their upstream efforts on drilling up their unconventional shale oil and gas resources. Their scope is limited and the running room is defined by remaining drilling areas estimated from net acreage holdings. Some companies such as Marathon Oil produce from a diversified number of plays, whilst other others such as Pioneer focus on the Permian play (west Texas/New Mexico). Some have ventured tentatively into shale or tight plays outside North America, as in Mexico, Colombia, Argentina and Oman, but with limited results so far.

Unlike their global peers, these companies lack the balance of operations. The lack of diversification presents three closely linked challenges for US independents, 1) high cash-intensity operations, 2) asymmetric operational risks, including those related to cost inflation and to US federal and state policies, and 3) stark exposure to commodity price cycles.

American independents typically rely on hedging to offset commodity price risks[xvi]. Hedging can prove to be expensive if prices remain resilient. However, these companies can expand their resource base by investing in longer-life integrated assets, in addition to their existing hedging strategies. Pipelines, storage assets and water management can provide ongoing cashflow even in a lower global price environment.

Strategic choices can have a direct impact on a company's portfolio by changing its scale, scope, costs, or running room. Despite oil price uncertainty, and even in an accelerated energy transition scenario, investments in upstream resources will be required to meet future demand.

THE ROLE OF EXPLORATION DROPS OFF

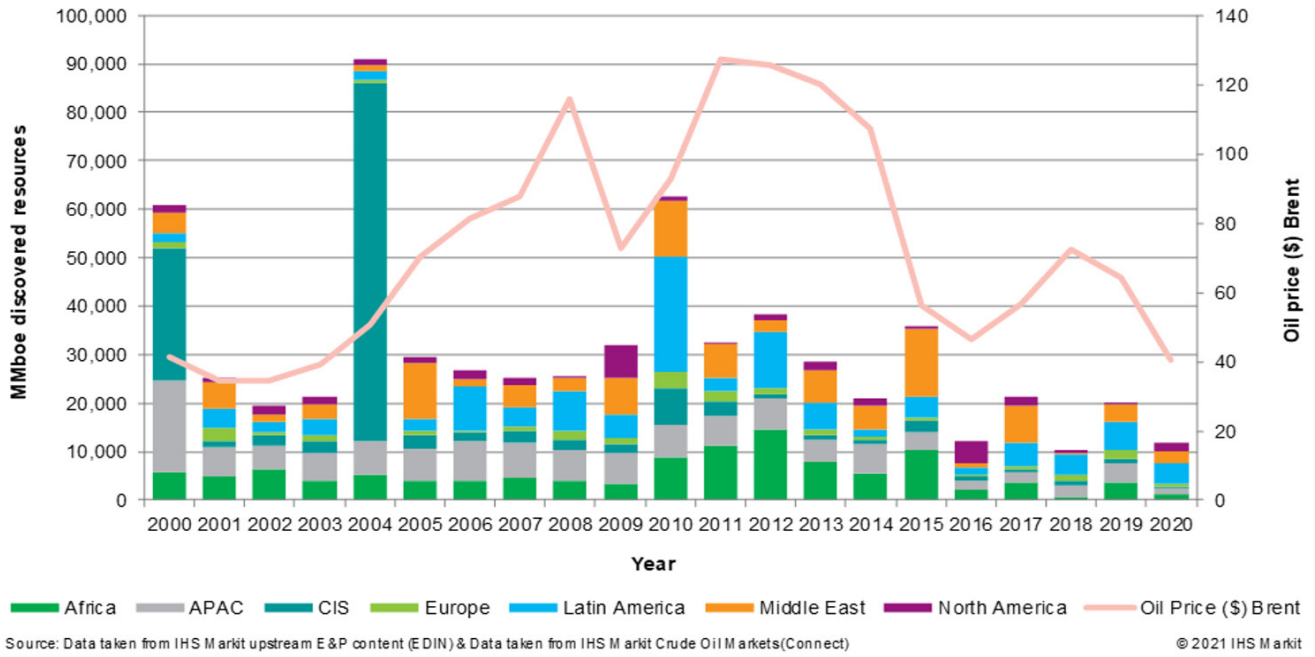
The IEA's report on reaching net-zero greenhouse gas emissions stated that no new oil and gas field developments would be required. That implies, even more so, that no new exploration would be required. However, exploration continues, albeit at a slower pace than in previous years (Figure 9).

There was a sharp drop-off in finds after 2015, probably the result of lower budgets following the late-2014 oil price crash. Discoveries have run at 10-20 billion boe per year, in comparison to about 36.5 billion bbl of oil production and 23.5 billion boe of gas production annually. That implies the world is running down its reserves and/or that production is being compensated by reserves additions in existing fields and unconventional resources. In fact, despite production, global gas reserves rose from 181.2 Tcm in 2015 (1103 billion boe) to 188.1 Tcm (1145 billion boe) in 2020, and oil reserves from 1684 billion bbl to 1732 billion bbl. This does indicate there is no immediate problem with supporting current production levels.

Given these issues, why does exploration continue?

1. As long as OPEC+ continues to restrain production, that keeps prices relatively high and allows new exploration in prolific and low-cost areas to remain economically viable. That is the case for Guyana and the Gulf of Mexico, for instance, and in near-field exploration in mature areas. This trend will be strengthened if more countries follow the lead of Denmark and cease future exploration in their territories.
2. New fields in large OPEC+ producers may be cheaper than increasing recovery from mature fields.
3. New resources can be lower-carbon than large known resources, notably Canada's oil sands.
4. Countries have security-of-supply reasons to support domestic output, as in the case of China and India.

Figure 9. Exploration results 2000-2020[xvii]



THE ROLE OF EXPLORATION DROPS OFF

Figure 10. Exploration and undiscovered resources[xviii]

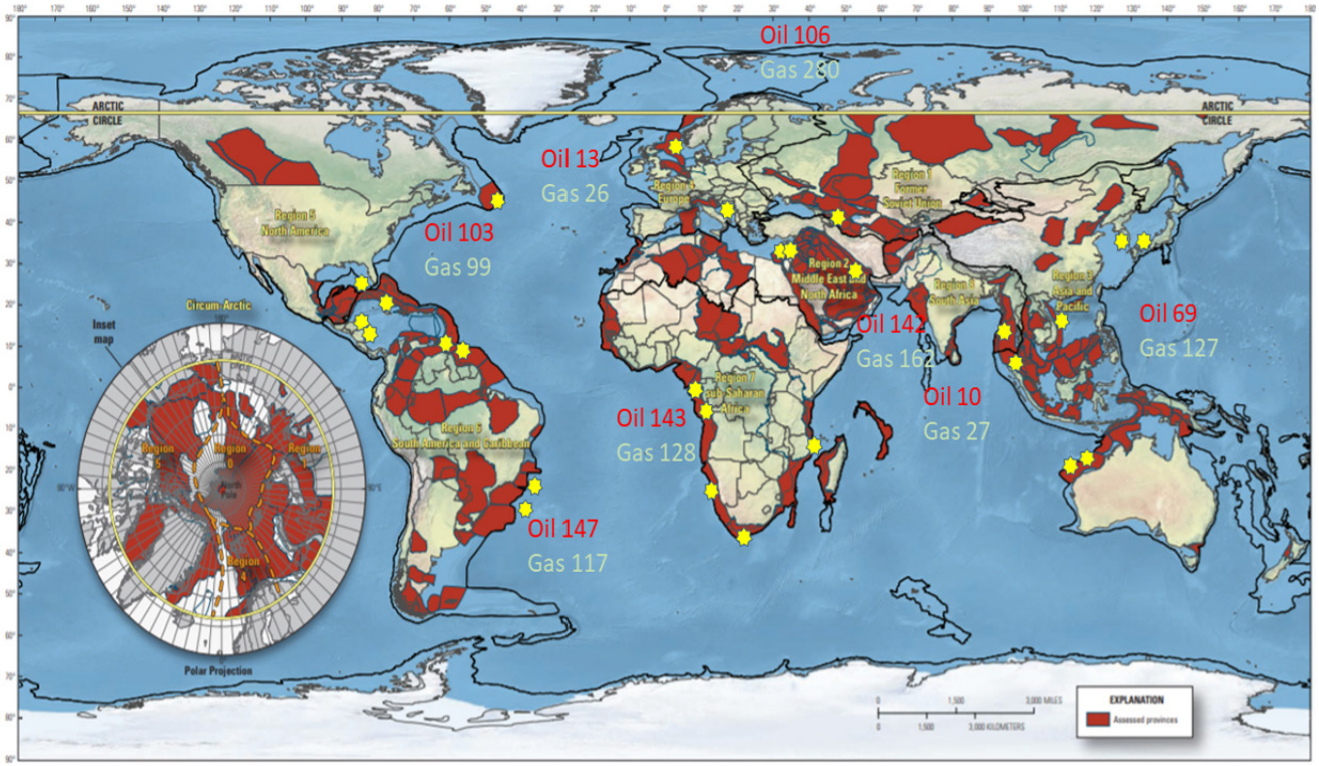
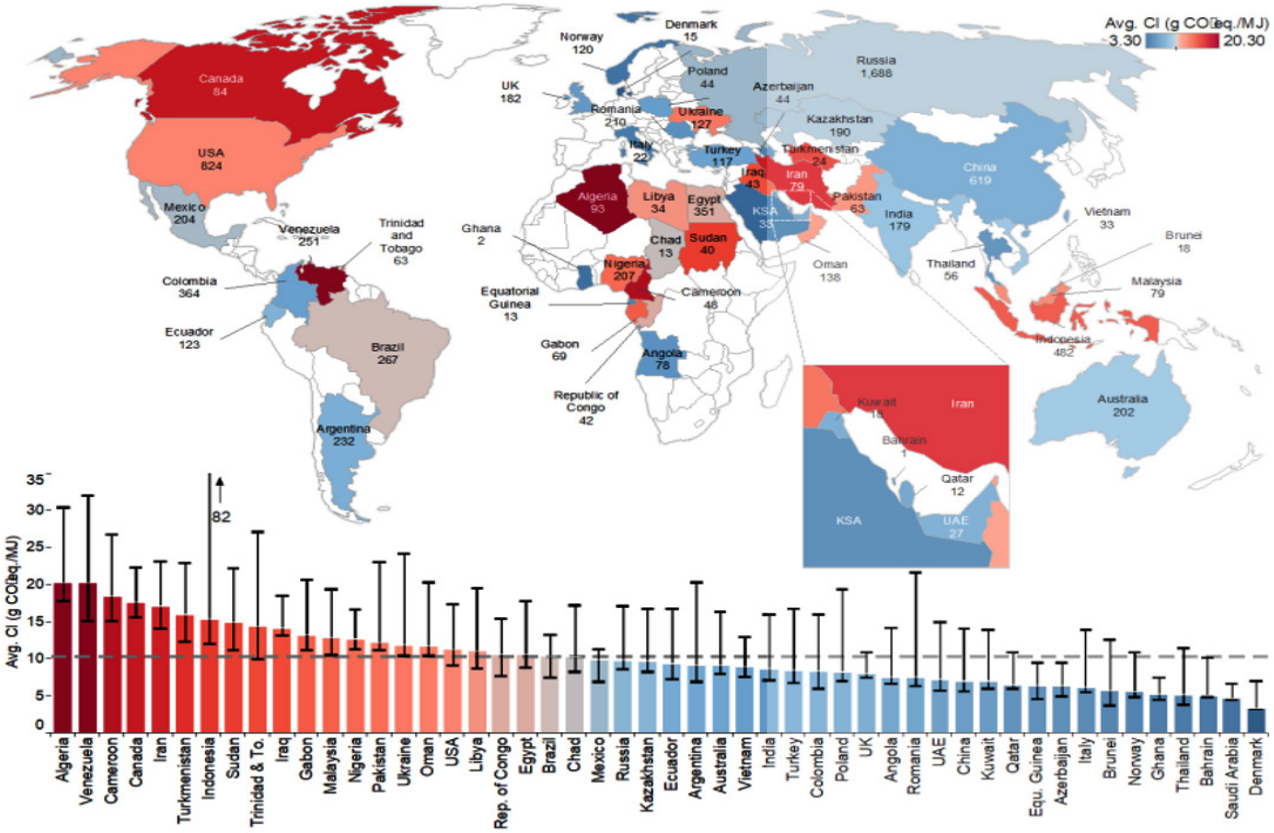


Figure 11. Estimated Global Upstream Crude Oil Carbon Intensity



Exploration success has shifted since 2015. Discoveries in Africa have dropped off sharply, with much less interest in frontier areas and reduced activity by the super-majors. Exploration in the FSU has almost disappeared for now, though this may partly be the result of lower visibility on the activities of Russian companies, with Western partners having scaled back due to sanctions. Middle East exploration has also reduced, but discovered volumes here are usually driven by large discoveries in the most prolific countries, notably Iran and Iraq, from a limited amount of exploration activity. Latin American exploration success, meanwhile, has remained quite stable with deepwater in Brazil, Guyana and Surinam remaining very attractive.

Exploration drilling has rebounded strongly in 2021 due to recovery from pandemic-induced delays. Figure 10 shows estimates of undiscovered conventional resources (billions of oils equivalent, boe) by region, and high-impact exploration wells (yellow stars) being drilled in 2021. Note that these estimates exclude the USA; and that natural gas liquids are included with oil. Some important observations are:

- Virtually all high-impact wells being drilled are offshore, and mostly in deepwater
- There is almost no high-impact drilling planned in the areas of greatest remaining potential (the Middle East and former Soviet Union), though this is partly an artefact of reporting
- Global undiscovered resources incline more to oil than gas – 732 billion boe of oil and 966 billion boe of gas, with only Africa, Latin America and (marginally) North America having more oil to find than gas

These patterns of exploration activity thus reflect the availability of exploration acreage and national and corporate priorities, more than the resource base.

THE ROLE OF UPSTREAM OPERATIONS IN A CARBON-CONSTRAINED WORLD

If the world is to meet the Paris Climate Agreement goal of limiting global warming well below 2^{0}C and countries are to meet their net–zero pledges; then upstream operators will have to play an important role. Oil and gas and their derivatives account for 56% of the overall annual CO_2 emissions from all fuel types[xix]. For the petroleum sector to play its part in mitigating the ongoing climate change, it is estimated that it must reduce its emissions by 3.4 $GtCO_2e$ / year by 2050[xx].

Currently, various initiatives are underway to tackle greenhouse gas emissions from oil and gas operations. The Oil and Gas Climate Initiative (OGCI) is a CEO-led initiative, grouping Shell, BP, Equinor, Saudi Aramco, CNPC, Petrobras and other major international oil companies, aims to accelerate the oil and gas sector's response to climate change. Under the initiative, member organisations will collectively invest US$ 7 bn in low carbon solutions and technologies that accelerate the decarbonisation of oil and gas operations.

Another initiative underway that tackles growing methane emissions is the Global Methane Pledge launched at the UN COP26 climate conference in Glasgow, November 2021. The pledge has attracted over 90 countries, and aims to reduce global methane emissions by 30% from 2020 levels by the 2030.

The Net-Zero Producers Alliance consisting of the United States, Canada, Norway, Saudi Arabia, and Qatar agreed to develop pragmatic net-zero emission strategies[xxii]. These strategies include ending methane leaks and flaring, the deployment of carbon capture, and diversification from oil and gas revenues.

Uncertainty about the future is a key factor in decision making. And there is no reason for upstream operators to apply a "wait and see" approach as they deliberate their strategic choices. The first step will be to minimise their emissions from core operations, regardless of the pathway the energy transition takes. There are various cost-effective technologies and opportunities to reduce the intensity of emissions from core upstream operations. These include minimising associated natural gas flaring, reducing methane emissions, improving energy efficiency, using carbon capture and storage, and integrating renewables and low-carbon electricity into new upstream and LNG developments.

Upstream operators can decarbonise their operations by minimising the deliberate and unintentional flaring of associated natural gas. Currently, natural gas flaring accounts for 40% of the scope 1 (direct) and scope 2 (purchases of electricity and heat) emissions that are associated with oil production[xxii]. Most oil wells yield a mixture of condensates, natural gas liquids, and natural gas, with gas often viewed as an unnecessary by-. Generally, the associated natural gas from oil production is considered less valuable, and it may have no ready market without available processing and pipeline infrastructure. This is a particular problem in West Siberia (Russia), Nigeria, Iraq and the Bakken and Permian basins of the US, the major centres of global flaring.

In 2020, upstream operators produced 595 Bcm of associated natural gas, of which 446 Bcm was transported directly to end users, in addition to being used for on-site operations such as electricity and heat, or reinjection for secondary liquids recovery[xxiii]. The remaining, 158 Bcm of associated natural gas was

flared or disposed in the atmosphere, either deliberately or through fugitive emissions. In most cases the "deliberate flaring" happened because of 1) the remoteness of the field, 2) the topography of the surrounding area, 3) the low base price of natural gas in the accessible markets, which discourages producers from investing in the transportation infrastructure, and / or 3) because of the time-lag between of developing a new resource and connecting it to transport infrastructure.

Flared natural gas is a wasted economic opportunity for oil and gas companies. Various initiatives are underway to reduce it. An example of such an initiative is the World Bank's "Zero Routine Flaring by 2030", which aims to support cooperation between NOCs, IOCs, governments, and regulatory institutions on the appropriate regulation, application of technologies, and financial arrangements[xxiv]. According to the initiative, upstream operators are required to minimise natural gas flaring across new developments by developing plans to use or conserve all of the associated natural gas without routine flaring. Across existing developments, upstream operators are required to eliminate routine natural gas flaring by no later than 2030. Until now 45 oil and gas companies, 34 governments, and 15 financial and development institutions have endorsed the initiative[xxv].

Another way to decarbonise upstream operations is by tackling methane emissions. The IEA estimates that global oil and gas operations emitted 72 Mt of methane in 2020, which is equal to the total energy-related CO_2 emissions of the European Union. The organisation also estimates that methane

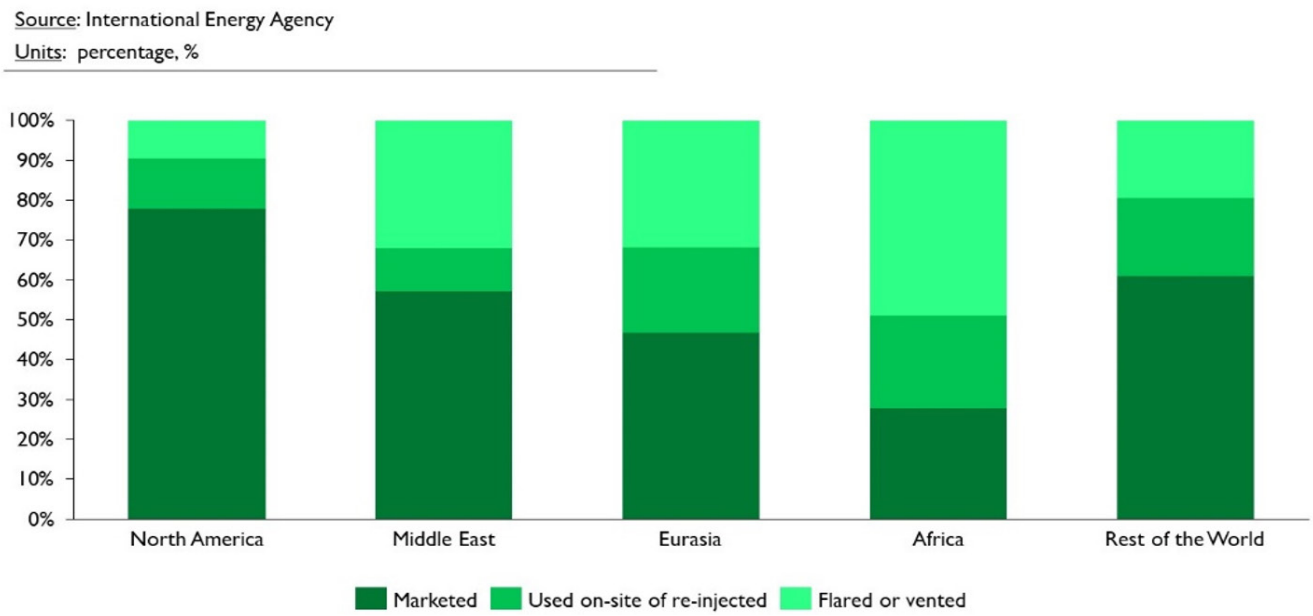
emissions declined by 10% from the previous year, as result of a fall in oil and gas production and the introduction of new methane regulations in some countries[xxvi]. Oil production accounts for 40% of the sector's total methane emissions and leaks from natural gas emissions account for the remaining 60%.

Similar to flared natural gas, methane is a wasted economic opportunity for oil and gas companies, and could be sold as a valuable commodity. The methane abatement technologies could lead to overall savings if the value of methane sales is greater than the cost of the technology. There are a wide variety of technologies and approaches that could be used to tackle methane emissions from upstream operations. For example, devices such as pneumatic controllers that lead to large levels of vented emissions can be replaced with instrument air systems; vapour recovery units can be installed on oil storage tanks; and implementing leak detection and repair programmes can also reduce the level of fugitive methane emissions.

Furthermore, upstream operators can also decarbonise their operations by integrating renewables. There are three main avenues through which increasingly cost-competitive renewables can contribute to low-carbon and low-cost upstream operations: 1) by electrifying technologies, 2) using renewables to produce low carbon heat, and 3) electrifying the liquification process in LNG developments with renewables.

Most upstream operations are in remote or off-grid locations, often in areas where the reliability of supply is not guaranteed. Upstream operations in these areas are typically powered by standalone natural gas or diesel-based generators. An alternative to these generators is hybrid electricity generators that operate on various renewable energy sources. An example of this is Algeria's 10 MW Bir Rebaa North Solar PV Project inaugurated by ENI and Sonatrach in 2018, which is used to power the upstream operations at Bir Rebaa North (BRN) oil field[xxvii].

Figure 12. Use of Associated Gas by Region, 2019

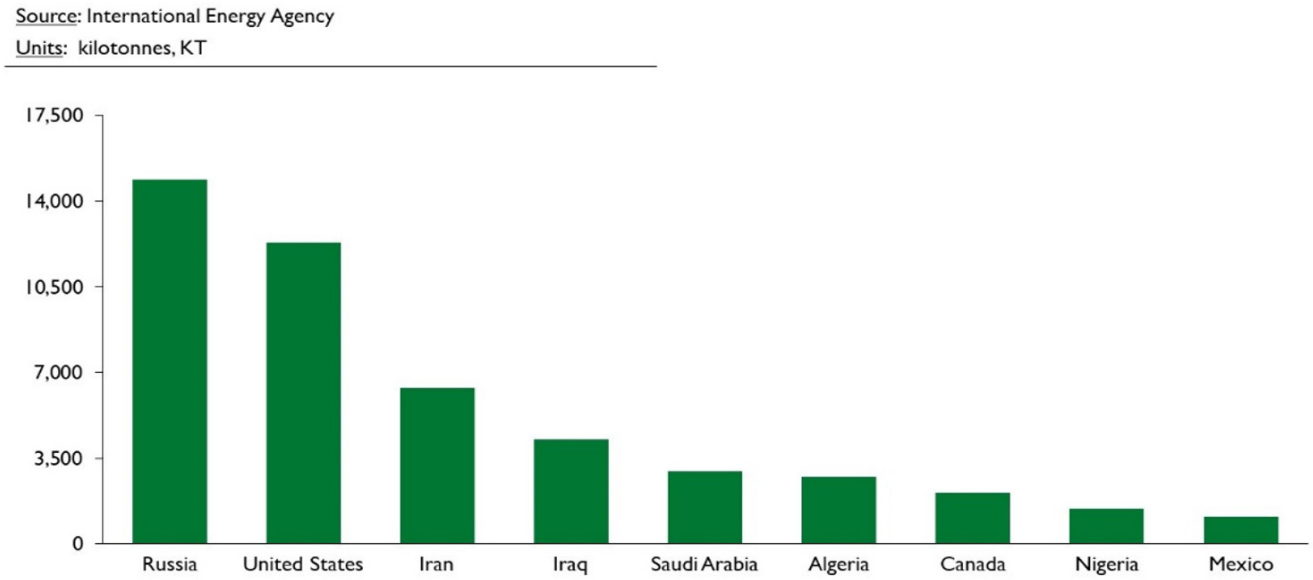


Another application of renewables in upstream operations is the use of solar thermal energy used to produce heat for solar-enhanced oil recovery (EOR). This could be of particular interest to NOCs in the GCC region. For example, in Oman, US-based, GlassPoint Solar constructed a 2 GW (thermal) solar steam project for an enhanced oil recovery project. GlassPoint Solar was founded in 2008 to replace the use of natural gas for steam flooding heavy oil reservoirs. However, in 2020, the Government of Oman divested its 31% stake in the company and ultimately in its solar-EOR project in Oman, after the fall in global oil prices[xxviii].

Renewables can also be used to power liquification operations in natural gas and LNG projects. An example of this, is the electricity-powered Hammerfest LNG Project in Norway operated by Equinor. The project achieved commercial operations in 2005 and is the world's first to feature electric LNG (eLNG) liquification trains[xxix]. Although there are barriers to widespread adoption of eLNG, including the need for liquification projects to be closer to reliable sources of low-carbon electricity, it is estimated that eLNG could reduce GHG emissions by 40% from coal-to-natural gas switching[xxx]. Qatar Energy (formerly Qatar Petroleum) plans to use the 800 MW Al Kharsaah solar photovoltaic plant to power part of its expanded LNG plant.

For emissions that cannot be eliminated, companies can use carbon offsets. These can be purchased to cover Scope 1 and Scope 2 emissions, or even Scope 3 emissions to cover end-use emissions and provide "climate-neutral" hydrocarbons. It is likely that offsets will play a significant role in oil companies' net-zero pledges.

Figure 13. Methane Emissions by Selected Oil and Gas Producers in 2020



However, offsets come in various types. Low-quality offsets, trading around $1/tonne of CO_2 equivalent, include renewable and energy efficiency projects, many of which would have happened without the credit. These attract criticism of "green-washing." Higher-quality offsets, which may range up to $10-20 per tonne, cover well-verified, additional and assured permanent carbon sequestration in the biosphere (e.g. forestry and soil carbon from agricultural practices). But given constraints of land-use and permanence, it is likely that ultimately only subsurface CO_2 storage or mineralisation of atmospheric carbon dioxide will be an acceptable offset. Costs for this, around $200-500 per tonne currently, could possibly reduce to $100 per tonne in the long term. Nevertheless, full offsetting of Scope 1, and 3 emissions would still represent a major cost addition ($43/barrel of oil or $5.48/Mcf of gas).

Upstream operators have a vital role to play in decarbonising their operations. How they choose to respond is a matter of corporate strategy.

Some IOCs are diversifying their core business operations by expanding their business portfolio with new energy technologies and fuel sources. Others that intend to continue focusing on their core operations could decarbonise by minimising associated natural gas flaring, reducing methane emissions, and integrating renewables in their upstream operations.

IMPLICATIONS

Upstream oil and gas companies are contending with strong near-term market conditions as well as opportunities, but a very cloudy medium- and long-term picture, which makes it the right time for CEOs and leaders in the value chain to develop an optimised path.

The 2020 decline in oil and gas prices prompted many upstream operators to launch strong cost-cutting measures, hence putting them in a position of relative financial strength.

At the same time, upstream operators are also contending with the challenges posed by the ongoing energy transition, the emphasis on decarbonisation and low carbon energy sources, as well as changes in mobility trends and consumer lifestyle preferences.

In order to capitalise on the opportunities, whilst navigating the challenges, these companies must focus on four domains as they map out a path:

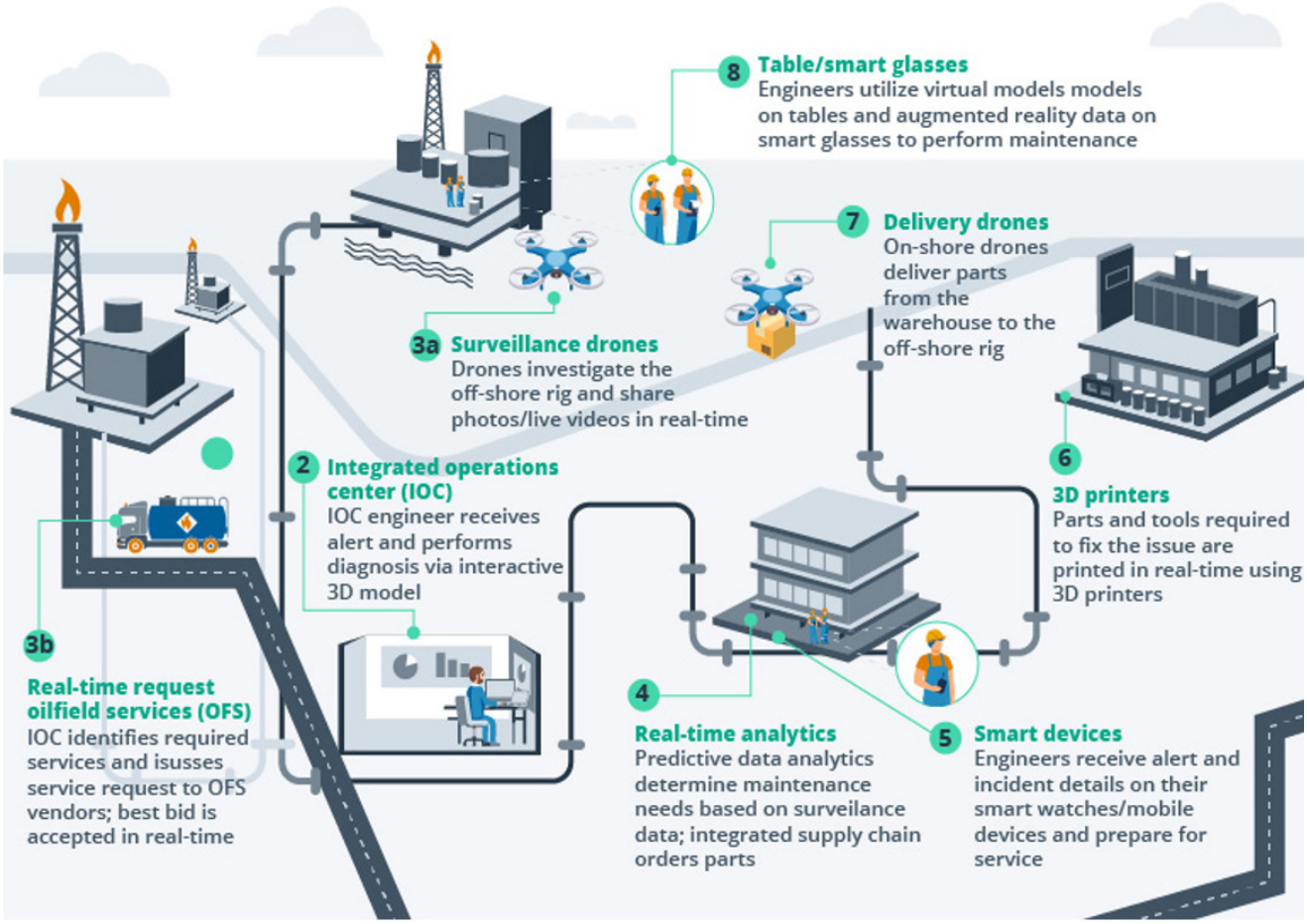
- Leverage their core capabilities and adopt agile practices that result in an efficient use of the financial invectives
- Rethink the operating model of their upstream business and incorporate low carbon technologies and solutions
- Find new avenues to collaborate with suppliers, redefine business terms with local governments, and derive greater value from assets that are operated by external partners
- And, pursue strategic M&A and asset acquisition opportunities that are in line with the strategic shift of their business model

A "wild card" in future upstream operations is digitalisation. Despite upstream operators having a long history of embracing technological innovation as a means of increasing their profitability, they have been slow to adopt to digital transformation.

Upstream operators need to push for greater cost competitiveness, which digitalisation can help achieve. Digital technologies and solutions such as big data, analytics, and artificial intelligence, can help addresses operational and organisational effectiveness and efficiency, and improve portfolio performance.

Technologies such as digital modelling and simulation tools can connect reservoir data, field architecture, equipment design, environmental impact, and economics into a single framework.

Figure 14. Digital Strategy in Oil Field Transformation



CONCLUSION

The oil and gas industry must reconsider its upstream strategy, by reducing the overall capital intensity of its portfolio, with low-carbon and low-cost operations. This will generate additional cashflow and improve investor returns, which could either be invested in diversifying their operations away from petroleum or expanding their current upstream portfolio.

The balance of investments is shifting from IOCs to NOCs, with supermajors mainly looking to generate additional cash from their upstream operations, in order to finance their diversification in new energy technologies and fuel sources. In comparison to the supermajors, NOCs such as Saudi Aramco, ADNOC, Qatar Energy and Kuwait Oil Company will continue to operate a large and growing portfolio of upstream operations, which are mainly a result of their national priorities.

Given the contrasting strategies, what is certain is that IOCs and NOCs are more careful in their resource selection and disciplined in their capital allocation.

Exporting-country NOCs will lead the way in global oil and gas production, producing large volumes from their conventional onshore resources, with supermajors and large IOCs preferring core assets that provide small to modest growth.

Importing-country NOCs, despite their near-monopoly in their respective domestic markets, will struggle to expand production due to their limited resource base. However, NOCs such as OGDC in Pakistan, ONGC and IOC in India, and CNOOC, Sinopec and CNPC in China, will expand their LNG and natural gas distribution business given the increasing gas demand in these countries.

International independents, and international NOCs such as Equinor and Petronas will focus on growth opportunities through high-impact exploration projects and US-independents will focus on unconventional oil and gas resource development and production across the United States.

NOCs in the Middle East will dominate global oil production in the long-term, accounting for 55% of global oil production in 2050. Their dominance will reflect their efforts to produce the "cheapest barrel" rather than "more barrels".

And finally, given the ongoing energy transition that is encouraged by various regulatory decarbonisation initiatives, upstream operators have a key role to play in mitigating climate change. There are various cost-effective technologies and opportunities they may use in order to reduce the intensity of emissions from core upstream operations, by minimising the deliberate and unintentional flaring of associated natural gas, tackling methane emissions, and integrating renewables in upstream operations.

Therefore, upstream producers must transform their portfolios through low-cost operations, reduce emissions footprint, and cut overall capital intensity, to generate additional free cashflow, which could either be invested in transitioning their operations away from oil and gas, or returned to their shareholders.

APPENDIX

i. Why Oil and Gas Companies Need to Transform Their Upstream Operations, BCG, 2020 (https://www.bcg.com/publications/2020/oil-gas-companies-need-to-transform-upstream-operations)
ii. https://www.spglobal.com/platts/en/market-insights/latest-news/natural-gas/020921-total-eyes-stable-oil-gas-output-in-2021-after-opec-cuts-hit-q4-production
iii. Energy Transition Outlook – A Global and Regional Forecast to 2050, DNV, 2021
iv. Energy Transition Outlook (Oil & Gas) – A Global and Regional Forecast to 2050, DNV, 2021
v. Shell Attains Break-even Costs of $30-$35 per Barrel in Brazil, OE Digital, 2018 (https://www.oedigital.com/drilling/item/17310-shell-attains-breakeven-costs-of-3035-per-barrel-in-brazil)
vi. Revisiting the Deepwater Cost Curve: Will Deepwater Remain an Industry for those with Deep Pockets, Wood Mackenzie, 2018 (https://www.woodmac.com/news/opinion/revisiting-the-deepwater-cost-curve/)
vii. Gas Market Report: Q3 – 2021, International Energy Agency, 2021 (https://www.iea.org/reports/gas-market-report-q3-2021/overview-and-key-findings)
viii. Appalachia Region – Drilling Productivity Report, United States Energy Information Agency, 2021 (https://www.eia.gov/petroleum/drilling/pdf/appalachia.pdf)
ix. Saudi Aramco Announces Regulatory Approval of the Development of Jafurah Gas Field, Saudi Aramco, 2020 (https://www.aramco.com/en/news-media/news/2020/jafurah-gas-field)
x. World Energy Investments, International Energy Agency, 2021 (https://www.iea.org/reports/world-energy-investment-2021/executive-summary)
xi. World Energy Investments, International Energy Agency, 2021 (https://www.iea.org/reports/world-energy-investment-2021/executive-summary)
xii. World Energy Investments, International Energy Agency, 2021 (https://www.iea.org/reports/world-energy-investment-2021/executive-summary)
xiii. Abu Dhabi Approves ADNOC Spending, Unveils Oil Discovery to Boost Murban Futures Plan, S&P Global Platts, 2020 (https://www.spglobal.com/platts/en/market-insights/latest-news/oil/112220-abu-dhabi-approves-adnocs-122-bil-5-year-capex-announces-oil-discovery)
xiv. Saudi Arabia needs Oil at US$ 85 – US$ 87 a Barrel to Balance Budget, Reuters, 2018 (https://www.reuters.com/article/us-saudi-arabia-imf-idUSKBN1I30H7)
xv. (https://data.imf.org/regular.aspx?key=60214246)
xvi. Hedging Surge: Operators Lock in 2018 Oil Hedges, The American Oil & Gas Reporter, 2018 (https://www.aogr.com/web-exclusives/exclusive-story/operators-lock-in-2018-oil-hedges)
xvii. IHS Markit, https://seekingalpha.com/article/4400181-high-impact-wells-outlook-for-2021
xviii. Undiscovered resources from USGS, https://pubs.usgs.gov/fs/2012/3042/fs2012-3042.pdf; high-impact wells from Westwood, IHS Markit
xix. CO2 Emissions by Fuel, Our World in Data, 2020
xx. The Future is Now: How Oil & Gas Companies can Decarbonise, McKinsey, 2020 (https://www.mckinsey.com/industries/oil-and-gas/our-insights/the-future-is-now-how-oil-and-gas-companies-can-decarbonize)
xxi. (https://www.climatechangenews.com/2021/04/26/saudi-us-net-zero-oil-producer-initiative-lands-scepticism/)
xxii. FACTBOX: Big Oil Climate Targets, Reuters, 2021 (https://www.reuters.com/business/cop/big-oils-climate-targets-2021-10-28/)
xxiii. BP Statistical review of World Energy, 70th Edition, BP, 2021
xxiv. Zero Routine Flaring by 2030, The World Bank (https://www.worldbank.org/en/programs/zero-routine-flaring-by-2030)
xxv. Flaring Emissions, International Energy Agency, 2021 (https://www.iea.org/reports/flaring-emissions)
xxvi. Methane Tracker, International Energy Agency, 2021 (https://www.iea.org/reports/methane-tracker-2021)
xxvii. ENI and Sonatrach Inaugurate the 10 MW Bir Rebaa North Photovoltaic Plant and Sign Agreements in the Renewable Energy Sector, ENI, 2018 (https://www.eni.com/en-IT/media/press-release/2018/11/eni-and-sonatrach-inaugurate-the-10-mw-bir-rebaa-north-photovoltaic-plant-and-sign-agreements-in-the-renewable-energy-sector.html)
xxviii. Omani- and Shell-Backed Solar EOR Firm Runs Out of Steam, Journal of Petroleum Technology, 2020 (https://jpt.spe.org/omani-and-shell-backed-solar-eor-firm-runs-out-steam)
xxix. All Electric LNG Maximizes Process Control in the Arctic, Gas Processing and LNG, 2020 (http://www.gasprocessingnews.com/features/202004/all-electric-lng-maximizes-process-control-in-the-arctic.aspx)
xxx. The Oil & Gas Industry in Energy Transition, International Energy Agency, 2020 (https://www.iea.org/reports/the-oil-and-gas-industry-in-energy-transitions)

Figure 11. Estimated Global Upstream Crude Oil Carbon Intensity (Source: https://www.osti.gov/pages/servlets/purl/1485127)

Figure 14. Digital Strategy in Oil Field Transformation (Source: https://intellias.com/digital-transformation-in-oil-and-gas-a-remedy-for-market-volatility/)

PAST ISSUES

Have you missed a previous issue? All past issues of The Al-Attiyah Foundation's Research Series, both Energy and Sustainability Development, can be found on the Foundation's website at **www.abhafoundation.org/publications**

September – 2021
Connecting the Global Power Grid

The transition to a more electrified society, and the greater dependence on variable renewable energy, raises the value of long-distance electricity interconnections. At the same time, advances in transmission and smart grids makes such links more feasible.

(QRCO.DE)

August – 2021
Global Energy Subsidies

Energy products are commonly subsidised in both industrialised and developing countries for a host of reasons, even as governments face increasing pressure for energy policy to converge around efficiency, sustainability, affordability, and access.

(QRCO.DE)

July – 2021
Energy Tradewinds

The aviation and shipping industries are widely considered to be hard-to-abate sectors. Some technological solutions, and fuel sources to decarbonise these sectors have been developed but require urgent implementation if emission targets are to be met.

(QRCO.DE)

OUR PARTNERS

The Al-Attiyah Foundation collaborates with its partners on various projects and research within the themes of energy and sustainable development.

مؤسسة قطر
Qatar Foundation
Unlocking human potential لإطلاق قدرات الإنسان

KAHRAMAA
كهرماء
المؤسسة العامة القطرية للكهرباء والماء
Qatar General Electricity & Water Corporation

World Petroleum Council

جامعة قطر
QATAR UNIVERSITY

جامعة حمد بن خليفة
HAMAD BIN KHALIFA UNIVERSITY

COLUMBIA UNIVERSITY
IN THE CITY OF NEW YORK

UIP-ICP
ULUSLARARASI İŞBİRLİĞİ PLATFORMU
INTERNATIONAL COOPERATION PLATFORM
İSTANBUL

ISAG
Istituto di Alti Studi in Geopolitica e Scienze Ausiliarie

MITSUI & CO.

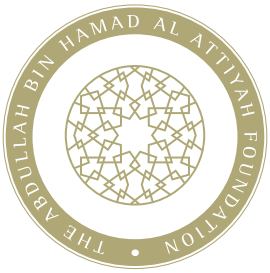
مجلس قطر للمباني الخضراء
QATAR GREEN BUILDING COUNCIL

GORD
المنظمة الخليجية للبحث والتطوير
Gulf Organisation for Research & Development

United Nations Global Compact

NATIONAL COUNCIL ON U.S.-ARAB RELATIONS

GULF TIMES



Barzan Tower, 4th Floor, West Bay, PO Box 1916 - Doha, Qatar

Tel: +(974) 4042 8000, Fax: +(974) 4042 8099
www.abhafoundation.org

AlAttiyahFndn
The Al-Attiyah Foundation
Al-Attiyah Foundation