Kazakhstan Association of Oil&Gas and
Energy Sector Organizations «KAZENERGY»

THE NATIONAL ENERGY REPORT

KAZENERGY 2021

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DEAR LADIES AND GENTLEMEN!

Over the past two years, there have been major changes in the global economy caused not only by the pandemic, but also by the political decisions made by key countries about the need to accelerate the transition to low-carbon development.

The “energy transition” concept, initiated in the European Union, has already become part of the political agenda in a number of countries, and influences the decisions made by international financial organizations. A movement to end coal project financing, and a shift from natural gas and refined petroleum products to hydrogen in the foreseeable future will have a major impact on the countries exporting hydrocarbons. Kazakhstan occupies a prominent place in global energy export markets and decreasing hydrocarbon energy demand poses a challenge for the entire country’s economy.

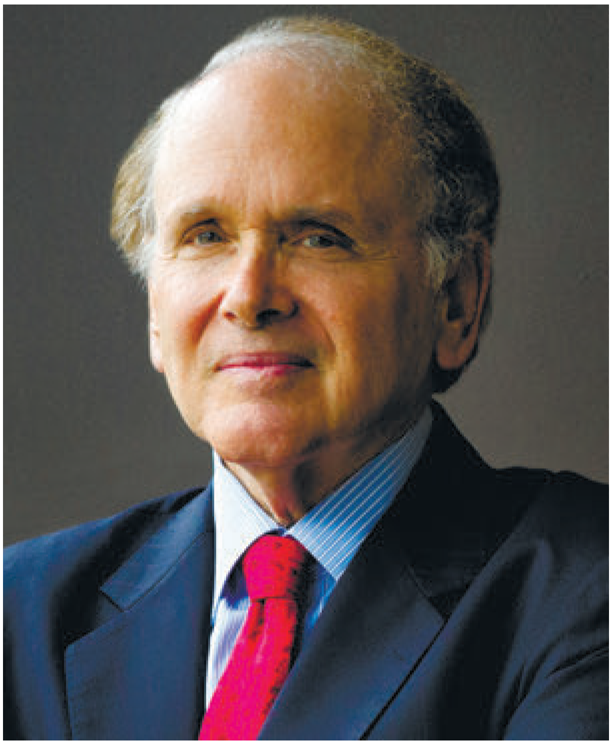
Therefore, the application of a systemic approach to planning the development of the Republic’s energy sector, which will support risk reduction and increased competitiveness, is of particular relevance for Kazakhstan today. The Republic is adopting consistent and conceptually new approaches for industry regulation and for achieving the goals voiced by the President of the Republic of Kazakhstan Kassym-Jomart Tokayev.

The latest issue of the National Energy Report is dedicated to the opportunities and challenges of the new global energy agenda, presenting the view of leading foreign and domestic experts on the prospects of Kazakhstan’s energy sector development, and ways of improving regulatory, pricing, and tariff policies.

This 5th edition of the National Energy Report, prepared by the KAZENERGY Association together with Kazakhstani and international experts, appears to be of special significance being published in the year of the 30th anniversary of the national independence of the Republic of Kazakhstan and provides an assessment of the historical development of the sector.

I believe that the competence and independence of the views presented in this Report make it useful for consideration when shaping the government’s decisions in the energy sector.

Sincerely yours,
Chairman of the KAZENERGY Association
Timur Kulibayev



DEAR READERS!

We once again have the distinct honor to participate in work on The National Energy Report 2021 for Kazakhstan (NER 2021). This marks our fourth edition of this significant and ground-breaking report covering the importance, diversity, successes, and challenges of Kazakhstan's energy sector. This year also marks 30 years of national independence, and we congratulate Kazakhstan on this historic anniversary!

This Report also marks an important shift for Kazakhstan – one in which the country and the world at large more directly confront the looming challenge of climate change and the implications of a global energy transition targeted toward reducing greenhouse gas emissions from fossil fuel consumption. Further, we deliver this new Report in the later stages of what is still an ongoing global pandemic from COVID-19; a pandemic that resulted in a broad-based economic contraction that produced a 5% decline in global primary energy demand in 2020. And although energy demand is expected to recover to 2019 levels next year (2022) and grow at a slow or moderate rate thereafter, incremental demand in the future will be increasingly met by low- or non-carbon sources of energy, reflecting a quickening pace of decarbonization worldwide in pursuit of "net-zero carbon" compared to our outlook prior to the onset of the pandemic.

There are a number of implications for Kazakhstan that are highlighted in NER 2021. Although Kazakhstan's economy has experienced considerable development and some diversification in the three decades since independence, hydrocarbons and other energy resources still remain central in the national economy. The oil and gas industries alone, together with related sectors (e.g., oil and gas transportation, upstream construction, and geology), contributed 17% of the country's GDP in 2020, with oil accounting for the bulk of Kazakh export earnings and constituting the primary source of the government's budgetary revenue. The development of the oil and gas industry has been a source of strength, generating economic activity, employment, and revenues that have been crucial since 1991 in solidifying Kazakhstan's independence as a nation and delivering increasingly higher incomes and standards of living for its people. It has also fortified Kazakhstan's relations with its neighbors and established the country as a major force in the global oil industry and a significant participant in global markets, the world community, and global affairs.

But this also increases the national economy's vulnerability to external shocks. This was painfully driven home in 2020 by the COVID-19 pandemic. As world liquids demand fell by nearly 11%, Kazakhstan entered its deepest recession in two decades: GDP fell by 2.6%, reflecting lower oil prices and weak external demand for hydrocarbon exports, compounded by the negative impact of lockdowns on domestic economic activity.

Yet, a paradox of sorts emerges. Given the importance of the energy sector within Kazakhstan's economy, revenues from exports of hydrocarbons and other energy resources will be essential for economic diversification initiatives and for funding the country's ongoing transition to low-carbon energy in the future. But as the Report highlights, international markets for hydrocarbons will shift in meaningful ways as the global energy transition continues to gather momentum. And, it is clear that Kazakhstan will face increased competition for scarce foreign investment capital worldwide (including from other major hydrocarbon producers). Investor-companies will still compete for new opportunities, but they are being much more selective with new projects, increasing the competition among resource-holding countries for available investment. It will be important in this emerging environment for Kazakhstan's policymakers to take steps, through enlightened fiscal and other policies, to demonstrate they are holders of "advantaged" or "resilient" resources – oil and gas supplies that can be developed, produced, and delivered at relatively low cost and with a low carbon footprint and, at the same time, with regulatory certainty and timely decision-making. These will be key criteria on which international companies make their investment decisions.

Despite the heightened concern, fruitful new mechanisms for international collaboration have emerged in response to the pandemic. The April 2020 OPEC+ "mega deal" to curtail output in response to the world oil demand collapse amounted to the largest-ever organized crude oil production cut, and to this point has been successful in stabilizing global oil markets, driving world oil prices back up from very low levels (and with that, export revenues for oil exporters). Kazakhstan has played a major role in the group's efforts to equilibrate global supply with demand. Another area of broad regional cooperation in the energy space is the pending formation of single markets within the Eurasian Economic Union for oil and oil products, natural gas, and electric power; integration among the members (which include Kazakhstan) will bring new benefits and opportunities, but will also require adjustments by Kazakhstan, for example in energy pricing. Another example is Kazakhstan's ongoing engagement in discussions of global climate policy, and the release of Kazakhstan's 2060 carbon neutrality goal, ahead of the 26th UN Conference of Parties to the United Nations Framework Convention on Climate Change (also known as the Glasgow Summit or COP26) in November 2021.

The signs of a changing global business environment in the energy industries were already evident in the previous National Energy Report 2019, when we observed that international oil and gas companies had shifted their focus from growing the size of their reserves increasingly toward cost-efficiency, embracing powerful technological innovations (big data, cloud computing, artificial intelligence) to cut costs and boost production from existing assets. We also noted that some oil and gas majors were already moving in the direction of becoming more diversified energy companies, branching out into "green" activities such as renewable energy production; electric vehicle charging; carbon capture, use, and storage (CCUS); and electricity and natural gas distribution.

These trends have now been accelerated by COVID-19. Rapidly evolving national climate policies and growing pressures, not only from governments, but also investors, climate activists, and the general public, are influencing the strategies and plans of energy companies and the broader business community worldwide. All are seeking to drive decarbonization, partly by pushing for long-term targets for company operations and products. At the same time, there is ongoing debate over which forms of energy should be considered "green" and thus suitable for government financing and future private investment. And there is a growing recognition that substantial progress toward reducing greenhouse gas (GHG) emissions will require the use of both proven low-carbon technologies such as wind and solar power in electric power generation, as well as technologies currently only at the demonstration or experimental phases, especially in sectors that are going to be more difficult to decarbonize such as heavy industry and transportation. This does not mean that hydrocarbon energy resources will no longer be important; they will. Undoubtedly, they will continue to play a major role in the world economy for the foreseeable future; but at the same time, the focus will increasingly shift to reducing their climate impact and increasing the efficiency of their consumption. And that will mean more emphasis on carbon capture and offsets.

One of the key themes we emphasized in our previous report (NER 2019) was the precarious balance between the Kazakh government's efforts to maintain low electricity, natural gas, and refined products prices for Kazakh consumers and the need to devise policy to incentivize production, processing, and distribution of these resources; this is partly to generate the revenues necessary to finance reinvestment in the energy sector. This challenge remains a theme in the current volume, but is now compounded by the need to develop energy resources in a way that reflects full awareness of the climate issues the world now faces. Therefore, a key theme in NER 2021 is a discussion of best available technologies (BATs) in world practice that can be applied to reduce the environmental impacts of energy production and consumption, and a general assessment of their economic feasibility within Kazakhstan.

We present NER 2021 at this key stage in the development of Kazakhstan's energy sector with the same sense of optimism and purpose as our first Report issued back in 2015. Our goal is to contribute to an ongoing process of understanding, and with it decision-making and policy formation, that will enable Kazakhstan to meet its energy and environmental challenges while promoting the economic and social well-being of its people.

Dr. Daniel Yergin
Vice Chairman IHS Markit
October 2021

Appreciation

The KAZENERGY National Energy Report 2021 was prepared by the KAZENERGY Association (with active participation from its members) and by IHS Markit and Avantgarde Group. However, it naturally builds on the previous work and analysis of many different experts, both within Kazakhstan and abroad. These specialists represent a wide variety of organizations, including KAZENERGY members, state authorities of the Republic of Kazakhstan, many research, development, design and engineering entities, as well as companies operating in the sector. The contributions of all these experts are significant and gratefully acknowledged. This most recent Report, published in 2021, marks the special occasion of 30 years of national independence for Kazakhstan, and we congratulate the people of Kazakhstan on this historic achievement!

Writing NER 2021 during a global pandemic presented numerous research challenges. We are grateful to the entities that took the time to conduct virtual interviews with the research team. We are also grateful to the KAZENERGY member companies and governmental agencies that responded to information requests and provided comprehensive, written feedback, data inputs, and insights. We particularly thank a number of international oil companies and other members of the Foreign Investors Council, for their comments and insights during the research process.

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We especially thank Uzakbay Karabalin, Deputy Chairman of the KAZENERGY Association, Kenzhebek Ibrashev, General Director of the KAZENERGY Association, Talgat Karashev, Executive Director of the KAZENERGY Association, and Rustam Zhursunov, Ombudsman for the Protection of the Rights of Entrepreneurs of Kazakhstan. This Report would not have been possible without their active assistance, advice, and support.

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In closing, throughout the preparation of this Report and despite the challenges posed by the COVID-19 pandemic, we have been truly fortunate to have worked with many remarkable and talented colleagues in Kazakhstan. We are particularly honored to present this report during the convocation of the XIV KAZENERGY Eurasian Forum and the World Energy Week Live 2021, hosted in Nur-Sultan and devoted to important issues of Kazakhstan's energy future.

In Appreciation,

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CONTENTS

Chapter 1

FUEL AND ENERGY BALANCE AFTER COVID-19

1 OVERVIEW AND OUTLOOK FOR THE POST–COVID-19 GLOBAL ENERGY MIX AND KAZAKHSTAN'S ECONOMY

1.1 Key Points

- COVID-19 upended the global economy and energy markets in 2020. Global GDP fell by 3.5% last year, while global primary energy consumption dropped 5.4%. The mobility restrictions imposed by governments worldwide to combat the pandemic's spread drastically reduced consumption of motor fuels in particular, thus substantially reducing demand for oil products (including the crude oil and gas condensate used to produce them) more broadly. Total world liquids demand fell by roughly 11% in 2020, and this drop accounted for over 60% of the total decline in global primary energy consumption last year. After oil demand, coal consumption registered the sharpest decline among the fossil fuels in 2020, falling by 4.9%, while natural gas demand fell by a relatively modest 2.7%. Meanwhile, nuclear power's contribution declined by 4.1%, while hydroelectricity and renewables demand both registered growth. Overall, global electricity demand dropped 1.2% in 2020.
- The new OPEC+ agreement has been a critical stabilizing factor in world oil markets over 2020-21. The April 2020 OPEC+ "mega deal" to curtail output in response to the world oil demand collapse amounted to the largest-ever organized crude oil production cut (condensate is excluded from the OPEC+ quotas). Kazakhstan has achieved better compliance over 2020-21 than during previous rounds of OPEC+ cuts, but has nevertheless typically fallen short of realizing its OPEC+ reduction targets in the estimate of IHS Markit (albeit Kazakh authorities' estimates of Kazakhstan's rate of compliance with OPEC+ targets tend to be higher, reflecting differences in ton-barrel conversion ratios used to calculate production volumes; see below). One key factor in the mixed results is Kazakhstan's oil industry structure, as the Kazakh government has only indirect levers of control over projects led by international oil companies (IOCs) that generate the bulk of national oil output, while Kazakhstan's relatively robust oil production growth rate on the eve of the pandemic also complicated the task of engineering a sharp reduction of output.
- With respect to oil price dynamics, the OPEC+ arrangement supported a "floor" in average Dated Brent oil prices of about $42/bbl in 2020 (versus an average of $65 in 2019), and has contributed, in conjunction with the global demand rebound in 2021, to significantly higher prices this year. Our current outlook is for Dated Brent to average around $62/bbl in real terms (2020 dollars) during 2021-25, and average about $60/bbl during the scenario period to 2050, albeit with significant volatility. The key factors in the price outlook for the 2021-25 period include continuing world oil demand recovery on the back of relatively strong (but moderating) global GDP growth, and a more than adequate supply response given the winding down of OPEC+ restrictions along with a substantial increase in Iranian output and exports following an eventual lifting of US sanctions.
- The global oil market has become even more bifurcated due to the differential impact of the pandemic, as Organisation for Economic Co-operation and Development (OECD) oil demand fell in 2020 at a significantly steeper rate than non-OECD oil consumption. The outlook is for still greater divergence going forward, even as total world oil demand reaches an expected maximum in the second half of the 2030s and then enters a decline trajectory that extends through the end of our forecast period in 2050. The non-OECD countries' aggregate consumption – especially non-OECD Asia Pacific demand – remains on a growth trajectory throughout the period 2021-50, while the OECD demand contraction continues; as a result, the non-OECD share of global oil (liquids) consumption rises from about 54% in 2020 to 66% in 2050 in our base-case scenario.
- IHS Markit now envisages a somewhat faster global pace of energy transition (i.e., decarbonization with the aim of limiting global warming) compared with our pre-pandemic outlook, reflecting largely the marked intensification starting in 2020 of efforts to counteract climate change on the part of virtually all key players. In our new base-case scenario, primary world energy consumption grows altogether by about 24% by 2050, and incremental demand is met largely by low-carbon sources of energy (above all, renewables); renewables' aggregate share of global demand rises from about 10% currently to around 24%, while the fossil fuel share declines from 80% to 64%. Energy transition pathways vary widely across the globe among regions and countries, however, in terms of timing as well as shifts in the fuel mix.
- In 2020, Kazakhstan entered its deepest recession in two decades, though the contraction was less sharp

than initially expected. GDP fell by 2.6% in 2020, given lower oil prices and muted external demand generally for Kazakh exports owing to the pandemic, along with the negative impact of the lockdowns on domestic economic activity. However, at last report the economy was growing again, and our base case is for Kazakh GDP to increase by 4.0% overall in 2021, though the recovery is uneven across economic sectors. The heavy reliance of the Kazakh economy on the energy sector means that global trends, such as commodity price declines, continue to have a broad effect in Kazakhstan – impacting the performance of industries not only in the energy sector itself, but in other areas related to energy production, including transportation, construction, trade, and professional services. Longer term, IHS Markit's outlook is for real Kazakh GDP to expand at an average annual rate of 2.8% during 2021-50, but with significant deceleration over time.

- Kazakhstan's total production of primary energy – including oil, gas, coal, and primary electricity (but not mined uranium) – declined by 4.2% in 2020. Meanwhile, domestic primary energy consumption dipped 2.7% in 2020, and net primary energy exports were down 5.6%. Our outlook is for production of primary energy to decline overall by 20% during 2021-50, while during the same period apparent consumption falls 3% and net exports drop 37%. With respect to the fuel mix, the biggest changes are anticipated in domestic consumption (as opposed to overall production and exports): coal retains the largest share of domestic demand of any fuel, but its portion declines from 56.7% in 2020 to around 37% by 2050, while the shares of natural gas, oil, and primary electricity expand (see Chapter 5 for comparative analysis of Kazakh coal demand trends in different sectors of the economy and our outlook to 2050, as well as the coal industry's responses to challenges posed by the decarbonization agenda).

1.2 Analysis of COVID-19's Impact on the Global Economy and Energy Markets

1.2.1 Global economic and energy market dynamics in 2020-21

The coronavirus 2019 (COVID-19) disease, first reported in December 2019 in China's Wuhan province, spread globally during the first quarter of 2020, hammering the world economy. By the end of the second quarter of 2020, more than half of the global economy had been "locked down" to slow the spread of the virus, before gradually re-opening, starting in the third quarter. Global GDP fell by 3.5% altogether in 2020. In the IHS Markit base case, real global GDP surges by 5.7% overall in 2021, but the rate of recovery remains highly variable from country to country, reflecting the uneven availability of vaccines worldwide, among other key factors.

Global primary energy consumption dropped last year by 5.4% to 13.80 billion metric tons of oil equivalent (Btoe), thus significantly outpacing the decline in world GDP.[1] This dynamic contrasts markedly with that seen during the previous downturn of the world economy in 2009, amid the global financial crisis, when world GDP and primary energy demand both fell by around 1% (1.4% and 0.9%, respectively). A key reason for the more differentiated global economic and energy demand decline rates in 2020 was the pandemic-related mobility restrictions that drastically reduced consumption of motor fuels, in particular (above all, gasoline and jet fuel demand), thus substantially reducing total demand for oil (liquids) (i.e., crude oil and gas condensate in primary form) more broadly. Total oil (liquids) demand fell worldwide by 10.8% in 2020 to 4.12 Btoe, and this drop accounted for 63.2% of the total decline in global primary energy consumption last year (oil's share of total demand nevertheless remained larger than that of all other fuels, at 29.8%). Global liquids production contracted somewhat less than consumption in percentage terms, by 7.2%, reflecting a massive global inventory buildup in 2020. Meanwhile, demand for natural gas, coal, nuclear power, and modern biomass declined by 2.7%, 4.9%, 4.1%, and 3.5%, respectively. The only major primary energy sources for which demand increased in 2020 were hydroelectricity and renewables; by 1.5% and 9.9%, respectively. Consumption of all other primary energy sources combined (i.e., aside from those noted above) edged up 0.3% in 2020.[2] The aggregate share of the fossil fuels (i.e., oil, natural gas, and coal) in the global energy demand mix thus dipped from 81% in 2019 to 80% in 2020, while the aggregate share of low-carbon sources (nuclear, hydro, and renewables) edged up from 9.8% to 10.4% (the first time in history when their combined share surpassed 10%) (see Figure 1.1 Annual changes in global primary energy demand by fuel type and GDP, 2000-20, and Table 1.1 Global primary energy demand by fuel type, 2019-20 (MMtoe)).

1 Global primary energy consumption is defined as the direct disappearance (or use) of produced energy before it has been subjected to any conversion or transformation process (to avoid double-counting derived, downstream fuels).

2 Oil consumption includes international marine/aviation bunkers, but does not include biofuels, which at the primary energy level are not associated with petroleum; the coal category includes steam and coking coal; renewables include solar, wind, geothermal, and tide/wave/ocean energy; modern biomass includes biofuels, biogas, biowaste, wood chips, and wood pellets; the "other" energy category includes solid waste, traditional biomass (including charcoal and wood), ambient heat, and net trade of electricity and heat.

Figure 1.1 Annual changes in global primary energy demand by fuel type and GDP, 2000-20

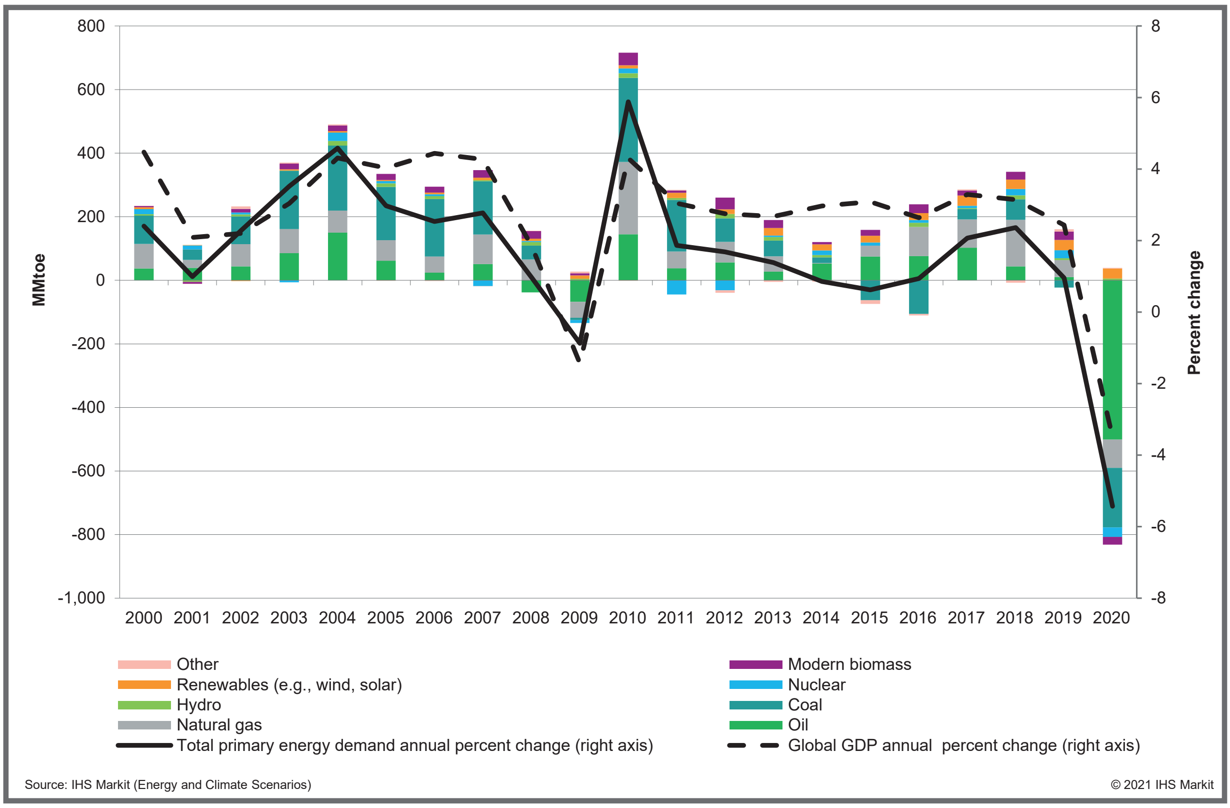


Table 1.1 Global primary energy demand by fuel type, 2019-20 (MMtoe)

	2019	2020	Percent change
Total	14,590	13,798	-5.4
Oil	4,618	4,117	-10.8
Natural gas	3,345	3,256	-2.7
Coal	3,854	3,667	-4.9
Hydro	369	375	1.5
Nuclear	733	703	-4.1
Renewables (e.g., wind, solar)	321	353	9.9
Modern biomass	697	672	-3.5
Other	653	655	0.3

Source: IHS Markit (Energy and Climate Scenarios)

1.2.2 The OPEC+ response to the global oil demand collapse

The OPEC+ coalition, otherwise known as the Vienna Alliance, has been a critical stabilizing factor in world oil markets overall during 2020-21. But OPEC+ members' initial actions during the onset of the world oil demand contraction in 2020 actually exacerbated the crisis.[3] Specifically, the OPEC+ co-leaders, Russia and Saudi Arabia, disagreed in March 2020 over methods for dealing with the first phase of COVID-19, leading to a temporary collapse of OPEC+ oil production constraint that intensified the negative impact of the disease on oil markets to the point of disrupting the entire global economy. The two countries

3 OPEC+ is an alliance of OPEC and non-OPEC producers formed in late 2016 with the aim of stabilizing world oil markets in the wake of the 2014-15 price collapse. The non-OPEC members were Azerbaijan, Bahrain, Brunei, Kazakhstan, Malaysia, Mexico, Oman, Russia, Sudan, and South Sudan.

soon returned to the OPEC+ bargaining table, however, in recognition of the new realities, and in tandem played the lead role in negotiating the 12 April 2020 Vienna Alliance "mega deal." The key factor reuniting Russia, Saudi Arabia, and other OPEC+ members was the transformation of the COVID-19 disease into a global pandemic, which led to the largest ever drop in world oil demand, and sent oil prices plunging. The "mega deal" envisioned an initial 9.70 MMb/d collective crude oil output cut by the Vienna Alliance (the biggest-ever organized cut in history), to be followed by progressively smaller reductions through April 2022 (a record in terms of the duration of OPEC+ cuts programs to date, a program later extended to December 2022; see below).[4] The original baseline for the proportional cuts was the October 2018 output level in the case of all countries except Saudi Arabia and Russia (whose baselines were both initially set at 11 MMb/d). The deal seems largely to have codified a shut-in of production that became inevitable over the following months; the April 2020 agreement essentially signified the Vienna Alliance's recognition of the fact that there was "nowhere for the oil to go," in the absence of adequate spare oil storage capacity globally (see Figure 1.2 Distribution of OPEC+ oil output reduction targets: First, second, and third rounds (initial plans)).[5]

The initial 9.70 MMb/d OPEC+ cuts target that took effect in May 2020 was at first intended to last through June 2020, but was later extended through July 2020. In August 2020, the planned collective cut was eased to 7.68 MMb/d, for the rest of 2020. According to the original agreement, in January 2021 the cuts were to drop further to 5.76 MMb/d through April 2022. However, global oil markets remained weaker in late 2020 than anticipated, leading to another recalibration of Vienna Alliance policy. At the end of a meeting of OPEC+ oil ministers convened during 30 November–3 December 2020, it was decided to increase production by only 500,000 b/d in January 2021 – a relaxation of the cuts to 7.20 MMb/d – with subsequent monthly meetings planned to decide on further necessary adjustments in increments of up to 500,000 b/d.

In 2021, the OPEC+ cuts program has continued to evolve in some important ways that were not envisioned in the April 2020 deal. In particular, in January 2021 negotiations, OPEC+ members mapped out divergent production paths during the remainder of the first quarter of 2021. Whereas Saudi Arabia pledged an additional "voluntary" reduction in the first quarter of 1 MMb/d, and other OPEC+ members agreed to hold their production steady at the planned January level, Kazakhstan and Russia both received permission to increase their production further in February-March, to ensure domestic oil demand was adequately covered, and both countries subsequently obtained a further extra production quota for April. Then on 1 April 2021 OPEC+ announced plans for a general phased increase of the members' output by a collective 2.14 MMb/d during May-July. In early July 2021, however, OPEC+ reached an impasse in the course of talks on the group's production quotas for August 2021 and beyond, as a demand by the United Arab Emirates (UAE) for a much larger quota (to reflect the build-up of UAE spare capacity) met resistance from Saudi Arabia and others. The upshot was a compromise agreement, announced on 18 July 2021 – extending the current supply management program through the end of 2022, providing for monthly collective OPEC+ production increases of 400,000 b/d starting in August 2021, and upwardly adjusting the production baselines from 1 May 2022 for the UAE and four other OPEC+ members (Saudi Arabia, Russia, Iraq, and Kuwait) by an aggregate 1.63 MMb/d.[6]

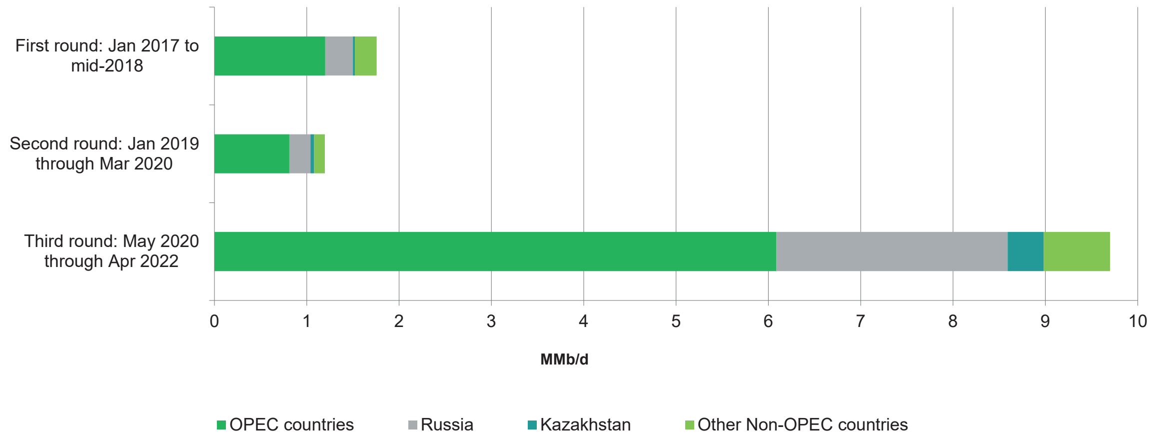
Kazakhstan's initial crude-only OPEC+ cuts target amounted to 390,000 b/d over May-June 2020 (subsequently extended through July) – dwarfing all previous Kazakh OPEC+ reduction commitments – for an initial voluntary crude oil production limit of 1.32 MMb/d (or around 19% below the average 2019 Kazakh crude oil output of 1.63 MMb/d). Kazakhstan's share of the total initial OPEC+ cuts target has also risen substantially overall (from only 1% in the first round to 3% in the second round and 4% in the third round), as has Kazakhstan's share of the initial cuts target among non-OPEC members of the Vienna Alliance (from 6% in the first round to 10% in the second round and 11% in the third round) (see Figure 1.3 Monthly Kazakh crude oil and condensate production, 2019-21, and Figure 1.4 Changes in Kazakhstan's share of OPEC+ cut targets within key categories of OPEC+ producers as initially planned).

4 Official statistics of Kazakhstan and the former Soviet republics typically report regional oil volumes in metric tons, but the OPEC+ agreements quantify production changes in units of barrels per day. The analysis of OPEC+ and other global oil trends in *The National Energy Report 2021* provides oil volumes in barrels per day, while Kazakh oil volumes as reported in other sections are provided in metric tons followed by barrel-equivalent estimates in parentheses where possible. Estimates of Kazakh crude oil and gas condensate volumes in barrels in this report are generally based on the average 2020 conversion ratio of 7.7 barrels per ton, but these are only approximate values. For more on Kazakh ton-barrel conversion issues, see the IHS Markit Insight *New OPEC+ agreement accentuates challenges of "barrelization" of oil production for Russia, Kazakhstan, and Azerbaijan,* 18 September 2020.

5 The Kazakh case is indicative of the storage capacity shortage globally amid the oil demand collapse. Kazakhstan's estimated total oil storage capacity is only around 3.3 MMt or 25.3 MMbbl, of which roughly half consists of the storage tanks of KazTransOil, the national oil pipeline company (a KMG subsidiary). This suggests an available (empty) storage capacity equivalent to no more than around 7-8 days of oil production (assuming an initial storage utilization rate of 50%).

6 See the IHS Markit Oil Market Briefing *New oil deal: OPEC+ to increase supply, revise upward reference production for five major countries, and extend agreement to end-2022,* 19 July 2021.

Figure 1.2 Distribution of OPEC+ oil output reduction targets: First, second, and third rounds (initial plans)



Notes: Initial reduction target during period of each OPEC+ deal.
Source: IHS Markit

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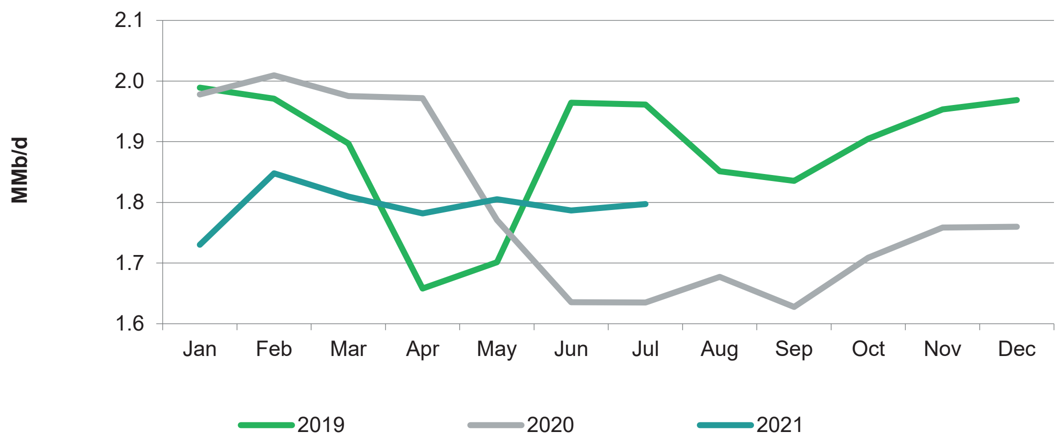
Kazakhstan's unique formula for implementing its overall OPEC+ cuts target this time focuses on export volumes rather than production – effectively tasking two of the IOC-led "Big 3" projects – the Tengiz (Tengizchevroil; TCO) and Kashagan (North Caspian Operating Company; NCOC) projects – with a disproportionately large share of the cuts since they export 100% of their output. The third "Big 3" project, Karachaganak (Karachaganak Petroleum Operating Company BV; KPO), mainly produces gas condensate, which was exempted from Kazakhstan's voluntary OPEC+ production quota starting in May 2020.

The national oil company KazMunayGaz (KMG) and other producers in Kazakhstan (aside from KPO) are mainly crude oil producers but have typically received a smaller share of the OPEC+ cuts burden than TCO and NCOC under the current allocation formula, since they export a

Figure 1.3 Monthly Kazakh crude oil and condensate production, 2019-21



Notes: Converted at an average of 7.7 bbl/ton.
Source: IHS Markit; Ministry of Energy RK

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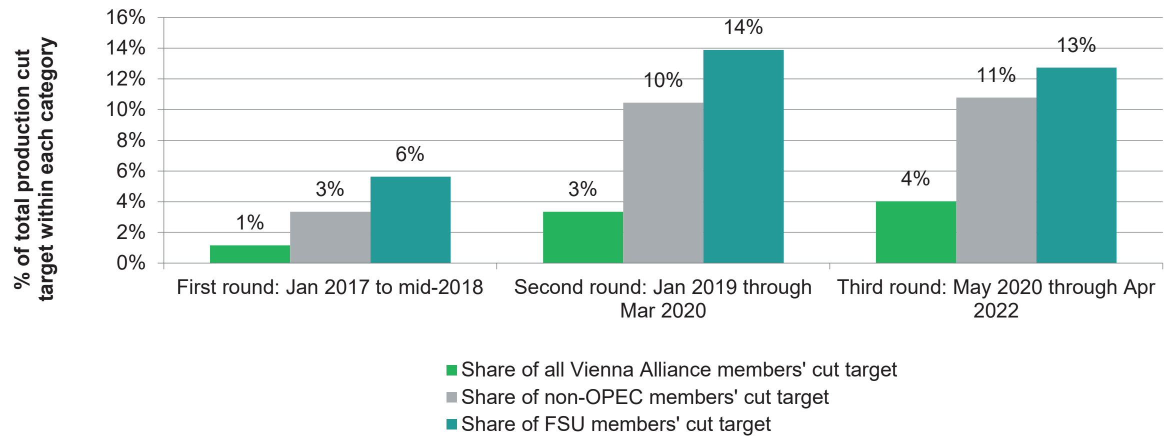
Figure 1.4 Changes in Kazakhstan's share of OPEC+ cut targets within key categories of OPEC+ producers as initially planned



Notes: Kazakh shares of initial OPEC+ reduction targets during each period.
Source: IHS Markit

much smaller share of total output. The current Kazakh OPEC+ implementation formula contrasts starkly with previous Kazakh reduction programs within the OPEC+ framework. In short, during previous (much smaller) rounds of OPEC+ cuts, Kazakhstan stayed on a growth track overall given rising aggregate "Big 3" output – with periods of Kazakh compliance with OPEC+ targets limited largely to the maintenance schedules of these projects.[7]

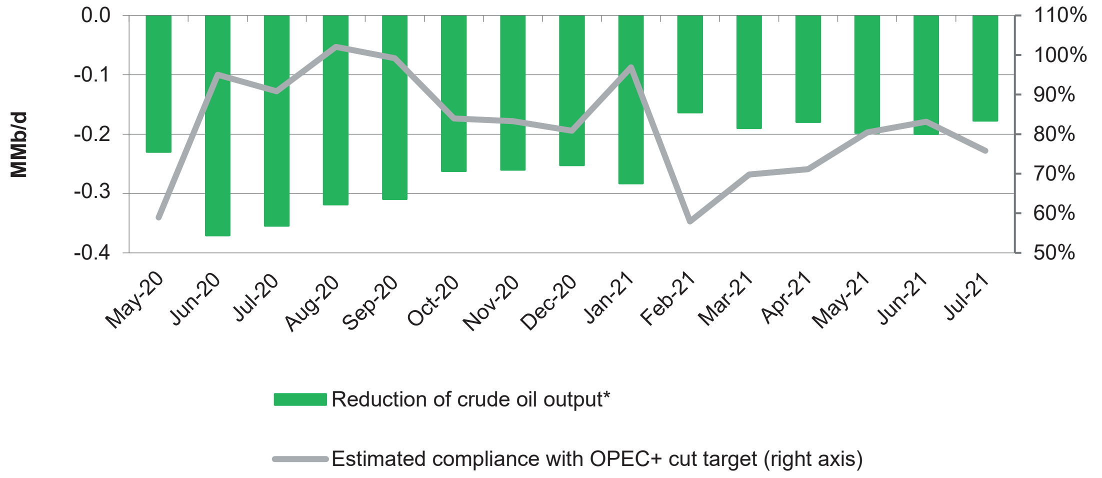
Kazakhstan has achieved better results over 2020-21 than during previous OPEC+ cuts programs, but has typically fallen well short of realization of its OPEC+ commitments in practice, registering the lowest compliance rate among any of the CIS members of OPEC+. IHS Markit estimates that during 2020 Kazakhstan achieved average compliance of 87%, and in the first half of 2021 the average fell to 77% (see Figure 1.5 Kazakhstan's crude oil production cuts and estimated compliance with OPEC+ targets by month, May 2020 onwards).[8] In contrast, Russian compliance has seldom fallen below 90%, and Azeri compliance has typically been 100% or higher. Two key factors in particular explain the comparatively weak Kazakh compliance rate. First, Kazakh levers of control over the IOC-led projects generating the bulk of national oil output are at most indirect (in contrast, the Russian government owns controlling stakes in companies that account for over half of total Russian oil production). Second, Kazakhstan's relatively robust oil production growth rate on the eve of pandemic spelled an additional obstacle to quick implementation of OPEC+ cuts; i.e., it has been relatively difficult for Kazakhstan to change course and implement deep cuts (Russia's oil production was also growing on the eve of the pandemic but at a much slower rate, while Azerbaijan's output had already long been in natural decline).

If anything, Kazakh compliance with OPEC+ targets is becoming more challenging as global oil markets recover, which may increasingly beg the question among Kazakh policymakers and oil producers of the rationale for continued Kazakh participation in OPEC+. The impact of the OPEC+ initiatives on Kazakhstan, and the degree of Kazakh collaboration with other Vienna Alliance members, depends ultimately on the longer-term evolution of the global liquids supply-demand dynamic. If there is significant global oversupply in the longer run, the Vienna Alliance probably will need to continue to cap (or at least directly manage) output in support of prices, and it will be relatively difficult for Kazakhstan to comply, let alone undertake additional cuts. But Kazakhstan will likely remain engaged with OPEC+ on production management questions for some time to come, especially given the continuing dependence of the Kazakh economy and government budget on oil export revenue. The latter fell sharply in annual terms during 2015-16 as well as 2020 on the back of lower world prices, before substantially recovering on both occasions thanks largely to OPEC+ policy. Like other Vienna Alliance members, Kazakhstan cannot really afford a steep prolonged fall in world oil prices, and active OPEC+ production management remains oil producers' primary means to minimize this risk.

7 TCO shareholders are Chevron (50%), ExxonMobil (25%), KMG (20%), and LukArco (5%). NCOC shareholders are Eni, ExxonMobil, Shell, and Total with 16.81% each; KMG and Samruk-Kazyna with 8.44% each; CNPC (8.33%); and INPEX (7.56%). KPO shareholders are Shell (29.25%), ENI (29.25%), Chevron (18%), LUKOIL (13.5%), and KMG (10%).

8 IHS Markit is one of six so-called secondary sources whose data are used by OPEC to assess compliance of Vienna Alliance members with OPEC+ production targets (the primary sources are the OPEC+ producing countries themselves, reporting directly to the OPEC secretariat). IHS Markit uses a different ton-barrel conversion ratio than that is reported by Kazakhstan, with the result that compliance estimates of IHS Markit and the Kazakh government frequently diverge; the average national liquids conversion ratio reported by Kazakhstan is relatively low compared with what most independent sources including IHS Markit estimate.

Figure 1.5 Kazakhstan's crude oil production cuts and estimated compliance with OPEC+ targets by month, May 2020 onwards



Notes: *Reduction compared with October 2018 production baseline.
Source: IHS Markit

1.2.3 World oil prices: More volatility, shorter cycles expected

Despite the somewhat fragile nature of the OPEC+ arrangement, it was instrumental in supporting a "floor" in average Dated Brent oil prices of about $42/bbl in 2020, by "buying time" for producers to manage (and mitigate) a chain of forced adjustments. This year OPEC+ has contributed, in conjunction with an accelerating global demand rebound, to a significantly higher oil price. In the (June 2021) IHS Markit outlook, the real Dated Brent price averages $65/bbl overall in 2021 ($66/bbl nominal), and $62/bbl over 2021-25 ($66 nominal).

Key drivers of global oil markets over the next few years in this outlook include the following:[9]

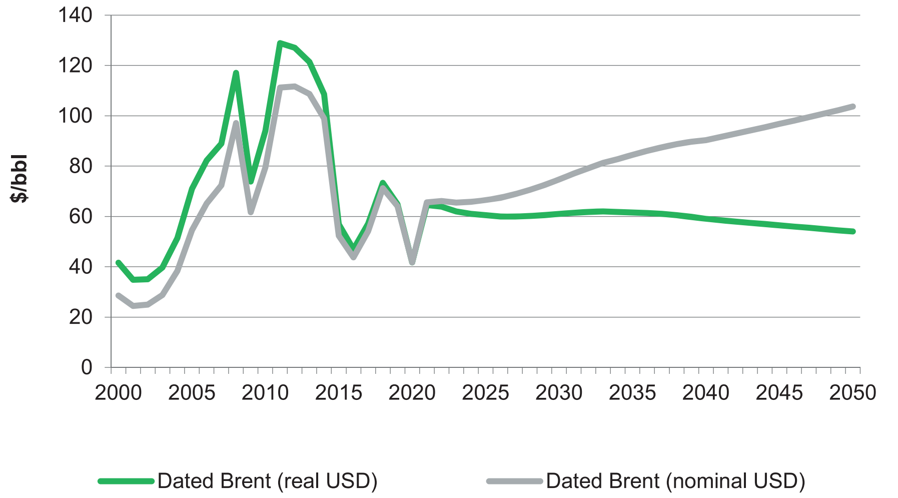
- Global GDP growth moderates starting in 2022, following the 2021 resurgence, and averages 3.3% over 2022-25 (compared with an annual average of 3.0% during the decade preceding the pandemic).
- After rising 6.6 MMb/d in the first three quarters of 2021, world oil demand growth slows to 0.3 MMb/d in fourth quarter of 2021. Demand further rises 4.0 MMb/d between the first and fourth quarters of 2022 (and surpasses the 2019 level starting in the second quarter of 2022).
- OPEC+ will gradually unwind its production cuts during 2021-22, and we assume that US sanctions on Iran (one of the OPEC+ members) are eventually lifted, allowing for a substantial increase in Iranian output and exports.
- US tight oil producers stick to capital discipline, limiting growth, and overall North American oil production remains below the 2019 level. Recent world oil price trends, however, suggest some potential for US producers to raise output more quickly without sacrificing near-term returns for investors (e.g., in the second quarter of 2021 US onshore crude producers saw the highest post-interest free cash flows since 2013).

Longer term (i.e., during the period out to 2050), the IHS Markit base case for the Dated Brent average is currently slightly lower in real terms, at about $60/bbl ($84/bbl nominal), as prices trend downward starting in the 2030s, reflecting our updated, lower long-term world oil demand outlook. Prices nevertheless remain above $50/bbl in real terms throughout the forecast period (see Figure 1.6 Long-term crude oil price outlook). As the energy transition accelerates, government policies and alternative fuels will restrain petroleum's long-term demand growth prospects (as discussed in more detail below). Equally important, the cost to develop several key sources of world oil supply declined significantly during 2015-16, in the wake of the oil price collapse beginning in 2014.[10] While costs

9 See the IHS Markit Scheduled Update *Global Crude Oil Markets Short-Term Outlook, July 2021: A test of Saudi Arabian oil power: The United Arab Emirates challenges the status quo,* 14 July 2021.

10 Specifically, IHS Markit estimates that full-cycle costs fell by a production-weighted average of 34% between 2014 and 2016 in the case of five major sources of supply: US tight oil, Middle East onshore, Russia onshore, Canadian oil sands steam-assisted gravity drainage, and global deep water. Key factors included oil field service sector cost deflation and improvements in the design, construction, and operation of projects. See the IHS Markit Strategic Report *Making Ends Meet: How the oil industry is cutting costs to make up for lower prices,* 18 May 2017. At the same time, it is important to note that cost dynamics have varied widely by region; e.g., in Kazakhstan costs remained comparatively high, reflecting the additional expenses involved in transportation of oil to market among other factors.

Figure 1.6 Long-term crude oil price outlook



Source: IHS Markit, Argust Media Limited (for historical prices) © 2021 IHS Markit

are expected to increase with the recovery in oil prices, another big cyclical upswing in upstream capital costs is unlikely. In short, an oil price level of around $60/bbl in real terms appears more than adequate to incentivize sufficient long-term supply needed to meet demand.[11]

The energy transition will eventually curb aggregate oil demand, but will not put an end to oil price cycles or volatility. On the contrary, we expect more frequent price fluctuations during the period out to 2050 due to a confluence of several key factors. With demand growth lessening over time and then declining, the most dynamic part of the oil balance equation shifts to the supply side. Two particular supply elements are highly reactive to market conditions – meaning they are more likely to go up and down faster than other parts of global supply. These two elements – OPEC+ supply management and US shale oil – now account for a larger share of production than in the past. In 2010, highly reactive supply – essentially OPEC production – was 41% of global crude oil production. In 2021, reactive supply, now including shale oil and OPEC+, accounts for about two-thirds of global crude oil production. The rise in relative importance of reactive supply at the same time that energy transition policies curb oil demand points to the likelihood of shorter oil price cycles. Weaker oil demand – and even declining demand in the long term – reduces the likelihood that upward demand pressure will catalyze price cycles. Instead, supply will adjust. However, it is impossible to neatly match changes in demand with more or less supply. In sum, oil prices will not consistently rise or fall for many years as they have in the past when cycles of deficit or surplus lasted 8–18 years. Day-to-day volatility may or may not increase, but year-to-year changes in the direction of oil prices will occur more often because of highly reactive supply.[12]

At the same time, the extreme 2020 volatility of differentials between Brent and CPC Blend (Kazakhstan's chief crude export grade) is not repeated in our base case. This phenomenon was due to essentially one-off, pandemic- related factors. COVID-19 had an exceptionally negative impact on CPC Blend prices (and resulting netbacks), as the usual advantages of the light CPC Blend in normal times were temporarily trumped amid the pandemic by other considerations:

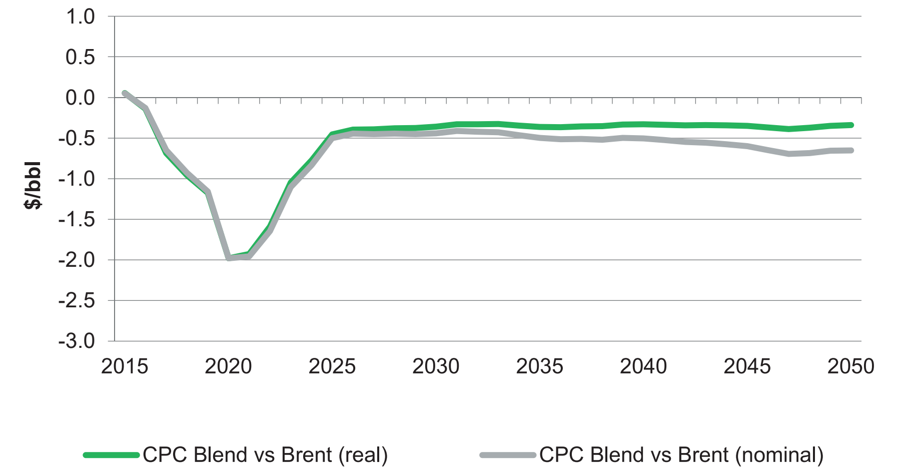
- **Especially sharp demand drop in European markets for crude grades such as CPC Blend with higher-than-average gasoline and jet fuel yields.** The global lockdown and mobility restrictions disadvantaged crude grades with high motor fuel yields, and CPC Blend was no exception; CPC Blend registered a record-low discount to Brent of around minus $10/bbl at one point.
- **Increased competition from Transneft routes for Kazakh oil volumes.** This was partly due to the comparatively higher prices on offer for Russia's Urals Blend exports. The denomination of Transneft tariffs in (depreciated) rubles also played a key role; in contrast, since the CPC tariff is set in dollars, the CPC route did not benefit from the ruble devaluation triggered by the world oil price collapse.

By the same token, the easing of the pandemic – and, in particular, the phasing out of the lockdowns in Europe – has been accompanied by a strong rebound in demand

11 See the IHS Markit Scheduled Update *Global Fundamentals Crude Oil Markets Price Long-Term Outlook – 2nd Quarter 2021,* 4 June 2021, and the IHS Markit Scheduled Update *Global Crude Oil Markets Annual Strategic Workbook, 2021,* 2 June 2021.

12 See the IHS Markit Strategic Report *The energy transition shortens oil price cycles: Highly reactive supply overtakes demand as the prime catalyst of price cycles,* 6 April 2021.

Figure 1.7 Long-term outlook for CPC Blend versus Brent differential



Notes: Dated Brent, CPC Blend Med CIF.
Source: IHS Markit, Argust Media Limited (for historical prices)

for CPC Blend, and a return of the CPC Blend–Brent differential to a more traditional range. The long-term (2021-50) CPC Blend discount to Brent is expected to average less than $0.50/bbl in real terms (less than $1/bbl nominal) (see Figure 1.7 Long-term outlook for CPC Blend versus Brent differential).

1.2.4 Regional oil market variations: Non-OECD nations play increasingly dominant role

The global oil market has become more bifurcated than before due to the differential impact of the pandemic – hitting OECD demand harder than non-OECD demand – and the outlook is for still greater divergence going forward. OECD total liquids demand reached a maximum in 2005 and had generally been declining at a moderate rate before 2020, when consumption plunged 12.3% to 42.12 MMb/d. In contrast, non-OECD total liquids consumption had been growing strongly overall for more than two decades prior to 2020, when non-OECD demand dropped by 8.4% to 49.40 MMb/d.

In the base-case scenario, global liquids demand rises from 91.54 MMb/d in 2020 to a mid-2030s maximum of about 106 MMb/d, before declining to around 101 MMb/d in 2050 (for a net rise over 2021-50 of roughly 10%). The non-OECD countries' aggregate consumption remains on a growth trajectory during the period 2021-50, rising by 34.8% altogether to 66.58 MMb/d, while OECD demand contracts by 18.2% to 34.45 MMb/d. Thus, the non-OECD share of global liquids consumption rises from 54.0% in 2020 to 65.9% in 2050. Meanwhile, crude oil's share of total global liquids supply declines from 78.1% to 73.8% during the scenario period, given relatively greater net growth of the other components (condensate and NGLs as well as biofuels and other liquids).

The IHS Markit base case envisions the following key liquids demand trends in selected major regions during the period out to 2050 (see Table 1.2 Outlook for world oil (liquids) balance to 2050 (MMb/d)).

- **The Asia Pacific market remains the chief center of oil demand growth worldwide longer term, supplied increasingly from outside the region.** The Asia Pacific region registers a net oil demand rise of 19.9% during 2021-50, to 41.37 MMb/d in our outlook (albeit peaking in 2036 at around 43.55 MMb/d). But dynamics within the region continue to vary widely in the base case. Non-OECD Asian demand increases by 31.5% to 35.74 MMb/d, reflecting expansion of Indian demand in particular (by 90.9%, to 9.11 MMb/d). Mainland China, with liquids demand of 14.17 MMb/d in 2020, remains the chief non-OECD Asian market by far, but Chinese oil demand peaks at around 17.82 MMb/d in 2032 and then declines to 14.44 MMb/d in 2050, so it only grows by 1.9% altogether during 2021-50. In contrast, OECD Asian oil demand drops 23.3% to 5.62 MMb/d during the same period, reflecting mainly the ongoing structural decline of Japanese oil demand. At the same time, non-OPEC Asia Pacific crude oil production falls overall by 55.3% to 2.82 MMb/d during 2021-50 in the IHS Markit outlook.

- **Europe's indigenous crude oil production falls even more precipitously than liquids consumption, leaving Europe highly dependent on oil imports to meet remaining demand.** European liquids demand drops overall by 31.6% to 9.08 MMb/d during 2021-50, while crude oil production (essentially North Sea output) is expected to contract by 87.4%, leaving total indigenous output at only 0.39 MMb/d in 2050 (see Figure 1.8 European oil demand outlook by refined product to 2050).[13]
- **US oil demand slowly contracts overall, while crude oil and gas condensate production reaches a maximum in 2030.** US liquids demand falls by 14.3% to 15.32 MMb/d during 2021-50, while crude and condensate production reaches a maximum of 12.59 MMb/d in 2030, and then falls to 9.34 MMb/d by 2050, for a net decrease during 2021–50 of 17.5%.

With respect to the geographic breakdown of global oil supply, an important trend is robust growth of OPEC liquids output, by 44.8% to 44.41 MMb/d – lifting the OPEC share of total world liquids production from 32.5% in 2020 to 44.0% in 2050. This, in turn, indicates the potential for strong continued or even increased OPEC+ influence on the supply side of the world oil price equation going forward, but key wildcards include the future evolution of the group's membership, and the production dynamics of the currently non-OPEC contingent of the Vienna Alliance (See Table 1.2 Outlook for world oil (liquids) balance to 2050 (MMb/d)).

Table 1.2 Outlook for world oil (liquids) balance to 2050 (MMb/d)

I. World liquids demand[1]	**2020**	**2025**	**2030**	**2035**	**2040**	**2045**	**2050**
North America	21.6	24.4	24.2	23.3	22.2	20.9	19.6
United States[2]	17.9	20.1	19.9	18.9	17.8	16.6	15.3
Canada	2.1	2.5	2.5	2.5	2.5	2.4	2.3
Europe	13.3	14.3	13.3	12.3	11.3	10.2	9.1
OECD Asia	7.3	7.6	7.4	7.1	6.6	6.1	5.6
Non-OECD Asia	27.2	32.5	34.8	36.4	36.8	36.6	35.7
China (mainland)	14.2	17.1	17.8	17.8	17.1	15.8	14.4
India	4.8	5.9	6.9	7.7	8.3	8.9	9.1
Non-OECD Asia excl. China and India	8.2	9.5	10.2	10.9	11.4	12.0	12.2
Latin America	5.8	6.8	7.3	7.7	7.9	8.0	8.1
Middle East	8.2	9.1	9.2	9.4	10.2	10.6	11.0
Commonwealth of Independent States	4.3	4.6	4.7	4.8	5.1	5.0	5.0
Africa	4.0	4.6	5.0	5.5	6.0	6.4	6.9
Total world liquids demand	91.5	103.9	106.0	106.4	105.9	103.9	101.0
Asia Pacific demand	34.5	40.1	42.2	43.4	43.4	42.8	41.4
OECD demand	42.1	46.3	45.0	42.7	40.2	37.3	34.4
Non-OECD demand	49.4	57.6	61.0	63.7	65.7	66.6	66.6

13 The relatively sharp drop in European oil production in our base case reflects an assessment by IHS Markit of North Sea petroleum geology and production dynamics, and also reflects the relatively great decarbonization of the European energy sector in Inflections (further reducing regional oil demand along with the incentive for incremental upstream investment).

	2020	2025	2030	2035	2040	2045	2050
II. World liquids production							
Non-OPEC Crude[3]							
North America	17.4	18.3	19.1	19.0	18.6	16.8	14.9
United States[2,4]	11.3	11.8	12.6	12.4	12.3	10.9	9.3
Canada[4]	4.4	5.1	5.3	5.4	5.2	4.9	4.4
Mexico	1.7	1.4	1.2	1.2	1.1	1.1	1.1
Commonwealth of Independent States[4]	13.1	14.4	13.5	13.2	12.8	12.3	12.1
Latin America	5.0	6.2	6.9	7.3	6.8	6.2	5.7
Brazil	2.9	3.9	3.8	4.1	4.5	4.8	4.9
Europe	3.1	3.1	2.5	2.0	1.2	0.7	0.4
Asia Pacific	6.3	5.3	4.8	4.5	3.9	3.3	2.8
Africa	1.2	1.1	1.1	0.8	0.5	0.8	1.0
Middle East	1.8	1.9	1.7	1.3	1.0	0.8	0.5
Total Non-OPEC crude	47.9	50.3	49.6	48.1	44.9	40.9	37.3
Non-OPEC condensate and NGLs	10.3	11.0	12.0	12.0	11.7	11.5	11.0
Total Non-OPEC liquids production	58.2	61.3	61.7	60.0	56.5	52.4	48.3
OPEC crude[3]	25.7	29.6	30.8	32.2	34.6	36.3	37.3
OPEC condensate and NGLs	5.0	6.0	6.2	6.5	6.8	7.2	7.1
Total OPEC liquids production	30.7	35.5	37.0	38.7	41.4	43.4	44.4
Processing gains	2.1	2.3	2.4	2.4	2.4	2.3	2.2
Global biofuels and other liquids[5]	3.3	4.7	4.9	5.3	5.6	5.8	6.1
Total world liquids production	94.3	103.9	106.0	106.4	105.9	103.9	101.0
Total crude oil production	***73.6***	***79.9***	***80.4***	***80.2***	***79.5***	***77.2***	***74.6***
Inventory dynamics							
Total liquids inventory change	2.8	0.0	0.0	0.0	0.0	0.0	0.0

Note: Mexico is included in North America.

(1) Includes biofuels and other synthetic oil.

(2) The United States includes 50 states, District of Columbia, and other US territories excluding Puerto Rico.

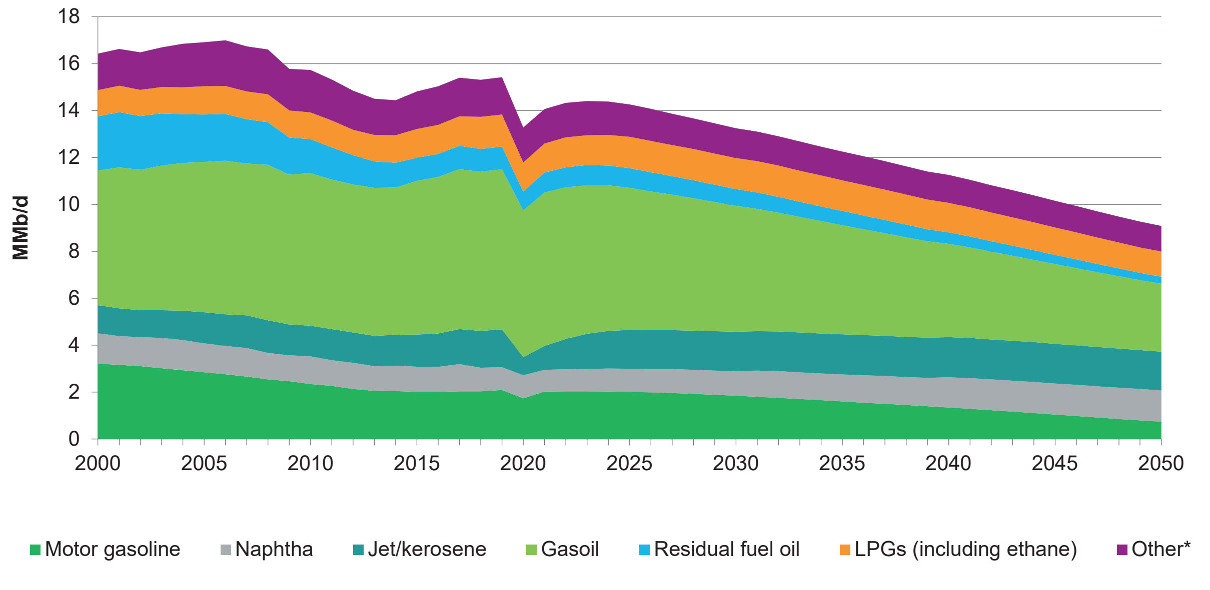
(3) The split of OPEC and non-OPEC countries is based on the member status as of July 2021.

(4) Includes condensate.

(5) Biofuels include US and Brazilian ethanol supply. Other liquids includes gas-to-liquids (GTL), coal-to-liquids (CTL), nonrenewable oxygenates, refinery additives, and oil shale (kerogen).

Source: Historical data from the International Energy Agency, US Energy Information Administration, national statistical agencies; projections from IHS Markit

Figure 1.8 European oil demand outlook by refined product to 2050



Notes: *Includes asphalt, petroleum coke, waxes, lubes, aviation gasoline, and miscellaneous products.
Source: Historical data from the International Energy Agency and US Energy Information Administration; projections by IHS Markit © 2021 IHS Markit

1.2.5 IHS Markit's base case (Inflections): Accelerated decarbonization begins to transform the global energy mix during 2021-50

IHS Markit's latest global energy scenarios (published in July 2021) reflect our assessment of the new energy market dynamics unleashed by COVID-19 as well as the intensification starting in 2020 of previous initiatives to decarbonize energy use. The global campaign to counteract climate change gained unprecedented traction during 2020-21, translating into new pressures on the energy industry (as discussed and analyzed in detail in Chapter 2).[14] Decarbonization of the energy sector had long been recognized as a major precondition for success of the international effort to limit global warming, since over 70% of global greenhouse gas (GHG) emissions (denominated in CO_2 equivalent [CO_2e]) are energy-related (74.7% of the total in 2020, in IHS Markit's estimate). The energy transition, which aims to limit temperature rises to less than two (or 1.5) degrees Celsius above pre-industrial levels through decarbonization, was already a key part of the international energy context and lexicon prior to COVID-19. The fifth report of the Intergovernmental Panel on Climate Change (IPCC) in 2014 was a key turning point in the transformation of the energy transition into a central concept worldwide, insofar as this report portrayed the human influence on climate systems and the evidence for global warming in stark terms. But the year 2020 seems to represent a new pivot point or "accelerator," given a confluence of new drivers.[15]

Inflections, our new base-case scenario of the energy future to 2050, portrays a world and global energy industry that is responding to key turning points in international geopolitics, national political and economic priorities, business and individual behaviors, and the financial criteria of investors and lenders (indeed, the marketplace often outpaces government in driving change and investment in "green" energy technologies). Whereas our 2020 base-case (Rivalry) scenario envisioned the energy transition moving at an evolutionary pace, in Inflections the energy transition gains pace overall, while nevertheless moving at very different speeds and in very different ways around the world. Key indicators, discussed in more detail in the next chapter, include:

- **A significant increase during the past year of carbon neutrality and greenhouse gas (GHG) emissions reduction pledges on the part of countries and companies.** Countries with official

14 For more on the new IHS Markit base case scenario and our two alternative global energy scenarios to 2050, as well as our two distinctive net zero 2050 cases, see the IHS Markit Scheduled Updates *Inflections (2021-50): The IHS Markit base-case view of the energy future,* 14 July 2021; *Green Rules (2021-50): A revolutionary transformation toward a sustainable low-carbon economy,* 14 July 2021; *Discord (2021-50): A stagnant world with weak markets and policies,* 14 July 2021; and *Net zero cases (2020-50): Accelerated Carbon Capture (ACCS) and Multitech Mitigation (MTM) – Reach net zero emissions in 2050,* 14 July 2021.

15 More broadly, the term energy transition characterizes major changes in the fuel mix underlying global or regional economies that have been ongoing for centuries; e.g., the world's transition from reliance primarily on wood to coal and then oil.

net zero ambitions accounted for about two-thirds of global emissions at last report. Kazakhstan joined the list in December 2020, when President Kassym-Jomart Tokayev announced that the country will reduce its emissions to zero by 2060. The government subsequently spelled out several intermediate targets on the road to net zero, including an increase of the share of renewables in total Kazakh electricity generation from 3% in 2020 to 15% by 2030, and an increase in the share of natural gas-fired power generation over the same period from 20% to 25%. A still greater increase in the share of renewables in the power sector fuel mix in 2030 is envisioned in the latest decarbonization program currently under consideration – which sees renewables meeting 24% of Kazakh power demand by 2030 – while the final official target for 2030 may be even higher. In parallel, many companies worldwide have announced more ambitious decarbonization targets starting in 2020. One of the latest examples is LUKOIL's July 2021 pledge to reduce its controlled GHG emissions by 20% by 2030 (compared with 2017 levels).[16]

- **Stepped-up efforts by the European Union (EU) to finalize the regulatory framework for a planned Carbon Border Adjustment Mechanism (CBAM) – effectively a tax on some high-carbon imports.** CBAM aims to "level the playing field" for industrial firms in Europe as they embark on additional complex and expensive decarbonization programs needed to meet the EU target of a 55% reduction in GHG emissions by 2030 (relative to 1990 levels), and net zero emissions by 2050.[17]

Global GHG emissions reached a new high in 2019 of 50.7 billion metric tons of CO_2e before declining by 5.3% in 2020 to 48.1 billion metric tons of CO_2e. In Inflections, GHG emissions remain on a downward path throughout most of the scenario period to 2050, and never return to the 2019 level again. The target of net zero emissions is not achieved globally by 2050 in Inflections, however, reflecting a number of constraints.

By mid-century, emissions are still high enough in the base case to put the world on a pathway that could raise average global temperatures by 2.6°C above pre-industrial times by 2100 – far short of the Paris Agreement target of a 2°C (and preferably 1.5°C) limit. But global GHG emissions are nevertheless around 16% lower than the 2019 peak by 2050 in Inflections.

Compounding the decarbonization challenge for energy companies, global primary energy consumption is expected to rise substantially during the scenario period – by 24.5% during 2021-50, to 17.18 Btoe. This outlook reflects our key assumptions about underlying demographic and economic trends, including a total population increase on the order of 25%, average annual GDP growth of 2.7% per year, and ongoing efforts by the developing parts of the world to boost energy consumption, even as the economies of the developed nations become less energy intensive (European and North American primary energy demand declines overall against a backdrop of rising consumption in most other major regions).

Along with a heightened emphasis on energy efficiencies, one key consequence of the increased pressures on the energy industry to decarbonize while meeting growing world energy demand in Inflections is a more rapid expansion of renewables' share of global primary energy demand than envisaged in our previous (Rivalry) base case – and correspondingly faster decline of the fossil fuels' share. The aggregate noncarbon share of global energy consumption (i.e., counting nuclear and hydro along with renewables) grows from 10.4% in 2020 to 23.6% in 2050, while the aggregate fossil fuel share (i.e., oil, gas, and coal) falls from 80.0% to 63.8% during the same period. Intensified electrification – together with reduction of the power sector's carbon intensity – will also prove critical to the energy transition's success, and Inflections envisages a 95% surge in global power generation during 2020-50, to 51.4 terawatt-hours (see Figure 1.9 Outlook for world's primary energy production and consumption by fuel to 2050, Figure 1.10 Historical and projected global primary energy demand growth by fuel, and Table 1.3 Outlook for world's primary energy consumption by fuel to 2050: Average annual growth rates, and changes in shares of global demand).

16 See the IHS Markit Insight *In 2020, a leap forward for net-zero pledges,* 29 January 2021.

17 See the IHS Markit Insight *EU Commission's Carbon Border Adjustment Mechanism proposal – Soft start to win global approval,* 15 July 2021.

Figure 1.9 Outlook for world's primary energy production and consumption by fuel to 2050

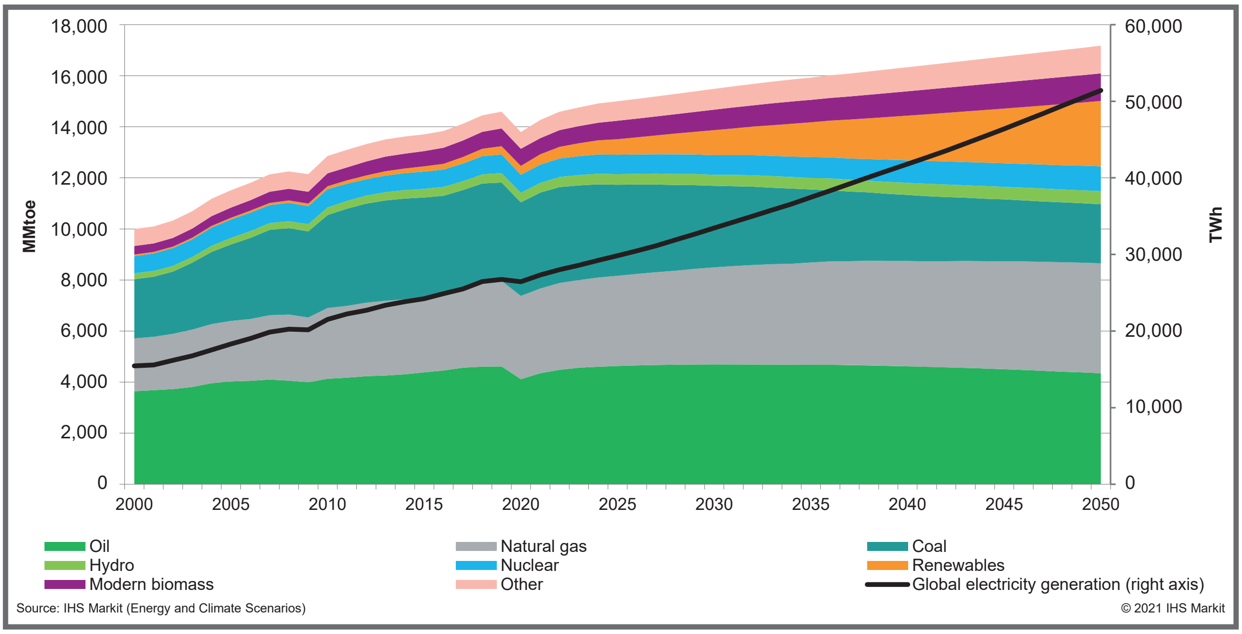


Figure 1.10 Historical and projected global primary energy demand growth by fuel

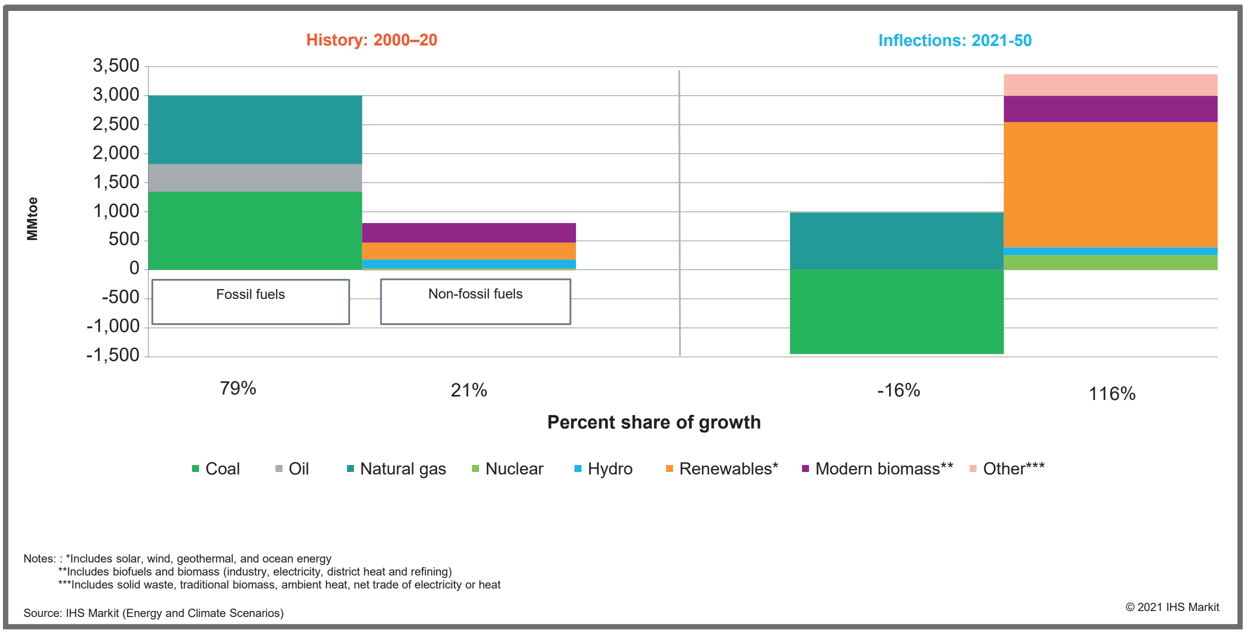


Table 1.3 Outlook for world's primary energy consumption by fuel to 2050: Average annual growth rates and changes in shares of global demand

	Average annual growth				Percent share of global consumption			
	2020–30	2030–40	2040–50	2020–50	2020	2030	2040	2050
Total	1.2%	0.5%	0.5%	0.7%	100%	100%	100%	100%
Oil	1.3%	-0.1%	-0.6%	0.2%	30%	30%	28%	25%
Natural gas	1.6%	0.8%	0.4%	0.9%	24%	25%	25%	25%
Coal	-1.4%	-2.1%	-1.1%	-1.5%	27%	21%	16%	13%
Hydro	1.6%	0.9%	0.7%	1.1%	3%	3%	3%	3%
Nuclear	0.9%	1.3%	1.0%	1.1%	5%	5%	5%	6%
Renewables	10.7%	6.1%	3.9%	6.8%	3%	6%	11%	15%
Modern biomass	1.8%	1.8%	1.2%	1.6%	5%	5%	6%	6%
Other	2.2%	1.4%	1.4%	1.7%	5%	5%	6%	6%

Source: IHS Markit (Energy and Climate Scenarios)

Looking more closely at the energy mix implications of Inflections, IHS Markit envisages the following key changes during 2021-50 in the relative shares of oil, gas, coal, and renewables:[18]

- **Oil's share of global primary energy consumption contracts from 30% in 2020 to 25% in 2050.** COVID-19 reset global oil demand at a lower level, and compared with our previous base case we now envision peak demand occurring sooner (in the mid-2030s versus the early 2040s in Rivalry) and at a lower level (107 MMb/d versus 114 MMb/d). But the oil demand trajectory in Inflections remains essentially the same as in Rivalry. This means that significant additional upstream investment will still be needed in order to meet demand throughout the scenario period (i.e., in order to grow supply during the remaining years of increasing global demand, and ensure the world oil production decline thereafter does not exceed the fall in demand). The expected contraction of oil demand mainly reflects new dynamics in the transportation sector, which remains the largest source of oil demand globally. Along with the traditional pressures to increase fuel economies, oil faces intensified competition from electricity as electric vehicle (EV) penetration accelerates, driven by zero emission vehicle (ZEV) mandates in different countries, and as the world's major automakers steadily increase capacity for EV manufacturing and sales.[19] Indeed, the intensified EV adoption worldwide in our Inflections scenario (compared with the previous Rivalry base case) reflects a sea change in attitudes towards EVs within the auto industry itself that has become increasingly evident in recent months, as a growing number of automakers have announced ZEV ambitions, supported in some cases by announcements for large investment plans. Such investment will not overcome the long-standing obstacles to electrification of the global automobile fleet overnight, and the limited storage capacity of traditional EV batteries remains a major challenge. The new planned spending programs nevertheless raise the likelihood of technological advances that will increase the price competitiveness and improve operational capabilities of EVs relative to vehicles based on the internal combustion engine. Falling battery costs along with improved powertrain manufacturing economies of scale are both key features of the base case. But electrification of transport is still likely to be much slower than some anticipate. Still, in 2050 more than 40% of the global car fleet is electrified. Finally, the utility of petrochemical products – and plastics in particular – allows their use to continue to grow through the outlook, despite challenges related to backlash against plastic pollution, including microplastics.
- **Natural gas's share rises from 24% to only 25% (as opposed to 26% in our earlier base case), as gas faces increased competition from renewables but proves quite resilient compared to other fossil fuels given its relatively low carbon footprint.** Environmental policy support helps gas surpass coal to become the second-largest component of primary energy demand in the world already by 2026, and increasingly to rival oil as the largest primary energy source globally by 2050. Aside from further displacement of coal in the power sector in various regions, gas demand growth hinges in large part on increased use as a feedstock for "blue" hydrogen production. Global hydrogen demand grows from about 300 million metric tons of oil equivalent (MMtoe) in 2020 (all of which is produced using steam reformation of fossil fuels or "gray" hydrogen) to

18 While the global energy demand shares of hydro and nuclear were each slightly higher than that of renewables in 2020, by 2050 the share of renewables is expected to be greater than the shares of hydro and nuclear combined.

19 For more on the new auto industry dynamics, see the IHS Markit Scheduled Update *ZEV Watch: Automakers bet on BEVs*, 6 August 2021.

almost 750 MMtoe in 2050 (over half of which comes from a mix of "green" and "blue" hydrogen) – rising from 2% of total final energy consumption globally to 5%.[20] Meanwhile, LNG's share of total gas supply rises from 12.9% to 20.9% during the scenario period.

- **Coal's share falls from 27% to 13% (versus 17% previously), due largely to increased displacement in the power sector by renewables.** The decline in coal demand that began in the years prior to COVID-19 continues, and by 2050 coal demand is more than 20% lower than in the previous (2020) Rivalry outlook. A key element of this lower pathway is the effort made by mainland China – accounting for roughly 51% of global coal demand in 2020 – to meet its net zero targets by 2060. In accordance with China's goals, large numbers of coal plants in the country are retired – some well ahead of the end of their normal operating lives. In the 2030s, almost 30 GW of coal is retired in China every year, offsetting all new coal capacity additions in the region during that decade. In the 2040s, however, although coal retirement levels double, net additions rise again, as more new coal plants are added during that decade than are closed. This seeming contradiction reflects China's continued reliance on coal-fired power as a key source of baseload electricity. In spite of the additions, coal's share of Chinese power generation falls from over 60% in 2020 to less than 15% in 2050. Coal's ability to retain key shares in selected regional energy markets depends increasingly on the application of more cost-effective carbon capture, utilization, and storage (CCUS) solutions (worldwide, initial coal industry carbon capture efforts about a decade ago turned out to be something of a "false start" given the relatively advantageous economics of competing renewables projects in the power sector).
- **Renewables' share jumps from 3% to 15% (versus 10% before), as wind and solar power prove increasingly cost competitive.** Renewables consumption soars by 626% over 2021-50 in Inflections, accounting for around 65% of total growth in world primary energy demand during the scenario period. By the 2030s and beyond, wind and solar projects outcompete fossil fuel generation projects on a levelized cost basis in most parts of the world – without special subsidies or government protection. Therefore, beyond the 2020s, it is largely market forces that propel global renewable power generation to 2050 to levels that are 50% higher than in the 2020 Rivalry outlook. Rapid growth of renewables and EV penetration of road transportation is not without challenges when demand for materials such as lithium occasionally outpaces supplies. There are also supply chain issues related to batteries, solar cells, and wind turbines, as overreliance on supplier markets such as China is difficult to overcome. Decentralization of manufacturing does occur as part of a broader onshoring trend in some advanced markets; however, it is relatively limited. The combination of these factors constrains the advance of cost competition for renewables over time but not to the extent that it significantly curtails growth.

At the same time, energy transition pathways vary widely across the globe in the base case. In China (the world's largest GHG emitter in 2020), the share of renewables will grow robustly together with that of natural gas and nuclear, displacing much existing coal demand. In the United States (the second largest emitter worldwide in 2020), the share of renewables grows at the expense of coal, nuclear, and oil, while natural gas's share remains about the same. Meanwhile, growth in renewables' share of total primary energy demand will be exceptionally great in the European market, reducing the shares of oil, natural gas, coal, and nuclear.[21] In Kazakhstan, natural gas's share of primary energy demand is expected to grow strongly during the scenario period, mainly at the expense of coal in power generation, while renewables will also play a growing role in the power sector fuel mix, along with nuclear starting in the mid-2030s (for more detailed discussion of Kazakhstan's changing energy balance, see the section below "Kazakhstan's energy sector performance in 2020-21 and outlook to 2050").

The increased impetus to mitigate the effects of climate change has also reshaped IHS Markit's two low-emissions cases – Accelerated Carbon Capture and Multitech Mitigation – which are designed to consider the energy implications of a global reduction of emissions to net zero by 2050. In contrast to our other scenarios, these cases start from a predetermined outcome and work backward using modeling as the primary basis for construction, rather than narratives that lay out possible development pathways. Notwithstanding the assumption of intensified decarbonization, however, the new low-emissions cases differ in some important ways from the International Energy Agency (IEA) "Net Zero by 2050" roadmap released in May 2021, which outlines a pathway to reach net zero emissions by mid-century that relies very heavily on aggressive electrification across all sectors, mainly

20 **Green hydrogen,** or renewable hydrogen, is hydrogen produced by the electrolysis of water, with the electricity produced from renewable sources (like wind, solar, or waterpower). The full life-cycle greenhouse gas emissions of the production of renewable hydrogen are close to zero. Renewable hydrogen may also be produced via the reforming of biogas or the biochemical conversion of biomass. **Blue hydrogen,** or fossil-based hydrogen with carbon capture, is hydrogen produced from fossil fuels, but the CO_2 emitted as part of the hydrogen production process is captured and stored (carbon capture and storage [CCS]) or utilized (carbon capture, utilization, and storage [CCUS]).

21 Relatedly, fossil fuels face growing competition within Europe, in particular from low-carbon hydrogen produced via electrolysis from renewable generation; see the IHS Markit Insight *Global Hydrogen: Europe leads soaring investments in supply over the next decade,* 22 April 2021.

provided by renewables. Whereas the IEA roadmap implies that global GHG emissions have already peaked, and outlines steps the world will need to take rapidly to reach net zero by 2050, the IHS Markit low-emissions cases assume that the massive energy infrastructure of today will not be reconfigured as quickly, and energy demand changes will take some time to reflect the more challenging country targets being adopted now. In contrast to the IEA pathway, each of our low-emissions cases envisions a near-term period of emissions "overshoot" that must then be compensated for later, in order to achieve the 2050 goal.[22]

1.3 Assessment of Kazakhstan's Economic and Energy Performance in 2020, and Outlook for Economic Recovery

1.3.1 Kazakhstan's economic performance in 2020-21 and outlook to 2050

Kazakhstan entered its deepest recession in two decades in 2020, as GDP fell by 2.6%, given the lower oil prices and muted external demand generally for Kazakh exports owing to the COVID-19 crisis, along with the negative impact of the lockdowns on domestic economic activity.[23] But this decline was still fairly mild, and ended up being much less than initially expected when the pandemic initially hit. GDP remained on a growth trajectory in the first quarter of 2020 year on year, but dropped 5.7% in the second quarter year on year, was down by 4.5% in the third quarter, and fell by 2.1% in the fourth quarter. More recently, however, higher oil prices and external recovery as well as improvement in domestic demand are allowing a recovery to take hold (see Figure 1.11 Kazakhstan's real annual GDP growth, 2000-20 and Figure 1.12 Kazakhstan's quarterly GDP change, 2019-21).

Persistent COVID-19–related challenges complicate the outlook for full-year 2021 GDP, but given the positive trends noted above, our base case is for 2021 GDP growth of 4.0%, while average annual growth during 2021-25 is on the order of 4.1%. At the same time, the recovery currently remains very uneven across sectors, and the most likely scenario in the near term is a continued "K-shaped" economic pattern, with some sectors returning to or surpassing pre-pandemic levels relatively soon and others remaining below pre-crisis levels for some time to come, owing to a wide variety of factors. Such disparity is even evident within selected sectors. In the case of industrial production, for example, even as oil and gas condensate output in the first quarter of 2021 remained 10.4% lower year-on-year (reflecting Kazakhstan's OPEC+ cuts program), production of copper ore surged during the same period (+14.4%) along with that of several other commodities.[24]

The following key Kazakh supply- and demand-side trends underlie GDP dynamics in 2020-21:

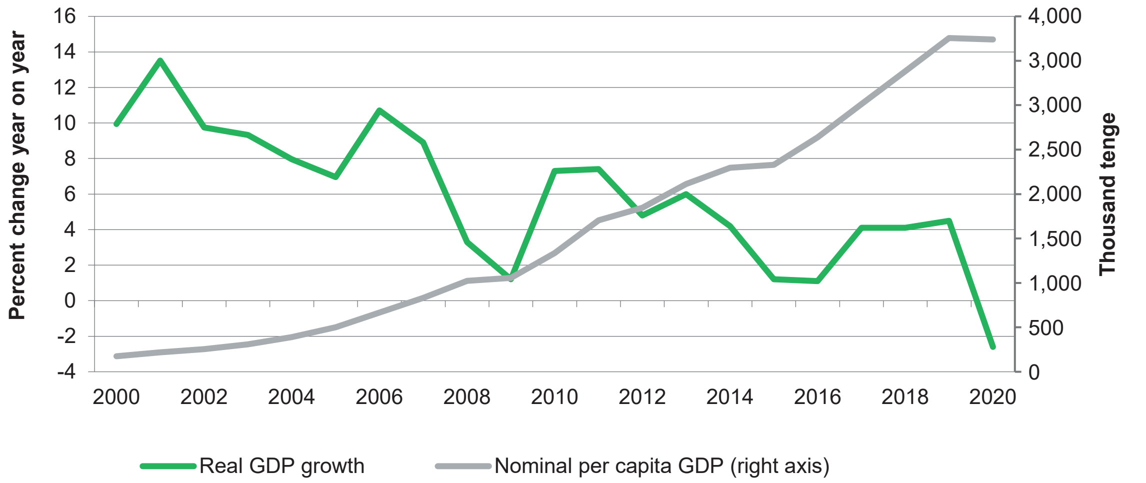
- **Supply side: energy and service sectors bear brunt of COVID-19.** Industry (including mining) is the single largest segment of the economy, comprising 28% of 2020 GDP (see Figure 1.13 Kazakhstan's GDP in 2020 by sector). Industrial output contracted overall by only 0.4% last year, following growth of 3.9% in 2019. The relatively small 2020 dip masks an exceptionally steep fall in selected components, especially oil and gas production. Notwithstanding its severe contraction in 2020, the energy sector remains the key driver of the Kazakh economy, considering both shares in total industrial production and GDP overall (while oil accounts for the bulk of Kazakh export earnings and is the primary source of the government's budgetary revenue). The oil and gas industries alone, together with related sectors (e.g., oil and gas transportation, upstream construction, and geology) contributed 17.2% of the country's GDP directly in 2020, down from 21.3% in 2019 (see Figure 1.14 Kazakhstan's oil and gas industry contribution to GDP). Such overwhelming reliance on the energy sector means that global trends, such as commodity price declines, continue to have a broad effect in Kazakhstan, impacting the performance of industries not only in the energy sector itself, but in other areas related to energy production, including transportation, construction, trade, and professional services. The 2020 global oil demand and price collapse thus had far-reaching ramifications beyond the oil sector in Kazakhstan. The drop in Kazakh oil export revenue last year was less sharp than the contraction that occurred in the aftermath of the 2014 oil price fall, but nevertheless one of the biggest one-year declines of the post-Soviet era – reducing Kazakh oil export earnings by 29.9% to $24.4 billion, the lowest level since 2016 (see Figure 1.15 Kazakhstan's oil export volumes and revenues, 2014-20). For its part, the Kazakh service sector was also particularly hard hit

22 See the IHS Markit Insight *IEA Net Zero: A radical shift away from hydrocarbons,* 2 June 2021.

23 The Kazakh government was the first in Central Asia to impose a nationwide lockdown, starting 16 March 2020.

24 For more on IHS Markit's near-term outlook for Kazakhstan's economy and underlying assumptions, see the IHS Markit Headline Analysis *Kazakh economy still contracting in Q1, recovery expected in H2,* 4 June 2021.

Figure 1.11 Kazakhstan's real annual GDP growth, 2000-20



Source: IHS Markit, Bureau of National Statistics RK

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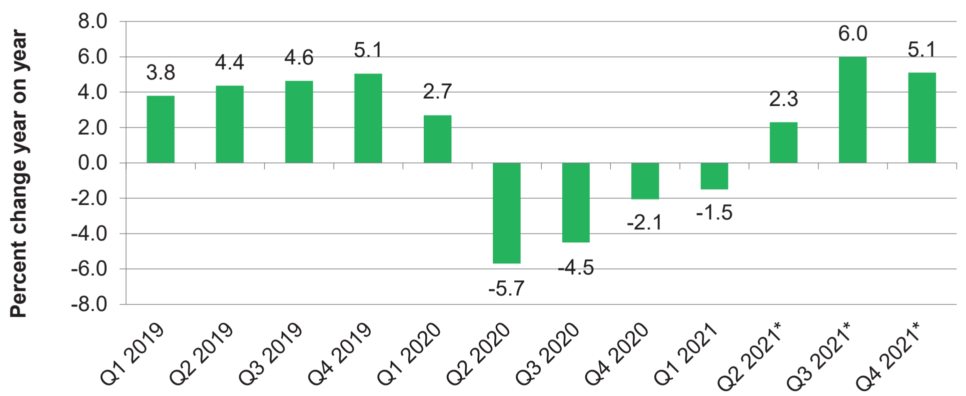
Figure 1.12 Kazakhstan's quarterly GDP change, 2019-21



Notes: *Preliminary estimate or IHS Markit outlook.
Source: IHS Markit, Bureau of National Statistics RK

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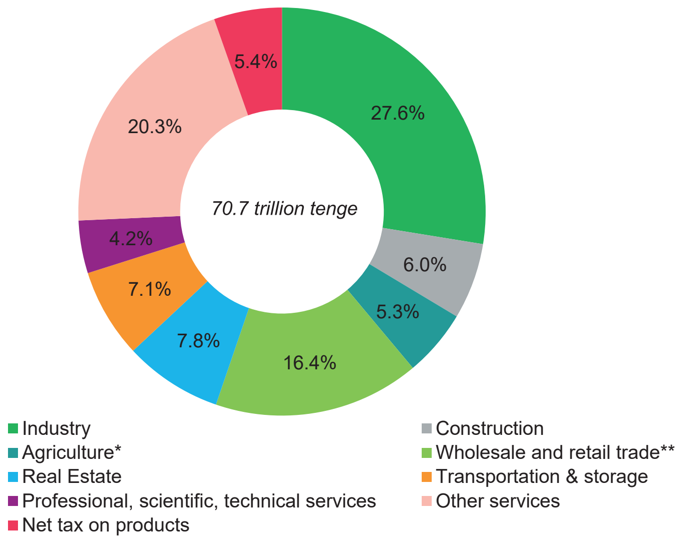
by the pandemic-related mobility restrictions, which greatly exacerbated any "normal" recessionary effects.[25]

- **Demand side: contraction of investment in fixed capital concentrated in the energy sector.** Investments in fixed capital – i.e., investment in durable (fixed) assets such as buildings, machinery, and equipment, or other infrastructure or structures that a firm holds for at least one year – fell by 9.9% to $27.2 billion (in current dollars). The decline in dollar terms was, however, much less sharp than during the 2016 downturn (when the corresponding figure was 31.3%), as the 2016 decline was intensified by a much greater depreciation of the tenge against the dollar than seen in 2020. Meanwhile, the 2020 drop in investment in fixed capital in (constant 2010) tenge terms amounted to 5.2% – the steepest fall since the global financial crisis year of 2009. Not surprisingly, the

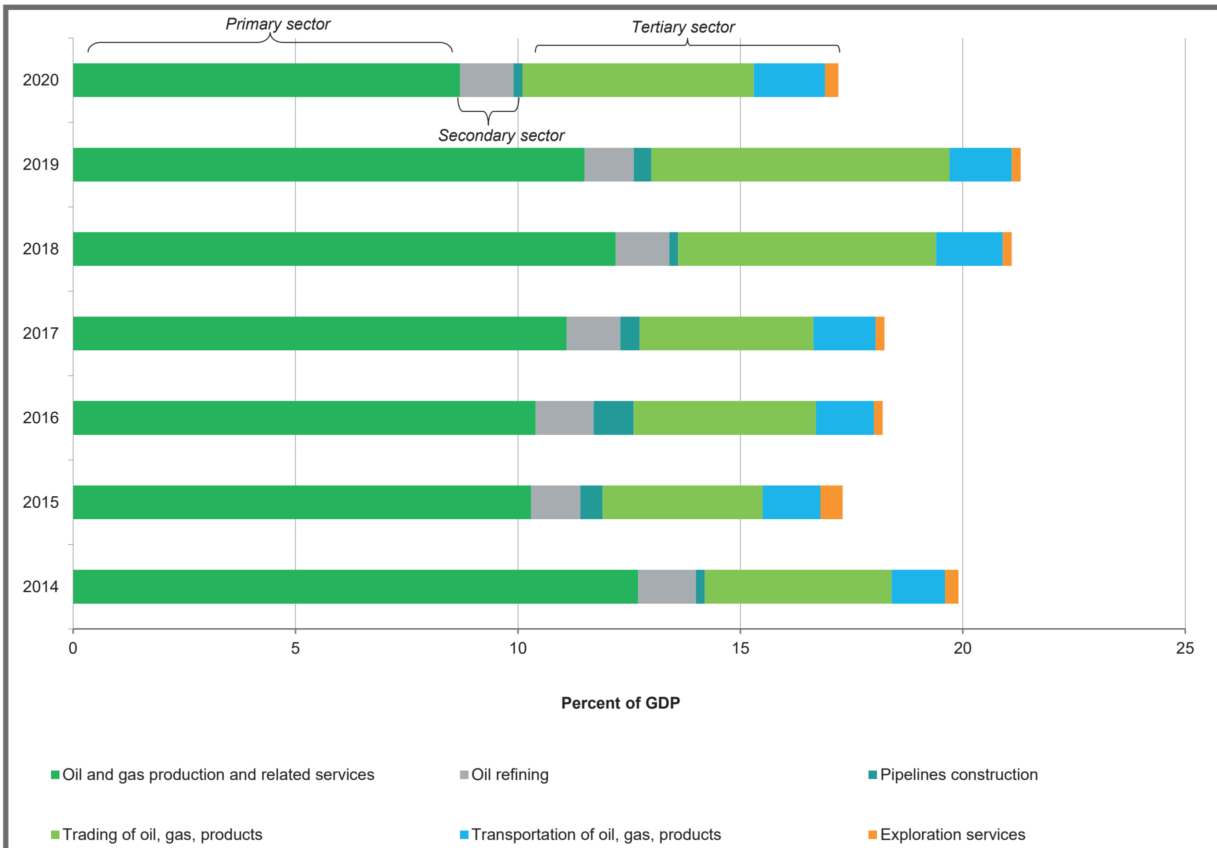
25 As noted above, much service sector activity is closely interrelated with energy industry dynamics, but the services most negatively impacted by the lockdowns were evidently hospitality, retail, travel, and leisure. The Kazakh service sector nevertheless still remains relatively underdeveloped overall (a legacy of the Soviet period); conversely, this is also part of the reason for the comparatively small decline of aggregate Kazakh GDP in 2020 vis-à-vis the global average.

Figure 1.13 Kazakhstan's GDP in 2020 by sector



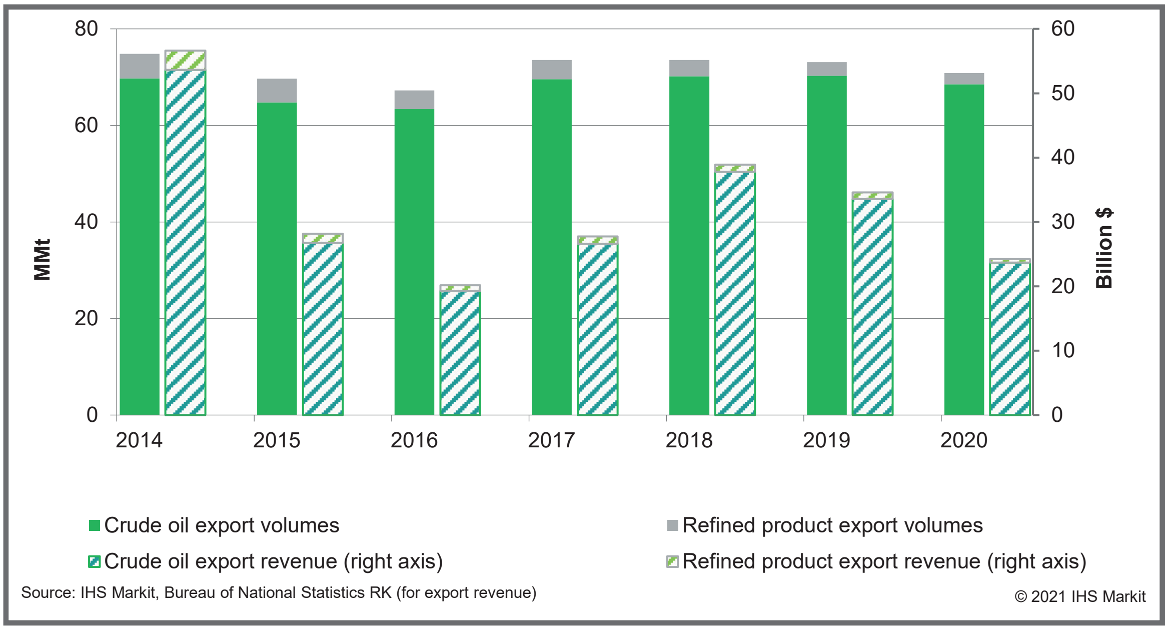
Notes: *Includes forestry and fishing; **Includes repair of automobiles and motorcycles.
Source: IHS Markit, Bureau of National Statistics RK

Figure 1.14 Kazakhstan's oil and gas industry contribution to GDP



Source: IHS Markit, Bureau of National Statistics RK

Figure 1.15 Kazakhstan's oil export volumes and revenues, 2014-20



share of the energy sector in fixed capital investment declined markedly last year (from about 53% to 39% of the total) (see Figure 1.16 Total investment in fixed assets in Kazakhstan's economy – current US dollars, and Figure 1.17 Total investment in fixed assets in Kazakhstan's economy – constant (2010) tenge).[26]

IHS Markit continues to see inflation risks from the exchange rate channel as relevant, although the current tenge volatility mainly reflects external conditions more than any inherently Kazakh financial pressures. In particular, the tenge is vulnerable to movements in the oil price and fluctuations in the exchange rate of the Russian ruble, while it is also affected by the overall weakened global growth outlook, risks from the global trade wars, and instability in global financial markets. The consumer price inflation rate in Kazakhstan stood at 6.8% in 2020, and IHS Markit expects that it will remain close to the upper limit of the National Bank of Kazakhstan's 4-6% target range throughout 2021-22.[27] Inflation risks have subsided somewhat, together with the partial recovery of oil prices and the related strengthening of the Russian ruble. Nevertheless, the potential for oil price volatility and the impact from Russian inflation and exchange rate movements present the most important risks to IHS Markit's inflation outlook for Kazakhstan. Oil price movements typically significantly affect the external value of the tenge, given the importance of oil and gas as Kazakhstan's export articles, especially as recently the National Bank has allowed more flexibility in the exchange rate (see Figure 1.18 World oil price and tenge-dollar exchange rate dynamics, 2000-20).

Foreign investment remained vital to the Kazakh economy in 2020 – albeit contracting significantly by most measures – and will remain so for the foreseeable future. Gross foreign direct investment (FDI) in Kazakhstan averaged around $21 billion annually during 2010-19, but fell by about 29% in 2020 to $17.1 billion according to the Kazakh government, while nearly half of the 2020 gross FDI ($8.2 billion) was concentrated in the "mining" sector (consisting chiefly of FDI in oil, gas, and metal ores mining). Kazakh authorities have forecast that gross FDI will return to the pre-pandemic level "at the turn of" 2022-23. IHS Markit estimates that net FDI into Kazakhstan fell by a more moderate 16.7% last year, to $4.5 billion.[28]

26 Private consumption in Kazakhstan, which accounts for the bulk of domestic demand, contracted by 3.4% in dollar terms, to $91.8 billion in 2020.

27 The (July 2021) IHS Markit forecast is that end-2021 inflation will be 7.1%, and that the above-noted inflation target will again be attainable only around mid-2023.

28 There are alternative evaluations of the FDI trend in 2020, depending on which FDI methodology is used; e.g., according to the United Nations Conference on Trade and Development (UNCTAD), the net flow of FDI into Kazakhstan actually increased sharply in 2020 (by 35%, to $3.9 billion). For more on Kazakh FDI trends, from different perspectives, see the IHS Markit Profile *Sovereign Risk – Kazakhstan,* 14 June 2021; "Kazakh Foreign Ministry Predicts Rise of Foreign Direct Investment to Pre-Pandemic Level In Next Two Years," *The Astana Times,* 31 May 2021; and the UNCTAD World Investment Report 2021, accessed at *https://unctad.org/system/files/official-document/wir2021_en.pdf*

Figure 1.16 Total investment in fixed assets in Kazakhstan's economy - current US dollars

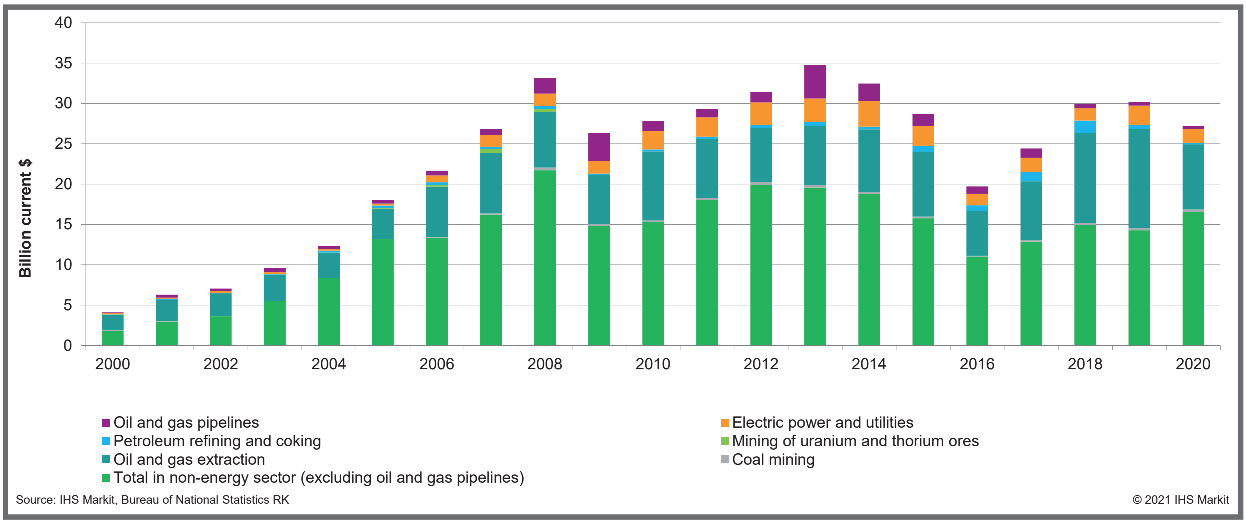
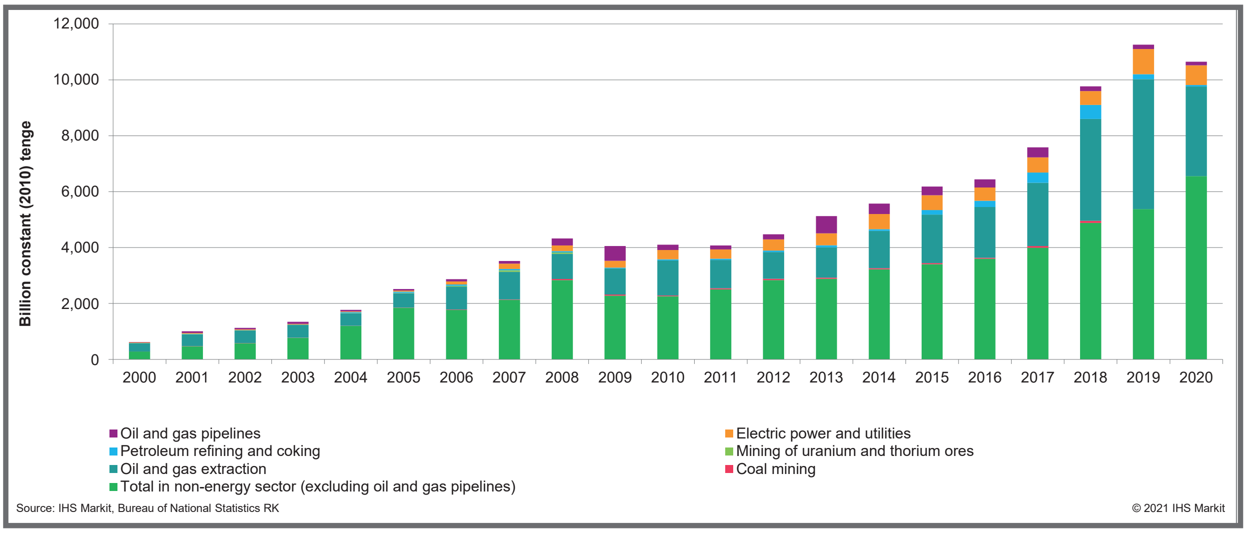


Figure 1.17 Total investment in fixed assets in Kazakhstan's economy - constant (2010) tenge



An ongoing issue is that Kazakhstan faces increased competition for scarce foreign investment capital worldwide from other nations (including other major hydrocarbon producers). On the positive side, Kazakhstan has made significant progress in recent years addressing selected concerns of foreign and Kazakh investors alike, as reflected in the country's improved position in the World Bank's latest Doing Business Report – measuring the ease of doing business in light of changes in the regulatory environment – issued in fall 2019: Kazakhstan moved up three spots to the 25th place (out of 190 countries), just ahead of Switzerland. The World Bank cited governmental efforts to reform legislation, improve the licensing system, simplify procedures for business creation, and optimize state oversight measures as key factors in its upward revision of Kazakhstan's score. But the World Bank also identified several key remaining obstacles to effective business activity (exacerbated in some cases by recent state policies), including difficulties registering property and resolving insolvency.[29] Remarks of company representatives at the time of the June 2021 plenary session of Kazakhstan's Foreign Investors Council, chaired by President Tokayev, underscored several important company concerns that will need to be addressed before energy sector FDI in particular reaches its full potential; e.g., a perception that certain reforms undertaken by authorities in support of investors unfairly benefit newly created companies and bypass more established market players, contradictions between various legislative acts, and continuing fiscal risks and uncertainties.[30]

29 For more on the World Bank ranking, see https://astanatimes.com/2019/10/kazakhstan-jumps-three-spots-to-25th-in-world-bank-doing-business-report/ and *https://www.doingbusiness.org/en/rankings*.

30 "Kazakhstan introduces new mechanisms for attracting investors," *Kazakhstan Newsline*, 23 June 2021.

With respect to government finances, a strong state spending response to the COVID-19 crisis amid declining tax revenue left Kazakhstan with a general government budget deficit, amounting to an estimated 8.5% of GDP in 2020 – the largest of any country within the Eurasian Economic Union (EAEU) – but the shortfall should diminish considerably starting in 2021:[31]

- **The government implemented stimulus measures amounting to 5.9 trillion tenge ($14.3 billion) – 8.7% of GDP – to combat the negative impacts of the COVID-19 crisis.** The support package includes increased state pensions and welfare payments and tax breaks to small and medium-sized enterprise (SME) companies. As part of the stimulus measures, the government expanded the applicability of tax exemptions across a number of tax categories for select entities and individuals, expanding upon measures introduced in 2019.[32] The VAT rate was lowered from 12% to 8% between March and 1 October 2020, while excise taxes were eliminated for gasoline and diesel exports through 31 December 2020. Minister of National Economy Aset Irgaliyev claimed that the relief program for SMEs would assist 500,000 entrepreneurs, and the amount of deferred taxes and payments was projected at 67 billion tenge ($155 million). As the crisis continues to subside, Kazakh authorities increasingly face the challenge of how to restore such "lost" governmental revenues and thereby rebalance the budget – without short-circuiting the nascent economic recovery. To that end, an important development that alleviated resource-constrained SMEs was the imposition of a three-year moratorium on business inspections by the Ministry of Finance in late 2019. Yet, in September 2021 the Ministry launched an about-face and is pursuing the moratorium's pre-emptive repeal, citing declining tax revenues. If realized, the Ministry of Finance's proposal would undermine investor confidence.
- **The outlook is for a narrowing of the budget deficit in 2021, with continued reliance on the National Fund to finance expenditures as needed during the remainder of the recovery period.** IHS Markit concludes that prudent Kazakh measures to curb spending, as well as adoption of a conservative oil price assumption in the 2021 state budget, will narrow the deficit this year to 1.2% of GDP, and put the fiscal balance on track to return to a surplus in 2023, contingent on oil prices. Kazakh authorities may well tap the National Fund more extensively to cover the budget deficit, as the National Fund was designed expressly as a financial stabilization mechanism to both shield the state budget from major fluctuations in global oil prices and absorb excess oil export revenues.[33] In contrast, the government will likely attempt to minimize any additional foreign borrowing, following the 2020 rise in the country's total foreign debt (IHS Markit nevertheless expects total Kazakh foreign debt to rise somewhat further over the next five years).[34]

One major signpost on the progress and sustainability of Kazakhstan's ongoing economic recovery will be the degree of realization of the National Development Plan through 2025 adopted by the Kazakh government in March 2021. The 2025 program essentially represents President Tokayev's formula to implement the next stage of the "Kazakhstan 2050" strategy of the First President, designed to make Kazakhstan one of the 30 "most developed" countries worldwide by 2050. The 2025 program is especially noteworthy for its emphasis on economic diversification, and includes several specific metrics by which to measure success achieving this and other targets. Major goals by 2025 as outlined in the program include: an increase in the annual GDP growth rate to 5%; a 27.1% jump in the real income of the population; reduction of the unemployment rate to less than 4.7% (from 5% in 2020); a 20.6% rise in labor productivity; an increase in the GDP share of investment in fixed capital to 30% (from 17.4% in 2020); growth of gross FDI to the level of $30 billion (from $14.5 billion in 2020); expansion of non-commodity exports by 41% in dollar terms; and reduction of the non-oil government budget deficit to less than 6% of GDP (from 7% in 2020) (see Table 1.4 Macroeconomic targets of Kazakhstan's National Development Plan through 2025 (selected examples)).[35]

While Kazakhstan's ability to realize the more ambitious objectives noted above remains uncertain, the economy is likely to find support from certain favorable tailwinds during the 2021-25 period:

- **A strong industrial performance should keep benefitting the economy, led mainly by oil and gas development in the medium term.** Assuming hydrocarbon and metal prices recover as expected, the outlook is for solid industrial sector growth during the next few years, especially as OPEC+ restrictions are gradually lifted.

31 The EAEU currently consists of Armenia, Belarus, Kazakhstan, Kyrgyzstan, and Russia.

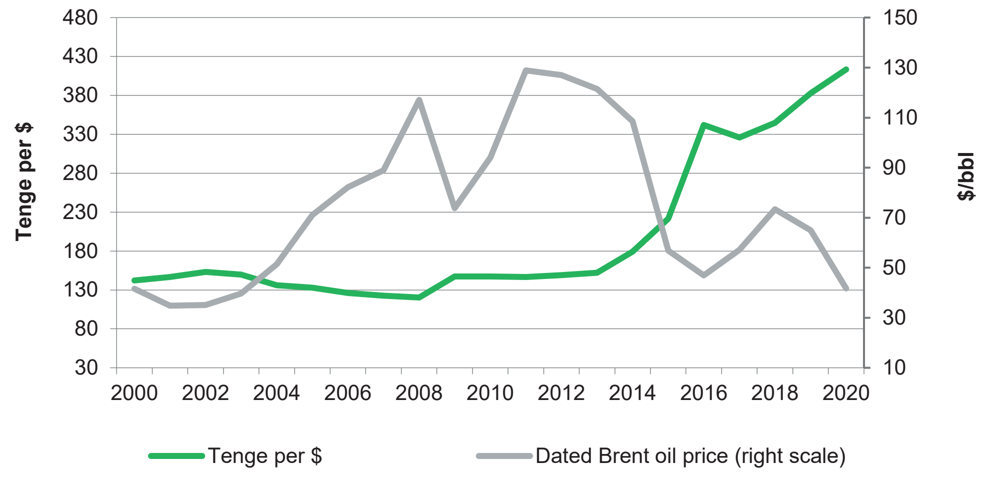
32 https://online.zakon.kz/Document/?doc_id=38130842#pos=3;-83

33 Even before the pandemic, the government had begun drawing more heavily from the National Fund in order to support spending on priority projects. In January 2021, the National Fund's asset value stood at $57.7 billion (equal to around two years of import cover), down from $61 billion at the start of 2020.

34 Kazakhstan's total foreign debt rose to more than $166 billion in 2020, but the country's debt burden is manageable, with short-term debt fairly stable. In 2020, Kazakhstan's external debt was estimated at 98% of GDP, but this was nonetheless down significantly from 2016, when government debt reached 118% of GDP.

35 All 2020 numbers in this paragraph are as reported by the Kazakh government in the March 2021 National Development Plan through 2025.

Figure 1.18 World oil price and tenge-dollar exchange rate dynamics, 2000-20



Source: IHS Markit, Argus Media Limited (historical price data) © 2021 IHS Markit

- **The national projects first envisaged by First President Nazarbayev remain an important investment stimulus.** Investment spending is still supported by the construction of roads and the development of special economic zones, and the overall development of the agro-industrial complex to support the 2050 strategy.
- **Considerable accumulated foreign currency assets support Kazakhstan's external creditworthiness.** Kazakhstan should easily be able to finance any potential current account deficits without much debt generation.

The other side of the ledger, however, includes the following serious constraints on growth and downside risks:

- **The outlook for business investment outside the oil sector remains persistently weak.** The challenge is to increase investment in the manufacturing sector, an industrial branch that remains relatively undeveloped. At the same time, economic diversification and a reduced dependence on imports are central to Kazakhstan's success in the long term. Although the government has announced increasingly detailed plans to diversify its economy,

Table 1.4 Macroeconomic targets of Kazakhstan's National Development Plan through 2025 (selected examples)

	2020	2021	2022	2023	2024	2025
Real income of the population, % increase from the 2019 level in 2019 prices	0.5	5.0	10.0	15.4	21.1	27.1
Unemployment rate, %	5.0	5.0	5.0	4.9	4.8	<4.7
Labor productivity, % increase from the 2019 level in 2019 prices	2.6	0.4	4.7	10.4	15.0	20.6
Share of medium-sized enterprises in GDP, %	8.7	10.0	11.2	12.5	13.7	15.0
Investment in fixed capital, % of GDP	17.4	20.0	21.3	23.5	25.2	30.0
Gross FDI, billion US dollars	14.5	15.9	23.9	25.1	27.6	30.0
Non-commodity exports (goods and services), billion US dollars	20.0	29.2	31.8	34.6	37.7	41.0
Non-oil government budget deficit, % of GDP	7.0	6.6-9.1	6.5	6.4	6.1	<6.0

Note: 2020 data as reported by Kazakhstan.
Source: IHS Markit, Decree of the President of the Republic of Kazakhstan dated 26 February 2021 No. 521 © 2021 IHS Markit

aiming to reduce its oil dependency, clear results from these plans remain to be seen.

- **Realization of the full potential of the oil industry itself (and energy sector more broadly) hinges on the ability of the government to make bold steps in boosting investor attractiveness, particularly in the upstream sector.**
- **If oil prices sharply weaken again or remain lower than expected, economic expansion may halt or even be reversed.**

To sum up IHS Markit's outlook for the Kazakh economy's longer-term growth prospects, our base case is for real GDP to expand modestly, at an average annual rate of 2.8% during 2021-50, but with significant deceleration over time (in some ways, a natural consequence of the economy becoming larger over time): after averaging 3.9% during 2021-30, annual GDP growth slows to an average of 2.4% over 2031-40, and 2.0% during 2041-50 (see Figure 1.19 Kazakhstan's GDP growth rate: historical and outlook to 2050).

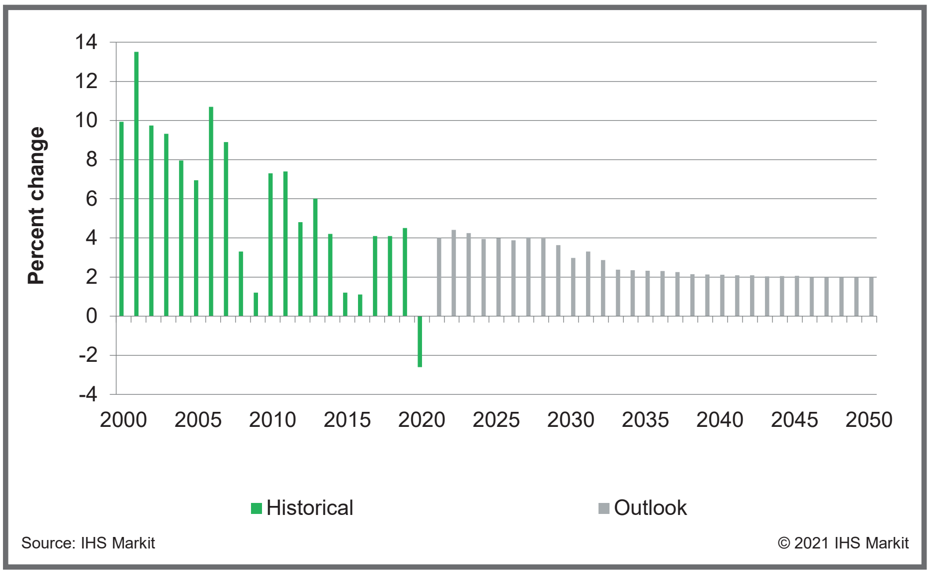
1.3.2 Kazakhstan's energy sector performance in 2020-21 and outlook to 2050

Kazakhstan remains a net exporter of primary energy (mainly crude oil), but the country's net primary energy exports contracted more sharply than domestic consumption amid the pandemic, with the result that the share of total primary energy production delivered to domestic markets edged up from 49.3% in 2019 to 50.1% in 2020. Going forward, we expect the share of production consumed domestically to average 52% during the scenario period (and reach 61% in 2050) (see Figure 1.20 Kazakhstan's primary energy balance by fuel in 2020 and Figure 1.21 Kazakhstan's primary energy balance: historical and outlook to 2050).

Total production of primary energy in Kazakhstan, which includes oil, gas, coal, and primary electricity (but not mined uranium), declined by 4.2% in 2020 to 178.7 MMtoe, as only primary electricity production (i.e., hydro and renewables) grew last year (by 6.7% to 2.7 MMtoe). There were particularly sharp drops in oil and natural gas output (by 5.4% to 85.7 MMtoe, and by 7.4% to 28.5 MMtoe, respectively), while coal output fell more moderately (by only 1.4% to 61.7 MMtoe). The 2020 drop in total primary energy production followed three consecutive years of growth; average annual expansion of total primary energy output during 2000-19 was an impressive 4.1%. We expect a further but smaller net decline in primary energy production in 2021 (around 2.2%), before output resumes a growth path in 2022 and surpasses the 2019 level again in 2025. It is expected to reach a maximum of 193.5 MMtoe in that year, after which output steadily declines, to 142.9 MMtoe in 2050, for a net fall of 20.0% during 2021-50. Falling coal output accounts for most of the expected drop in primary energy output during the scenario period (see Figure 1.22 Outlook for Kazakhstan's primary energy production by fuel to 2050).

Kazakhstan's primary apparent energy consumption fell by 2.7% in 2020 to 89.5 MMtoe, reflecting a particularly sharp drop in oil demand (by 12.3% to 15.8 MMtoe) as well as declines in consumption of consumption of coal (by 0.9% to 49.8 MMtoe), natural gas (by 0.2% to 21.3 MMtoe), while primary electricity consumption increased (by 7.5%

Figure 1.19 Kazakhstan's GDP growth rate: historical and outlook to 2050



to 2.6 MMtoe). Longer term, the IHS Markit outlook is for total primary energy demand to trend slightly downwards overall during 2021-50, falling by 2.9% during the scenario period to 86.8 MMtoe, reflecting further improvements in aggregate energy efficiency. Demand trends diverge widely by fuel type in our base case. Natural gas consumption is expected to grow robustly (by 25.1% to 26.6 MMtoe), while we expect demand to grow even more sharply in percentage terms for primary electricity (up 180.8% to 7.3 MMtoe), and oil demand also remains on a strong growth path (rising by 31.8%, to 20.8 MMtoe), but coal consumption falls substantially during the scenario period starting in 2021 (dropping altogether by 35.4% to 32.1 MMtoe).

A key driver of the changes in the fuel mix to 2050 is the further displacement of coal in the power sector, primarily by natural gas along with more modest expansion of renewables and nuclear energy. Aggregate gas consumption growth is muted by efficiency gains, so consumption does not expand as quickly as in the earlier periods. In our base case to 2050, coal still claims the largest share of the Kazakh domestic primary energy demand pie (not including mined uranium), at 37%, followed by gas (31%), oil (24%), and primary electricity (8%). Within the primary electricity sector, we believe wind power has exceptional potential for growth during the scenario period; electricity generated by wind stations exceeds the volume of hydroelectricity starting in 2045 in the IHS Markit outlook and reaches 14 billion kWh in 2050 in the base case (around 10% of total generation). We also envision the addition of nuclear power to the electricity fuel mix during the scenario period, starting in the mid-2030s, but its share of generation remains relatively small (see Figure 1.23 Outlook for Kazakhstan's primary energy consumption by fuel to 2050).

Kazakhstan's net primary energy exports, around 80% of which consisted of oil recently, declined by 5.6% to 89.2 MMtoe in 2020, as global petroleum markets reeled from COVID-19. IHS Markit expects net exports to fall further in 2021 before resuming the previous growth trend in 2022, and surpass the pre-pandemic level again starting in 2025, when they reach a maximum of 104.0 MMtoe in the base case, and trend downward during most of the remainder of the scenario period, to 56.1 MMtoe in 2050. This represents a net 2021-50 decline in primary energy exports of 37.1%, and reflects the anticipated longer-term drop in nearly all export categories: in the base case, oil exports reach a maximum of 80.2 MMt in 2035 before declining to 52.6 MMt in 2050, coal exports diminish to 5.5 MMtoe in 2050, and Kazakhstan switches from being a net gas exporter to a net gas importer in the early 2040s. As discussed in more detail in Chapter 4, our outlook for Kazakhstan to become a net gas importer in the early 2040s reflects our assumptions of increased gas demand (due in part to accelerated coal-to-gas switching in the power sector) and relatively flat commercial Kazakh gas production longer term. In contrast, the primary electricity export stream expands slightly overall during the scenario period but remains very small (around 0.1 MMtoe/y).

One of the few positive trends amid the pandemic was a continuing decline of the energy intensity of Kazakhstan's economy – a long-term dynamic in evidence since 1991. Measured as the tons of oil equivalent (toe) consumed to produce a million dollars of GDP (in real 2005 dollars), Kazakhstan's energy intensity decreased by 0.1%, to

Figure 1.20 Kazakhstan's primary energy balance by fuel in 2020

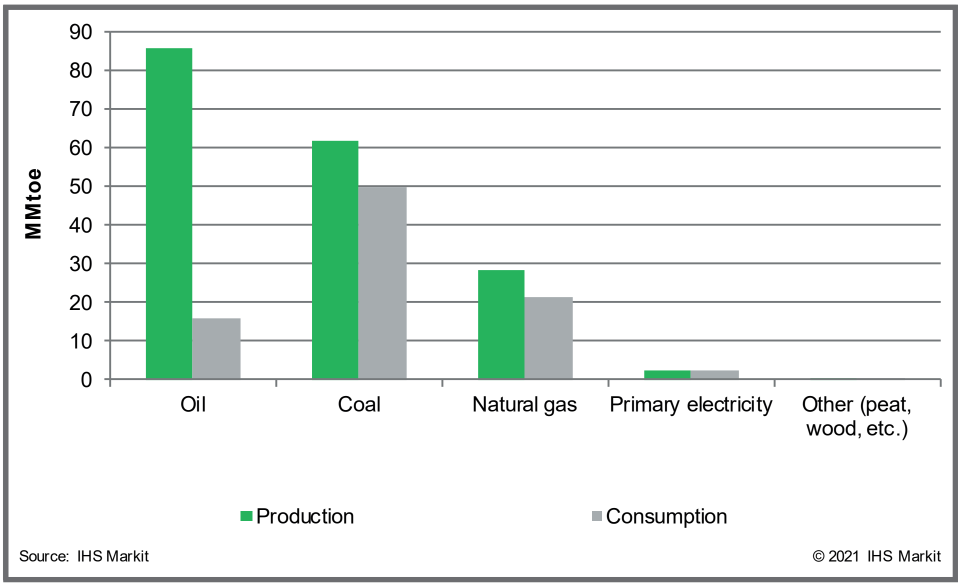


Figure 1.21 Kazakhstan's primary energy balance: historical and outlook to 2050

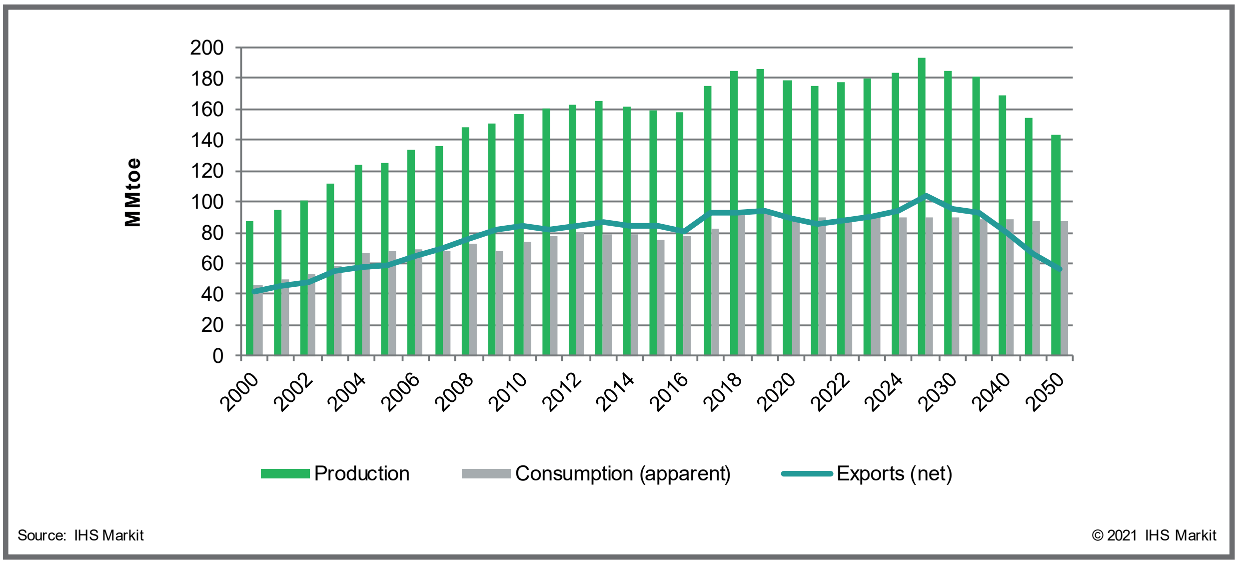
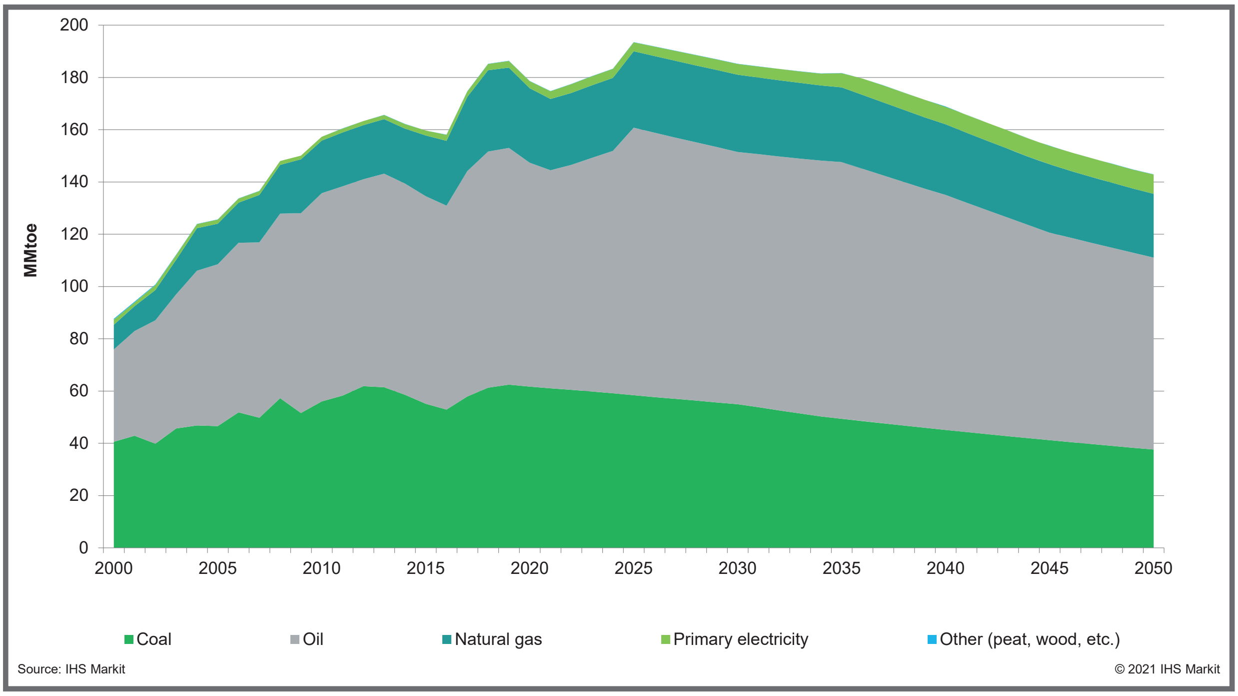
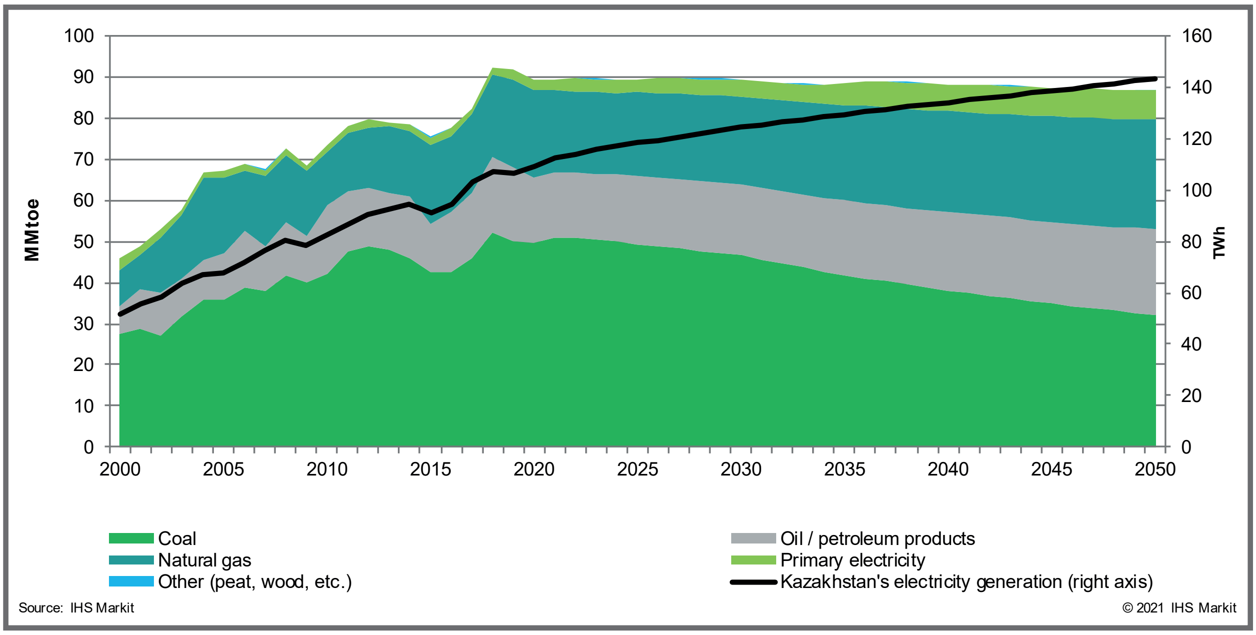


Figure 1.22 Outlook for Kazakhstan's primary energy production by fuel to 2050



356.6 toe in 2020 (for the period 2000-20, the total decrease in energy intensity was 37.7%). Kazakhstan still displays comparatively high energy intensity levels in global terms, but in the forecast period achieves stronger energy efficiency gains than historically – reducing energy intensity by 55% during 2021-50, to 160.7 toe (see Figure 1.24 Kazakhstan's energy intensity dynamics in the base case to 2050).

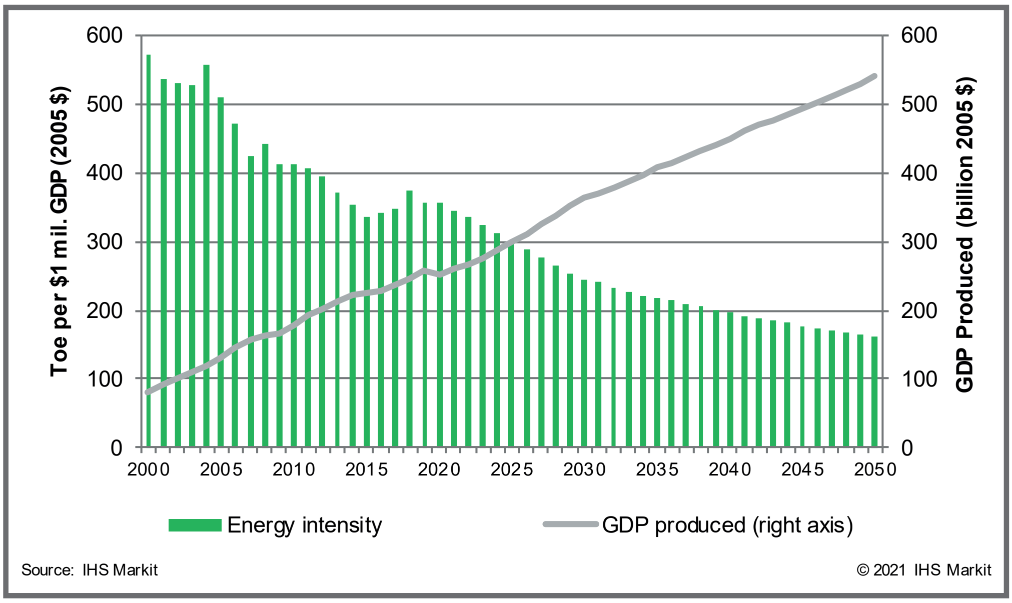
Figure 1.23 Outlook for Kazakhstan's primary energy consumption by fuel to 2050



1.4 High-level Takeaways and Recommendations for Future Energy Demand, Energy Mix, and Energy Transition

- **Investment attractiveness: The Ministry of Finance's September 2021 proposal to preemptively terminate the moratorium on inspections seems ill-advised, and should be avoided.** Such a move would undermine investor confidence, making investors question the integrity of legislation and statements by officials for years to come. Instead, the government should continue to work with the Foreign Investors Council (FIC) and other entities, and seriously consider reforms, keeping in mind that any fruits of their efforts will likely accrue only over the medium to long term and not immediately.
- **Energy demand: The enormous global task of meeting burgeoning energy demand while decarbonizing poses unique risks and opportunities for Kazakhstan.** On the one hand, the intensifying worldwide push to decarbonize energy consumption raises the obvious risk of shrinking markets longer term for all major hydrocarbon producers and exporters. But we believe that oil and gas supply will remain vital to the global economy during the upcoming transition period; the energy transition will require considerably more time than is being postulated by many. Moreover, depending on their evolving position on the global oil supply cost curve, some Kazakh oil companies may be members of the select club of producers holding "advantaged" or "resilient" barrels during much of the scenario period; i.e., oil supplies that can be produced at a comparatively low cost and with a lower carbon footprint. Kazakh policymakers would be well-advised to ensure that the country's export-oriented hydrocarbon producers remain competitive on the global stage, through enlightened fiscal and other policies. Perversely, given the current structure of Kazakhstan's economy, revenues from hydrocarbon exports will be essential for funding the country's own energy transition to lower-carbon forms of energy in the future. Finally, fossil fuels will remain essential to the domestic economy for decades to come, while Kazakh energy consumers increasingly vie with export markets for incremental Kazakh hydrocarbons supply. Further refinement of current policies is needed to ensure that domestic energy market regulations and prices incentivize producers to keep domestic markets well supplied throughout the scenario period – and facilitate the planned formation of common EAEU markets in oil and refined products, natural gas, and electricity.
- **Energy mix: Overreliance on coal to give way to a more balanced energy mix with increased reliance on gas, renewables, and possibly nuclear in reaching Kazakhstan's decarbonization goals.** Achievement of Kazakhstan's decarbonization ambitions hinges largely on diversifying the power sector fuel mix so as to reduce the share of coal- fired

Figure 1.24 Kazakhstan's energy intensity dynamics in the base case to 2050



generation that spews the bulk of GHG emissions in Kazakhstan.[36] Natural gas will likely play a major role in this process given its cleaner burning profile and its ability to serve both as a base-load and flexible generation option. While Kazakhstan currently remains a "gas-rich" country in international terms, it shares some of the challenges of "gas-poor" nations as well during the latter part of the scenario period, in that it becomes a net gas importer in the early 2040s in our base case and needs to import a growing share of the gas required to meet incremental domestic gas demand (mainly in the power sector). Meanwhile, coal also has an important (if diminished) role to play in Kazakhstan's economy for decades to come, with substantial coal sector emissions reductions possible and needed through cleaner coal technologies. Renewables will clearly make a growing contribution to Kazakhstan's power sector transition as well throughout the scenario period, while nuclear could also play a significant role. In contrast, hydrogen has less potential as a decarbonization pathway for Kazakhstan, particularly over the near term, in IHS Markit's view, in light of the comparatively high costs (without subsidies) vis-à-vis other GHG reduction options currently available, reflecting the nascent state of its development (see Chapter 2) and substantial expenses associated with the generation and transportation of hydrogen

- **Energy transition: Kazakhstan's transition depends on complex balancing acts by key state and energy industry players, given the importance of multiple competing interests.** While President Tokayev has clearly signaled Kazakhstan's carbon neutrality ambitions, the mechanisms for achieving the transition over the longer term still remain unsettled. The above-noted 2030 renewables and gas targets incorporated within the country's Roadmap for achieving its Nationally Determined Contribution to the Paris climate agreement nevertheless represent two key intermediate steps. Additional finetuning of the mix of policy "carrots and sticks" designed to decarbonize the national economy will likely be necessary (to date, the emphasis has been largely on penalties, with at best mixed results). For its part, the Kazakh energy industry must find a way to balance the heightened energy transition priorities of Kazakh authorities embodied in the re-launch of its national emissions trading system and new Ecology Code – and, increasingly, of non-state stakeholders as well – with the imperative of delivering an adequate financial return to investors. At the same time, the challenges vary depending on company type. The largest energy producers in Kazakhstan – the "Big 3" hydrocarbon projects – are consortia led by IOCs that face comparatively great pressures from private sector stakeholders intent on accelerated reduction of emissions. In contrast, as an NOC, KMG may be under less obligation to demonstrate energy transition commitments than its IOC partners, as its funding and priorities more heavily reflect state policy rather than the demands of private investors. However, all companies with international exposure, or those planning IPOs, are compelled to respond to energy transition goals to one degree or another.

36 Kazakhstan's power sector is relatively carbon intensive, accounting for around two-thirds of Kazakhstan's GHG emissions recently, of which coal-fired generation amounted to around 90% of emissions from this segment.

Chapter 2

ENERGY TRANSITION

2 THE GLOBAL ENERGY TRANSITION AND KAZAKHSTAN: STATE POLICIES AND INDUSTRY RESPONSES TO REGULATORY AND STAKEHOLDER PRESSURES

THE GLOBAL ENERGY TRANSITION

2.1 Key Points

- The energy transition, a process featuring the decarbonization of energy consumption, is driven by the global agenda of reducing greenhouse gas (GHG) emissions in order to address climate change. This transition has been accelerated by the disruption caused by the COVID-19 pandemic. At present, in the period leading up to the 26th UN Conference of Parties to the United Nations Framework Convention on Climate Change (also known as the Glasgow Summit or COP26) in November 2021, roughly 130 countries have announced pledges to achieve carbon neutrality by mid-century (e.g., 2050, 2060) as part of an overall upgrading and renewal of Intended Nationally Determined Contributions (INDCs, or GHG emissions reduction pledges), originally codified in the 2015 Paris Climate Agreement. Despite recent policy and industry efforts, it is likely that many countries will not meet their Paris Climate Agreement obligations without much greater and more immediate action.
- While it is not a foregone conclusion that Kazakhstan will also miss its INDC (unconditional) target for 2030, this currently appears the most likely outcome, particularly if policymakers do not move more quickly to implement measures aimed at reducing GHG emissions throughout the economy and to expand (natural) carbon sinks.
- Rapidly evolving national climate policies and pressures from governments, investors, climate activists, and the general public are now heavily influencing the strategies and plans of energy companies and the broader business community to announce and meet decarbonization targets for their operations and products. There is ongoing debate over which forms of energy should be considered "green" and thus "suitable" for government financing and leveraging of private investment. Views on the future role of natural gas, blue hydrogen, and nuclear power in the energy transition vary widely across geographies and among stakeholders.
- Achieving substantial progress toward reducing GHG emissions requires engagement of private sector players, and use of proven low-carbon technologies such as wind and solar power, as well as technologies that are currently at the demonstration or experimental phase. Hydrogen is prominent among the as-yet unproven technologies; its development is aimed at sectors that will be more difficult to decarbonize (e.g., heavy industry, transportation, power storage/grid backup).
- Kazakhstan's updated INDC to COP26 restates its original unconditional INDC to reduce GHG emissions by 2030 by 15% relative to the 1990 level. In addition, in December 2020 President Tokayev pledged that the country would achieve net carbon neutrality by 2060, and in September 2021, a first draft of Kazakhstan's Doctrine (Strategy) to achieve carbon neutrality by 2060 was released for comment.
- The Strategy for carbon neutrality (also known as the Strategy for Low-Carbon Development) to 2060 is based on a comprehensive study designed to generate a specific outcome of zero, or nearly zero, carbon emissions by mid-century. IHS Markit's outlook (presented in NER) reflects our independent view on the likely development of Kazakhstan's economy and energy sector, taking into account existing infrastructure and economic structures and activities, political ambitions, investment levels and supply constraints, institutional support, and pricing policies, among other factors. These considerations impact policy implementation and the pace of change that can be achieved, helping to explain the difference in views between the suggested path to zero net emissions and the IHS Markit one.
- To this end, a national "roadmap" for achieving the INDC outlines a series of specific and ambitious interim targets for Kazakhstan (2021–25 and out to 2030) to help achieve its obligations under the Paris Climate Agreement through:
    - enhanced operation of the national emissions trading system (ETS) for large stationary emissions sources in electric power, oil and gas, mining,

metallurgical, chemical, and building materials industries

- a proposed carbon tax for smaller enterprises and others in sectors not included in the ETS
- a decrease in the share of coal in electric power generation (69% in 2020) to 40% of the total in 2030; an increase in renewable power (solar, wind, hydro) from 3% to 24% of the total; and an increase in natural gas-fired generation to 25%
- a 38.9% increase in energy efficiency economy-wide by 2030 and a lowering of carbon intensity by 41.4%.

- The new Ecology Code ("EcoCode," enacted on 2 January 2021, entered into force on 1 July 2021) represents an important advancement in Kazakhstan towards reducing and mitigating the environmental impact of economic activities, particularly the operations of large industrial enterprises.

2.2 The Global Energy Transition: 2020 as a Turning Point

In simple terms, the "energy transition" can be described as a movement away from fossil fuels as the primary source of global energy consumption toward renewable and other forms of energy whose use involves zero or low GHG emissions. Already quietly under way for some three decades, its key characteristic is the *decarbonization of overall energy consumption.*

Zero- or low-carbon energy carriers and strategies that will play a prominent role in the transition include, but are not limited to:

- Solar
- Wind (onshore and offshore)
- Carbon capture, use, and storage (CCUS or CCS)
- Hydroelectric power
- Advanced biofuels
- Hydrogen (if it is produced from electricity generated by renewable sources or employs CCS, if generated from hydrocarbon fuels)
- Geothermal
- Tidal (ocean, wave).

In addition to the move toward low-carbon energy sources, the energy transition also features expanded *digitalization,* the application of a suite of data storage, handling, and processing technologies to energy production, transmission, and consumption. These technologies include, but are not limited to, robotics, artificial intelligence (AI), the "internet of things," the Cloud, horizontal networks, and blockchain. Although they are not intrinsically low-carbon, their application in the energy space increases the *efficiency of energy production and consumption,* and therefore reduces the overall carbon footprint of economic activity.

The current iteration of the energy transition, focused on decarbonization, has a precursor in even longer-standing 20th century concerns over *energy security and access.* Even as recently as the first decade of the 21st century, conventional wisdom still held that the world's hydrocarbon resources were limited and their continued utilization was threatened by looming shortages, given seemingly inexorable demand growth (as exemplified by fears of reaching "peak oil"). Further, the unequal distribution of fossil fuel energy resources among countries of the world was viewed as conferring a permanent economic advantage to so-called "petro-states" vis-à-vis countries lacking substantial oil and gas endowments. Under this view, a "transition" toward renewable energy sources such as wind and solar power, which were ubiquitous (and coincidentally also zero-carbon), offered a path to overcome both energy scarcity and its unequal spatial distribution. Of course, these more traditional motivations supporting an energy transition – i.e., the desire to possess adequate energy supplies not subject to exhaustion or political manipulation – have now been eclipsed by the more urgent need to respond to *climate change,* an imperative only accelerated by the disruption of conventional modes of activity caused by the COVID-19 pandemic.

As noted in Chapter 1, COVID-19 provided a global economic shock in 2020 – reducing GDP by 3.5% and cutting primary energy demand by 5.4% (liquids by 10.8%) – while at the same time delivering a fleeting, albeit welcome, reduction of GHG emissions, of around 5.3%. It also exposed more clearly latent economic, healthcare, and national security vulnerabilities.

The year 2020 appears to have marked an inflection point in the trajectory toward a low-carbon future, in which non-carbon energy's 30-year "slow-motion" march to reach roughly 10% of global energy demand is poised to accelerate, to perhaps reach as much as 16% by 2030.[1] Five key changes can be identified:

- **Investment flows**. Money is shifting from hydrocarbon development and into renewables and related low-carbon energy. This trend is evident in company stock market valuations and is occurring at a time of increasing importance of environmental, social, and

1 Non-carbon energy here includes hydropower, nuclear, renewables, and geothermal; see IHS Markit Crude Oil Markets Strategic Report *The energy transition: Moving beyond slow motion,* 29 October 2020.

corporate governance (ESG) investment guidelines and requirements.[2]

- **Future demand expectations.** The 2020 decline in fossil fuel demand, particularly for oil, is leading companies and investors to re-evaluate medium- and long-term demand prospects; although the near-term sentiment has been bearish, global liquids demand is not expected to peak until the mid-2030s (see Chapter 1). Still, the day when battery electric cars reach cost parity with oil-powered cars is fast approaching, and wind and solar power have already attained cost parity in some cases with fossil fuels in electric power generation.
- **State policy support for "green" activities and updated emissions reduction pledges.** In many parts of the world, including the Organisation for Economic Co-operation and Development (OECD) countries and China, pending or recently enacted legislation designed to stimulate post-COVID economic recovery include robust measures to develop zero- and low-carbon energy (see below a plan for the US). Further, in the run-up to the COP26 to be held in November 2021, roughly 130 countries have announced pledges to achieve carbon neutrality by mid-century (e.g., 2050, 2060) as part of an overall upgrading and renewal of GHG emissions reduction pledges. Collectively these countries account for nearly 80% of global CO_2 emissions.[3]
- **Energy (and other) company responses.** As this chapter will document, pressure from governments, investors, climate activists, and the general public is influencing corporate strategies and plans – first and foremost by energy companies but also by the business world more broadly – to meet long-term decarbonization targets for their operations and products.
- **Behavioral changes.** Finally, the economic lockdown and "stay-at-home" orders forced by the pandemic in 2020 accelerated the digitization of communications and commerce, while altering the daily routines and mobility patterns for millions. Remote, at-home work routines supplanted lengthy commutes to the office, padding personal discretionary time and reducing expenditures on gasoline, subway fares, clothing, dry cleaning, and workday food service. In the aftermath, some workers may prefer to continue their new routines and mobility patterns rather than returning to the old ones, working from home on a permanent basis and only visiting the office occasionally.[4] Collectively, the mass reorientation of workers' daily behavior has, and will continue, to shape energy consumption during the post-pandemic recovery.

2.3 Government Policy Measures Supporting the Energy Transition

Many governments around the world, including Kazakhstan, have embraced the energy transition as part of strategies to address climate change through INDCs to the Paris Climate Agreement and net-zero carbon pledges.[5] It is beyond the scope of this report to provide a comprehensive accounting of these strategies, but it is necessary and instructive to highlight key trends and the variable approaches underlying these strategies in different countries. The key policy themes that will have a major impact in how the transition unfolds include:

- The tendency of governments worldwide to use post-pandemic economic stimulus and recovery packages as a vehicle for promoting green energy investments (e.g., the proposed American Jobs Plan infrastructure package in the United States [US], the EU's NextGenerationEU post-pandemic economic stimulus package, and China's economic recovery program launched in May 2020)
- The ongoing debate regarding which forms of energy should be considered "green" and thus suitable for government financing and support (and future private investment), and in particular the role that should be assigned to natural gas, blue hydrogen, and nuclear power in the energy transition (e.g., the "taxonomy" now being introduced as part of the European Platform on Sustainable Finance is supposed to provide the basis for future "green" energy investment in the European Union)
- The emerging role of technologies not yet at commercial scale – such as hydrogen and CCUS – in state energy policy given their nascent status relative to more established technologies such as wind and

2 Overall investment in 2020 devoted to the energy transition in the world economy is estimated by the World Economic Forum at $500 billion (World Economic Forum, *Fostering Effective Energy Transition*, 2021 edition).

3 https://www.visualcapitalist.com/race-to-net-zero-carbon-neutral-goals-by-country/

4 The shift in workplace practices brought about by COVID-19 stay- at-home orders accelerated the telecommuting trend that has evolved over decades. In the US, about 2.3% of workers primarily "telecommuted" to work in 1980, whereas by 2018 the share had increased to 5.7%. Precise numbers are not yet available post-pandemic, but the share is believed to have more than doubled, temporarily reaching as high as one-third – believed to approach the potential upper threshold for jobs that can be performed remotely ("Working from home could change rush hour," *New York Times*, 13 June 2021; "The pandemic changed how we spent our time," *New York Times*, 29 July 2021).

5 For details on the 2015 Paris Climate Agreement, see Chapter 9 in the KAZENERGY *National Energy Report 2017*.

solar (e.g., the European Union's recently enunciated Hydrogen Strategy)[6]

- The early-stage policy efforts to allow for extra-territorial extensions of Paris Agreement climate policy (particularly its Article 6) beyond national borders to cover trans-border trade relations (e.g., the EU's Carbon Border Adjustment Mechanism [CBAM]).[7]

2.3.1 Trying not to let a crisis go to waste: The American Jobs Plan (US infrastructure package)

The US provides an example of an effort by a major-country government to use a calamity – a pandemic that has decimated healthcare systems and economies for well over a year – as an opportunity to pivot energy policy decisively in the direction of the energy transition, as part of a larger mandate to reconstruct the nation's aged infrastructure. On 31 March 2021, the administration of US President Joseph Biden announced its intention to propose to the US Congress a plan to "build back better" in the wake of the pandemic, to spend roughly $2 trillion to upgrade and renovate the country's infrastructure over an eight-year period (roads, bridges, broadband, water systems) through a proposed legislative package (the American Jobs Plan). The plan included a number of programs specifically designed to promote energy transition, reduce carbon emissions, and respond to climate change. These energy-related initiatives include:

- efforts to make infrastructure more resilient to climate change–induced events such as more severe storms, fires, and flooding ($50 billion)
- spending on clean energy research and development ($35 billion for utility-scale energy storage, CCUS, hydrogen, advanced nuclear, offshore wind, biofuels, electric vehicles, quantum computing)
- retrofitting and weatherization of 2 million buildings to increase energy efficiency ($213 billion)
- support for electrification of the vehicle fleet ($174 billion), particularly light-duty vehicles used by the general population, including the build-out of electric vehicle charging infrastructure ($15 billion)
- updating and modernization the electric power grid to both handle a greater volume of electricity (increase capacity of the system by at least 20 GW) and to be more resilient to support greater wind and solar capacity ($100 billion)
- creation of a "Clean Electricity Standard" – designed to facilitate the Biden Administration's goal of making US electricity generation 100% carbon free by 2035 –that would build on state and regional renewable portfolio standards already in place to require (and provide financial incentives for) utilities to generate a certain percentage of electricity nationwide from zero-carbon sources
- updating and modernization the electric power grid to both handle a greater volume of electricity (increase capacity of the system by at least 20 GW) and to be more resilient to support greater wind and solar capacity ($100 billion)
- worker retraining – transition of some fossil-fuel workers to jobs in remediation work (capping wells, mine reclamation; $16 billion), and creation of a Civilian Climate Corps ($10 billion)
- support for public (mass) transit ($85 billion)
- a 10-year extension of current investment and production tax credits for wind and solar generation and storage.

However, which elements of the Plan ultimately will be incorporated into legislation is now open to question, as opposition crystallized around the Plan's staggering cost, preventing its realization as a standalone law. By mid-summer 2021, owing to the intricacies of legislative procedures in the US Congress, elements of the original Plan had been assigned to one of two proposed successor laws now on a dual track for debate and possible adoption.

2.3.2 What is green? Weighing the good versus the perfect in financing future energy development

A recent trend shaping the energy transition is the debate centering on two simple questions: what is "green" energy and what are acceptable fuels for the energy transition? The short answer is that it depends. Certainly, coal and crude oil have long been considered "dirty" fuels. But natural gas, which was previously embraced as a cleaner alternative to coal in the electricity segment and a critical

6 The emphasis in this section will be on hydrogen rather than CCUS. The development of CCUS to date has largely been undertaken by the private sector, and particularly by major oil and gas companies seeking to reduce the carbon footprint of their operations (covered in Section 2.4). According to the International Energy Agency, for the world to reach net-zero GHG emissions by 2050, global CCUS capacity will need to grow to 5.6 billion tons by 2050 from roughly 40 MMt at present.

7 Article 6 sets out a framework for international cooperation that enables countries to meet their climate commitments through the transfer of "mitigation outcomes" – i.e., to work together in "cooperative approaches" to support the achievement of their INDCs; see Section 2.3.4 of this report and IHS Markit Energy and Climate Scenarios Insight *Setting rules: Article 6 negotiations under way pre-COP26*, 23 March 2021.

"bridge fuel to low carbon world," is now subject to greater and persistent scrutiny.[8]

In that same spirit, a legal opinion commissioned by the nonprofit Oil Change International (OCI) concludes that the export credit agencies (ECAs) of the governments of the UK, US, Japan, and other developed countries may find themselves in violation of international obligations (and be exposed to litigation risks) as OECD members and as signatories to the 2015 Paris Agreement if the ECAs continue to support oil and gas projects.[9] The World Bank Group has not financed a new coal-fired power plant in more than a decade, and halted funding for upstream oil and gas projects in 2019 except in special cases where such projects provide energy access to the poor in conformance with a country's Paris climate commitments. The Asian Development Bank (ADB) is also considering terminating its financing of coal mining, oil and gas exploration and production (E&P), and coal-fired and nuclear electricity generation.[10] And, at a meeting of the G7 countries in June 2021, leaders pledged to stop international funding for any coal project that lacked CCS technology by 2022, and to phase out direct government support for other international fossil fuel projects as soon as possible.

In Europe, the retreat from fossil fuel investment appears to have advanced the farthest. As of this writing (summer 2021), four EU countries – France, Denmark, Ireland, and Spain – have instituted bans on issuing permits for new E&P development projects.[11] Bans on hydrocarbon exploration and production in these four countries run well ahead of any similar actions relating to hydrocarbon demand, placing the onus on producers to respond to the mandate well before consumers.[12]

In addition to outright opposition to new coal and hydrocarbon development, momentum appears to be intensifying in Europe toward limiting support to "certified green" projects, as opposed to simply lower-carbon forms of energy – placing the long-term viability of such once-touted transition strategies as coal-to-gas switching, nuclear energy, and blue hydrogen in question. The planned roll-out of the EU Taxonomy Climate Delegated Act (on 1 January 2022) has only intensified the debate. Approved by the European Commission (EC) on 4 June 2021, the EU Taxonomy Climate Delegated Act specifies a *taxonomy* for Sustainable Finance that effectively identifies and certifies "green" energy sources. The taxonomy will act as a seal of approval of sorts for financial firms seeking to invest in environmentally sustainable energy projects. The initial version of the taxonomy *includes neither natural gas nor nuclear power.* The opposition to gas is based on the view that the standard operational lifetime of new gas infrastructure exceeds the timetable required to achieve carbon neutrality by mid-century. The opposition to nuclear power is based on the absence to date of a viable, safe, and long-term method of disposal of high-level nuclear waste.[13] However, the EC has announced that it intends to include nuclear power in the taxonomy later, under a complementary delegated act that will confirm the technology as sustainable.[14] In the interim, nuclear energy's status is subject to the review of two expert groups and considerable debate before a final decision, which is not expected until the end of 2021.

A further move away from natural gas and toward hydrogen in European financing for low-carbon energy development is on the horizon, as the EC revises its Trans-European Networks for Energy (TEN-E) regulation, a source of financing for gas networks. Future TEN-E funding will expand the offshore wind energy and hydrogen sectors, but *will end financing for oil and gas exploration and infrastructure,* the EC announced in December 2020. However, a compromise proposed by the European Council (a discussion forum consisting of the heads of the EU member states) would allow financing for natural gas projects to proceed provided that project developers can prove that the assets will produce and/or deliver a natural gas–hydrogen blend upon completion and can be converted to dedicated hydrogen assets by December 2029.[15] Yet even this compromise has provoked opposition among nearly half (11) of the EU member states, a stance that places into question the role of gas as a "bridge fuel" in the overall energy transition.

8 One of the more attention-grabbing headlines from an influential report prepared by the International Energy Agency (IEA) on potential pathways for the world to achieve carbon neutrality (net-zero GHG emissions) by 2050 is an immediate ban on new fossil fuel development: "Beyond projects already committed as of 2021, there are no new oil and gas fields approved for development in our pathway [to net-zero 2050], and no new coal mines or mine extensions are required." See International Energy Agency, *Net Zero by 2050: A Roadmap for the Global Energy Sector,* Paris: IEA, May 2021, p. 21. It should be emphasized that the IEA is not formally proposing such a prohibition, only observing that its strategy for achieving global carbon neutrality would require it.

9 Among the larger ECAs are the Export-Import Bank of the United States (EXIM) and the UK Export Finance (UKEF); see IHS Markit Climate and Sustainability Research and Analysis *Export credit agencies warned about their continued support for fossil fuel projects,* 11 May 2021.

10 IHS Markit Climate and Sustainability Research and Analysis *Asian Development Bank pledges no coal, oil, nuclear plant investments,* 13 May 2021.

11 The Danish ban also includes its autonomous territory of Greenland; its government announced on 15 July 2021 a de facto moratorium on the issuance of new petroleum exploration licenses.

12 Spain, for example, is a major importer of pipeline gas and LNG.

13 Joint Research Centre, European Commission, Technical Assessment of Nuclear Energy with Respect to the "Do No Significant Harm" Criteria of Regulation (EU) 2020/852 ("Taxonomy Regulation"), 2021, pp. 17–18.

14 https://www.foronuclear.org/en/updates/news/european-taxonomy-commission-announces-plans-to-include-nuclear-energy/

15 See IHS Markit Net-Zero Business Daily *EU body proposes TEN-Erule fund hydrogen in Europe's grids,* 22 June 2021.

And even for hydrogen, the future of so-called blue hydrogen (derived from natural gas via steam reforming with emissions captured by CCUS) in the EU appears to be uncertain. There is currently debate in the lead-up to updating the EU Renewable Energy Directive (RED II) over whether blue hydrogen should be broadly certified as a renewable form of energy, or only applied to certain hard-to-abate sectors such as transportation and heavy industry.[16]

Yet in the developing world, opposition appears to be crystallizing against the insistence upon the fast-tracking of only "perfect" climate solutions vis-à-vis "good" alternatives that can be implemented more quickly at lower cost and wider scale as bridges to a net-zero future. Coal-to-gas switching in electric power and industry is estimated to have cut over 600 MMt of CO_2 emissions worldwide over the last decade, more than the annual emissions of all but the seven largest global economies.[17] At the Columbia Global Energy Summit (New York) on 18 May 2021, Nigeria's Vice President Oluyemi Osinbajo lambasted international financing restrictions on gas-fired electric power generation projects that hamper the efforts by developing countries to curtail GHG emissions and reduce oil consumption.[18] Further, some of the benefits that gas provides, including in the power sector, are difficult to replicate cost effectively with renewable sources of energy at utility scale, especially in countries with very weak electricity networks. Supporting gas-fired generation and adoption of natural gas as a vehicle fuel is critical to weaning the country off reliance on much dirtier fuels and incentivizing the reduction of methane flaring and leakage, by providing an expanded market for commercial gas.

Not surprisingly, gas remains important in the energy transition strategies across a range of countries, such as Angola, Malaysia, and Columbia.[19] In China, although an average of 90–100 GW of new renewable electricity generating capacity will be added every year in 2021–25, natural gas capacity also is expected to grow at a rate of 10 GW annually, replacing coal-fired generation in pollution-prone eastern regions and oil products as a fuel for medium- and heavy-duty vehicles.[20] The Russian Federation also envisages maintaining the already large role played by gas and nuclear power in its energy mix as part of its strategy to fulfill its Paris Climate Agreement commitment of reducing emissions by 25–30% of 1990 levels by 2030.[21]

Thus, a "one-size-fits-all" strategy appears ill-advised and unrealistic as an approach to carbon mitigation in a world in which countries have decidedly different levels of development, natural resource endowments, and energy consumption patterns. Reducing low-carbon emissions quickly (the "good") can provide valuable room to maneuver on the road toward adoption of truly zero-emissions technologies (the "perfect") later. Consequently, natural gas (and nuclear power) will undoubtedly retain a meaningful share in the global energy mix under a moderate decarbonization path, buying time for decisions regarding how to effectively deploy resources supporting renewable energy as well as new energy technologies not currently at a commercial stage of development.

16 See IHS Markit Climate and Sustainability Research *Iberdrola, Enel slam plan to add blue hydrogen to EU Renewable Energy Directive,* 13 April 2021. Part of the reluctance is the dependence of blue hydrogen on the success of the CCUS roll-out at commercial scale (by no means a given and subject to concerns of "lock-in" of fossil fuels) and the methane emissions linked to the upstream gas supply chain. But almost every stage in the blue hydrogen process – from extracting natural gas to transporting it, compressing the hydrogen, and capturing the CO_2 and moving it to storage – entails both hydrocarbon energy consumption and at least low-level GHG emissions or leakage (https://www.rechargenews.com/energy-transition/upstream-emissions-risk-killing-the-concept-of-blue-hydrogen-says-equinor-vice-president/2-1-1040583).

17 International Energy Agency, *The Role of Gas in Today's Energy Transitions.* Paris: IEA, 2019 (https://www.iea.org/reports/the-role-of-gas-in-todays-energy-transitions).

18 Although natural gas is by no means zero-carbon, its GHG emissions coefficient (GHG emitted per thousand metric tons of oil equivalent consumed) is only slightly more than half (55%) that of coal and less than three quarters (73%) of oil products, and – significantly for the case of Nigeria and other developing countries – only about one-third (33%) of other widely used fuels in households such as peat, wood, and animal dung. The carbon footprint of gas could be reduced even further through the use of combined-cycle gas turbine (CCGT) technology in the electric power sector, which: (i) raises overall thermal efficiency compared to conventional gas turbine stations; (ii) reduces CO_2 emissions by 45%; and (iii) opens the way for mixing of low-carbon hydrogen into the fuel mix at gas-fired power plants, lowering emissions even further.

19 See IHS Markit Global Power and Renewables *Angola power and renewables market profile,* June 2021; IHS Markit Global Power and Renewables Insight *Malaysia's new energy transition plan: Lower renewable capacity addition and a phaseout of coal lead to a sizeable increase in gas requirements and affordability concern,* 25 June 2021; IHS Markit Global Gas Insight *Relying on natural gas to decarbonize: The case of Colombia's energy transition,* 10 May 2021.

20 IHS Markit Regional Integrated *China Power Market Briefing: Ten-year high demand growth and weak hydropower put pressure on power supply,* May 2021; IHS Markit Regional Integrated Strategic Report *China's carbon neutral pledge: Setting the stage for another four decades of transformation,* 25 September 2020.

21 Russia's electric power sector is already relatively "green." Slightly under one-half of total capacity of its Unified Electricity System is fired by gas, with large hydro accounting for another 20% and nuclear 12% (see IHS Markit Regional Integrated *Russia Watch: Energy sector passes unprecedented stress test from COVID-19 impact,* 19 February 2021, p. 62; Sistemnyy Operator Yedinoy Energeticheskoy Sistemy, "Yedinaya energeticheskaya sistema Rossii: Promezhutochnoye itogi (operativnyye dannye), Dekabr 2020 goda," 2020, p. 12).

2.3.3 Hydrogen poised to become a key element of the global energy transition?

An important "threshold" technology – in the sense of being at the stage where further impetus can have a measurable impact – is hydrogen.[22] Hydrogen is among the more abundant chemical elements in the Earth's atmosphere and oceans, but in nature is only found combined with other elements. In order to be used as a carbon-free energy carrier, it must be separated from these other elements via energy-intensive processes that until recently involved the use of unmitigated fossil fuels (so-called "gray hydrogen").

However, when that separation is powered by electricity generated by renewable sources ("green hydrogen"), or when the carbon emissions resulting from production are captured and stored or utilized ("blue hydrogen"), hydrogen potentially can play a major role in lowering GHG emissions. Hydrogen can be used in segments of heavy industry that cannot be easily electrified (e.g., as a direct energy source in steel and cement production), and also can play a role in electric power sector management, especially energy storage, to support renewable generation capacity.[23] Other potential applications of hydrogen include its use in the transportation sector (e.g., vehicles powered by fuel cells, ammonia-powered ships, aircraft powered by liquid hydrogen), and as a means of transporting renewable energy over long distances, enabling imports of renewable energy from distant sources.[24]

One of the other advantages of hydrogen is that its initial penetration into the economy does not require the construction of a completely new transmission and distribution infrastructure. It can be blended with natural gas for distribution to end-users via existing pipeline systems, although pure hydrogen will require a retrofit of existing pipelines and the build-out of dedicated storage and handling capacity. Further, recent studies in the UK indicate that gas-fired appliances (e.g., stoves) are capable of operating with a 20% hydrogen blend safely, reliably, and without the need for adjustments (while also reducing the risks of carbon monoxide poisoning).[25] In the electricity sector, existing gas-fired capacity can be retrofitted to co-fire with hydrogen, as can coal-fired power plants to co-fire with ammonia, one of the main forms of hydrogen used in industry (see below).

In 2020, IHS Markit estimated that $50 million was invested in green hydrogen electrolysis.[26] IHS Markit projects capital spending increasing to $50 billion *annually* in low-carbon hydrogen production more broadly (green hydrogen, blue hydrogen) by 2030, at which time cumulative investment will have reached approximately $265 billion (see Figure 2.1 Global capital investment for low-carbon hydrogen by region – 2030 Inflections and Green Rules).[27] In the IHS Markit base case, global hydrogen production expands from 84 MMt in 2019 to 115 MMt in 2030, just over 10% of which will be low carbon. A majority of production under this scenario will take place in Europe, which is projected to produce about 70% of global low-carbon hydrogen by 2030, reflecting the broad range of hydrogen strategies unveiled over the last few years (see below). Rolling out electrolyzers at the pace required for them to play a meaningful role in the energy transition, however, is a key challenge for boosting the share of green hydrogen, given limited manufacturing capacity at present.

22 Much of the discussion of hydrogen is derived from IHS Markit Hydrogen and Renewable Gas Forum Strategic Report *Putting strategy into action: Opportunities to shape the future European hydrogen market,* 15 February 2021; and IHS Markit Hydrogen and Renewable Gas Forum *European hydrogen policies – framework, context, and next steps,* 18 February 2021.

23 Somewhat overlooked is the role hydrogen (e.g., as ammonia) could play in longer term, seasonal storage of renewable energy for later use in electricity generation, since it can be compressed in gaseous form and stored in converted gas storage facilities (e.g., depleted oil and gas fields, salt domes) that have several orders of magnitude more capacity than battery storage projects (IEA, *Net Zero*, 2021, p. 177–178). It can also be liquefied and stored in special containment vessels closer to sites of use.

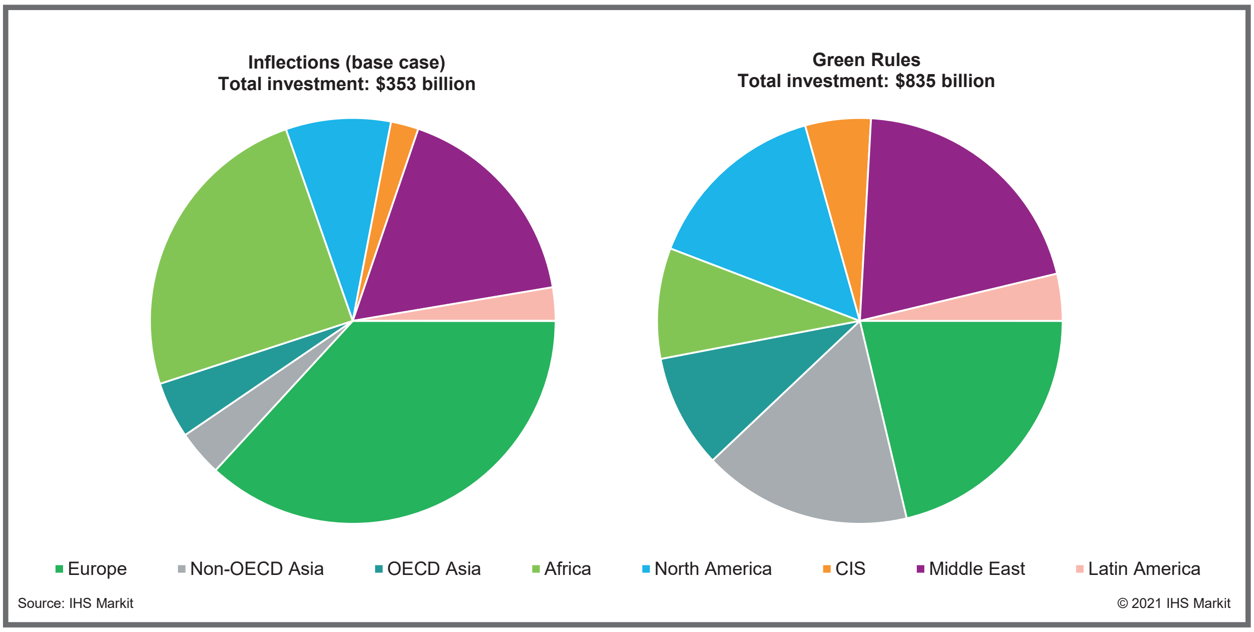
24 In the light-duty vehicle market, for example, hydrogen fuel cells have two major advantages vis-à-vis electric batteries as a power source: longer ranges between recharging and shorter recharging/refueling times.

25 "The role of hydrogen in the energy transition," *OIES–Oxford Energy Forum* no. 127, May 2021, pp. 19–20.

26 Electrolysis utilizes electricity (in this case generated by renewable energy sources) to separate water into hydrogen and oxygen (without any CO_2 byproduct). See IHS Markit Hydrogen and Renewable Gas Forum Strategic Report *Global hydrogen production: Hefty capital investments in low-carbon hydrogen ahead,* 6 April 2021. Presently, it accounts for no more than 5% of the hydrogen produced globally. Other, non-electrolysis methods of producing green hydrogen – using microbes that use light to produce hydrogen, converting biomass into gas or liquids and separating the hydrogen, using solar energy directly (not via electrolysis) to split hydrogen from water molecules – are still being researched and are farther from actual commercial prototypes (see KAZENERGY, *The National Energy Report 2017,* p. 243).

27 Blue hydrogen converts natural gas (methane) and steam into hydrogen and CO_2 through the process of steam methane reforming. If the resulting CO_2 is captured and stored or utilized (i.e., combined with CCUS), the hydrogen is considered low carbon. Newer plants use autothermal reforming, a promising technology that is highly compatible with carbon capture (see IHS Markit Climate and Sustainability Research and Analysis *Swiss asset manager FiveT launches fund to "clean up" hydrogen infrastructure,* 9 April 2021).

Figure 2.1 Global capital investment for low-carbon hydrogen by region – 2030 Inflections and Green Rules



Globally, variations in renewable power availability and suitable sites for CO_2 sequestration mean that the potential demand for low-carbon hydrogen cannot always be met by purely domestic resources within a single country. The mismatch between supply and demand centers is likely to facilitate a global hydrogen trade. Ammonia (NH_3) and liquified hydrogen (LH_2) are currently the two competing options for long-distance transport of hydrogen in international trade. Due to its high energy density, easy containment, and relatively low transportation costs, ammonia offers an economical solution for long-distance transport.[28] However, LH_2 regasification costs at the destination are lower compared to ammonia and IHS Markit estimates that LH_2 could become more economical when transported at scale.[29]

Over 30 countries globally have adopted national hydrogen strategies aiming to integrate the fuel into their energy mix, and a number of countries are now looking at the opportunity for exporting hydrogen (e.g., Australia, Saudi Arabia, Canada, UAE, Russia, Chile, and recently Kazakhstan [see below]), while others (Japan, Germany) are exploring importing. It is becoming clear that if hydrogen becomes an important part of the energy mix, a hydrogen market will emerge as an internationally traded business.

European countries have taken the lead in the global campaign for hydrogen adoption; they have promised support for production, infrastructure, and consumers; and they have outlined their ambitions (if not yet specific programs) for hydrogen over the next 30 years. The potential use of hydrogen spans several sectors – transport, industry, power generation, commercial, and residential.

The EC issued its Hydrogen Strategy in July 2020, and it was endorsed by the EU Council in December 2020. The EU Hydrogen Strategy has prioritized green hydrogen by setting ambitious electrolyzer capacity targets of 6 GW and 40 GW in 2024 and 2030, respectively.[30] However, much remains to be done to create a policy and regulatory framework to put this strategy into action. The EU is consulting on a range of legislative proposals in 2021 that

28 Ammonia has a number of benefits over liquid hydrogen when used as an energy carrier. It is a lot denser – one cubic meter of ammonia carries 70% more hydrogen than the same volume of LH_2. NH_3 is gaseous at ambient conditions but is easily liquefied and therefore has low energy cost for liquefaction. It is also easily transported in regular tankers not requiring bulky and costly insulation to maintain extremely low temperatures (-253°C). Commercial infrastructure for shipping and trading ammonia exists already, unlike for LH_2.

29 Similar to LNG, hydrogen has to go through a liquefaction process to be transported as LH_2 on trucks and ships and re-gasified at the destination. When using ammonia as an energy carrier, nitrogen (N_2) is added to hydrogen to create ammonia via a Haber-Bosch synthesis process, which will either be used directly or cracked back to hydrogen (IHS Markit Hydrogen and Renewable Gas Forum *Hydrogen trade: Ammonia the most economical option for long- distance transport,* 25 May 2021).

30 Using renewables to produce electricity is a more efficient application than using renewable-sourced electricity to produce hydrogen. Whereas one kWh of renewable electricity would replace one kWh of fossil-based electricity, it would replace only the equivalent of 0.8 kWh of natural gas if used to produce hydrogen, because of conversion losses. Therefore "green hydrogen" is more effective from a comprehensive energy efficiency standpoint when produced in a system in which renewable energy has already been (or will be) fully integrated into the electric power sector ("The role of hydrogen," p. 27).

will determine the future of hydrogen in Europe. Four major challenges at present include:

- development at a scale sufficient to ensure competitive production costs; the future of hydrogen will ultimately depend on whether the cost can be lowered to the \$1–2/kg of H produced range, rather than the \$3–4/kg range for green hydrogen at present
- resolving the appropriate mix of "green" versus "blue" hydrogen
- integration with the broader energy transition strategy[31]
- identification of economic sectors most suitable for initial penetration of hydrogen.

A significant hydrogen pipeline infrastructure project is envisaged as the European Hydrogen Backbone (EHB), a network consisting of 23 transmission system operators from 21 countries. According to an April 2021 report that details the EHB vision, by 2030 it could consist of an initial 11,600 km pipeline network, connecting emerging hydrogen clusters. The hydrogen infrastructure could then grow to become a pan-European network, with a length of 39,700 km by 2040, consisting of 69% repurposed natural gas pipelines and 31% new build, at a total capital cost estimated at €43–81 billion.[32] The government of the Netherlands and state-owned gas infrastructure operator Gasunie already have plans to link an incipient Dutch national hydrogen system to the EHB by 2027 via a connection with Germany. The system would be based on 1,200 km of converted/retrofitted 36-inch-diameter natural gas pipeline for 85% of its length. The purpose is to deliver 100% hydrogen instead of a hydrogen–natural gas blend.[33]

2.3.3.1 Potential hydrogen development in Kazakhstan

Several Kazakh companies are contemplating small-scale hydrogen demonstration projects to assess its applicability in Kazakhstan. But a site in western Kazakhstan already has been identified as the location of an ambitious proposed build-out of hydrogen capacity. In July 2021, Svevind Energy GmbH – a privately owned group of renewable energy companies based in Germany and Sweden – announced that it had forged an MOU with the local government of Mangystau Oblast and Kazakh Invest National Company JSC to construct 30 GW of wind and solar power capacity in Mangystau Oblast. Of this, 20 GW would be used to power electrolyzers to produce around 3 MMt/y green hydrogen for use in the steel and aluminum industries, transport, or export. The ambitious plan will take some time to materialize – the FEED and financing phases are expected to take three to five years, and construction would take another five years.

Even if the project is developed at the scale and on the timetable originally envisaged, it is not yet clear whether hydrogen will emerge as an economically competitive fuel source in Kazakhstan.[34] Hydrogen is still not economically viable even in Europe (where gas and power prices are much higher), and in Kazakhstan the penetration of a different, much cheaper gaseous fuel (natural gas) continues to struggle for market share vis-à-vis coal in industry and the electric power sector. Additional obstacles to hydrogen adoption in Kazakhstan include:

- the relatively small size of the domestic market, which impedes economies of scale in production, unless surplus production can be exported
- the long distances exports must travel to reach foreign markets overland, and difficult access to maritime transport, making such exports potentially very costly
- the need for ample quantities of water in this semi-arid area to support electrolysis for green hydrogen production[35]
- energy conversion losses when renewable electricity is used to produce hydrogen as opposed to being used directly as electric power.

2.3.4 International emissions trading and the European Union's Carbon Border Adjustment Mechanism (CBAM)

One element of the 2015 Paris Climate Agreement that is now being worked out in the run-up to the COP26 meetings in November 2021 involves rules governing how international carbon market mechanisms function under Article 6. Article 6 sets out a framework for international cooperation that enables countries to meet their climate commitments through the transfer of "mitigation outcomes" – i.e., to collaborate in efforts to achieve their INDCs. In theory at least, a country that has overachieved its own emissions reduction target could sell, for instance, part of this surplus (emissions credits) to another country that has fallen short in achieving its INDC. Similarly, a country importing goods from another that has a less

31 On the same day it published its Hydrogen Strategy, the EC also published its Energy System Integration Strategy. This complements the Hydrogen Strategy as it sees a role for hydrogen in helping manage the intermittency of renewable energy sources.

32 "The role of hydrogen," pp. 32–33.

33 See IHS Markit Net-Zero Business Daily *The Netherlands to retrofit natural gas network for pure hydrogen,* 23 July 2021.

34 The massive scale of the project is evident when it is compared with the projected growth of overall global electrolyzer capacity estimated by IHS Markit out to 2030 of 150 GW.

35 Conservatively assuming that 9 kg of water is needed to produce 1 kg of green hydrogen, the proposed 3 MMt/y project would require approximately 27 MMt/y of water annually. Water management is already an acute issue in Kazakhstan, and Central Asia more broadly. Therefore, realization of this project in a sustainable fashion is contingent on the identification of a stable water supply that would not jeopardize water availability to other industrial and agricultural entities and households.

rigorous regime of emissions reductions would be entitled to compensation for "importing" these excess emissions, either by charging an "import carbon tax" or through some other approach.[36]

The EU's CBAM is the first such instrument that takes into account the carbon emissions embedded into products traded internationally (in this case of imports from outside EU borders). It was presented in its initial form on 14 July 2021 by the EC, with staged implementation slated to begin on 1 January 2023 and entry in full force on 1 January 2026. Its primary goals are: (a) to prevent EU "carbon leakage" – i.e., relocation of low-carbon European production volumes to countries with less strict carbon reduction regimes, and (b) to create "a level playing field" for EU industries by increasing their competitiveness in the EU market (i.e., to offset the higher costs of European producers incurred by adherence to more stringent environmental standards).[37]

While many of the finer points of the Mechanism remain subject to consideration and change, the July 2021 draft proposal outlines the key measures.

- CBAM will initially apply to the direct GHG emissions involved in the manufacturing of a product. Indirect emissions (e.g., the emissions from the generation of electricity used in production or other inputs) will not be taken into account during the initial CBAM rollout.
- It will be integrated with the EU emissions trading system (ETS); i.e., the rules governing emissions trading within the EU ETS will be extended to products imported from beyond the EU's borders. As a general concept this means:
    - Exporters to the EU will receive a free allowance of "CBAM certificates" (GHG emissions credits, each equivalent to 1 ton of CO_2e of GHG emissions) valid for one year.
    - Exporters of goods with above-allowance emissions for a product will be required to purchase additional certificates to compensate.[38]
    - Exporters will be able to receive credits/compensation for carbon payments made in their home countries (in the form of a carbon tax or ETS payments).
- CBAM is mandatory for all EU states. For all goods covered, no imports will be allowed from exporters not registered with the CBAM Authority (the mechanism's executive body). Unless exporters are content to accept "default values" as measures of their emissions (typically the carbon intensity of the highest-emitting 10% of companies in each sector in the EU ETS), they will be required to keep detailed records of emissions and to submit these to support claims for reimbursement during the annual accounting procedure.
- Countries whose emissions trading systems are integrated with or otherwise linked to the EU ETS are exempt from CBAM; these include Iceland, Norway, Lichtenstein, Switzerland, and small offshore territories of the EU. Further bilateral agreements can be introduced in due course to account for, and deduct, carbon costs in the emissions systems of Europe's major trading partners. Presumably this could be the case for the United Kingdom, whose carbon market is a mirror of the EU ETS, with similar prices.
- The first phase of CBAM will be restricted to a limited number of products: electricity, cement, fertilizers, aluminum, and selected iron and steel products.

Implementation of CBAM will be a complex and challenging task. No trans-border carbon adjustment mechanism has yet been deployed anywhere in the world. In the run-up to COP26, its validity will be scrutinized by EU members, climate activists, government officials, and representatives of the international business community. There is also a possibility of legal challenges by major exporting nations at the World Trade Organization (WTO).[39]

Prior to the draft announcement (when the extension of CBAM to a wider range of products could not be ruled out), major oil and gas exporters to Europe, including Russia and Kazakhstan, were quite concerned about the implications of CBAM for their positions in the EU market.[40] However, *crude oil, natural gas, coal, and refined products are not covered* in the draft proposal. Nonetheless, these products could be included at a later date if the production of these commodities eventually

36 IHS Markit Energy and Climate Scenarios Insight, *Carbon trading rules under debate: The importance to trading credits and the offset markets under Article 6 of the Paris Agreement,* 23 March 2021.

37 For background on the debates leading up to the formulation of CBAM, see IHS Markit Refining and Marketing Insight *European Union gets ready to fight over the Carbon Border Adjustment Mechanism,* 16 March 2021; IHS Markit Regional Integrated Insight *Europe's herculean task: Devising a Carbon Border Adjustment Mechanism,* 9 April 2021; IHS Markit Regional Integrated, *Carbon Border Adjustment Mechanism: Powerful policy tool clouded by uncertainty,* 4 May 2021.

38 In practical terms, this will be in the form of a surcharge (duty) added to the price of the imported good at the EU border. To reduce complexity, the surcharge will initially be a "default" value, to be adjusted via an annual accounting procedure (the "handing in" of certificates to the CBAM Authority by importers).

39 The massive scale of the project is evident when it is compared with the projected growth of overall global electrolyzer capacity estimated by IHS Markit out to 2030 of 150 GW.

40 Russian analysts' projections of the economic costs (lost revenues, additional expenditures) associated with the extension of CBAM to diverse groupings of Russia's exported products to the EU ranged from $2 billion to $6 billion annually (Vedomosti, 27 May 2021; https://www.rbc.ru/business/26/05/2021/60ae103d9a7947cb55c1277f?from=from_ main_10; https://ria.ru/20210421/effekt-1729276555.html?utm_ source=yxnews&utm_medium=desktop).

were to fall within the scope of the EU ETS.[41] Refined products and (non-fertilizer) chemicals are said to be on a "watch list" for later inclusion in CBAM.

The immediate effects on Kazakhstan will be quite modest. IHS Markit's review of exports of goods in categories that will be encompassed in the initial stages of CBAM, based on Kazakhstan foreign trade statistics in recent years (2018 and 2019), revealed that only $193 million of goods exported to Europe (all European countries, not only EU members) were affected (see Table 2.1 Kazakhstan's exports to Europe of CBAM-related goods, 2017-20 (thousand US dollars)). This is less than 1% of the total value of Kazakhstan's exports to the European Union ($24.8 billion in 2019).

Further, perhaps anticipating the disruptive and contentious nature of CBAM, the EC's formal draft proposal released on 14 July calls for a milder roll-out than earlier (leaked) versions. It specifies a progressive but slow phasing-in of the CBAM, featuring an initial transition or reporting-only phase (2023–25), with actual payments not required until 2026 at the earliest, followed by a very gradual ramp-up in payments to 2036 when free allocation of emissions quotas in the EU ETS concludes.[42] The price of CBAM certificates will be set weekly, amounting to the weekly average of all closing carbon prices at EU ETS auctions.

In any event, the ultimate shape of both Article 6 and CBAM are still not finalized, and the outcome of any subsequent trade-based litigation is still far in the future. But the robust introduction of such measures, even in preliminary forms, underpins the growing trend of transnational policy efforts to mitigate GHG emissions. For Kazakhstan, which relies heavily on trade of raw materials and especially energy, this is an extremely important development that should be considered when shaping its domestic ETS and future policies.

Table 2.1 Kazakhstan's exports to Europe of CBAM-related goods, 2017-20 (thousand US dollars)

HS code	EU product	2017	2018	2019	2020
2523	Portland cement	-	-	10	-
3102	Nitrogenous fertilizer	1,888	295	311	-
7208-7228	Iron and steel products	76	8	0	-
7601	Aluminum	230,710	192,185	192,932	146,189
Total CBAM-related		232,674	192,489	192,932	146,189
Total exports (to all countries)		49,503,300	61,11,200	58,065,600	46,949,700

Source: Kazakhstan foreign trade statistics

41 The ETS scope will widen to include shipping, and new, separate markets will be created to regulate emissions from buildings and road transport, although these changes are unlikely before 2023.

42 IHS Markit Regional Integrated, *EU Commission's Carbon Border Adjustment Mechanism proposal – soft start to win global approval,* July 2021.

2.4 Company Responses to the Energy Transition

The sweeping regulatory and market design modifications described in the previous section, coupled with growing public and judicial pressure, set the stage for companies and individuals to mobilize. But the response of the business sector – including energy, information-technology (IT), and other companies; financial institutions; and even individual citizens – to the energy transition is complex and multifaceted. For energy producers, many now expect that they will reach maximum oil and gas output earlier and at lower levels than forecasted prior to the pandemic and have pursued portfolio diversification, mergers and acquisitions (M&A) activity, divestments, and new ventures to address the energy transition.[43] Among energy consumers, many companies across a broad range of sectors are increasing their focus on procuring low-carbon electricity or natural gas (e.g., "green" LNG) and increasing their energy efficiency to reduce their carbon footprints. Because of the importance of major oil and gas companies not just as producers but as consumers of energy, this section first examines the myriad responses of these companies (including select case studies), before discussing the strategies followed by major information technology (IT) companies. It then closes by examining a somewhat different, "bottom-up" rationale for private-sector energy transition featuring renewable energy adoption in the developing world. Such approaches and creative solutions may find application in Kazakhstan.

2.4.1 Oil and gas companies

In recent years many major integrated oil and gas producers have responded to the energy transition by:

- paring back capex and operating costs by focusing on core hydrocarbon portfolios (so-called "portfolio concentration and specialization")
- taking steps to diversify their income stream away from operations based solely on hydrocarbons extraction and processing by launching activities in the energy space that can be described as "green" (lower carbon emissions) or sustainable (the resource is not subject to depletion)
- energy-sector efficiency improvements, including digitalization, which are manifest in many areas:
  - reduced labor costs in drilling and equipment monitoring
  - improved geologic data analysis, project design, seismic modeling, and field development
  - more efficient energy trading
  - decentralization of network management
  - increased network reliability (e.g., pipelines)
- emissions reduction efforts in their own operations, particularly upstream, where fuel use and power generation can account for as much as 85% of total emissions in some assets.

The goal of these strategies in aggregate is to slash GHG emissions stemming directly and indirectly from operations, as well as to rein in operating costs. Further, the revenue streams from new, low-carbon investments (although not as lucrative as from oil and gas over the entire 2010–18 period) are less volatile, and thus serve to smooth out some of the volatility of revenues derived from oil and gas production.[44]

2.4.1.1 "First movers"

Among the "first movers" in the drive to decarbonize and diversify upstream oil and gas operations thus far have been the European majors (which view their incremental future revenues as coming not from hydrocarbons production but from new low-carbon operations), providing energy as a service (increasingly in the form of electric power) and less as a commodity per se. Of a total market capitalization of $650 billion for major international oil companies (IOCs) now with zero emissions targets, $550 billion is from those headquartered in Europe.[45] And among the 39 publicly traded IOCs rated by Bloomberg for climate preparedness, five European companies (TotalEnergies, Equinor, BP, Royal Dutch Shell [hereafter Shell], and Galp) account for 78% of total renewable energy assets held by these companies.

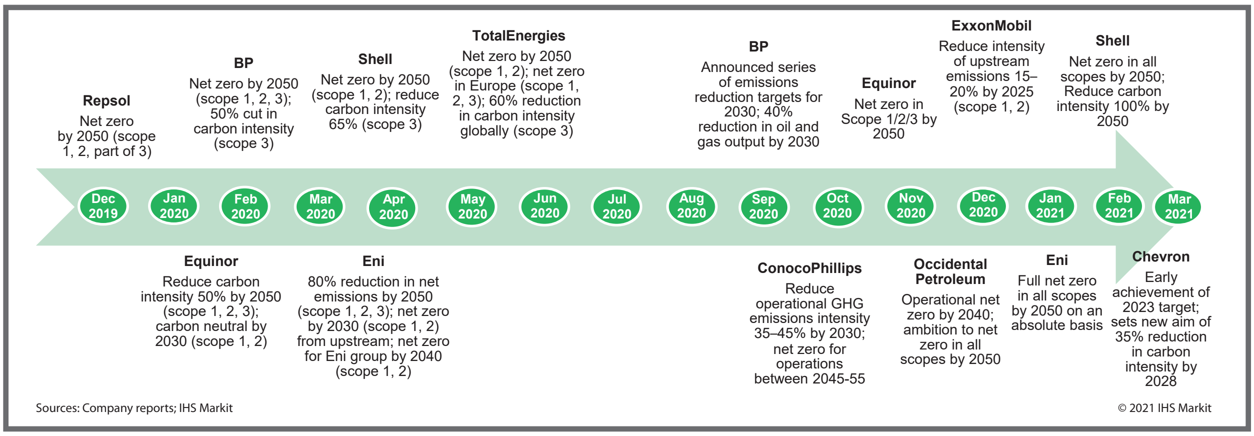
Moreover, in early 2021, about 80% of all IOCs had announced an emissions reduction target – up from 44% in 2019, and 40% had pledged some type of net-zero target (either Scope 1, Scope 2, or Scope 3 – up from 8%) (see Figure 2.2 Announcements of oil company GHG

43 The transition globally is expected to advance first in power generation, and more slowly in such sectors as transportation and industry. In the global power sector, annual renewable power capacity additions of 270–280 GW are expected in 2021 and 2022, when they will account for 90% of total global power capacity increases (see IHS Markit Net-Zero Business Daily *Stabilizing at the new normal for renewable newbuild,* 17 May 2021).

44 See IHS Markit Upstream Competition Insight *Can low-carbon be profitable? Understanding the value proposition of alternative businesses for oil and gas companies,* 3 June 2019; IHS Herold Upstream Topical Insight *Market conditions in 2020 demonstrate the value proposition of renewables, but can these returns be sustained?,* 22 July 2021.

45 IHS Markit Energy View – Climate and Cleantech Insight *As ESG investment trillions eye billions of dollars in oil industry equity, IOC strategy is aligning with net-zero commitments,* 16 March 2021.

Figure 2.2 Announcements of oil company GHG emissions reduction and net-zero commitments



emissions reduction and net-zero commitments).[46] Yet despite these proliferating announcements, little progress has been made in terms of harmonizing and standardizing decarbonization metrics. There also appears to be much more clarity in green targets upstream than in downstream (refining, petrochemical) operations, although Shell is something of an exception, setting downstream emissions reduction targets for its refining and chemicals operations.

In order to reach their announced emissions targets, most of these firms are counting on a combination of further reduction in renewable energy costs, the adoption of universal carbon pricing, and technological innovation. Over the short-term, revenues from conventional oil and gas operations are likely to be reinvested in new "green" ventures.

2.4.1.2 More traditional company approaches

Not all energy companies have rapidly embraced the energy transition, particularly those that are holders of "advantaged" barrels or volumes that can be produced at a comparatively low cost (or low carbon footprint). For such companies, a shift away from oil or gas by their traditional competitors "could actually open up more opportunities; this result could mean an ongoing ability to compete for what may become a shrinking pie, at least in the case of world oil demand, over the next two decades."[47] Put another way, the move away from hydrocarbons is occurring more rapidly on the part of investors and IOC energy transition "first movers" than by global consumers, perhaps opening at least a near-term window for increased production by other companies. One company pursuing this strategy is the Abu Dhabi National Oil Company (ADNOC) in the United Arab Emirates (UAE). ADNOC is aggressively investing in upstream development ($120 billion over five years) and plans to boost production capacity from 3.8 MMb/d (190 MMt/y) to 5 MMb/d (250 MMt/y) by 2030. ADNOC's ambitious program of capacity expansion has put it at odds with the OPEC+ group's plan to gradually relax production cuts post-pandemic, which led to a temporary stalemate in early July 2021 when the UAE failed to support the group's proposed periodic adjustment of production levels. The disagreement was quickly resolved, however, when OPEC+ granted the UAE a higher production baseline (the maximum volume OPEC recognizes it is capable of producing) of 3.65 MMb/d (from 3.2 MMb/d at present) starting in April 2022.

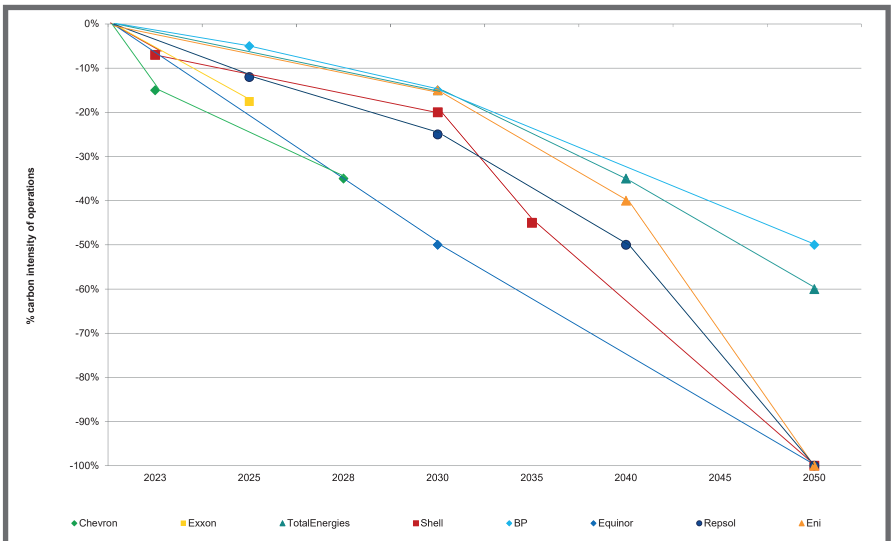
Still, even these companies are employing a variety of "green" strategies, such as reducing the carbon intensity of their operations, increasing renewable energy and associated gas utilization, and allocating some of their research budgets to CCUS, nuclear technologies, and biofuels (e.g., ExxonMobil, Imperial Oil, and Chevron).[48] These companies' environmental pledges thus far have tended to focus on reducing *emissions intensity* in operations (e.g., GHG emissions reduction per barrel produced) rather than achieving a net zero target (see Figure 2.3 Announced IOC carbon intensity targets through 2050).

46 IHS Markit Oil and Gas Insight *Global emissions: 2020 a watershed year for IOC decarbonization targets,* 11 March 2021.

47 IHS Markit, Russian and Caspian Energy *Big questions for Eurasian energy in 2021,* 5 February 2021.

48 In the area of carbon storage (the "S" in CCUS), IOCs have a distinct early-mover advantage given their capital, physical equipment, drilling and field engineering expertise, and in some cases, rights to the depleted oil and gas fields themselves. The latter, along with saline geological formations, are expected to serve as the primary early reservoirs for carbon storage. The current pipeline of CCUS projects is estimated to use less than 1% of the available supply of depleted oil and gas fields (see IHS Markit Climate and Cleantech *Carbon capture and storage: Investors weigh hub model for scale to cut costs,* 13 July 2021).

Figure 2.3 Announced IOC carbon intensity targets through 2050



Notes: Emissions scopes not all comparable. Base year varies. Furthermore, there are inconsistencies relative to which products/emissions these targets include. For example, the goal for Exxon pertains to its upstream operations, whereas those of BP and TotalEnergies refer to the energy products the firms sell to customers.

Source: IHS Markit, company reports

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2.4.1.3 A tale of two companies: Different strategies engender a similar complaint from stakeholders: "you are not doing enough"

Pressure on companies to address GHG emissions has been building from shareholders in recent years, including private-sector financial institutions that have investments in oil and gas companies. The Net Zero Asset Managers Initiative, which counts BlackRock and Vanguard among its 128 signatories, is an international effort to (eventually) limit investments to projects and companies aiming for net-zero carbon footprints. The group, which has $43 trillion in assets under management (AUM), has set targets for percentages of its members' assets that are aligned with zero-carbon goals. So too has the larger Glasgow Financial Alliance for Net Zero (GFANZ), launched in April 2021 in collaboration with the UN, with which the Net Zero Asset Managers Initiative is associated. Encompassing a global array of over 160 large banks, investment management companies, insurance companies, and pension funds, it has AUM of over $70 trillion.

An illustration of the diverse pressures exerted on oil and gas companies to respond to the energy transition is provided by recent events involving two companies. One, Shell, is a standard bearer for the European IOCs approach. The other, ExxonMobil, has conformed to a more traditional strategy. Yet each was brought to task on the same day in May 2021 for their respective responses to the energy transition.[49] In the case of Shell, the decision rendered against it is from a court in the Netherlands, whereas for ExxonMobil it was from activist shareholders at its annual general meeting.

Shell: On 26 May 2021, the First District Court in The Hague, in Shell's home country of the Netherlands, ruled that Shell had not done enough to mitigate the environmental impacts of its operations and is required to reduce its CO_2 emissions by a net 45% by 2030 from 2019 levels.[50] While the court specified that the Shell group's emissions (Scope 1, 2, and 3) should contract by a net 45%, it only imposed an "obligation of result" to Scope 1 emissions, noting the company should expend "significant best-efforts obligation" to curtail Scope 2 and 3 emissions. The Court's assessment was based on the Dutch Civil Code's unwritten standard of care, and asserted that "human rights offer protection against the impacts of dangerous climate change and that companies must respect human rights."[51]

49 Also, on 26 May 2021, in addition to the actions against Shell and ExxonMobil, a resolution backed by the activist group "Follow This" demanding that Chevron reduce its Scope 3 carbon emissions was supported by 61% of shareholders at the company's annual meeting.

50 The claimants in the case were seven NGOs, including Milieudefensie (the Dutch branch of Friends of the Earth), and over 17,000 individuals. Ultimately, only six of the NGOs were admissible, and the court ruled the individual co-claimants lacked standing. The ruling, although intended to be applicable to the company's global operations, is only legally enforceable for its operations in the Netherlands.

51 The Hague District Court, Milieudefensie et al. v Royal Dutch Shell plc, NL:RBDHA:2021:5339 (26 May 2021, https://uitspraken.rechtspraak.nl/inziendocument?id=ECLI:NL:RBDHA:2021:5339).

The ruling is the first of its kind, as it (1) affirms the relationship between climate change and human rights in Dutch jurisprudence, (2) implicates an individual company for a global environmental problem, and (3) binds Shell to curtail CO_2 emissions to a court-determined threshold. Shell is appealing the decision, arguing that a judgment limited to a single company is insufficient to address the threat posed by climate change. In any event, as part of its Powering Progress strategy unveiled in April 2021, Shell is undertaking additional emissions reduction measures, including increasing low-carbon spending to $3 billion annually (to about 15% of total capex) and further concentrating its downstream portfolio to only five large "energy and chemicals parks" by 2030.[52]

ExxonMobil: At ExxonMobil's 2021 annual shareholders meeting on 26 May, investment firms BlackRock and Vanguard, along with the pension funds CalPERS, CalSTERS, and New York State Common Retirement Fund, voted in favor of installing three of four nominees supported by the activist group Engine No. 1 to the company's board of directors. The goal was to help steer the company further toward cleaner energy and away from oil and gas. Shareholders also voted to require the company to report on how its climate lobbying aligns with the goals of the Paris Climate Agreement and to disclose the risk climate change poses to company operations.[53]

2.4.1.4 National oil companies (NOCs)

The need to respond to stakeholder concerns is not always as immediate for NOCs, which, by virtue of their charters and ownership structures, often prioritize state interests over the demands of private investors or activists. Equally important is the obligation for many NOCs to husband the national hydrocarbon resource in the interests of their citizens. If the future is uncertain for hydrocarbons, this may even increase the incentive to accelerate production (monetize the resource as soon as possible) so as to not strand assets "in the ground."

For Kazakhstan's NOC, KazMunayGas (KMG), such concerns might incentivize maximizing output from already producing fields that are capable of generating additional output quickly (i.e., the "Big 3" projects) rather than pursuing new greenfield developments. And in Kazakhstan, as in many other major hydrocarbon-producing countries, the government is targeting carbon neutrality while simultaneously relying on oil and gas revenues to sustain government budgets. This confluence of competing interests and goals highlights the challenges of realizing the energy transition, and the importance of sustained foreign investment in host countries' oil and gas upstream in the short to medium term.

52 *Oil & Gas Journal,* 20 July 2021.
53 IHS Markit Climate and Sustainability Research and Analysis *Oil majors forced to reckon with climate impacts,* 26 May 2021.

In addition to their role as stewards of the national hydrocarbon wealth, other obligations complicate NOC operations beyond a mere "profit and loss" calculation. A major challenge for NOCs globally in 2020 and 2021 is government pressure to increase expenditures on unrelated "national projects" and social programs, given the increased need for such spending during and in the immediate aftermath of the pandemic. NOCs (to varying degrees in individual countries) are counted on to: generate revenue for the national budget; provide employment for citizens; provide social policy support; and serve as an agent of foreign policy.[54]

Despite their common obligations, NOC responses to the energy transition have been mixed. Some, such as Norway's Equinor (formerly Statoil), have embraced the transition, whereas others (e.g., Petrobras, Pemex) still appear to be formulating their next steps. Rosneft provides an interesting example of a "national" company that seeks to both embrace green energy initiatives and grow oil and gas production.[55] On one side of the ledger, Rosneft launched the Carbon Management Plan to 2035 with BP, in which it echoes BP's pledge to become net zero carbon by 2050.[56] At the same time, Rosneft increased its development drilling in 2020 as the company launched the full-scale development of the Erginsky cluster, the Severo-Danilovskoye field, and the widely publicized Vostok Oil project (600,000 b/d).[57] Furthermore, in late January 2021 Rosneft announced that it had reached an agreement with the government to secure mineral extraction tax (MRET) deductions for its large Priobskoye field in exchange for expanded investment commitments over the 2021–30 period. Rosneft said that the deal would incentivize additional drilling, help maintain production, and generate an additional 70 MMt of oil output over the coming decade.[58] This "both ways" approach – monetizing the asset while seeking to reduce the carbon footprint from it – may become the game plan of several NOCs for addressing the transition.

Ultimately, even NOCs will have to deal with the energy transition, as end-consumers will come to demand it. The timeline for action is fast approaching for those NOCs seeking to attract international investment through

54 See IHS Herold Upstream Companies and Transactions *Five key questions for NOCs in 2021,* February 2021.
55 The largest block (40.4%) of Rosneft shares is held by Rosneftegaz JSC (100% owned by the state), whereas sizable although not controlling blocks of shares are held by BP (19.75% through BP Russian Investments Ltd.) and QH Oil Investments LLC (18.46% through a group of Qatari enterprises).
56 Under the plan, Rosneft and BP agreed to jointly work on low-carbon technologies (renewables, CCUS, hydrogen), advanced fuels (blue hydrogen, biodiesel), and emissions trading offsets (e.g., forest plantations). Rosneft's specific pledges include the prevention of 20 MMt CO_2e in GHG emissions, a reduction in upstream emissions intensity by 30%, and elimination of associated petroleum gas flaring.
57 See IHS Markit Strategic Report *Russia Watch 2020.*
58 For details, see IHS Herold Upstream Companies and Transactions *NOC Insights – Rosneft touts carbon management plan as pandemic cuts 2020 financial and operational results,* 18 February 2021.

initial public offerings (IPOs) or in joint ventures. Indeed, institutional investors and IOCs are already incorporating ESG and emissions metrics into their strategic calculations. West African and Southeast Asian NOCs, for example, are now under considerable pressure to restore previous levels of outside hydrocarbon-sector investment after several majors (Shell, TotalEnergies, and Eni) abandoned projects.[59]

2.4.2 Responses of companies outside the energy sector

Given that the energy transition involves a systemic broad-based change, it is worthwhile to analyze what non-energy companies are doing. Companies outside the hydrocarbon sector have responded by focusing on their consumption of electricity (and secondarily on carbon emissions from their consumption of fuels). In the US, the private sector drove nearly half of all renewable energy contracting activity in 2020. The segment's share of all contracted renewable power generation capacity increased significantly in 2020, accounting for 46% of total capacity (up from 31% in 2019).[60] And among American companies, information technology (IT) companies maintained the lead in 2020 among sectors in terms of total contracted capacity, accounting for roughly 50% of the private-sector total. Partly because of the nature of their products, IT companies have been able to commit to, and achieve, more ambitious carbon reduction goals than many others.

2.4.2.1 Google and Amazon

Google has a long track record in clean energy. According to the company's website, in 2007 it became the first major company in the world to become carbon neutral.[61] In 2017, Google became the first company of its size to cover 100% of its electricity needs with renewable energy.[62] Google's vision is to attain continuous (24/7) carbon-free energy by 2030.[63]

Google has reduced its carbon footprint by entering large-scale purchase agreements with renewable energy suppliers. In September 2019, the company announced that it had concluded the largest corporate purchase of renewable energy in history (at that time): a 1,600 MW package of dedicated capacity that included 18 energy deals worldwide. When all contracted projects come online, Google's carbon-free energy portfolio will produce more electricity (with more than 5 GW capacity) than entire countries such as Lithuania or Uruguay consume each year. The purchases not only bolster demand from existing wind and solar projects but are long-term commitments that result in the development of new projects.

Google has supplemented these efforts with direct investments in renewable power and AI (to increase heating/cooling efficiency in its buildings). Further, Google is attempting to modify its power demand patterns to better match renewable production schedules through various process changes, including optimizing server load based on the carbon intensity of electricity in the grid.

Amazon is an online retail company that also has a substantial presence in information technology (cloud computing). Nonetheless, it consumes considerable energy to heat/cool its offices and warehouses and power its delivery fleets. In December 2020, it announced it had contracted 26 new utility-scale wind and solar energy projects totaling 3.4 GW of renewable electricity generation capacity in Australia, France, Germany, Italy, South Africa, Sweden, the UK, and the United States.[64] Subsequently, in June 2021, it announced commitments of 1.5 GW of additional renewable capacity (14 additional wind and solar projects), bringing the company's renewable generating assets to a total of 220 renewable energy projects worldwide (with 10 GW generation capacity) that can produce enough electricity to power all of its corporate offices, fulfillment centers, Whole Foods Market stores, and Amazon Web Services (AWS).[65] Amazon has thus now surpassed Google to

59 See IHS Markit E&P Terms and Above-Ground Risk *Turbulent transitions: Evolving above-ground risks in West Africa's maturing hydrocarbon producers,* 19 March 2021; IHS Markit E&P Terms and Above-Ground Risk *Asian NOCs and the energy transition,* April 2021. Short of halting activities in environments no longer viewed as attractive, another IOC upstream portfolio concentration strategy is the merger – e.g., the proposed cost-cutting joint ventures by Eni and BP in Angola and Algeria that will merge the companies' exploration and development assets in those countries, in order to derive operating efficiencies and synergies (see IHS Markit Oil and Gas Insight Africa Upstream: *Eni and BP's joint ventures offer a new approach for energy transition,* 14 July 2021). Such mergers may become more common as the energy transition gains momentum, particularly in mature basins.

60 IHS Markit Climate and Cleantech US Renewables Insight: *Corporate deals nearly match that of all other US renewable contracting in 2020,* 5 February 2021.

61 https://cloud.google.com/blog/topics/inside-google-cloud/announcing-round-the-clock-clean-energy-for-cloud

62 "Our Biggest Renewable Energy Purchase Ever" (blog.google).

63 https://www.greentechmedia.com/articles/read/google-pledges-24-7-carbon-free-energy-by-2030

64 https://www.businesswire.com/news/home/20201210005304/en/Amazon-Becomes-World%E2%80%99s-Largest-Corporate-Purchaser-of-Renewable-Energy-Advancing-its-Climate-Pledge-Commitment-to-be-Net-zero-Carbon-by-2040; https://www.nbcnews.com/business/business-news/amazon-ramps-purchases-renewable-energy-amid-worker-battle-climate-change-n1264469; https://www.businesswire.com/news/home/20210623005093/en/Amazon-Becomes-Largest-Corporate-Buyer-of-Renewable-Energy-in-the-U.S.

65 AWS also provides efficient data storage services to energy companies. BP and AWS have a partnership whereby BP provides renewable energy to Amazon in Europe, and AWS accordingly supplies BP with data and cloud services for digital operations that are more efficient than traditional data storage centers. See AWS Speaking Session Reinventing the Energy Industry, CERAWeek 2021, AWS, 2 March 2021, https://pages.awscloud.com/GLOBAL-event-OE-energy-ceraweek-replay-2021-reg.html?Languages=French.

become the world's largest corporate buyer of renewable energy. The company's goal is to power all company operations with renewable energy by 2025, to purchase 100,000 electric vehicles for its delivery fleet, to invest $2 billion in carbon-reduction technologies, and to reach net carbon neutrality in its operations by 2040.

The contribution of efficiency improvements in data center electricity consumption to global GHG emissions reductions is certainly laudable, but should not be overestimated, however. A pair of recent academic studies estimated that the aggregate power demand of the world's large cloud-based data storage centers (including Google, Amazon, Alibaba, Apple, Facebook, and Microsoft) accounts for only about 1% of the world's annual electricity consumption.[66]

Google and Amazon's renewable power purchases and strategies are illustrations of how non-energy, IT companies and retailers are accelerating the energy transition. Such examples are directly relevant to companies in Kazakhstan, which is home to the Astana International Financial Center (AIFC) and the regional fintech player Kaspi.kz.[67]

2.4.2.2 Corporations banding together to achieve scale for renewables contracting

Other companies, lacking the size and financial resources of Google and Amazon, have banded together to capture scale economies in negotiating power purchases from large renewable power producers. The most prominent recent example is the Samson Solar Energy Center, which is slated to be the largest corporate procurement–backed solar development in the United States.[68] Invenergy is developing the 1.3 GW center in northeast Texas, having secured offtake contracts with AT&T, Home Depot, Honda, McDonalds, and three municipalities in Texas (as well as the corporate giant Google). In addition to these major players, smaller companies also are involved in the project by signing virtual power purchase agreements (VPPAs) with the larger buyers.

2.4.2.3 Distributed renewable power in areas lacking grid access

Another type of response is the private sector adoption of renewable electricity in the Middle East and in Africa, the continent least connected to an electric power grid.69 Here, non-energy companies are motivated to respond to the energy transition as much by a desire for reliable electricity access at predictable cost as by concerns over climate change. Although competitive state tenders involving energy companies have continued to drive the build-out of *large-scale renewable projects* (solar and wind) in Africa and the Middle East, in many of these countries the growth of *small-scale distributed renewable generation,* especially in rural areas, is less a function of state policy support than an organic response to demand (e.g., self-consumption). Even in urban areas, small-scale distributed power initiatives are proliferating, featuring rooftop solar PV.70 Much of this small-scale renewable adoption by the private sector is "bottom up" in the sense that it reflects grassroots private initiatives rather than state policy. In Kazakhstan, the TOO Rodina agricultural enterprise has operated a 750 MW wind turbine on site since 2013, and other enterprises could pursue similar arrangements.

Solar leases are the most common contract type for smaller companies in the Africa–Middle East region, as they enable renewable procurement while keeping projects off the company balance sheet and avoiding high up-front capital costs.[71] While such arrangements would have limited applicability to the majority of companies operating in the Kazakh economy, where grid access and reliability are significantly higher, they may nonetheless be worthy of consideration for small business start-ups in remote areas of the country.

66 "The internet is eating up less electricity than expected," *New York Times,* 26 June 2021.

67 Kaspi.kz, for example, is the leading fintech company in Kazakhstan, with 9.1 million active users at the end of 2020, roughly half of the country's population. Total payment value (TPV), which measures the total value of payment transactions conducted on Kaspi.kz's various platforms, was 23,882 billion tenge (about $57.8 billion), which amounted to 34% of Kazakhstan's GDP (70,649 billion tenge or $170.9 billion) in 2020.

68 https://samsonsolarenergycenter.com/#overview

69 World Bank Group, *Electricity Access in Sub-Saharan Africa,* 2019, https://openknowledge.worldbank.org/bit s t rea m/ha ndle/10986/31333/9781464813610. pdf?sequence=6&isAllowed=y. The development of local distributed (off-grid) renewable power is an important component of many developing-world energy systems, including countries as diverse as India, mainland China, Indonesia, Bolivia, and Mongolia.

70 IHS Markit Power and Renewables *Renewable policy trends in Asia, Africa and the Middle East, and Latin America,* 24 October 2018.

71 In a solar lease, a company leases a PV system for an agreed-upon period, paying a fee plus interest for equipment rental. In lease financing, the lessee does not take ownership of the asset, unlike in a power purchase agreement or lease purchase agreement, despite having full control of the asset during the lease period. Such arrangements help address a major impediment to the build-out of renewable electricity – the shortage of capital.

KAZAKHSTAN AND THE ENERGY TRANSITION

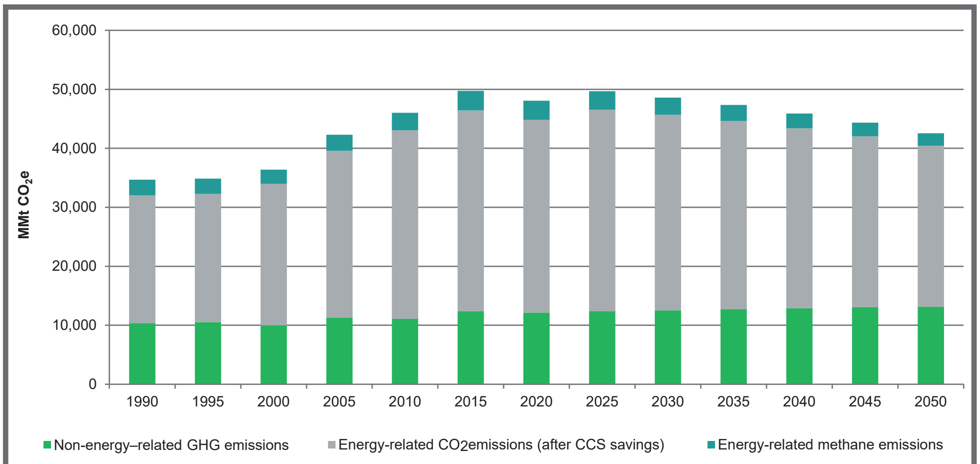
2.5 Kazakhstan's Updated Intended Nationally Determined Contribution (INDC) to the Paris Climate Agreement

Global GHG emissions have climbed steadily over the past three decades, before being disrupted temporarily by the COVID-19 pandemic in 2020 (see Figure 2.4 Global GHG emissions: historical to 2020 and outlook to 2050). Energy use has been the key contributor, accounting for 75% of the total in the current millennium. Electric power generation is the largest source of energy-related CO_2 emissions, accounting for about one-third of the total, followed by transportation and industry, each contributing roughly one-fifth of emissions (see Figure 2.5 Global energy- related CO_2 emissions by sector: historical to 2020 and outlook to 2050).

A key question is whether the current trajectory (and existing level of responses and national policies) will be sufficient to cut emissions and achieve the Paris Climate goals by 2030, and subsequently achieve net-zero by mid-century. At present, it appears that without much greater changes (e.g., driving a faster uptake of renewables, more accelerated retirement of coal generation, or faster penetration of electric vehicles) it will be enormously challenging for the world as a whole to meet the 2030 targets and then reach net-zero by mid-century, although some individual countries may manage to achieve their respective goals.[72] Indeed, as noted in Chapter 1, the new IHS Markit base-case scenario Inflections assesses that global emissions are going to continue to rise, and instead of holding the global mean temperature increase within 1.5°C or 2°C as called for in the Paris Agreement, the eventual outcome is more likely to be a 2.6°C increase relative to pre-industrial levels.[73]

Kazakhstan's GHG emissions reportedly totaled 364.5 MMt CO_2e in 2019, down 6% from 388 MMt CO_2e in 2018.[74] Emissions of carbon dioxide (CO_2) represent the bulk of overall GHG emissions, averaging around 300

Figure 2.4 Global GHG emissions: historical to 2020 and outlook to 2050



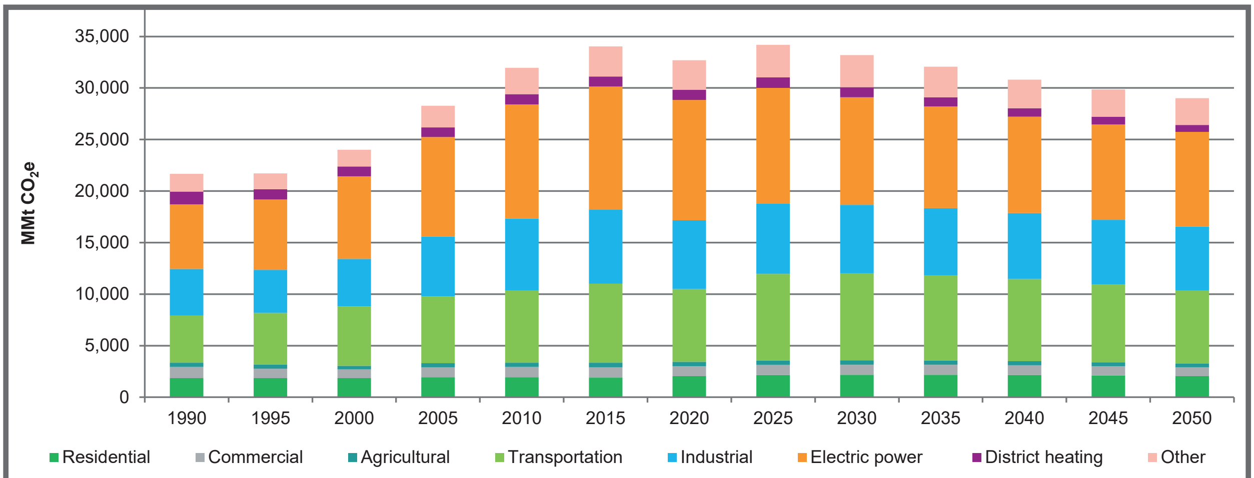
Notes: (1) Total GHG emissions are measured in units of CO_2e.
(2) Non-energy–related GHG emissions are measured in units of CO_2e and represent all GHG emissions from agriculture, waste, industrial processes, and LULUCF.
(3) Total energy-related GHG emissions represents CO_2 and methane emissions related to energy production and use.
(4) CO_2 emissions after CCS savings reflect CO_2 emissions from combustion-related activities after CCS has been applied to capture emissions.
(5) Methane emissions represent fugitive and vented emissions resulting from the production of hydrocarbon resources.
Source: Historical data from the International Energy Agency; projections from IHS Markit

72 "Climate change widespread, rapid and intensifying – IPCC," IPCC, 9 August 2021, https://www.ipcc.ch/2021/08/09/ar6-wg1-20210809-pr/.

73 *IHS Markit Inflections (2021-50): The IHSM Markit base-case view of the energy future,* 14 July 2021.

74 This includes the contribution to national emissions from land use, land-use change, and forestry (LULUCF), which is usually an offset against emissions coming from other activities. Data for 2020 GHG emissions were not yet available at the time of the writing of this report.

Figure 2.5 Global energy-related CO_2 emissions by sector: historical to 2020 and outlook to 2050



Notes: (1) Total unabated CO_2 emissions excluding the use of CCS.
(2) Includes refineries, coke ovens, and hydrogen production.
(3) Includes own use, distribution losses, etc.

Source: Historical data from the International Energy Agency; projections from IHS Markit

MMt/y, while emissions of methane (CH_4), nitrous oxide (N_2O), hydrofluorocarbons (HFCs), perfluorocarbons (PFCs), and sulfur hexafluoride (SF_6) collectively amount to around 19% of Kazakhstan's annual GHG emissions (see Figure 2.6 Kazakhstan's GHG emissions by type). The sectoral structure of GHG emissions has not changed substantially in recent years, with the energy sector constituting the largest source of GHG emissions (about 80%) in 2019, followed by agriculture (10%) and then industry (6%) (see Figure 2.7 Kazakhstan's historical GHG emissions by sector) (see text box: Emissions accounting in Kazakhstan). This aggregate total ranks Kazakhstan in 26th place among countries of the world and 16th place among so-called Annex I countries.[75] Kazakhstan's GHG emissions are of the same general order of magnitude as countries such as Spain, France, the UAE, and Malaysia.

When measured relative to economic activity, Kazakhstan's energy-sector GHG emissions per million dollars of GDP amounted to 1.16 tons in 2020. Comparing this figure with total GHG emissions produced by United Nations Framework Convention on Climate Change (UNFCCC, or "the Convention") Annex I parties, Kazakhstan's GHG emissions intensity relative to GDP was the second highest, behind only Ukraine, reflecting Kazakhstan's heavily industrialized and energy-intensive economy (see Figure 2.8 Emissions intensity of GDP for Annex I countries in 2019).

As a party to the Paris Climate Agreement, Kazakhstan's INDC includes an unconditional target of reducing GHG emissions economy-wide by 15% below 1990 levels by 2030, and a conditional target of 25% below 1990 levels by 2030. Kazakhstan's GHG emissions (including LULUCF) amounted to 386.3 MMt CO_2e in 1990, which means that Kazakhstan's GHG emissions should not exceed 328.4 MMt CO_2e by 2030 to be compliant with its unconditional INDC obligation.[76] As total GHG emissions amounted to 364.5 MMt CO_2e in 2019, achieving the unconditional INDC target requires Kazakhstan to reduce emissions by approximately 36.2 MMt CO_2e, or 3.6 MMt CO_2e annually, between 2020 and 2030. Achieving the 25% conditional reduction in GHG emissions (viewed as dependent upon receiving external funds), to 289.7 MMt

75 The United Nations Framework Convention on Climate Change contains three categories of member countries, or "parties." The groups are generally determined by the country's emissions-reduction commitments and level of economic development. Annex I parties include OECD members as of 1992, as well as economies in transition (so-called EIT parties) in Europe and Central Asia. Annex II parties to the UNFCCC include OECD members as of 1992, excluding EIT parties. Non-Annex I parties are primarily developing countries. The key difference between the various groupings is that Annex II parties are required to provide financial assistance to developing countries. Kazakhstan's status is unique, as it is an Annex I party to the Kyoto Protocol, but a non-Annex I Party to the Convention, thereby eliminating financial obligations. This was decided at COP7 in 2001, following a formal request by Kazakhstan. See "Proposal to amend Annexes I and II to remove the name of Turkey and to amend Annex I to add the name of Kazakhstan," UNFCC, https://unfccc.int/process-and-meetings/the-convention/history-of-the-convention/proposal-to-amend-annexes-i-and-ii-to-remove-the-name-of-turkey-and-to-amend-annex-i-to-add-the-name.

76 Official GHG emissions data prepared by Zhasyl Damu and submitted to the UNFCC have changed over the years as methodologies have evolved. In Kazakhstan's official 2020 National Inventory Report (NIR) to the UNFCC, total GHG emissions in 1990 amounted to 401.9 MMt CO_2e, excluding LULUCF and 386.3 MMt CO_2e including LULUCF. In Kazakhstan's 2021 NIR, these numbers were revised downwards to 385 MMt CO_2e and 373.4 MMt CO_2e, respectively. IHS Markit is working with the assumption that 1990 GHG emissions amounted to 386.3 MMt CO_2e, including LULUCF.

CO_2e in 2030, necessitates emissions reductions on the order of 75 MMt CO_2e by 2030 (relative to 2019), or by approximately 7.5 MMt CO_2e annually.

Mirroring commitments made by other world leaders, President Tokayev announced in December 2020 Kazakhstan's intention to achieve carbon-neutrality

Figure 2.6 Kazakhstan's GHG emissions by type

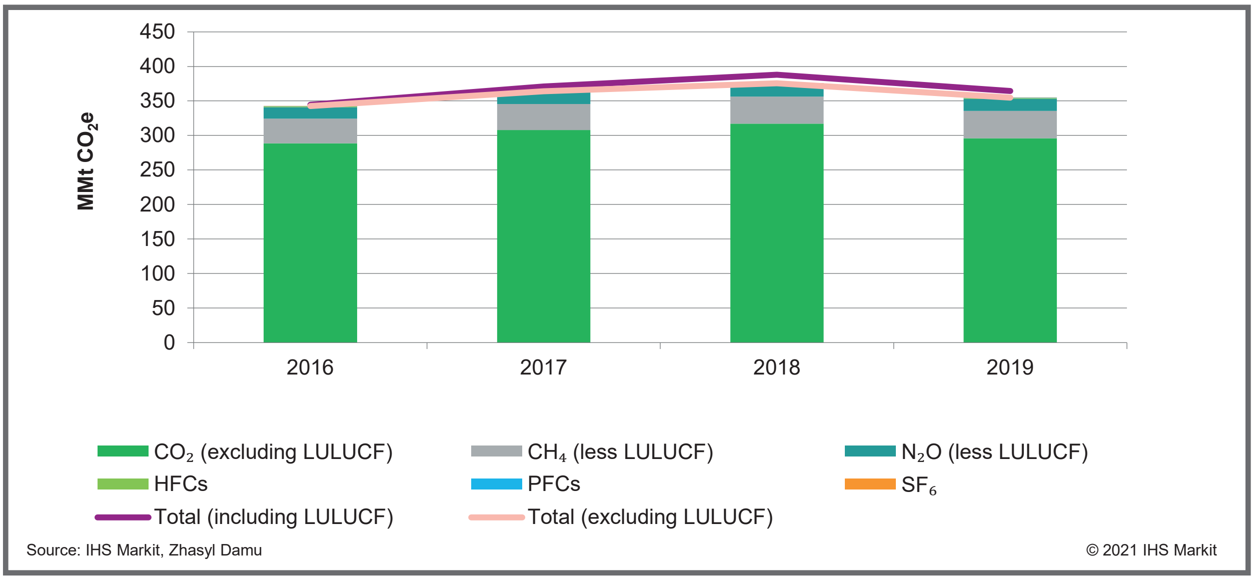


Figure 2.7 Kazakhstan's historical GHG emissions by sector

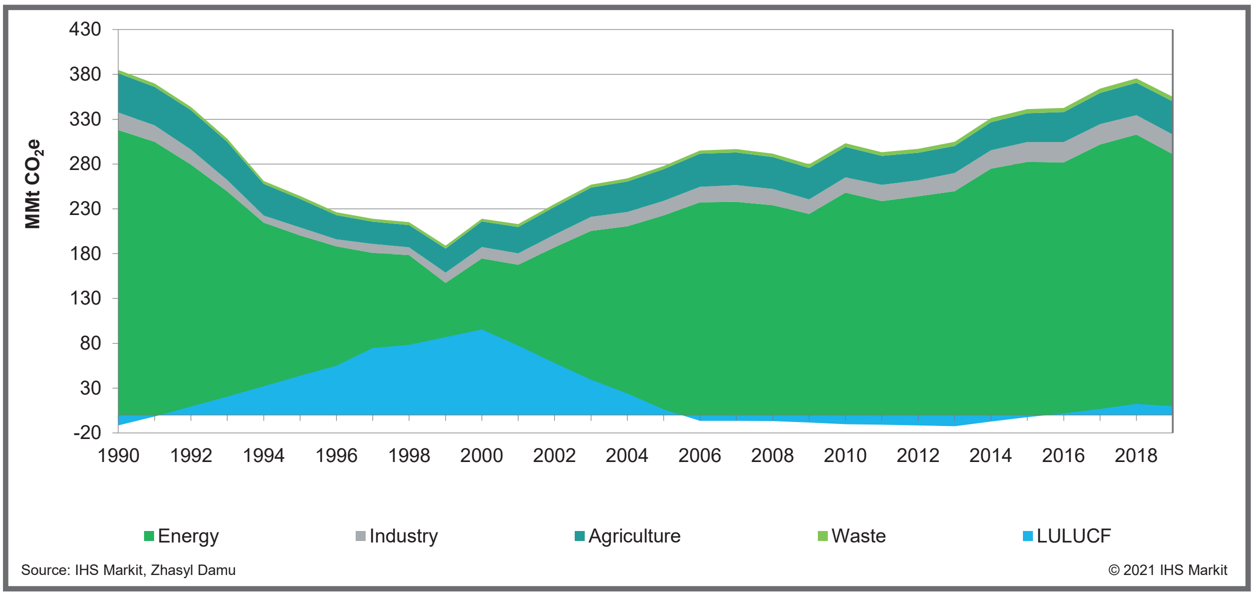
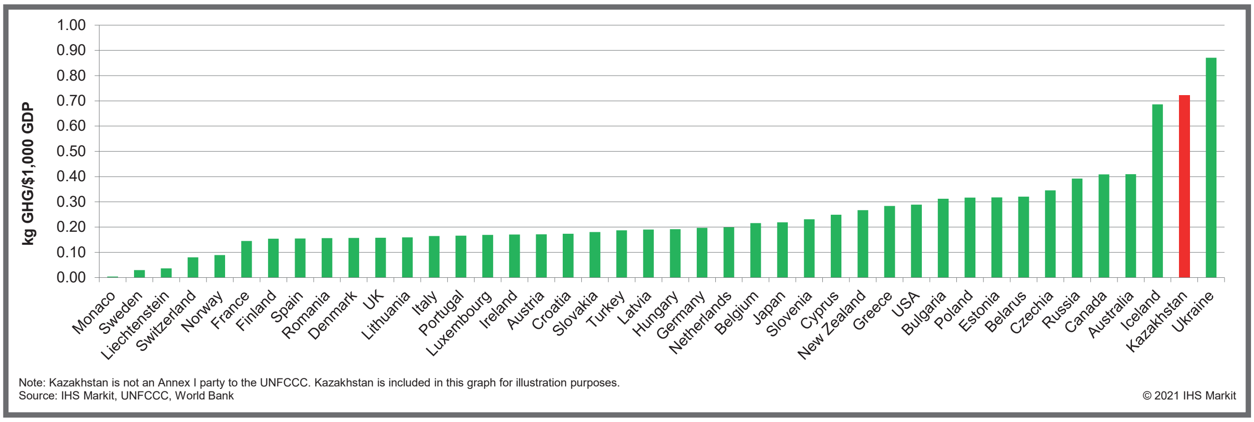


Figure 2.8 Emissions intensity of GDP for Annex-I countries in 2019



Emissions accounting in Kazakhstan

Despite recent efforts to standardize GHG, atmospheric, and particle matter (PM) emissions accounting methodologies globally, definitional, regulatory, and administrative approaches still vary widely across jurisdictions. Kazakhstan effectively has two systems for emissions accounting: one system that adheres to the UNFCCC standards for GHG emissions, and a localized system used by the Ministry of Ecology, Geology, and National Resources (MEGNR) to monitor entity-level atmospheric emissions in Kazakhstan.

The first system, used by the Zhasyl Damu entity in preparation of Kazakhstan's National Inventory Report (NIR) to the UNFCCC, generally adheres to the methodology spelled out in the UNFCCC 2006 Handbook.[77] GHG emissions, as defined by the UNFCCC (and Kazakhstan's new EcoCode), include carbon dioxide (CO_2), methane (CH_4), nitrogenous oxide (N_2O), hydrofluorocarbons (HFC), perfluorocarbons (PFC), and sulfur hexafluoride (SF_6).

The second system relates to how emissions are reported by companies in the domestic economy and regulated by the MEGNR (and Zhasyl Damu).[78] Zhasyl Damu administers Kazakhstan's carbon trading system (ETS) and regulates emissions of CO_2. Participating companies report their CO_2 emissions only, as emissions of other GHGs are not included in the ETS. Emissions of non-CO_2 GHGs, and PM pollutants – a group that includes carbon monoxide (CO), nitrogen oxides (NOx), nonmethane volatile organic compounds, sulfur dioxide (SO_2), and sulfur oxides (SOx), among others – are considered "atmospheric emissions." Companies annually secure allowances for acceptable levels of atmospheric emissions (*vybrosy zagryaznyayushikh veshestv v atmospheru)* and emissions of harmful substances *(vrednye veshestva or vrednye vybrosy v atmospheru)*, and pay quarterly fees for their emissions. Emissions exceeding permitted volumes are subject to different rates (see below).

77 See https://unfccc.int/resource/docs/publications/handbook.pdf

78 JSC Zhasyl Damu was formed by the government of Kazakhstan on the basis of the Kazakh Research Institute of Ecology and Climate under the Ministry of Environmental Protection, pursuant to Government Decree No. 978 of 26 July 2012; it was registered as a legal entity in March 2013.

by 2060.[79] In September 2021, the first version of the Strategy for Low-Carbon Development, aimed at achieving this goal was released for public commentary. The Strategy, based on a comprehensive study carried out by German research body DIW Econ, is designed to detail changes needed to generate a targeted net-zero emissions result. The Strategy features a roadmap detailing the extensive steps required to achieve this goal; the steps involve a radical transformation of the entire economy, including daily practices and behaviors at the household level, and more particularly a transformation of the production and consumption of energy sources, as well as massive changes in crop cultivation, livestock herding, and overall land-use practices. In contrast to the Strategy, and cognizant of its commendable goals, the IHS Markit base-case outlook presents an independent view of how Kazakhstan's economy, society, and energy sector will likely develop, taking into account prevailing economic structures, institutional capacities, pricing policies, production trends, and supply chain capacities.

To date, Kazakhstan has achieved concrete progress in several dimensions intended to help reach its stated Paris goal, particularly in renewable power:

- **Kazakhstan's power generation from renewable sources (wind, solar, small hydro, and biomass) reached the target of 3% of the total in 2020.**[80] Renewable generation increased by 35% in 2020 compared to 2019, amounting to 3.2 billion kWh. In 2020, solar generation reached about 1.25 billion kWh, wind about 1 billion kWh, small hydro 812 million kWh, and biomass 6.6 million kWh.
- **Between 2016 and 2020, renewable installations operating under a purchase agreement with the Financial Settlement Center of Renewable Energy swelled from 190 MW to 1,570 MW.** Installed wind generating capacity grew five-fold, from 105 MW in 2016 to 544 MW in 2020, while installed solar capacity ballooned from 55 MW in 2016 to 948 MW in 2020. Investment in renewable projects multiplied from $2 million in 2014 to $379 million in 2019, amounting to 18% of total investments in the power sector.
- **Between 2018 and 2020, the Financial Settlement Center of Renewable Energy accepted 65 renewable projects, with a total of 1,219 MW of generation capacity, through renewable auctions.** Some of these projects are already commissioned; IHS Markit anticipates an additional 1,966 MW of renewable capacity to come online between 2021 and 2025.
- **In 2018, Kazakhstan relaunched the first carbon-trading system in Eurasia, the Emissions Trading System (ETS).** While initial ETS operation following the relaunch did not lead to a substantial reduction in aggregate GHG emissions, its launch was nonetheless an important first step. Further refinements are needed to increase its effectiveness; the European ETS, for comparison, was launched in 2005 and it continues to be regularly reworked and tweaked.
- **Kazakhstan also made progress in gasification, as end-of-pipe consumption reached 17 Bcm in 2020, up from 13 Bcm in 2016.** Gas-fired generation was up by 10% in 2020 compared to 2016, at 21.6 billion kWh, accounting for about 20% of total generation. By year end-2020, 53.1% of Kazakhstan's population had access to pipeline gas, and the completion of the SaryArka pipeline in 2020 enabled pipeline gas to reach Nur-Sultan and the opportunity to gasify coal-consuming regions in central and northern Kazakhstan. The share of gas in primary energy consumption reached 23.2% in 2020.
- **The 2018 launch of the Astana International Financial Center (AIFC) established a local stock market, the Astana International Exchange (AIX), which has evolved into a platform for local energy-related financial transactions.** In November 2018, as part of its IPO, Kazatomprom listed 15% of its shares on the AIX and the London Stock Exchange (LSE). KMG, 5A Oil LLP, and the Ministry of Finance of the Republic of Kazakhstan have also issued bonds through the AIX.[81]
- **Two successful green bond sales occurred in local stock markets in 2020.** Green bonds globally are becoming increasingly popular, with $312.7 billion in green bonds issued in 2020 alone. Following AIX's adoption of the Green Bond Principles (GBP) and the Climate Bonds Standards (CBS) as guiding frameworks, the first green bond was issued on AIX in August 2020 by JSC Entrepreneurship Development Fund Damu (Damu Fund) in cooperation with the UN Development Programme (UNDP). The 200 million tenge (approximately $477,760) bond, which was fully subscribed to, will support the development of energy efficiency improvements and renewables infrastructure across various municipalities.[82] Kazakhstan's second green bond issuance occurred in November 2020 on the Almaty Stock Exchange (KASE). The Asian Development Bank (ADB), with the assistance of Tengri Capital Partners, sold two green bonds worth 10.09

79 https://www.gov.kz/memleket/entities/ecogeo/press/news/details/128232?lang=ru

80 Kazakhstan's 2013 Concept for the transition to a green economy targeted 3% of total power generation to come from wind and solar installations by 2020. Although generation from these two types of renewables sources amounted to only 2.1% in 2020, small hydro and biomass generation propelled aggregate renewable generation to 3% of the total. Installed renewable capacity for all four types of renewable sources reached 1,570 MW, or 6.6% of total national capacity.

81 Updated information of AIX listings can be found on the AIX website, https://www.aix.kz/listings/listed-companies/.

82 https://s3- eu- cent ra l-1. a ma zonaws .com/w w w-a ix-k z/uploads/2020/08/Offer-Document_DAMU.0823_GreenBonds.pdf

billion tenge ($23.47 million) and 3.87 billion tenge ($9 million) to support renewable project development in Kazakhstan. Mirroring the Damu Fund sale, the ADB's green bonds offering was fully subscribed.

Despite these positive signposts, other dynamics indicate less progress in reducing overall GHG emissions:

- **Coal-related consumption was responsible for about 53% of Kazakhstan's GHG emissions in 2019.** Although coal's share in primary energy consumption declined to 56% in 2020, it was still on par with its contribution in 2010 and 2015. Given coal's outsize contribution to Kazakhstan's GHG emissions, a substantial reduction in coal use is probably critical in realizing Kazakhstan's Paris Climate Agreement objectives.
- **Coal-fired power generation has continued to rise.** In 2020, 74.5 billion kWh was generated with coal, representing 69% of national generation. The 2020 figure was 19% larger than in 2016.
- **While there have been economy-wide energy efficiency improvements, even recently-modernized coal-fired plants compare poorly with older gas-fired generation in this regard.** For example, the gas-fired Shymkent TETs-3, with generating turbines dating from 1981 and 1982, shows a higher level of energy efficiency (and emitted less CO_2) than coal-fired plants with turbines installed over the past decade (see Figure 2.9 Intensity of carbon dioxide emissions for select power plants relative to generation and specific fuel consumption in 2020).[83] Even modernized coal-fired plants still rank among the largest CO_2 emitters in the country. This observation again underpins the imperative to reduce coal consumption in electricity and heat generation if Kazakhstan is to achieve its Paris Climate Agreement obligations.
- **Kazakhstan's net GHG emissions from LULUCF turned positive in 2016 (again).** Traditionally, in Kazakhstan and elsewhere, LULUCF is a net "sink" for GHG emissions, as forests and other land use absorb CO_2 through photosynthesis, thereby providing an offset against emissions from other sectors. But after absorbing more GHG than it emitted (12.5 MMt CO_2e in 2013 declining to 2.3 MMt CO_2e in 2015), since 2016 LULUCF has been emitting (on net) a positive amount of GHG.[84] The resurgence of emissions from LULUCF is concerning. Between 2009 and 2019, emissions from forests and croplands grew by an annual average of 5% and 3%, respectively.

To achieve Kazakhstan's INDC unconditional emissions target of 328.4 MMt CO_2e by 2030, Kazakhstan would need to have total GHG emissions contract by almost 11% relative to 2019. This is certainly possible if (1) gasification expands at an accelerated pace, displacing coal consumption; (2) already-sanctioned and already-programmed renewable projects materialize as planned, (3) energy efficiency improvements across the economy continue apace, and (4) GHG emissions from industry, agriculture, LULUCF, and waste decline substantially (see Figure 2.10 Kazakhstan's GHG emissions by sector and outlook (INDC compliant)). Another factor that would help considerably would be if the construction of the contemplated nuclear plant is brought forward into the 2020s, and displaces coal-fired generation (but seems unlikely to occur).

IHS Markit's base-case outlook for energy-related GHG emissions envisions a decline from about 290 MMt CO_2e in 2020 to about 277 MMt CO_2e in 2030, a drop of about 13 MMt (see Figure 2.11 IHS Markit base-case outlook for GHG emissions from energy use in Kazakhstan); unfortunately, this is only about a third of the needed adjustment. This moderate outlook is underpinned by the assumption of some gas-for-coal displacement in power (e.g., in southern Kazakhstan, especially Almaty), further gasification in other sectors, continued improvement in aggregate energy efficiency, and continued roll-out of renewables as planned. To meet the INDC goal, another 23 MMt of cuts would be needed outside of energy consumption, in industry, agriculture, LULUCF (including cropland use), and waste.[85] This seems fairly ambitious given the 73.4 MMt CO_2e emitted from the four categories in 2019. Of course, what would be also really helpful would be if LULUCF could be shifted back over to become a net carbon sink as it was before through reforestation, afforestation, and other changes in land use. With respect to emissions from waste, best available technologies (BAT) for recycling and waste-gas recovery could also contribute to a reduction in GHGs.

Therefore, it seems most likely that Kazakhstan will come up short in meeting the 2030 INDC target. But this is not a foregone conclusion – it is still a target that can be reasonably achieved, if prudent policies are implemented prodigiously and expediently.

83 ERG's coal-fired Aksukskaya power plant installed 975 MW of new turbines since 2010 (38% of the plant's installed capacity).

84 One issue driving this change may be forest fires. Official data indicate that the number of forest fires grew from 456 in 2011 to 628 in 2019, after being down to 358 in 2018; see "Number of incidents of forest fires," (Число случаев лесных пожаров) published in "Environment" by CIS Statistics, http://www.cisstat.org/1base/frame01.htm.

85 GHG emissions from the agricultural sector are quantified separately from LULUCF emissions. However, LULUCF emissions in Kazakhstan include forest lands, croplands, grasslands, wetland, and settlements. Thus, LULUCF emissions partially reflect emissions from agricultural land use. In fact, the croplands category is the largest emitting subsegment of LULUCF, amounting to 36,700,000 tons CO_2e in 2019.

Figure 2.9 Intensity of carbon dioxide emissions for select power plants relative to generation and specific fuel consumption in 2020

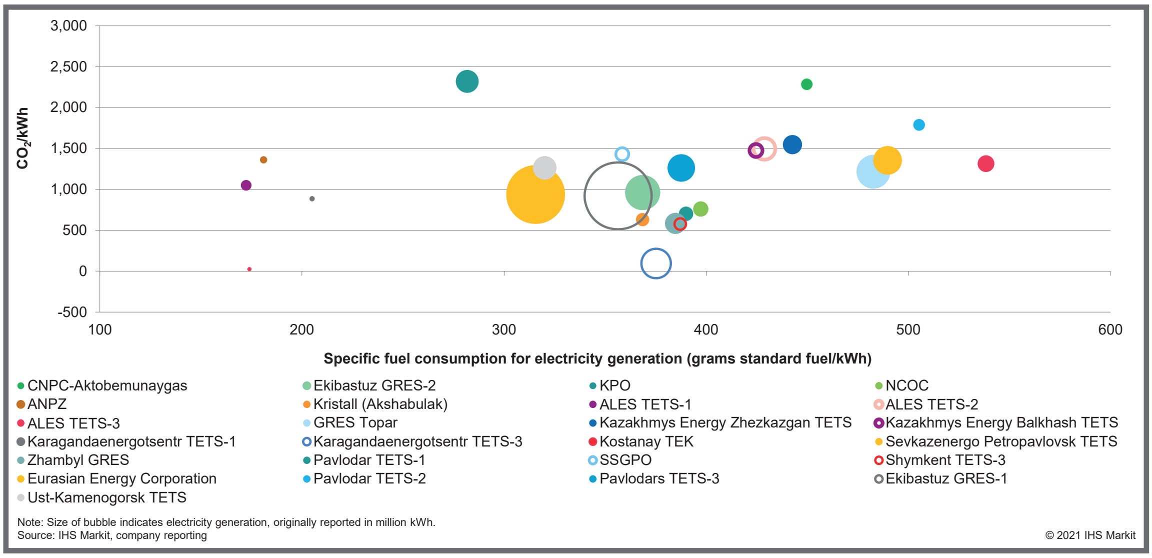
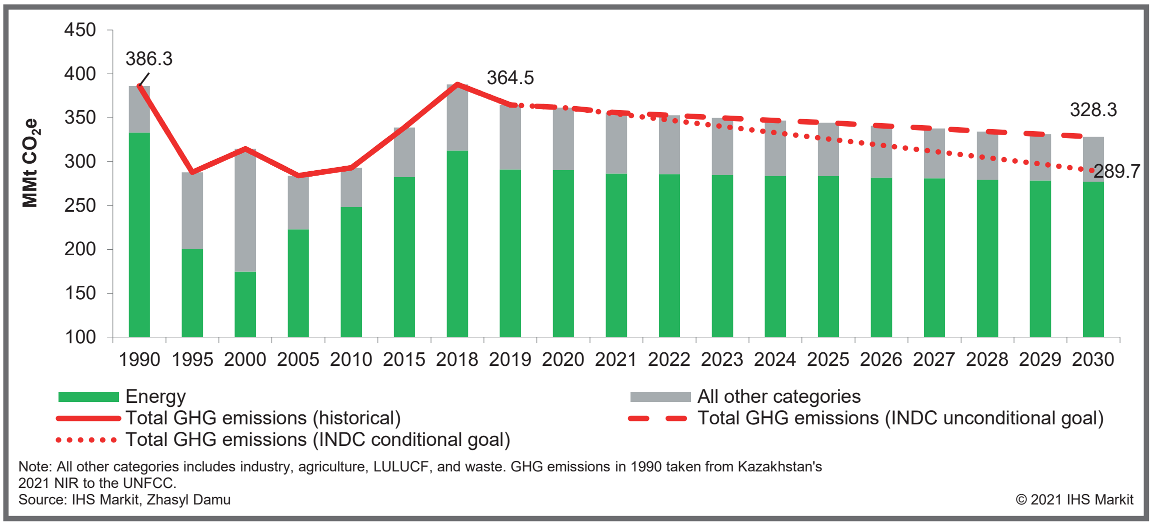


Figure 2.10 Kazakhstan's GHG emissions by sector and outlook (INDC compliant)

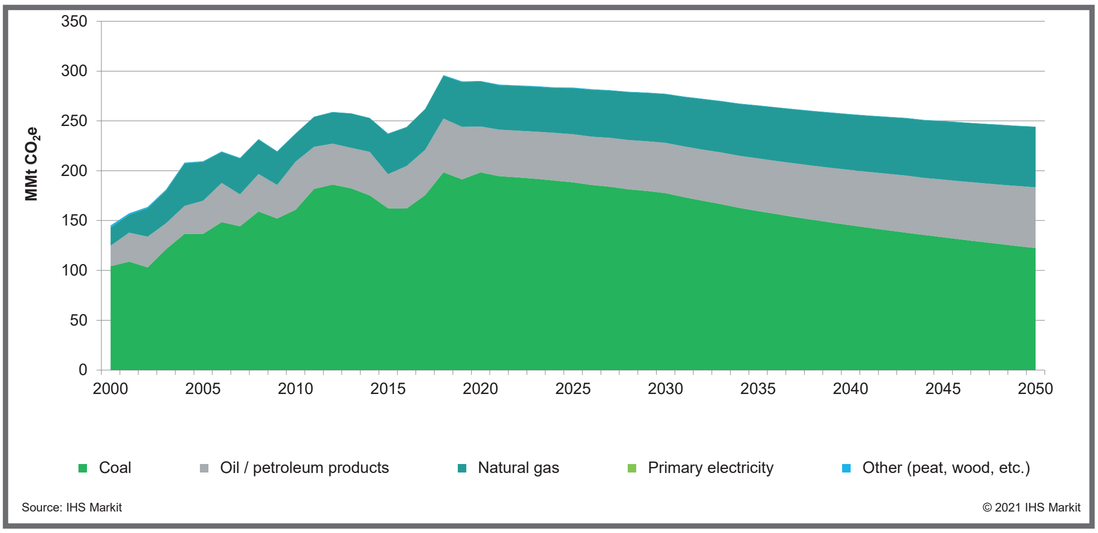


Zhasyl Damu's own base-case ("business as usual", or BAU) outlook envisions total GHG emissions rising to 435 MMt CO_2e by 2030. Reducing emissions to the targeted level of 328.4 MMt CO_2e materializes only in the entity's alternative scenarios where the ETS is robustly used to drive up carbon prices, facilitating a faster buildout in renewables and other decarbonization measures (see Figure 2.12 Kazakhstan's historical and projected GHG emissions by Zhasyl Damu under different scenarios).

Although our focus in this report is mainly upon energy, which is still the outsized contributor to total GHG emissions, another major challenge for Kazakhstan is emissions from the agricultural sector; the latter employs around 13% of Kazakhstan's workforce and accounts for 5.3% of GDP. Emissions from agricultural activities grew by an annual average of 1% between 2009 and 2019, and annual growth was 3% between 2014 and 2019. GHG emissions from agriculture now account for 10% of the national total (including LULUCF). Hopefully, some relatively simple measures such as adjusting crop rotations and implementing a few changes in production and irrigation practices could lead to a sizable reduction in Kazakhstan's agricultural GHG emissions.[86]

86 In June 2021, it was announced that the Government plans to spend 80 billion tenge ($188 million) to plant 2 billion trees across Kazakhstan through 2026. Full implementation of this announced plan would likely be a positive step towards enhancing Kazakhstan's natural carbon sequestration.

Figure 2.11 IHS Markit base-case outlook for GHG emissions from energy use in Kazakhstan



2.6 *Kazakhstan's Ecology Code and the Pathway to Paris Compliance*

The process of revising Kazakhstan's existing Ecology Code (that regulates this sphere of activity in the country) launched several years ago; the previous Code, in place since 2007, had been amended over 100 times as part of this process. Policymakers and investors alike sought to modernize the Code and to establish a cogent framework for sustainable development. Several years of consultations and drafting culminated in the President's signing of the revised Ecology Code ("EcoCode") on 2 January 2021. Its introduction was accompanied by modifications to several other laws, including the "Code of the Republic of Kazakhstan on Administrative Offenses" and the Tax Code, among others. Kazakhstan's revised Ecology Code entered into effect on 1 July 2021.

The EcoCode preserves the previous system and approach to ecological regulation, but introduces several new, key elements.

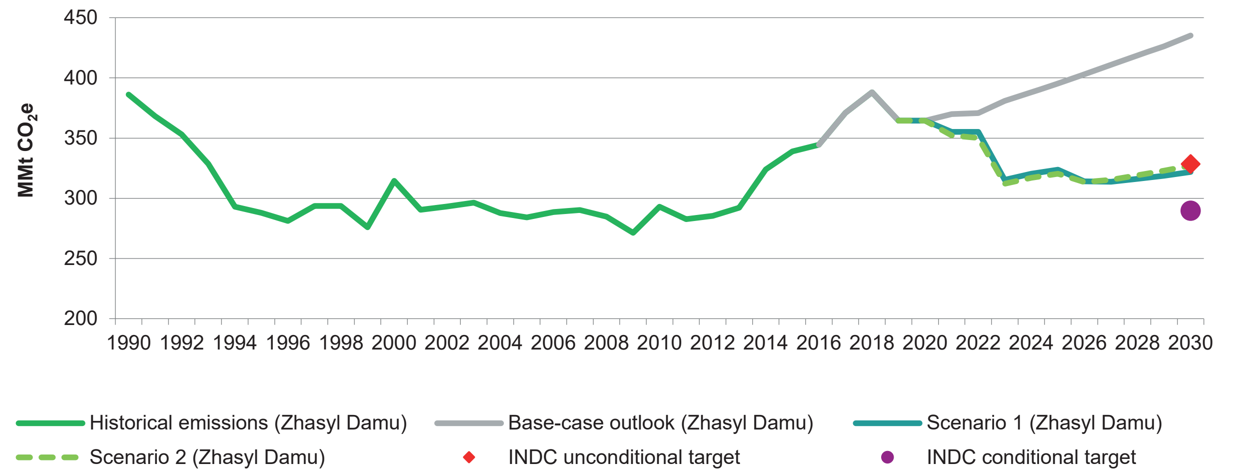
- **The "polluter pays (and remedies)" principle replaces the "pay and pollute" principle.** As defined in Article 5 of the EcoCode, the "polluter pays" principle stipulates that the polluting entity (or person), whose activity results in direct harm to the environment or human life, bears all the remediation and restorative costs and work to prevent future damage.[87] This principle is underpinned by the premise that entities will proactively work to prevent pollution and other environmentally detrimental activities in order to avoid onerous financial penalties.[88]
- **The new EcoCode replaces the term "payments for environmental emissions" *(plata za emissii v okruzhayushchuyu sredu)* with "payments for negative environmental impact" *(plata za negativnoe vozdeistvie na okruzhayushchuyu sredu)*, representing the Code's new preventionist ethos.** However, the general categorization of environmental payments in the Tax Code was only slightly modified, while the administrative mechanism through which payments are levied remains largely the same as under the previous 2007 Code.
- **Revenues collected from environment payments are directed towards activities exclusively devoted to environmental protection measures and infrastructure development, rather than general budgets.** During 2016-18, only between 36% and 53% of all environmental payments supported environmental expenditures, with the remaining receipts essentially cushioning local budgets.
- **The new EcoCode requires large emitting enterprises to install Automatic Emissions Monitoring Systems by 2023.** This will replace the manual collection methods currently in place.
- **In June 2021, the Senate passed an amendment to the Code of Administrative Violations that removes discriminatory penalties related to gas flaring at upstream projects.**[89]

87 https://adilet.zan.kz/rus/docs/K2100000400

88 See Article 136 "Obligations for repairing ecological damage," in the Ecology Code of the Republic of Kazakhstan published on *Adilet.kz,* January 2021, http://adilet.zan.kz/rus/docs/K2100000400.

89 "On amendments and additions to the Code of the Republic of Kazakhstan on Administrative Offenses," 2 July 2021, No. 63-VII ZRK, https://adilet.zan.kz/rus/docs/Z2100000063#z27.

Figure 2.12 Kazakhstan's historical and projected GHG emissions by Zhasyl Damu under different scenarios



Note: Total emissions include LULUCF.
Source: Zhasyl Damu, IHS Markit

Under the provisions of the amendment, *administrative penalties* related to emissions from flaring will be the same as penalties from other stationary sources. However, outsized payment rates for flaring still remain; the changes did not go as far as to levelize payments for emissions from flaring and stationary sources, as payments for the former remain higher than the latter.

- **Critically, the new EcoCode compels implementation of best available techniques (BAT) for Category I enterprises.** It also elucidates the general framework through which BAT will be implemented.[90]

2.6.1 *BAT implementation in Kazakhstan*

The compulsory implementation of best available techniques (BAT) is perhaps the most ambitious component of the new EcoCode, and also the most contentious. Modeled after the EU's BAT system, which was invoked to support the Industrial Emissions Directive (IED), Kazakhstan's BAT push is effectively a means to modernize industry through environmental governance.[91] Article 113 of the EcoCode defines BAT as the "most effective and advanced" applied technologies and techniques in industry that, when utilized appropriately during the design, construction, operation, management, and decommissioning of an industrial asset, prevent or minimize environmental damage.[92]

The idea of BAT is not new in Kazakhstan; it existed in the previous 2007 EcoCode, but earlier it was a voluntary route for improved environmental performance. Entities could either secure a permit for a certain level of emissions (air, solid waste, and water) and pay the required fees that went along with them, or qualify for an integrated environmental permit (through BAT implementation) (see text box: Ecological payments in Kazakhstan). Nearly all entities in the energy sector actually opted for the former, as it eliminated many uncertainties, the possibility of substantial expenditures, and a variety of bureaucratic burdens.

Under the new EcoCode, however, BAT is compulsory for all Category I enterprises, and its rollout will begin with the top 50 emitters within this group. Collectively, these entities are responsible for over 80% of Kazakhstan's atmospheric emissions. They will be required to adhere to the standards established by the so-called "BAT conclusions" in the BAT reference books, which are currently being developed by the International Green Technologies and Investment Projects Center (IGTIC). The forthcoming BAT reference books will effectively be Kazakhstan's version of the EU's Best Available Techniques Reference Documents (BREFs), and follow the same template, including the all-important "BAT conclusions."[93] The BAT conclusions are included in every industry BREF in the EU and feature a list of techniques

90 Kazakh law identifies four main categories of polluters. Category I entities are those whose activities yield a significant harmful impact on the environment, primarily oil and gas companies, mining companies, and power plants. Category II enterprises have a "moderate" impact on the environment, Category III entities wield minor environmental damage (small businesses, car washes, service stations, etc.), while Category IV businesses generate a minimal environmental impact.

91 EU Best Available Techniques reference documents (BREFs), *European Environmental Agency,* 2018, https://www.eea.europa.eu/themes/air/links/guidance-and-tools/eu-best-available-technology-reference.

92 https://adilet.zan.kz/rus/docs/K2100000400, accessed 17 June 2021.

93 For further details, see "BAT reference documents," *European Commission,* 2020, https://eippcb.jrc.ec.europa.eu/reference/, accessed 29 June 2021.

as well as associated emissions levels (BAT-AELs), which are quantitative benchmarks designating the acceptable threshold of certain emissions. The IGTIC has confirmed that the Kazakh BAT reference books will not focus on CO_2 emissions (which are explicitly dealt with by the ETS) but will instead target (1) emissions of atmospheric pollutants, or so-called “markers” (nitrogen oxide, carbon monoxide, sulfur dioxide, and hydrogen sulfide) and (2) the discharge of other identified substances. It appears water use and wastewater handling will not be included in the BAT reference books as a mandatory measure. Energy efficiency will be addressed in a separate BAT reference book.

The general timeline for BAT implementation is as follows:

- By year-end 2021, the IGTIC carries out integrated technological audits on the identified 97 Category I enterprises, including the so-called “top 50” largest emitters. By July 2021, 83 of the 97 entities, including 48 of the top 50 emitters, had been audited.
- The process of auditing companies enables the IGTIC to collect data, understand existing emissions levels, energy sources and usage, and establish benchmarks. This information will subsequently inform the formulation of the BAT reference books and BAT conclusions. The BAT reference books will cover eight sectors, including chemicals production, oil refining, cement production, electricity generation, nonferrous

Ecological payments in Kazakhstan

Entities operating in the energy sector are required to pay environmental or emissions payments *(plata za vybrosy)* on their activities, just as they are elsewhere in the economy. The categories subject to payments include atmospheric emissions (other than for CO_2), waste disposal, and water disposition. While emissions limits are sanctioned annually, companies submit their atmospheric emissions, waste generation, and water disposal to the MEGNR on a quarterly basis, and pay the fees associated with these respective amounts.[94]

While specific payments vary across companies and sectors, they are calculated as a product of a constant *(stavka)*, published in the Tax Code, and the Monthly Calculation Index, or “MRP,” which is set by the Ministry of National Economy annually (see Table 2.2 Selected categories and rates of payments for pollution (negative environmental impacts) in Kazakhstan). In the case of emissions in excess of the approved amount, or emissions from repeat offenders, an additional constant or coefficient is applied when calculating their payments, often increasing the total payment. Moreover, natural monopolies subject to regulation by the Committee for Regulation of Natural Monopolies (KREM) are eligible to apply another coefficient that historically tended to reduce their total payment (this coefficient for Category I natural monopoly enterprises was previously set at 0.3, but will be 2.4 starting 1 January 2022).

94 For additional information on specific emissions and payments, visit the unified ecological internet resource under the MEGNR, http://prtr.ecogosfond.kz/otchety-rvpz/.

Table 2.2 Selected categories and rates of payments for pollution (negative environmental impacts) in Kazakhstan (rate, to be multiplied by MRP)

Emissions of pollutants into the air	2019	2020	2021	2022	2023	2024	2025
From stationary sources							
Sulfur oxides (SOx)	10	10	10	20	20	20	20
Nitrogen oxides (NOx)	10	10	10	20	20	20	20
Dust and ash	5	5	5	10	10	10	10
Lead and its compounds	1,993	1,993	1,993	3,986	3,986	3,986	3,986
Hydrogen sulfide	62	62	62	124	124	124	124
Phenols	166	166	166	332	332	332	332
Hydrocarbons	0.16	0.16	0.16	0.32	0,32	0.32	0.32
Formaldehyde	166	166	166	332	332	332	332
Carbon monoxide	0.16	0.16	0.16	0.32	0.32	0.32	0.32
Methane	0.01	0.01	0.01	0.02	0.02	0.02	0.02
Soot	12	12	12	24	24	24	24
Iron oxides	15	15	15	30	30	30	30
Ammonia	12	12	12	24	24	24	24
Chromium hexavalent	399	399	399	798	798	798	798
Copper oxides	299	299	299	598	598	598	598
Benz (a) pyrene, per 1 kg	498.3	498.3	498.3	997	997	997	997
Discharge of pollutants							
Nitrite	670	670	670	1,340	1,340	1,340	1,340
Zinc	1,340	1,340	1,340	2,680	2,680	2,680	2,680
Copper	13,402	13,402	13,402	26,804	26,804	26,804	26,804
Biological oxygen demand	4	4	4	8	8	8	8
Ammonium saline	34	34	34	68	68	68	68
Petroleum products	268	268	268	536	536	536	536
Nitrates	1	1	1	2	2	2	2
Iron total	134	134	134	268	268	268	268
Sulfates (anion)	0.4	0.4	0.4	1	1	1	1
Suspended substances	1	1	1	2	2	2	2
Synthetic surfactants	27	27	27	54	54	54	54
Chlorides (anion)	0.1	0,1	0,1	0	0	0	0
Aluminum	27	27	27	54	54	54	54
Placement of sulfur in the open form on sulfur pads	3.77	3.77	3.77	3.77	3.77	3.77	3.77
Payments for negative influence on the environment (Tax Code) From the combustion (flaring) of associated and/or natural gas							
Hydrocarbons	45	45	45	45	45	45	45
Carbon oxides	15	15	15	15	15	15	15
Methane	1	1	1	1	1	1	1
Sulfur dioxide	200	200	200	200	200	200	200
Nitrogen dioxide	200	200	200	200	200	200	200
Soot	240	240	240	240	240	240	240
Hydrogen sulfide	1,240	1,240	1,240	1,240	1,240	1,240	1,240
Mercaptans	199,320	199,320	199,320	199,320	199,320	199,320	199,320
From mobile sources							
Unleaded gasoline	0.33	0.33	0.33	0.33	0.33	0.33	0.33
Diesel	0.45	0.45	0.45	0.45	0.45	0.45	0.45
Liquified, compressed natural gas and kerosene	0.24	0.24	0.24	0.24	0.24	0.24	0.24

Source: Adilet.zan.kz

metals industry, iron and steel industry, precious metals production, and the oil and gas sector.[95]

- The IGTIC will finalize the eight BAT reference books by 1 July 2023, before submitting them to the MEGNR and industry groups for review and commentary. The MEGNR is expected to approve the BAT reference books no later than 31 December 2023, although the timeline could shift to 2024.[96] Thus, by the end of 2023, the IGTIC and the Committee for Ecological Regulation and Control (CERC) under MEGNR will possess a clear understanding of the current environmental state of large-emitting enterprises, as well as realistic technological pathways and targets. The approved BAT reference books will also serve as the benchmark against which Integrated Environmental Permits (IEP) will be calibrated.
- Between 1 January 2024 and 1 January 2025, relevant Category I enterprises are required to apply for an IEP via CERC. New or reconstructed technical installations (facilities) will also be required to obtain an IEP, while operating facilities with no reconstruction plans, may obtain an IEP on a voluntary basis. However, failure to adopt BAT or obtain an IEP will result in a precipitous increase in payments on atmospheric emissions for the Top 50, Category I enterprises, starting in January 2025. Entities with environmental activities compliant with the standards outlined will be eligible to receive an IEP. Issuance of the IEP is an affirmation that the company's activities comply with Kazakhstan's ecological standards. As a result, the company is exempt from paying emissions fees, assuming it remains in good standing.[97]
- Entities in violation of the standards articulated in the BAT conclusions are required to draft a program for environmental performance ("BAT implementation program"). The BAT implementation program must include (1) the timeline for meeting technical standards, (2) the timeline for meeting emissions standards, (3) the schedule of planned measures for reconstruction or modernization of technical installations, and (4) details regarding the potential, phased reduction of emissions based on proposed BAT solutions. If, after review, CERC approves the entity's BAT implementation program, an IEP is issued. That entity is entitled to forgo emissions payments while implementing BAT, and is expected to maintain communication with CERC throughout the process. Because these companies will receive an IEP under the assumption that they will ultimately be compliant, even though their activities were not in line with the BAT standards at the time of IEP issuance, failure to realize their BAT program on schedule will require the company to compensate the government retroactively for fines it did not pay during the implementation period. Officially, the 97 Category I enterprises have until 1 January 2035 to implement their BAT programs.

95 In 2021, the IGTIC was in the process of developing five BAT reference books covering (1) combustion of fuel at large installations for energy production, (2) oil and gas refining and processing, (3) production of inorganic chemicals, (4) cement and lime production, and (5) energy efficiency measures in the context of general economic and/or other activity. The IGTIC also intends to commence work on five additional reference books for the mining and metallurgical sector in the near future.

96 The BAT reference books are slated to be updated every eight years.

97 Article 112 in the new EcoCode stipulates that an Integrated Environmental Permit is required for Category I entities only; the permit should contain ecological requirements on (1) technological standards, (2) environmental emissions limits, (3) norms of acceptable physical impacts, (4) waste disposal and accumulation limits, (5) limits for special water use, (6) energy efficiency and energy-saving measures, (7) waste management program, and other preventative action plans designed to prevent hazardous or toxic materials from affecting the environment.

2.6.2 Obstacles and limitations in implementing BAT under the new Ecology Code

Currently, the only fiscal incentive offered to stimulate BAT adoption is the elimination of emissions payments. Some companies, however, contest that this incentive alone is insufficient to cover the costs of implementing BAT. Analysis of data provided by 28 KAZENERGY member companies (in the electric power sector) indicates that on average, emissions payments *(plata za vybrosy)* amounted to only about 2% of annual expenditure (opex) in recent years, ranging between $140,000 and $2 million annually for these entities.[98] For comparison, the total annual investment (capex) by these companies was about three times higher, averaging about $5.75 million per year. Therefore, MEGNR and the Ministry of Finance probably should consider some type of additional fiscal incentives for BAT implementation, such as relief from other taxes or special measures to subsidize bank loans. This might be particularly important for enterprises with older equipment that need substantial modernization through BAT, especially if they provide critical social functions.

Some companies that are not required to secure an IEP have opted to participate in the process, nonetheless. These companies are primarily export-oriented enterprises that are anticipating stringent environmental regulations on their export products (such as the EU's CBAM). Evidently, they consider such environmental certification a useful "insurance" policy. Other companies may find the IEPs could perform a similarly useful purpose domestically.

But many challenges remain, and there are a number of other considerations that must be considered in formulating and implementing BAT:

- **For some Category I entities (especially those that rely on the national grid for power), BAT implementation could drive up electricity needs substantially and potentially result in higher aggregate emissions.** Many enterprises source their electricity from the grid, which is predominantly coal-fired. As a result, certain types of BAT, especially for decarbonization purposes such as CCUS or CO_2 Enhanced Oil Recovery (EOR), demand considerable electricity. In this case, if an upstream oil and gas operator is devoid of a stand-alone power generator with sufficient capacity, and the operator is implementing a CO_2 EOR program to reduce emissions, it could end up generating higher aggregate emissions vis-a-vis greater electricity demand from coal-fired plants.
- **Questions over procurement procedures and local content requirements could curtail BAT implementation.** Nearly all energy entities in Kazakhstan have wholeheartedly embraced measures to increase the share of local content in their procured goods and services. But the rollout of BAT will likely necessitate the use of more imported equipment procured from abroad. Policymakers should resist penalizing companies for implementing BAT if entities' local content declines. Similarly, historically onerous procurement procedures should be adapted to accommodate BAT needs.
- **IGTIC and the MEGNR's timeline for drafting the BAT materials is overly ambitious.** While expediency is admirable, urgency should neither supersede quality nor discourage third-party review and input. It took Brussels many years to formulate and develop its various BREFs (and this work remains ongoing). As advocated in previous iterations of NER, a meaningful comment period that allows for independent review and feedback would instill greater investor confidence and produce a more cogent approach to BAT.
- **Another major obstacle relates to the multiplicity of regulations governing environmental activity, both within Kazakhstan and around the world.** Overlapping and potentially conflicting regulations create confusion. An internal review conducted by Brussels in 2019 to evaluate the efficacy of BAT implementation recognized that "industry rais[ed] concerns about potential double regulation and overlaps with EU climate and energy policy."[99] In fact, the Regulatory Scrutiny Board recommended amendments to regulations to further smooth overlaps, gaps, and inconsistencies across various jurisdictions. Other EU governments continue to advocate greater clarity and consistency.[100] Failure to provide clear technical and regulatory guidance with respect to BAT expectations, BAT-AELs, institutional responsibilities, and local content could greatly encumber actual BAT implementation and diminish Kazakhstan's attractiveness as an investment

98 By far, the largest expenditure for most power plants is fuel, which amounted to an annual average of 44% of annual expenditures for the companies analyzed between 2017 and 2020.

99 Page 63 in "Commission Staff Working Document Evaluation of the Industrial Emissions Directive (IED), Directive 2010/75/EU of the European Parliament and of the Council of 24 November 2010 on industrial emissions (integrated pollution prevention and control)," 23 September 2020, https://eur-lex.europa.eu/legal-content/EN/TXT/?uri=CELEX:52020SC0181, accessed 28 July 2021.

100 See "A more consistent and effective EU environmental legislation" published by the government of the Netherlands, https://www.government.nl/topics/spatial-planning-and-infrastructure/revision-of-environment-planning-laws/a-more-consistent-and-effective-eu-environmental-legislation.

destination. Such guidance is particularly important for Category I entities that also participate in the ETS.[101]

- **KREM, as the natural monopoly regulator, as well as the Ministry of Energy, which determines the maximum tariffs for power plants, needs to incorporate BAT costs into its regular tariff-setting rules and procedures.** For energy companies with regulated prices, it will be nearly impossible to implement BAT projects if they are unable to cover the additional costs through higher tariffs.

2.7 Kazakhstan's Emissions Trading System (ETS)

A primary mechanism for dealing with CO_2 emissions in Kazakhstan is the ETS. Kazakhstan's ETS was originally launched in 2013 and included 178 major enterprises that accounted for 77% of the country's CO_2 emissions in 2010. This 2013 scheme was a pilot program that lasted until 2015. During this time, only 75 trades occurred, for a total of 1.27 MMt CO_2 in 2013 and 1.98 MMt CO_2 in 2014-15. The average carbon price was 301 tenge/ton CO_2 ($1.49/ton CO_2) in 2013 and 830 tenge/ton CO_2 ($3.38/ton CO_2) in 2014-15. Due to this limited success, policymakers decided to halt the program, reconfigure it, and relaunch the ETS in 2018. This time the scope was narrowed to 130 entities and 225 technical installations across the oil and gas, mining, electricity, fertilizers production, metallurgical, and construction materials manufacturing sectors. Collectively, the 130 entities participating in the ETS accounted for 53% of Kazakhstan's CO_2 emissions in 2019. Similar to other national carbon trading schemes, the transportation sector is not included.[102]

Zhasyl Damu oversees the ETS, while MEGNR possesses the legal authority to determine and allocate quotas, grant additional quotas to entities based on capacity additions, manage the quota reserve, and shepherd Kazakhstan's overall GHG emissions reporting to the UNFCCC. Mirroring the European ETS, Zhasyl Damu grants CO_2 emissions quotas to participating entities for free. If additional allowances are necessary, companies can either purchase quotas from other companies on the Caspy Commodity Exchange (CCX), the "Modern Trading Solutions" exchange, or other accredited exchanges. They can also appeal to MEGNR for higher quotas (based on capacity additions and higher production), or purchase them in a Zhasyl Damu-organized auction (none of which have officially transpired).

In the 2018 relaunch of the ETS, quotas were granted for the three-year period 2018-20. Quota use for each company could be dispersed over the three years, but any unused quotas cannot be transferred or rolled over to subsequent periods. Total emissions quotas initially amounted to 485.9 MMt CO_2 in 2018-20, although Zhasyl Damu subsequently issued an additional 30.1 MMt CO_2 to various companies to compensate for capacity expansion in 2018 and 2019 (see Table 2.3 Sectors, quotas, and actual emissions in Kazakhstan's ETS, 2018-20 (thousand tons CO_2)).[103]

According to CCX operational data, no carbon emissions quota trades occurred in 2018, three occurred in 2019, and two officially transpired in 2020; all the 2020 transactions occurred in December, at the end of the year. In 2021, a record six trades occurred on CCX between April and late July, as companies rushed to reconcile their carbon budgets for 2018-20.[104] For 10 out of the 11 trades conducted on the CCX since 2019, the carbon price was 500 tenge/ton CO_2 (about $1.2/ton). Moreover, in 2021, it appears there was a step-change of trading activity (39 trades), not only through CCX, but on other exchanges and through bilateral arrangements, as companies reconciled their emissions balances for the 2018-20 period, ahead of the August 2021 deadline. Companies that exceeded their emissions quotas in 2018-20 had until 12 August 2021 to compensate through market mechanisms or the direct acquisition of additional quotas, or risk incurring substantial financial penalties.

In total IHS Markit estimates that around 52 transactions, trading over 7.35 MMt CO_2 in emissions credits, took place over the 2018-20 ETS period, across various trading mechanisms. In several instances, carbon credits were bought and sold between different subsidiaries of

101 Some companies have reportedly struggled to reconcile ETS compliance with BAT, even though Article 9 of the EU IED explicitly states, "Where emissions of a greenhouse gas from an installation are specified in Annex I to Directive 2003/87/EC … the permit shall not include an emission limit value for direct emissions of that gas, unless necessary to ensure that no significant local pollution is caused." See "Commission Staff Working Document Evaluation of the Industrial Emissions Directive (IED), Directive 2010/75/EU of the European Parliament and of the Council of 24 November 2010 on industrial emissions (integrated pollution prevention and control)," 23 September 2020, https://eur-lex. europa.eu/legal-content/EN/TXT/?uri=CELEX:52020SC0181, accessed 28 July 2021; EU IED, https://eur-lex.europa.eu/legal-content/EN/TXT/HTML/?uri=CELEX:32010L0075&from=EN. ; https://eur-lex.europa.eu/legal-content/EN/TXT/HTML/?uri=CELEX:32010L0075&from=EN#d1e34-51-1.

102 For more on the 2013 and 2018 ETS, see Section 9.3.3.3 in the KAZENERGY *National Energy Report 2017*.

103 It is worth noting that some of these additional quotas applied to a handful of entities that were only included in the ETS system in 2020. Due to data discrepancies, IHS Markit made the best effort to "balance" the ETS quotas for 2018-2020.

104 The eleventh-hour trades that occurred after 29 July 2021, engineered to close the books for the 2018-20 period, are legally questionable, as they were not sanctioned by the relevant government authority. Under Article 299, point 7 of the revised EcoCode, trades can only occur on a platform organized by the designated body. Therefore, the estimated 0.08-0.13 MMt CO_2 traded in July 2021 could be legally challenged.

the same company. It appears that market participants informally agreed to preserve a carbon price of 500 tenge ($1.2)/ton CO_2, registered on the CCX exchange, thereby undermining the entire market basis of the mechanism.

Importantly, in July 2021, 15.2 MMt of quotas were removed from 42 companies, due to an excess of initial quotas issued. Most of the quotas were removed for companies that were likely to be well within their initial quota allotment; quotas for one company were removed due to the entity's liquidation.

Analysis of CO_2 emissions data indicates varied results and interesting insights (see Figure 2.13 Sectoral performance under Kazakhstan's ETS, 2018-20):

- **The top 15 emitting companies in the ETS produced 36% of total national CO_2 emissions in 2018 (and 38% in 2019).** Of the top 15 emitters, ten are in the electricity sector, two are in metallurgy (albeit with on-site power generation for their own use), two are in mining, and one is in the upstream oil and gas sector. The bulk of these emitters rely on coal (and some mazut) for fuel.
- **The electricity sector, with 52 participating companies covering 94 technical installations, dominates CO_2 emissions, generating 94 MMt/y in 2018-20, representing about 31% of Kazakhstan's total annual CO_2 emissions.** The electricity sector participants absorbed 56% of all initial quota allocations and 76% of additional quota allocations in 2018-20 (granted on the basis of increased production and/or capacity upgrades) on the ETS.
- **While the electricity sector in aggregate actually emitted within its overall quota, the sector incurred the largest noncompliance rate among individual participants, with 27% of all power producers, or some 14 of the 52 companies participating in the ETS, exceeding their respective quotas in 2018-20.** In total, the amount of excess emissions after purchasing quotas or securing additional ones based on reported capacity upgrades was on the order of 2.9 MMt CO_2. To contextualize this figure, the electricity sector's amount of "excess" (or rather, deficit) CO_2 emissions is about the sum of annual CO_2 emissions from the three major refineries combined.
- **Electricity companies were also the most active participants in carbon trading (buying and selling).** Based on data on the 45 transactions made in 2020 and 2021, 12 electricity company technical installations sold carbon credits (2.6 MMt CO_2), while 26 electricity company technical installations purchased credits (4.5 MMt CO_2). In comparison, 13 technical installations of oil and gas companies sold 2.4 MMt CO_2 of credits, and four technical installations of oil and gas companies purchased 0.59 MMt CO_2 of credits.

Table 2.3 Sectors, quotas and actual emissions in Kazakhstan's ETS, 2018-20 (thousand tons CO_2)

Sector	Number of technical installations (units)	Initial 2018-20 quotas	Additional quotas granted, 2018-20	Actual emissions 2018-20	Quotas purchased on exchanges or bilaterally, 2018-21	Quotas removed	Quotas remaining at end of period
Electric power	94	269,955	23,009	281,038	6,008	6,517	-600
Oil and gas	67	68,565	1,671	57,343	588	2,527	9,777
Mining	24	30,643	-	21,330	344	3,113	5,856
Metallurgy	20	91,154	971	87,650	245	2,155	2,074
Chemicals (fertilizers)	6	4,686	265	5,119	15	23	-205
Construction materials	14	20,907	4,213	21,218	153	865	2,884
Total	**225**	**485,909**	**30,129**	**473,699**	**7,354**	**15,201**	**19,785**

Source: IHS Markit

- **At the end of the 2018-20 period, taking into account credits purchased, sold, and secured through Zhasyl Damu, the oil and gas sector incurred a quota surplus of 8.5 MMt CO_2, although the sum for entities exceeding their respective quotas amounted to 0.48 MMt CO_2.** Of the 39 oil and gas entities (covering 67 technical installations) included in the ETS, five exceeded their emissions quotas, of which two were small, independent upstream producers and three were midstream gas transportation operators.
- **The mining sector, which includes 9 companies and 24 installations, achieved the highest level of compliance; none of the participating companies exceeded their emissions quotas.** The sector generated 21.3 MMt CO_2 in 2018-20, nearly 10 MMt CO_2 below its allotment of 30.6 MMt CO_2. Taking into account the 3.1 MMt CO_2 in quotas removed by Zhasyl Damu for the segment, along with purchases and sales, the sector ended up with a 5.3 MMt CO_2 surplus. This suggests that the initial CO_2 quotas were exceedingly generous, and should be reviewed in the future.
- **Similarly, most of the 13 entities (20 technical installations) in the metallurgical sector also complied with their allotted quotas.** Several companies included installations that exceeded their respective quotas, but such deficits were compensated for by other installations owned by the same company, and provided an offset. Total emissions for this segment were 87.7 MMt CO_2, versus 91.2 MMt CO_2 in quotas.
- **The 19 producers of chemicals (nitrogenous fertilizers) and construction materials (cement, etc.) participating in the ETS generally emitted within their respective quotas.**[105] But there were some enterprises that missed the mark entirely. About five entities exceeded their quotas, while the rest managed to meet their quotas by purchasing new ones and securing capacity additions, without which they would have certainly been in deficit. Total CO_2 emissions from these two sectors amounted to 26.3 MMt CO_2 in 2018-20, although the balance, including all transactions and quota additions, was -0.29 MMt CO_2 for the chemicals sector and 2.8 MMt CO_2 for construction materials.
- **Companies across almost all sectors benefited from additional quotas for growth in production and capacity expansion.** An additional 14 MMt CO_2, 3.5 MMt CO_2, and 12.6 MMt CO_2 of carbon credits were granted in 2018, 2019, and 2020, respectively. Of these allotments, 76% went to the electricity sector, 14% went to the construction materials segment, and the remainder was allocated to oil and gas (6%), chemicals (1%), and metallurgy (3%) segments. The nature of these technical expansions that merited additional credits was not detailed.

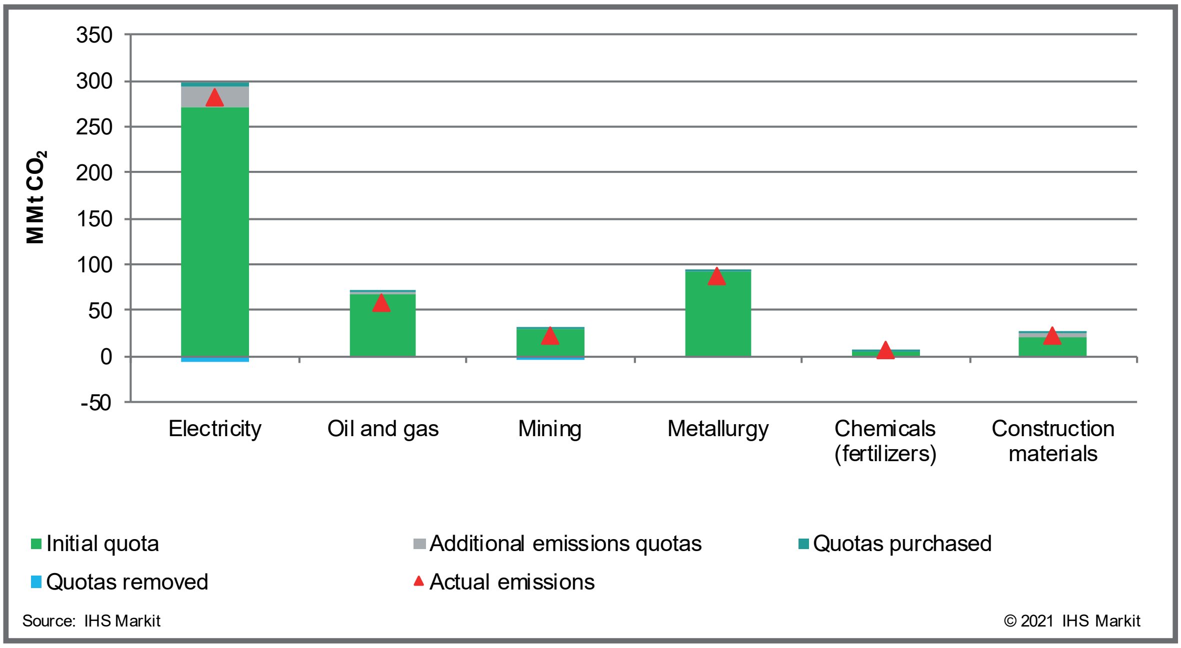
In total, 26 companies in the ETS ended the 2018-20 period with emissions in excess of their quotas at about 4.0 MMt, even after receiving additional capacity credits or purchases. The bulk of these non-compliant entities are directly subject to KREM rules as natural monopolies. While the allocations for 2021 have been published, it appears that its official implementation is delayed until after Zhasyl Damu and participating companies close the 2018-20 period. Reportedly, there are discussions underway with respect to how quotas are allocated within large companies that have numerous operational subsidiaries participating in the ETS, and how companies "sell" quotas through intra-company transactions. Other ETS participants report issues with respect to trading quotas, as corporate procurement procedures preclude purchases without a tender, prohibiting direct market transactions between participating ETS companies. Certainly, in the future, such rigid procurement principles should be put aside for trading quotas in the ETS, which by the very nature of its design, should operate as a fluid market.

Zhasyl Damu plans to develop and expand the ETS in three phases, although the timing will inevitably shift given the delayed closure of the 2018-20 period, and the fact that the official 2021 trading period, while announced, has not yet entered into effect. As of this report's writing, there are several planned stages for the ETS: stage 1 (January-December 2021), and two subsequent stages through 2030. The proposed quota volume for stage 1 is 180.69 MMt CO_2.

Looking ahead, the ETS will likely require substantial institutional fine-tuning, as would be expected. The questionable legality of last-minute trades that transpired in 2021 – a question brought about by the terms of the new EcoCode – underpins the need for a well-functioning institution governing the ETS. There must also be more transparency governing trades in various markets. Currently, for example, the CCX only lists the trades and price, but does not provide any information on buyers and sellers. More importantly, neither Zhasyl Damu nor the participating companies routinely publish the ETS data. Zhasyl Damu and regulators should communicate the rules of the system clearly, and publish data required for normal market operations. Zhasyl Damu (and other regulators) should reevaluate how quotas are granted, and take additional steps to cultivate effective market mechanisms. The future allotment of CO_2 quotas should also be coordinated with the Ministry of Energy, and relevant companies, to incentivize coal-to-gas switching and energy efficiency improvements.

105 Two companies in the construction materials manufacturing segment were added to the ETS in 2020. Partial data are available for these two entities and they are excluded from aggregated figures for the overall system, but noted here.

Figure 2.13 Sectoral performance under Kazakhstan's ETS, 2018-20



Policymakers are also contemplating the introduction of a "Carbon Fund," to ensure revenues secured from ETS transactions are reinvested to support the development of low-carbon technologies and initiatives. In theory, dedicating ETS revenues to such initiatives would be a positive development. However, it is important that the Fund is managed efficiently and transparently, and does not interfere with market mechanisms, skew the quota allocation process, or discriminate against certain emitting entities.

2.8 Recommendations

The energy transition and the daunting challenges for countries to attain the global GHG emissions reductions targets embodied in their INDCs to the Paris Climate Agreement can, upon initial assessment, seem overwhelming. But what is important is to define a plan of action, starting with the most obvious measures and, upon taking steps to implement them, reach a new level or vantage point from which to tackle other, more difficult issues. So, with a measure of humility, we submit the following general observations that, it should be noted, harmonize with many of the objectives specified in Kazakhstan's updated INDC and are addressed in greater detail in subsequent sections of the report.

- First and foremost, policymakers must adopt an inclusive, systemic approach towards reducing GHG emissions, focusing on the energy sector as well as emissions from other activities, such as waste, industry, land use (LULUCF), and agriculture. The growth in emissions from LULUCF in Kazakhstan is particularly concerning, as this segment is no longer a GHG offset, but a net GHG emitter. Policymakers should consider greater implementation of a variety of nature-based solutions to reverse this trend, including afforestation and reforestation, soil carbon sequestration, etc. (albeit in as cost-effective manner as possible); some of this can be encouraged by simplifying permitting processes and empowering local NGOs.
- The best starting point on the path toward a green economy in the energy sector proper – i.e., the "lowest-hanging fruit" – in most countries is the decarbonization of electric power generation, and this is also true in Kazakhstan. It is easier to reduce GHG emissions by *avoiding* fossil fuel consumption than to find ways of disposing or storing them post-combustion. In Kazakhstan, the electric power and heating sector accounted for 40% of all emissions in 2019, ranking among the highest share for countries globally.
- This reflects the dominance of coal in electric power generation in Kazakhstan, so a phased reduction in coal's share of electric generation is going to be absolutely essential for reducing total GHG emissions. But reducing coal consumption requires a plan. In other countries where coal has been or is in the process of being phased out, there were long-term plans and a concerted effort to transition coal-fired power plants, or to build new non-coal capacity to replace older plants.[106]

106 Older coal-fired plants, effectively facing a fairly limited remaining lifetime, actually may have little incentive to implement BAT in their operations.

In countries where coal consumption has been reduced dramatically, at least one of two factors were present: (1) government edicts banning coal use after a certain date; or (2) changes in underlying market conditions that rendered coal more expensive relative to other fuels. Kazakhstan can look to countries such as Sweden, Italy, or Portugal, which have either totally phased out coal-fired plants or will do so at the end of 2021. These countries also had to deal with BAT rules, a carbon trading system, as well as their own national priorities; their experience possibly can provide a coherent framework that Kazakhstan can borrow from, such as modifications in BAT rules at older plants that are going to be retired.

- Relatedly, policymakers must make gasification of the power sector more of a priority and perhaps create targeted policy and fiscal instruments to facilitate this transition. Renewables have expanded largely because the Ministry of Energy established a cogent policy mechanism to develop renewables. It is enormously difficult for coal-consuming entities to gasify under existing economic and regulatory conditions. Therefore, a similar level of rigor must be devoted to gasification, and a special set of fiscal tools, perhaps mirroring the preferences given to renewables, be developed to incentivize gasification and flexible generation in the power sector. Such actions should also be undertaken in parallel with measures to incentivize commercial gas production. The December 2021 auctions for flexible generation capacity are a positive signpost, but it remains to be seen if they will offer the right incentives required to secure investment.
- Financial incentives to implement BAT remain fairly weak, so to support BAT implementation at enterprises with older equipment, some of which may still provide socially critical functions, MEGNR and the Ministry of Finance may want to consider additional fiscal measures to ensure their continued operation, such as tax relief or subsidized bank loans.
- KREM and the Ministry of Energy should incorporate costs associated with BAT into their tariff-setting rules and procedures. It will be nearly impossible for companies to carry out meaningful BAT projects if they are unable to obtain higher tariffs to cover the additional costs (for more details, see Chapter 6 on Kazakhstan's electric power sector).
- Kazakhstan's private sector should consider some of the flexible, small-scale solutions pursued by private sector players in other markets, and regulators should adopt a flexible, supportive stance to accommodate them.
- The administration of the ETS must become more transparent and the rules must be clearly communicated to all market players in advance. The performance of the sector in 2018-20 demonstrates that allowing special treatment for certain entities can undermine the overall mechanism. In particular, quotas must be allocated via a method that allows for competitive carbon pricing to emerge.
- The ETS and other voluntary carbon mechanisms globally are looking for credible offsets. CO_2 EOR and CO_2 CCUS by oil companies in Kazakhstan could become a source of carbon offsets, not only domestically but globally as well.
- It is important that Kazakhstan's policymakers take steps to mitigate both the growing proliferation of governing bodies and regulations governing environmental activity. This will help achieve better environmental performance, by helping to ensure better alignment and minimal contradictions between them. To that end, IHS Markit does not recommend the creation of a yet another special government body to oversee the process of simplifying regulatory oversight, but rather to vest sufficient decision-making authority and oversight in the most logical organizations to simplify decision-making. For example, with respect to environmental payments, the Ministry of Ecology is responsible for overseeing company compliance; therefore, it also should be vested with the authority to render decisions on environmental payments.

Chapter 3

OIL EXPLORATION AND PRODUCTION

3 KAZAKHSTAN'S OIL AND CONDENSATE UPSTREAM SECTOR

3.1 Key Points

- Overall, it appears that much of Kazakhstan's considerable remaining upstream oil potential is now becoming less likely to ever be developed, given a combination of factors: (1) a more limited upstream investment appetite among companies longer term from the ongoing global energy transition away from hydrocarbons; (2) relatively high upstream costs for new projects; and (3) a less attractive business environment than is found in other countries. Although national output is expected to return to a growth trajectory in 2022, we now expect that it will reach a maximum of only about 102 MMt (2.17 MMb/d) in the mid-2020s before beginning to slowly contract, falling to around 73 MMt (1.53 MMb/d) in 2050.
- In the short term, following a national oil production decline in 2020 by 5.4%, to 85.7 MMt (1.80 MMb/d), we expect output to remain at about this same level in 2021, as the country's oil industry is assumed to continue operating fairly closely to its OPEC+ targets. After the current OPEC+ mega deal winds down at the end of 2022, by 2025 national production is expected to be around 19% above the 2020 result. Kazakhstan's level of engagement with OPEC+ during this period may be contingent on the group's flexibility given this already "baked in" expansion.
- The "Big 3" IOC-led mega projects – Tengiz, Kashagan, and Karachaganak – remain the chief factors in Kazakhstan's oil production profile; their aggregate share of national output was about 61% in 2019, and reaches a maximum of 73% in 2030 (in our base outlook) before contracting to around 58% by 2050. Tengiz expansion will be the main driver of Kazakh oil production growth in 2022-25, when we expect the field to reach maximum output of about 42 MMt/y (915,000 b/d), while Kashagan's future production profile remains the main wildcard – particularly the scheduling and scale of a proposed Phase 2. The Kashagan consortium is under pressure from Kazakh authorities to finalize a "full-scale" development plan by the end of this year, but the consortium stakeholders are uncertain if Phase 2 oil is "advantaged" relative to other projects in their overall portfolios to facilitate a final investment decision (FID). A modified Phase 2 program along the lines outlined by KMG earlier this year is expected to eventually go forward in our outlook, raising the field's output to a maximum of around 35 MMt/y (743,000 b/d) in 2040.
- Kazakhstan's crude oil and condensate exports contracted by 2.5% in 2020, to 68.5 MMt (1.45 MMb/d). In our base-case scenario, overall Kazakh oil exports return to a growth trajectory in 2022, and reach a maximum of 83.2 MMt (1.78 MMb/d) in 2025, before entering a long-term decline that leaves 2050 export volumes at around 51 MMt (1.07 MMb/d). The CPC pipeline (that transits Russia to the Black Sea) handled around 76% of Kazakhstan's total exports in 2020, and remains the chief outlet for Kazakh oil exports out to 2050. Kazakhstan's "multi-vector" export strategy means that Kazakh oil will continue to be evacuated via multiple routes. Despite the overall decline in exports, the Kazakhstan-China Pipeline (KCP) is expected to handle increased export volumes during the outlook period.
- In 2020, the Kazakh government took another step forward in expediting the issuance of subsoil license rights when it introduced an electronic (online) auctioning process for exploration and production (E&P) blocks. But the results of the first two online auctions, held by the Energy Ministry in December 2020 and April 2021, fell well short of expectations, as key international majors did not participate. With less industry focus on exploration globally, and uncertainties surrounding project economics, Kazakhstan has found it difficult to generate as much interest in its online block auctions as was hoped. A main precondition for driving greater interest in online auctions is likely to be a more far-reaching reform of Kazakhstan's upstream regulatory regime.
- Government tax take for Kazakhstan is classified as "high" (between 65% and 85%, according to the IHS Markit methodology). Most producers are taxed within the regular fiscal regime – consisting of a variety of essentially "one-size-fits-all" fiscal instruments based primarily on gross revenues or production, while the major projects operate under long-term contractual arrangements. Key signposts for altering the current tax situation include progress finalizing and implementing the planned Improved Model Contract fiscal regime for new oil and gas upstream projects. This would offer would-be investors the option of a model concession contract that spells out fiscal terms in advance.
- Relatively high upstream oil production costs in Kazakhstan render producers vulnerable to low oil prices, and challenge future upstream investment longer term. However, costs and resilience to low prices vary widely from company to company; it is estimated that the highest-cost producers' expenditures recently

averaged nearly twice as much as those of the lowest-cost upstream producers in Kazakhstan. Around half of a typical producer's total costs comprise the major oil sector taxes, while operating costs and transportation expenses each make up around a quarter of total costs. Cost trends internationally make Kazakhstan's position towards the high end of the global upstream supply cost curve for new projects (i.e., incremental oil production) even more precarious. In recent years there has been a progressive ratcheting downward of the cost of the global marginal barrel needed to meet global demand. The expanding role of low-cost producers worldwide greatly constrains the ability of more expensive producers such as Kazakhstan to compete for new investment.

- Two new emerging sets of government requirements posing additional cost and other challenges for the Kazakh oil industry are the latest best-available technologies (BAT) and digitalization initiatives. The long-standing modernization priorities of many Kazakh oil producers appear to dovetail with certain components of both official initiatives, but there are also downside risks, particularly in the event that new state mandates translate into additional expenses, which could further impair Kazakh producers' cost-competitiveness globally.
- With respect to downstream trends, COVID-19 hit Kazakh refiners' markets hard overall, resulting in a sharp reversal of the trend of increasing Kazakh refinery throughput seen during 2017-19 (facilitated by completion of the modernization program at all three major Kazakh plants by 2018). Kazakh refinery throughput fell by 7.2% to 15.8 MMt in 2020. Particularly sharp declines were registered for the output of kerosene, diesel, and fuel oil; in contrast, gasoline output proved relatively resilient. Aggregate domestic apparent refined product consumption is rebounding, and is expected to reach the 2019 level again in 2022; it appears set to grow by around 34% altogether during 2020-50, driven heavily by increased diesel demand (mainly by trucking and agriculture).
- The Kazakh refining sector as well as domestic refined product markets remain highly administered, and margins on domestic market deliveries of crude are typically much lower than on exports (albeit the 2020 world oil price collapse briefly left global prices lower than domestic prices during part of the year). The basic dichotomy between global and domestic prices is set to continue, but the imperatives of EAEU oil market integration (officially scheduled to take place by 2025, though the schedule for actual implementation remains uncertain) will likely necessitate further domestic price liberalization in order to operate as part of a genuine common market; Kazakhstan still has the lowest retail gasoline and diesel price levels of any of the five EAEU member states.

3.2 Recent Evolution of Kazakhstan's Oil Balance and Outlook to 2050

COVID-19 negatively impacted all elements of the Kazakh oil balance, to varying degrees. Oil production fell by 5.4% (to 85.7 MMt or 1.71 MMb/d) in 2020, and crude oil exports declined by 2.5% (to 68.5 MMt or 1.37 MMb/d), while apparent crude oil demand – i.e., production minus net exports – tumbled 15.6% to 17.1 MMt (0.34 MMb/d). Kazakhstan's 2020 oil production decline was relatively moderate compared with the average for the major CIS oil producers (including Russia, Azerbaijan, and Turkmenistan) (see Table 3.1 Crude oil and condensate balance for Kazakhstan (MMt)).

In general terms, the IHS Markit outlook is for Kazakh oil production to return to a growth trajectory in 2022 and trend upwards through about 2025, after which a slow but steady decline is envisaged overall during the remainder of the outlook period, leaving national liquids output roughly 14% lower in 2050 than in 2020. The bulk of oil output continues to be directed to export markets, but export volumes are expected to contract along with aggregate oil production, alongside a moderate ongoing increase in domestic oil demand. As a result, the share of total production directed to export markets (versus domestic markets) declines from around 80% in 2020 to 70% in 2050. Some further growth in export-oriented refining is also probable, although this is unlikely to emerge as a very strong driver of domestic crude oil demand (partly owing to limited product demand growth potential in Kazakhstan's surrounding regional export markets, and given the higher logistical costs associated with delivery to more distant demand centers) (see Figure 3.1 Kazakhstan's crude oil and condensate balance: historical and outlook to 2050).

3.3 Crude Oil and Condensate Production Dynamics

For an overview of the geography of key Kazakh oil fields and industry infrastructure, see Figure 3.2 Kazakhstan's oil sector (selected key elements).

3.3.1 Liquids reserve base and exploration trends

Kazakhstan has a large oil resource base, including several major identified fields and the prospect of substantial oil reserves yet to be discovered, particularly in the country's offshore sector of the Caspian Sea. As of 1 January 2019, the latest date for which official Kazakh reserve numbers are reported, the State Commission on Reserves listed Kazakhstan's petroleum liquids (crude oil and gas

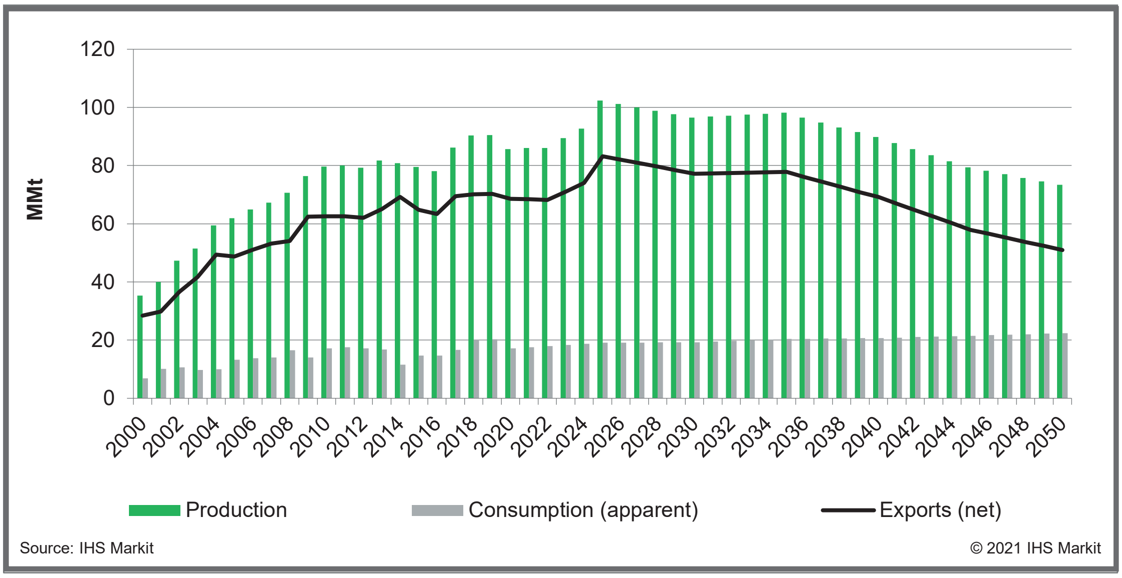
Table 3.1 Crude oil and condensate balance for Kazakhstan (MMt)

	2015	2016	2017	2018	2019	2020	Percent change 2019-20
Production	79.5	78.0	86.2	90.4	90.6	85.7	-5.4
Total exports	64.8	63.4	69.6	70.2	70.3	68.5	-2.5
Exports outside FSU	61.6	61.6	69.2	69.4	70.1	68.0	-3.0
Exports to FSU	3.1	1.7	0.4	0.8	0.2	0.5	170.6
Russian Federation	2.8	0.8	0.1	0.5	0.1	0.1	-9.4
Ukraine	0.3	0.6	0.0	0.0	--	--	
Azerbaijan	--	0.1	0.1	0.1	--	--	
Kyrgyzstan		0.1	0.0	0.0	--	--	
Lithuania	--	--	--	--	--	--	
Uzbekistan	0.0	0.1	0.2	0.2	0.1	0.5	285.6
Belarus	--	0.0	0.1	0.0	0.0	0.0	0.0
Total imports	0.1	0.0	0.0	0.0	0.0	0.0	-62.5
From Russia*	7.0	7.0	10.1	10.0	10.0	10.0	0.0
From Other	0.1	0.0	0.0	0.0	0.0	0.0	-98.6
Net exports	64.7	63.4	69.5	70.2	70.2	68.5	-2.5
Consumption (apparent)	14.7	14.7	16.7	20.2	20.3	17.1	-15.6
Refinery throughput	14.5	14.5	14.9	16.4	17.0	15.8	-7.2
Pavlodar	4.8	4.6	4.7	5.3	5.3	5.0	-5.4
Shymkent	4.5	4.5	4.7	4.7	5.4	4.8	-11.2
Atyrau	4.9	4.8	4.7	5.3	5.4	5.0	-6.9
Other facilities	0.4	0.6	0.7	1.1	1.0	1.0	4.6
Other consumption**	0.3	0.2	1.8	3.8	3.3	1.3	-59.4

*Russian oil swap volumes in 2014 (7 MMt and since 2017 at 10 MMt) are included in import and export flows for Kazakhstan for comparative purposes with flows in 2013.
**Balancing item; its composition is unknown, but it would include field and transportation losses (including losses in stabilization of condensate), changes in stocks, direct crude use, etc.

Source: IHS Markit, National trade statistics, Ministry of Energy RK

Figure 3.1 Kazakhstan's crude oil and condensate balance: historical and outlook to 2050



condensate) reserve base (state balance) at 5.0 billion metric tons (about 38.5 billion barrels), including 4.5 billion tons of crude oil reserves and 420 MMt of gas condensate (see Table 3.2 Kazakhstan's proven and probable oil and condensate reserves, 1 January 2019 (MMt)).[1]

IHS Markit estimates Kazakhstan's remaining proven and probable (2P) oil reserves at 26.5 billion barrels (around 3.44 billion metric tons) at the end of 2020; the volume did not change substantially from our 2019 estimate, as no large discoveries were made. For comparison, the BP Statistical Review of World Energy 2021 quotes 30 billion barrels (3.9 billion metric tons) of proved (P1) oil as of the end of 2020 (also unchanged compared to 2019).

Not surprisingly, the (limited) available data indicate a major drop in spending on oil industry exploration activity during 2020. Therefore, relatively few discoveries were announced last year or during the first part of 2021. Some noteworthy exploration successes were nevertheless registered:

- **Of two new discoveries made in 2020, the most important was Tethys Petroleum's Klymene prospect to the west of the Aral Sea, in the North Ustyurt Basin.** Discovered in June 2020, Klymene is located in the Kul-Bas block (Aktobe Oblast), situated to the west of the current producing fields in Tethys's Akkulka exploration contract zone (Akkulkovskoye, Doris, Kyzyloy, and others). Gross 2P oil reserves estimated for two of the three productive zones (Jurassic and Lower Aptian) are around 224 MMb (about 29 MMt). IHS Markit concludes that the Klymene prospect has the potential to be an order of magnitude bigger than the Doris oil discovery and surrounding prospects (the geographical area of the prospect is up to 10 times the areal extent of the Doris oil field). Klymene has been independently estimated to hold 422 MMb (around 55 MMt) of unrisked mean recoverable oil resources.[2]
- **In February 2021, a "large" oil discovery was announced by Meridian Petroleum in Mangystau Oblast (western Kazakhstan), also in the North Ustyurt Basin.** Meridian Petroleum, a small independent, said that it found a significant oil deposit in the Tepke area, near the Arystanovskoye, Karakuduk, and Komsomolskoye fields. Although no reserve estimate had been provided at last report for the newly discovered field – named the Halel Uzbekgaliyev field, after a prominent Soviet-era oilman – Meridian Petroleum's president has claimed that it is the largest oil discovery in the region and perhaps in Kazakhstan overall since the country's independence in 1991.[3]

Our expectation is for significant further discoveries to be made during the scenario period to 2050, as application of more modern exploration techniques, together with some increased governmental spending on exploration, unlocks additional yet-to-find (YTF) potential. One positive signpost is the ongoing development by Kazakh authorities of a national geological exploration program for 2021-25, due to be finalized by the end of this year, with a budget that will reportedly be around 167 billion tenge (roughly $400 million) – equating to about four times

1 This is reported according to the domestic definition, in categories A+B+C1+C2. Kazakhstan's remaining reported reserves in the sub-category of A+B+C1 (roughly equivalent to the international proven + probable "2P" reserves category) for the same period were 3.2 billion metric tons (or 24.6 billion barrels).

2 See the IHS Markit overview of 2020 Kazakh E&P trends, *Kazakhstan Review 2020*, 26 February 2021.

3 See the IHS Markit exploration activity monitoring *Tepke discovers Halel Uzbekgaliyev oil field*, 3 March 2021.

Figure 3.2 Kazakhstan oil sector (selected key elements)

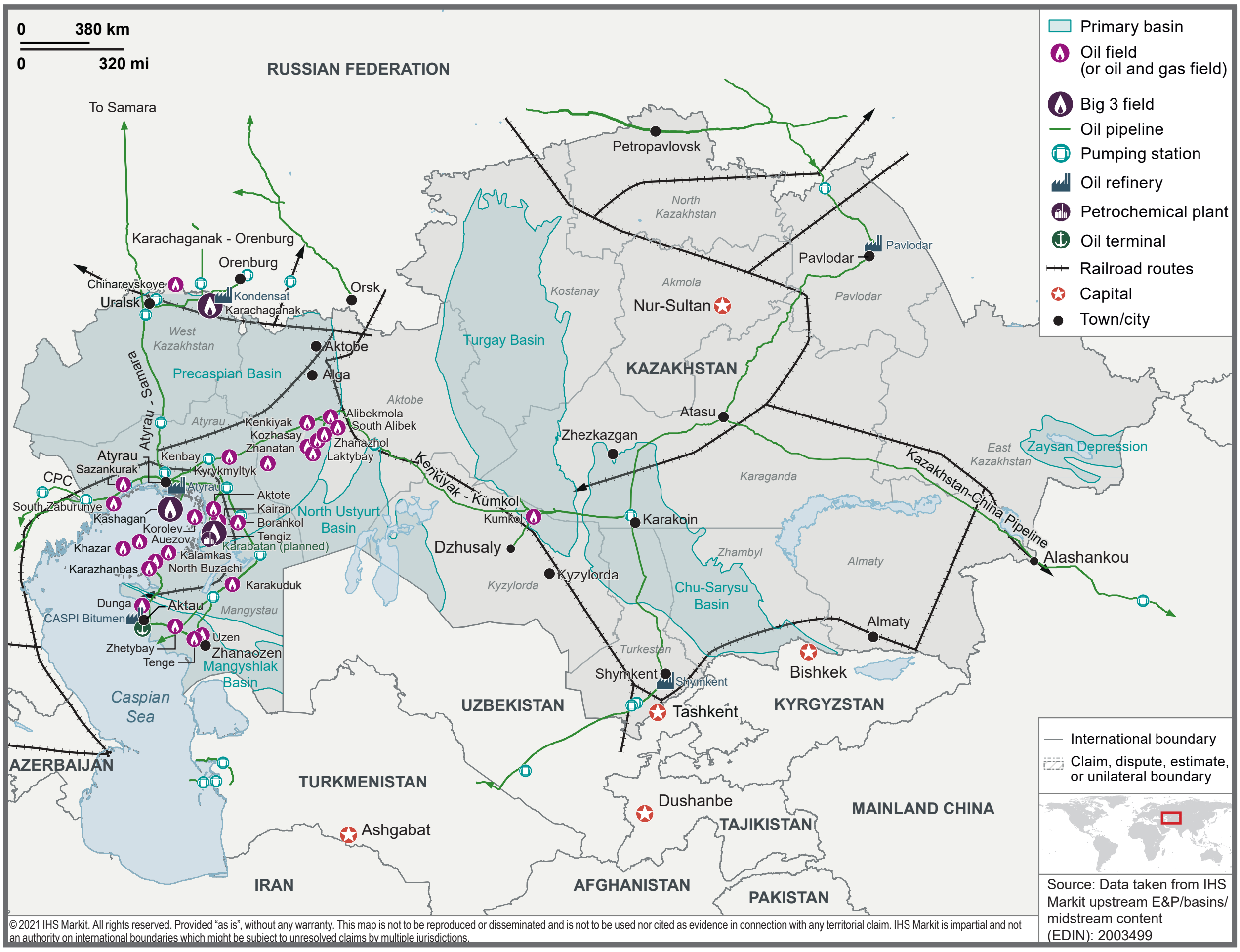


Table 3.2 Kazakhstan's proven and probable oil and condensate reserves, 1 January 2019 (MMt)

	A+B+C1	C2	A+B+C1+C2
Crude oil	2,900	1,630	4,530
Condensate	333	88	420
Total	3,232	1,718	4,950

Source: Subsoil user data

the average annual state spending on exploration over the last decade. State initiatives also include a program to modernize infrastructure for storing geological materials and digitalization of archives, so as to provide online access. Full-scale development of new discoveries is more uncertain, especially without improvements in the overall business environment; in the current IHS Markit outlook, crude oil production from the YTF category nevertheless becomes fairly significant, amounting to over a third of national output by 2050.[4]

3.3.2 Production trends for oil and gas condensate (historical and outlook)

Following the above-noted 2020 decline, we expect national output to remain about the same in 2021, coming in somewhere around 86 MMt (1.8 MMb/d) – as the country's oil industry is assumed to operate fairly closely to its OPEC+ targets. The "Big 3" mega projects led by international oil companies (IOCs) – Tengiz, Kashagan, and Karachaganak – remain the chief factors in Kazakhstan's oil production profile, and the "Big 3" in aggregate accounted for 62.8% of the national production total in 2020, up from 60.9% in 2019. Aggregate "Big 3" output fell by only 2.6% in 2020, as a Tengiz production decline slightly exceeded an aggregate rise in output from Kashagan and Karachaganak. In contrast, legacy producers in western Kazakhstan and in Kyzylorda and Aktobe oblasts registered declines last year of 7.3%, 17.2%, and 21.9%, respectively (see Figure 3.3 Monthly oil production of selected companies in Kazakhstan, 2019-21, and Table 3.3 Kazakhstan's "Big 3" upstream projects (selected key features)).[5]

One wildcard for Kazakh oil production during 2021-25 is a possible extension of the OPEC+ cuts program beyond the current end date of the mega deal (December 2022), along with the response by Kazakh policymakers to any additional Vienna Alliance cuts programs after 2022. Any OPEC+ calls for output constraints beyond 2022 would present Kazakhstan with a dilemma, since Kazakhstan oil output will enter a substantial new growth phase starting in about 2024, with the expected expansion of two of the "Big 3" projects. Kazakhstan is likely to remain engaged with OPEC+ for some time to come, given the country's overriding interest in a price "floor" that will probably continue to depend on management of global oil markets through periodic producer restraint. But the degree of this engagement is an open question. Whereas Russia has made Vienna Alliance cooperation an integral part of its official energy strategy over the next 15 years – corresponding to the period to the mid-2030s when world oil demand is expected to peak – the duration of Kazakhstan's participation after the winding down of the current mega deal remains more uncertain, and may well be contingent on OPEC+ flexibility with respect to Kazakh quotas in light of the "Big 3" production trajectories. However, by the late 2020s Kazakhstan is likely to be increasingly in the same camp as other OPEC+ members, as Kazakh oil production declines. But the upstream Kazakh dynamics in our base case will not automatically lead to increased Kazakh cooperation with OPEC+ longer term; other key considerations include the relative importance that Kazakh policymakers attach to oil price support through production management versus the potential gains from a strategy of maximizing output at lower prices before markets for Kazakh oil exports contract in connection with the global energy transition.

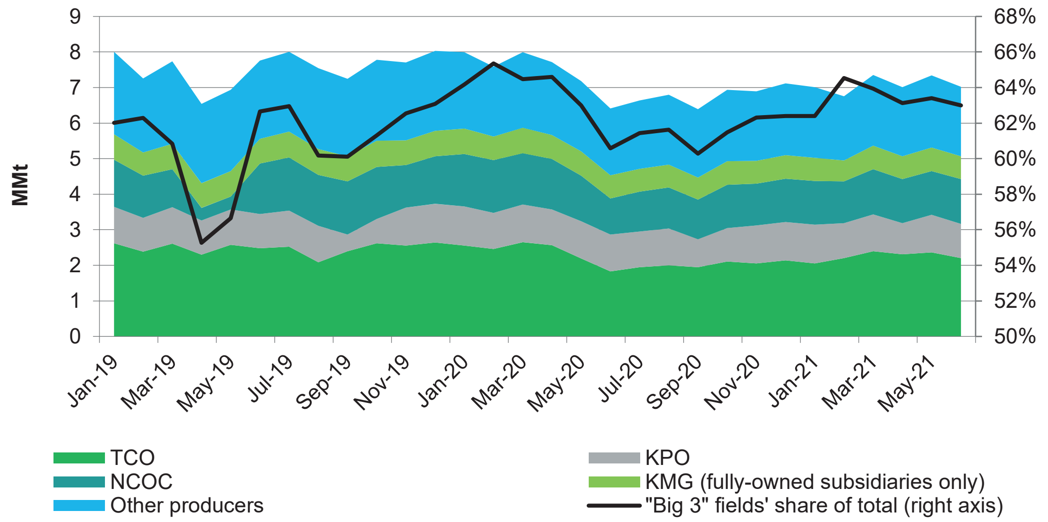
With respect to the period 2022-25 more specifically, our outlook is for Kazakh oil production to ramp up substantially over these years. Specifically, in the IHS Markit base case, Kazakh oil production reaches a maximum of 102.3 MMt (2.17 MMb/d) in 2025 – a 19% rise compared with 2020 volumes – and then slowly falls to 73.4 MMt (1.53 MMb/d) in 2050. There are alternate high and low production cases that reflect different assumptions (see Figure 3.4 Outlook for Kazakhstan's oil production by scenario). The main Kazakh developments driving the overall production trend are the three aforementioned "mega" projects. The "Big 3" projects' aggregate share of total Kazakh oil production reaches a maximum of around 73% in 2030 in the base case, before contracting to around 58% by 2050. However, besides the "Big 3," the fully-owned production subsidiaries of KMG – EmbaMunayGaz (EMG), OzenMunayGaz (OMG), and KazakhTurkmunay (KTM) – and a host of smaller projects also contribute to Kazakhstan's oil development, albeit less prominently. Importantly, we also assume only a relatively slow decline in Kazakhstan's older, legacy fields (especially in western Kazakhstan), given the growing application of new technology and improved production practices. However, as discussed below in more detail, our current base case envisions a smaller contribution than before from shelf projects to Kazakhstan's production profile longer term, due in part to the termination in 2019 of plans for co-development of the Kalamkas-more and Khazar offshore projects (see Figure 3.5 Outlook for Kazakhstan's oil production by major project/region to 2050 in the base case).[6]

4 See the IHS Markit Scheduled Update *Kazakhstan Crude and Condensate Supply Profile – 2nd Quarter 2021,* 11 June 2021.

5 COVID-19 took a heavy toll on Kazakhstan's oil field service sector, which saw a 25% decline in revenue last year, to $6.7 billion. Key indicators of the impact of the spending contraction on upstream operations include the drop in the number of completed oil and gas wells by around 27%, to 807 in total. TCO accounted for 72% of the service sector market in 2020 (as the ramp-up of the Tengiz field expansion project generated the bulk of new expenditure), followed by KPO (8%), NCOC (7%), and KMG's MangistauMunayGaz (MMG) subsidiary (3.5%). See "Obzor nefteservisnogo rynka Kazakhstana – 2020," Deloitte, accessed at: *https://www2.deloitte.com/content/dam/Deloitte/ru/Documents/energy-resources/Russian/oil-gas-survey-kazakhstan-2020.pdf*

6 At last report (August 2021), Kazakh authorities were forecasting total national oil output of 85.3 MMt (1.79 MMb/d) this year, while the Ministry of Economy has forecast Kazakh oil output of 87.9 MMt (1.85 MMb/d) in 2022, rising to 107.4 MMt (2.26 MMb/d) in 2026. Oil production targets for the period after 2026 are not specified, but prior to the pandemic the Energy Ministry envisioned national output reaching a maximum of 113 MMt (2.38 MMb/d) in 2031.

Figure 3.3 Monthly oil production of selected companies in Kazakhstan, 2019–21



Source: IHS Markit, Infotek, Ministry of Energy RK © 2021 IHS Markit

Table 3.3 Kazakhstan's "Big 3" upstream projects (selected key features)

Project	Current Shareholders	Con-tract term	Capex incurred to date	Fields	Location***	Liquid reserves****	Liquids production in 2020	Share of local content in 2020 (selected examples)
TCO*	Chevron (50%), ExxonMobil (25%), KMG (20%), and LukArco (5%)	1993-2033	over $135 billion	Tengiz, Korolev	Atyrau Oblast	3.4 billion metric tons (27.1 billion bbl) of estimated oil in place, of which 3.2 billion metric tons (25.5 billion bbl) in Tengiz	26.5 MMt (576,000 b/d) of oil	92% of TCO full-time employees, 84% of FGP-WPMP employees
NCOC**	Eni, ExxonMobil, Shell, and Total with 16.81% each, Samruk-Kazyna (8.44%), KMG (8.44%), CNPC (8.33%), and INPEX (7.56%)	1997-2041	over $60 billion	Kashagan, Kashagan Southwest, Aktote, Kairan	Caspian Sea (Atyrau oblast)	1-2 billion metric tons (9-13 billion bbl) of recoverable oil	15.1 MMt (322,000 b/d) of oil	9.7% of goods, 67.3% of employees, and 47.2% of services
KPO**	Shell (29.25%), ENI (29.25%), Chevron (18%), LUKOIL (13.5%), and KMG (10%)	1995-2037	over $22 billion	Kara-chaganak	West Kazakhstan Oblast	9.0 billion bbl of condensate initially in place (equates to around 1.1 billion metric tons)	12.2 MMt (277,000 b/d) of gas condensate	16% of goods, 73% of employees, and 80% of services*****

*TCO is structured as a JV.

**PSA project.

***All of the elds are geologically part of the Precaspian Basin.

****Latest available estimate from consortium.

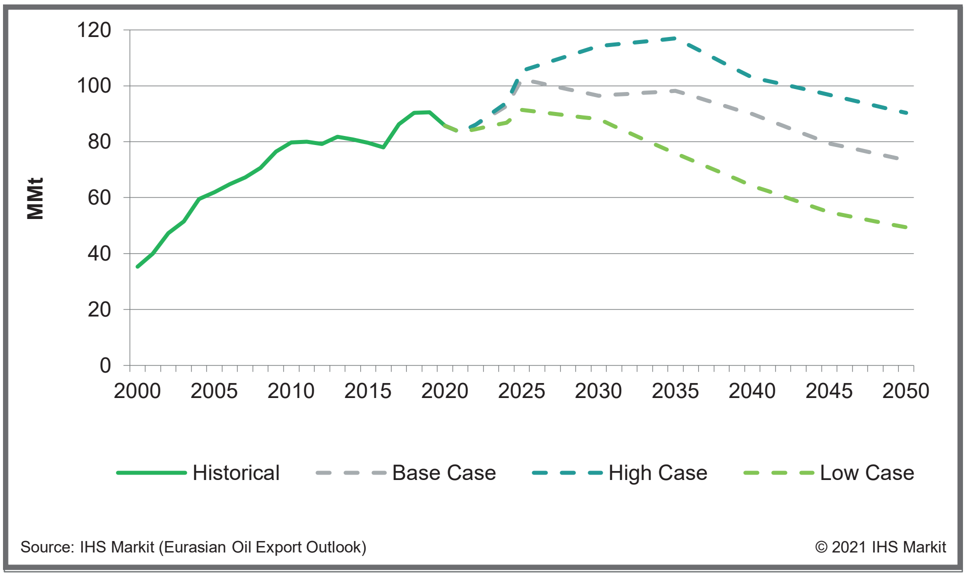
*****Kazakh residents comprise 95% of technical workforce, and 77% of project leadership.

Source: IHS Markit, consortium reports, TOO PSA © 2021 IHS Markit

Historically, IHS Markit has become increasingly pessimistic about new sources of liquids production in Kazakhstan, and this is reflected in the progressive reduction in our base case for maximum Kazakh output over time. Changing global demand, limited investor appetite, and the impact of the energy transition on liquids demand makes it increasingly challenging to sanction new, large offshore projects without a substantial improvement in fiscal terms. More likely with the energy transition is a shift in upstream investment away from traditional greenfield mega projects, especially given the heightened risks associated with full-scale development of such plays as global peak oil demand looms. Upstream operators worldwide have typically shifted from expensive, large-scale, single-project investments to small- or medium-scale projects, and those ventures with multiphase expansion opportunities with economical break-even prices are expected to fill in the majority of new source conventional crude oil production over the next two decades.[7]

Among the key differences between the latest IHS Markit outlook and the earlier base case presented in *The National Energy Report 2019* is a substantial scaling back of the expected contribution from the "other offshore" category (i.e., new offshore production in addition to Kashagan).[8] Prospects for new offshore production were dealt a major blow in the last quarter of 2019 with the collapse of a tentative co-development project for two key fields. In October 2019, the North Caspian Operating Company (NCOC) and the Shell-led Caspi Meruerty Operating Company (CMOC) shelved plans to co-develop the NCOC Kalamkas-more and CMOC Khazar offshore fields after concluding that the project was insufficiently competitive versus other opportunities. There are still some positive countervailing offshore development trends, however. For example, during the past year LUKOIL and KMG expanded their initial plans for collaboration in the Kazakh sector of the Caspian Sea, in particular with an October 2020 agreement spelling out terms for a planned joint venture (JV) to develop the Al-Farabi block (known formerly as the I-P-2 block), following KMG's expected

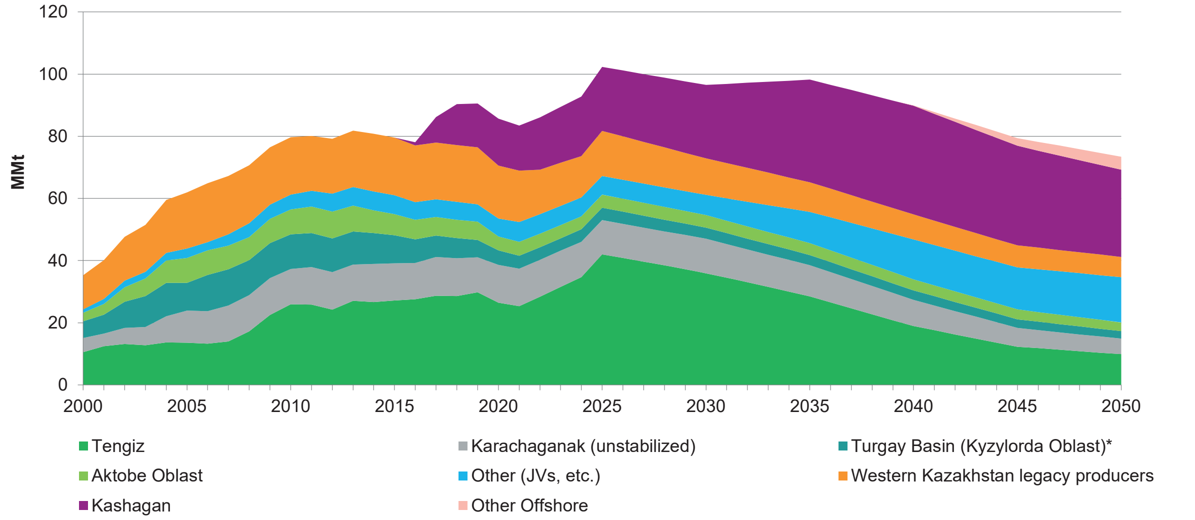
Figure 3.4 Outlook for Kazakhstan's oil production by scenario



7 See the IHS Markit Scheduled Update *Global Crude Oil Cost Curve in the energy transition era,* 7 September 2021.

8 Production from the "other offshore" component was previously expected to begin in 2029 and rise to 15.2 MMt (323,000 b/d) by 2040 (the latest year of the earlier scenario); in the current IHS Markit base case, "other offshore" output does not begin until 2040 and only reaches 4.2 MMt (89,000 b/d) in 2050.

Figure 3.5 Outlook for Kazakhstan's oil production by major project/region to 2050 in the base case



Notes: *Includes Amangeldy in Zhambyl Oblast.
Source: IHS Markit (Eurasian Oil Export Outlook)

acquisition of the license to the acreage (in June 2021, LUKOIL signed an agreement envisioning the purchase of a 49.99% stake in the JV). Moreover, President Tokayev announced that LUKOIL would be participating in Khazar and Kalamkas-more development during a September 2021 Russia-Kazakh interregional cooperation forum. And in 2019, ENI Isatay B.V., KMG, and Kazakhstan's Ministry of Energy signed the Abay offshore block hydrocarbon E&P contract. But the economics of offshore Kazakh projects are difficult in current conditions, especially in light of the typical dependence of such ventures on imported equipment and services (denominated in dollars).

The following sections look more specifically at key recent dynamics for the top oil producers in Kazakhstan, and provide our base-case expectations for their future evolution.

Tengiz consortium (TCO)

Located in Atyrau Oblast, the Tengiz project remains the largest Kazakh oil development by production, accounting for 30.9% of national oil output in 2020 (the Tengizchevroil operating entity was also still the largest taxpayer and contributor to the national economy in Kazakhstan last year). TCO output decreased by 11.2% in 2020, to 26.5 MMt (576,000 b/d); the Tengiz project thus accounted for 68% of the 4.9 MMt (101,000 b/d) decline in aggregate Kazakh oil production last year. The challenges to TCO operations in 2020 posed by the global oil demand collapse and OPEC+ restrictions were compounded by widespread COVID-19 infections among Tengiz personnel during the initial phase of the pandemic – accounting for over 10% of Kazakhstan's total confirmed coronavirus cases within about a month of the outbreak; this occurred at one of the TCO field camps in April 2020.

TCO attempted to minimize the negative impact of the disease on company personnel and field operations through a vigorous and systematic response. Following the initial outbreak, Chevron announced a temporary reduction of activity (though activities of most critical importance were apparently uninterrupted), and around two-thirds of the Tengiz workforce of over 30,000 was temporarily evacuated from the Tengiz field in an effort to limit the spread of the virus. In September 2020, TCO began relocating personnel back to the field in monthly increments (4,500 to 5,000 employees per month), and the Tengiz workforce numbered 34,000 employees at the end of 2020.

In our base case, TCO production returns to a growth trajectory during 2022-25. The key driver of Tengiz growth during the next few years is the Future Growth Project (FGP) and Wellhead Pressure Management Project (WPMP) (collectively known as FGP-WPMP). Designed to add 12 MMt/y (260,000 b/d) of capacity, FGP-WPMP now has a price tag of $45.2 billion following the consortium's fall 2019 upward revision of its cost estimate. One important milestone in 2020 was the completion of the planned three-year "Sealift" program involving transportation of 408 large modular cargo items from various international locations.[9] The project was 84% complete in July 2021, and the WPMP component is now scheduled to start up in mid-2023, while the FGP component is expected to be online by mid-2024. We envision a maximum output of 42.0 MMt (915,000 b/d) in about 2025 by TCO in our base case. For Tengiz longer

9 The impact of COVID-19 on global supply chains was a worry in 2020, at least initially, but appears to have been a relatively minor issue, partly because the consortium had already imported 80% or so of the equipment needed for this project before the worldwide lockdown. TCO was able to offset an estimated $1.9 billion in incremental expenses associated with the pandemic through cost reductions and from favorable exchange rate dynamics.

term, a critical point will be the government's decision on whether to take over operations in 2033 when the current JV expires, as this will likely affect the overall rate of decline longer term. In our current base-case outlook, Tengiz output slowly contracts to about 9.9 MMt (216,000 b/d) in 2050.

Kashagan consortium (NCOC)

Output from the Kashagan field, located around 80 km offshore from Atyrau, amounted to 15.1 MMt (322,000 b/d) in 2020, a rise of 7.2% year on year, and accounted for 17.7% of the Kazakh total last year. The field can now regularly operate at sustained levels of 370,000 b/d, the designed output level for Phase 1, following a maintenance turnaround that took place in the spring of 2019. But because of demand limitations and the OPEC+ agreement, production currently remains constrained.

IHS Markit's base case is for Kashagan output to decline slightly this year, but return to a growth trajectory in 2022. Our near-term outlook assumes completion in the early 2020s of a planned debottlenecking project that boosts Phase 1 sustained production by an additional 80,000 b/d, to 450,000 b/d, by increasing gas compression and injection capacity offshore.

Kashagan's longer-term production profile – particularly the scheduling and scale of a proposed Phase 2 – is the main wildcard in the outlook for Kazakh output overall going forward. The consortium is under pressure from Kazakh authorities to finalize a "full-scale" development plan by end of this year. In any event, however, FID for the first stage of Phase 2 is not slated to occur until 2023, according to KMG. Clearly, the Kazakh authorities must convince the NCOC shareholders that Phase 2 oil is "advantaged" relative to other projects in their overall portfolio.

The most recent Phase 2 development plan announced by KMG earlier this year in its annual report envisions a smaller total Phase 2 increment than previously envisaged. The new concept delivers slightly more oil sooner (earlier) than suggested by previous concepts, while then producing less oil in the longer term because the new plateau is lower.

Specifically, the new Phase 2 plan presented by KMG envisages an increase of field production in two stages, in the event that the consortium goes ahead with separate FIDs on both stages:[10]

- **Phase 2A: Increasing production to about 500,000 b/d. KMG expects FID in 2023, and start-up of the project in 2026.** This stage includes an option (undergoing technical review as part of the pre-FEED study) to supply up to 2 Bcm/y of raw gas to a new KazTransGas (KTG) processing plant (key gas supply terms have already been agreed with KTG).
- **Phase 2B: Raising output to a maximum of around 700,000 b/d.** KMG envisions FID in 2024, and start-up of the project in 2030. This stage includes the option (also part of the pre-FEED study) to supply 6 Bcm/y of raw gas to either TCO or KTG for processing.

Although the actual timing of FID remains a question mark, IHS Markit assumes that a modified Phase 2 will go forward. Kazakhstan's government also understands the challenge of staying attractive for this investment in a lower oil price environment. The government could extend the PSA and reduce the project royalty as part of this process. In the IHS Markit base case, Phase 2 makes Kashagan the largest producing Kazakh field in the mid-2030s, reaching maximum output of 35.0 MMt (743,000 b/d) in 2040, after which production declines to 28.0 MMt (595,000 b/d) in 2050 (see Figure 3.6 Kashagan's production outlook: Changing expectations).

Karachaganak consortium (KPO)

The Karachaganak Petroleum Operating BV (KPO) consortium registered a 7.8% rise in (unstabilized) liquids production in 2020 to 12.2 MMt (277,000 b/d), representing around 14.2% of the national total last year. Meanwhile the amount of stabilized liquids produced within Kazakhstan also increased by 7.8%, to 10.6 MMt (229,000 b/d).[11] The Karachaganak field mainly produces condensate, so operations are not constrained by the OPEC+ deal, given the condensate exemption that the Vienna Alliance granted Kazakhstan in 2020.

The field's future production profile is designed to maintain liquids production at around 10-11 MMt/y (roughly 230,000-250,000 b/d) in the longer term through increased gas reinjection. The Karachaganak Gas Debottlenecking (KGDBN) project, launched in 2018 and completed in March 2021, will help maintain output of condensate, while another such initiative – the Fourth Injection Compressor project – is scheduled to be commissioned in the fall of 2021.

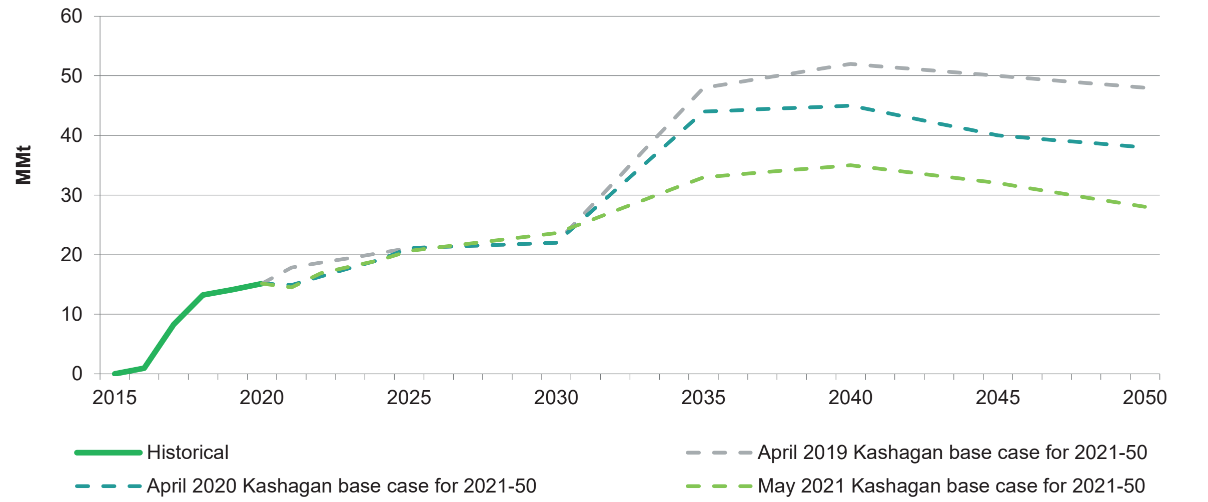
Late in 2020, the Karachaganak consortium and the government finally reached a general and amicable settlement of a long-standing dispute over cost recovery issues that, in turn, paved the way for construction of the Fifth Injection Compressor and associated facilities, within the larger framework of a project known as PRK-1A (or KEP-1A). A decision to proceed with this project was made in December 2020; it is expected to be completed by 2025.[12] In our base-case scenario, KPO output remains

10 KMG Annual Report 2020, p. 57.

11 Raw liquids production loses approximately 18-19% of its volume in the process of stabilization, now undertaken entirely at the field itself (previously some of this took place in Russia).

12 The December 2020 final settlement agreement reached between KPO and the Kazakh government was along much the same lines as envisioned in the 2018 "agreement on principles"; see the IHS Markit Insight *Karachaganak partners and Kazakhstan finally resolve their long-standing dispute*, 17 December 2020.

Figure 3.6 Kashagan's production outlook: Changing expectations



Source: IHS Markit (Eurasian Oil Export Outlook)

stable at 10-11 MMt/y through the mid-2030s, before subsequently tailing off to about 5 MMt/y (114,000 b/d) in 2050.

KazMunayGaz (KMG)

The oil production of KMG's fully-owned subsidiaries was down 6.3% in 2020, to 8.0 MMt (around 168,000 b/d), or 9.3% of the Kazakh total (if counting all of KMG's equity production, including stakes in the "Big 3" projects and its JVs, the company's share of national output was 25.6% in 2020).[13] Nonetheless, KMG has felt relatively little of the burden of the OPEC+ cuts, reflecting the fact that KMG exports a comparatively smaller share of its output (given its domestic market delivery obligations), and was therefore required to reduce production less under the terms of Kazakhstan's "export ratio" OPEC+ cuts formula.

Our base case is for a continued long-term secular fall of legacy KMG output, that may nevertheless be attenuated through improved decline rate management at the mature fields that constitute the bulk of KMG's producing portfolio. KMG's ongoing energy saving and efficiency program, a process that involves year-on-year and peer benchmarking, should also help to keep upstream costs manageable or even reduce them. For example, KMG reported implementation in 2020 of 55 such initiatives with target annual fuel and energy savings on the order of 0.9 million gigajoules (6.9 million kWh of electric power, 10,300 metric tons of fuel, and 11.8 million cubic meters (MMcm) of natural gas). The initiatives include upgrades to processing equipment and greater development of the KMG Group's own power generation assets, including on-site generation fueled by associated gas.[14]

The Chinese-owned equity share of Kazakh oil production

The state-owned China National Petroleum Corporation (CNPC) remains another key player in the Kazakh upstream, where its main assets include majority stakes in CNPC-AktobeMunayGaz and PetroKazakhstan.[15] In 2020, the Chinese-owned equity share of Kazakhstan's oil production (including not only CNPC but other Chinese companies) was 13.8 MMt (290,000 b/d) or 16.1% of the national total, compared with 15.6 MMt (329,000 b/d) and 17.3% in 2019.

Smaller ("independent") companies

In 2020, a total of 82 smaller ("independent") companies produced 12.3 MMt (259,000 b/d) of oil or 14.5% of the total output in the country. This was down by 9.8% compared to 2019. The potential for the independents' production growth is limited by many factors; regulatory, fiscal, and contractual rules continue to impact smaller producers more strongly than larger companies overall. But these companies still hold resources that provide significant upside potential. Notwithstanding the difficult investment environment and their relatively small production volumes recently, the smaller producers' "economies of specialization" could contribute significantly to both incremental new field development and brownfield rehabilitation in Kazakhstan, given the right mix of incentives.

13 Another key indicator of the deterioration of the global investment climate in 2020 was KMG's May 2020 announcement of postponement of an initial public offering (IPO) that was previously expected to go forward in autumn of 2020. The final decision on the timing and scale of any KMG IPO rests with Samruk-Kazyna, the sovereign wealth fund, which holds a 90.4% stake in the company. For background, see https://kapital.kz/finance/86726/kazmunaygaz-ne-vyydet-na-ipo-v-2020-godu.html

14 KMG Annual Report 2020, p. 101.

15 For additional background on CNPC's upstream activity in Kazakhstan, see *The National Energy Report 2015,* pp. 99-101.

3.4 Crude Oil Transportation

Oil transportation remains a critical issue for Kazakhstan, especially since the country is landlocked and oil exports loom so large in the overall Kazakh oil balance. Kazakh oil exports contracted along with national oil production in 2020, but are expected to begin growing again on an annual basis in 2022 and reach new heights in the mid-2020s before entering a long-term decline trajectory.

The Caspian Pipeline Consortium (CPC) pipeline, transiting Russia and terminating at the Black Sea terminal of Yuzhnaya Ozereyevka, handled an increasing share of Kazakhstan's rising oil export volume for several years prior to 2020.[16] An ongoing pipeline debottlenecking project will facilitate a resumption of the rise in CPC's share of the Kazakh oil export total in the near to medium term, as the country's total exports rebound. CPC remains the chief outlet for Kazakh oil exports throughout the scenario period to 2050. Through the mid-2020s, CPC is likely to see a marked increase in throughput compared with pre-pandemic volumes. The rise in CPC volumes will be facilitated in part by a $600 million CPC debottlenecking project that is on track to boost capacity to at least 72.5 MMt/y, or 1.45 MMb/d (or around 78 MMt/y, or 1.56 MMb/d, with drag-reducing agents) by 2023 or sooner – in time to accommodate incremental Tengiz production following completion of FGP.

Kazakhstan's "multi-vector" export strategy means that Kazakh oil will continue to be evacuated via multiple routes. Despite the overall decline, for example, the Kazakhstan-China Pipeline (KCP) is expected to handle increased export volumes during the scenario period.[17]

Total Kazakh shipments via KCP, not including Russian transit crude (much of it swapped for deliveries to the Pavlodar refinery), dropped by 46.5% in 2020 to 0.5 MMt (10,000 b/d) – only 0.7% of total Kazakh oil exports last year – as Kazakhstan relied more on long-haul tanker shipments via westward outlets to increase exports to China last year. The price at the Chinese border for Kazakh oil exported via KCP remains a key factor limiting exports in that direction, because the border price is set too low (at around Brent minus $5.70/bbl) to stimulate a large-scale increase in shipments from western Kazakhstan. Relatedly, China's main consuming centers on the east coast, accessible via long-haul tanker shipment, remain the primary demand growth points within the country as opposed to refineries in western China linked to KCP.

16 CPC shareholders are the Russian Federation (31%; represented by Transneft with 24% and CPC Company with 7%), Kazakhstan (20.75%; represented by KMG with 19% and Kazakhstan Pipeline Ventures LLC with 1.75%), Chevron Caspian Pipeline Consortium Company (15%), LUKARCO B.V. (12.5%), Mobil Caspian Pipeline Company (7.5%), Rosneft-Shell Caspian Ventures Ltd. (7.5%), BG Overseas Holding Ltd. (2%), Eni International N.A. N.V. (2%), and Oryx Caspian Pipeline LLC (1.75%).

17 KCP is owned 50-50 by KazTransOil and the CNPC subsidiary China National Oil and Gas Exploration and Development Corporation (CNODC).

The expected completion later in 2021 of a long-standing project to reverse the flow of the Kenkiyak-Atyrau pipeline segment (from west to east) will nevertheless allow KCP to regularly access up to 6 MMt/y (120,000 b/d) from the main oil-producing area in northwestern Kazakhstan near the Caspian Sea.

3.4.1 Recent export trends and outlook to 2050

Kazakhstan's crude oil and condensate exports fell overall by 2.5% in 2020 to 68.5 MMt (1.37 MMb/d), with significant variation via destination and route. Kazakh exports to European destinations (primarily via CPC and Transneft outlets on the Black Sea and Baltic Sea) remained virtually the same in 2020 as in 2019, at 54.1 MMt (1.08 MMb/d), although the European share of Kazakh exports dipped slightly, from 77.3% of the total in 2019 to 76.6% in 2020. The drop in deliveries to European destinations was concentrated in Western Europe (except Italy, which remained the single-largest importer of Kazakh oil at the country level). Meanwhile, Kazakhstan increased exports substantially to other parts of Europe (e.g., Central Europe, the Balkans, and the Baltics).

Oil exports to Asia Pacific destinations contracted by only 0.8% to 13.3 MMt (266,000 b/d), and the Asia Pacific share of Kazakhstan's exports declined from 19.1% in 2019 to 18.8% in 2020 – notwithstanding a surge in aggregate Kazakh exports to China, by more than 50% last year, to 3.8 MMt (76,000 b/d). The downward trend in total Kazakh exports to Asia Pacific markets was largely due to the collapse of Kazakh exports to South Korea. Traditionally the main importer of Kazakh oil east of the Suez (and the biggest Asia Pacific buyer of CPC Blend in particular), South Korea cut its imports of Kazakh oil by 61% in 2020 to only 2.3 MMt (46,000 b/d). At the same time, Kazakh exports to destinations other than Europe and Asia Pacific markets jumped by 30.8% to 3.2 MMt (64,000 b/d) last year, lifting the combined share of these markets from 3.5% of the total in 2019 to 4.6% in 2020; Uzbekistan was one of the key components (see Figure 3.7 Distribution of Kazakhstan's oil exports by regional destinations, 2019-20; and Figure 3.8 Kazakh oil exports: Main outlets in 2020 and percent change year on year.)

Longer term, export trends are expected to largely follow the national oil production dynamic. Overall Kazakh oil exports return to a growth trajectory in 2022, and reach a maximum of 83.2 MMt (1.66 MMb/d) in 2025, before entering a long-term decline that leaves 2050 export volumes around 26% lower than the 2020 total, at 51 MMt (1.02 MMb/d). European markets remain critical throughout the scenario period, but Asia Pacific markets take a growing share of the total (partly via increased long-haul tanker shipments from western export outlets as well as the KCP route) (see Figure 3.9 Outlook for Kazakhstan's crude oil exports to 2050 (primary routes/destinations)).[18]

18 For additional analysis and detail, see the IHS Markit Strategic Report *Eurasian Oil Export Outlook,* April 2021.

One significant change from *The National Energy Report 2019* in terms of the mix of export outlets is that we no longer include the Baku-Tbilisi-Ceyhan (BTC) pipeline as a route for Kazakh oil exports in any of our scenarios (whereas previously, Kazakh oil was expected to eventually reenter BTC). The prospects for the Kazakhstan-Caspian Transportation System (KCTS) developing into a major export route for Kazakh oil now seem fairly remote, and BTC is simply not needed by Kazakh producers given lower

Figure 3.7 Distribution of Kazakhstan's oil exports by regional destinations, 2019-20

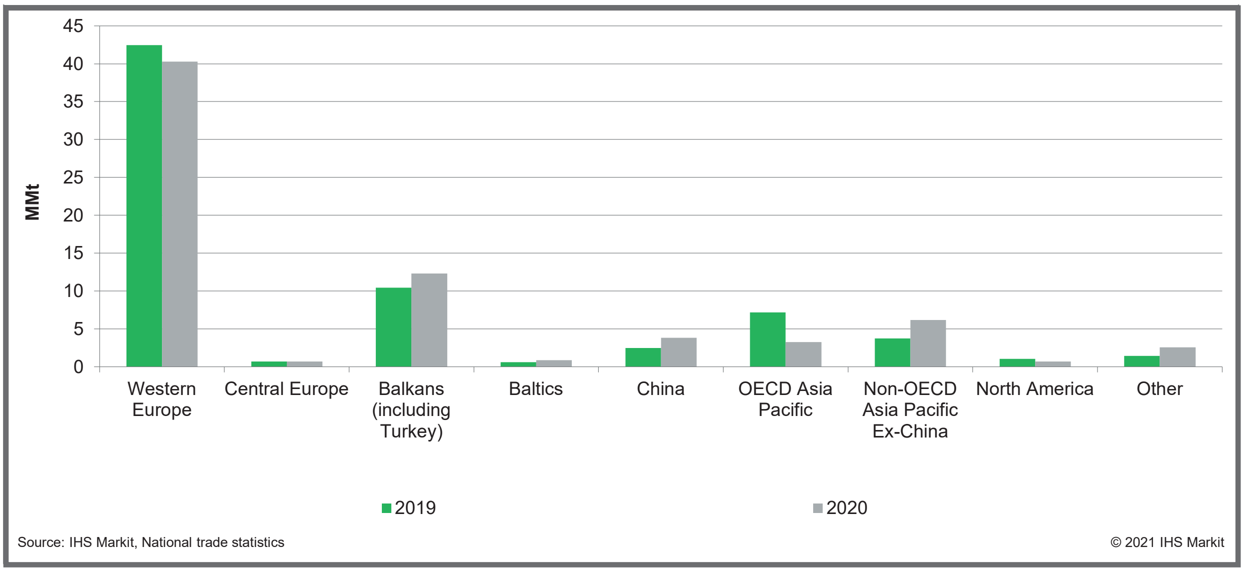


Figure 3.8 Kazakh oil exports: Main outlets in 2020 and percent change year on year

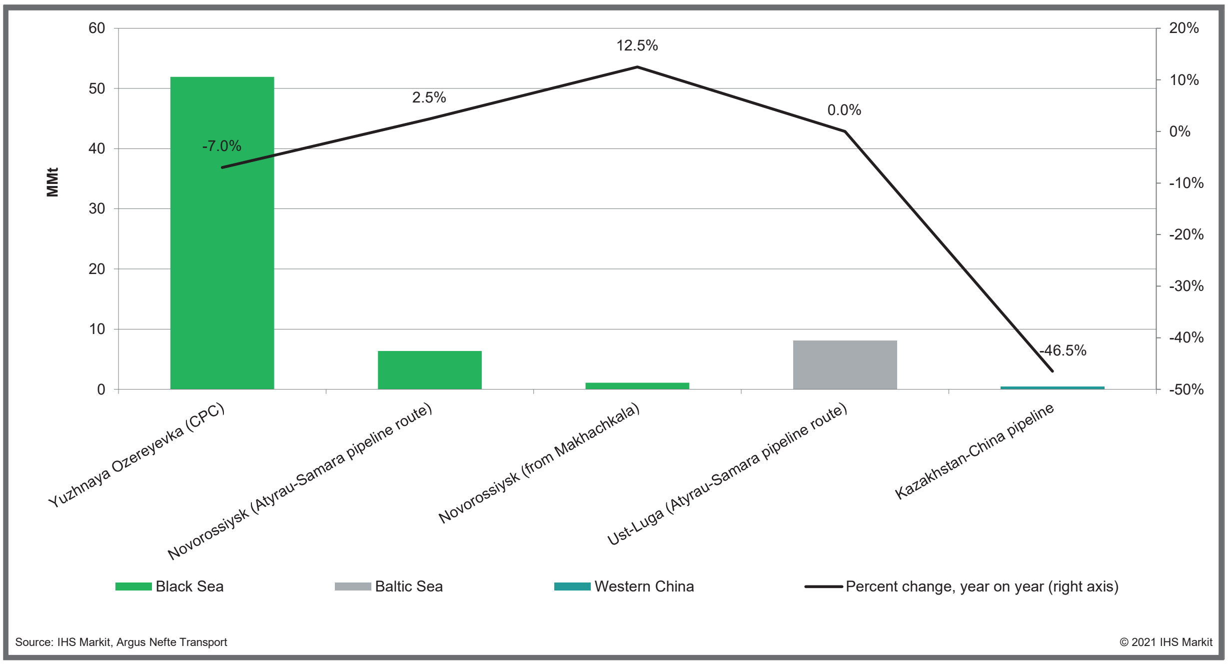
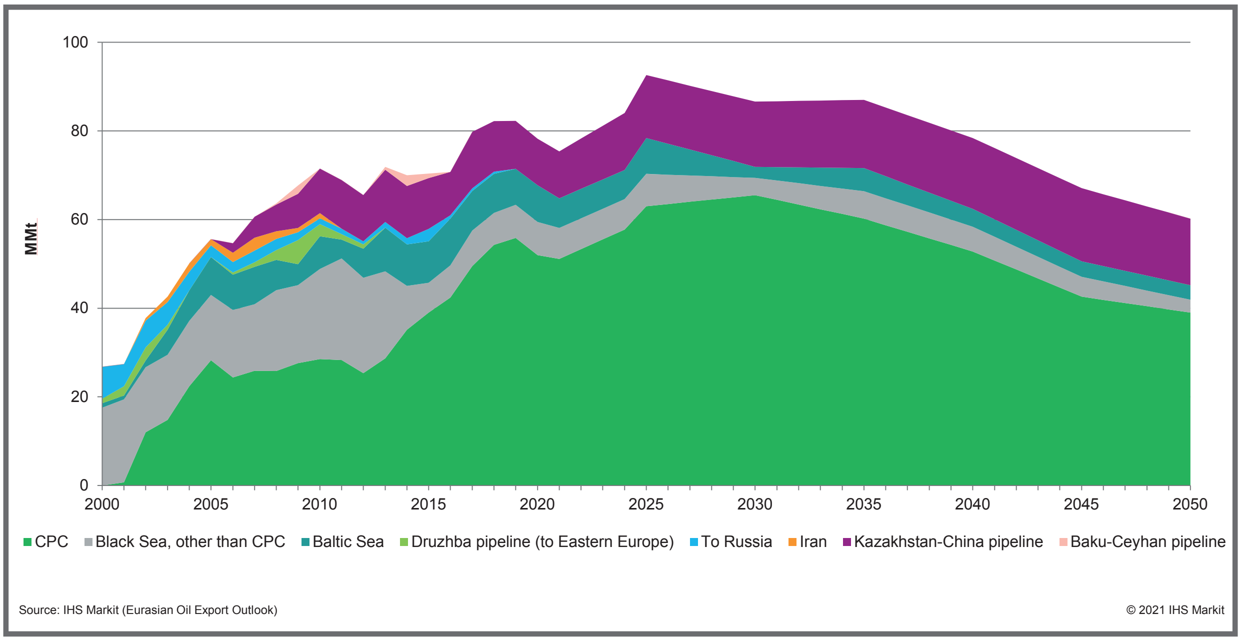


Figure 3.9 Outlook for Kazakhstan's crude oil exports to 2050 (primary routes/destinations)



overall exports and the more economical alternatives that are available.[19]

3.5 Overview of Regulations Governing Kazakhstan's Upstream Segment

Kazakhstan has taken important steps in recent years to improve the regulatory framework governing upstream investment, especially through implementation (starting in 2018) of amendments to both the Tax Code and the Subsoil and Subsoil Use Code (hereafter, Subsoil Code). The Tax Code changes were designed (in part) to incentivize investors to choose a simplified alternative tax regime in lieu of the existing tax system, while the Subsoil Code amendments were geared to simplify and accelerate the process for awarding licenses and signing contracts.[20]

Much remains to be done, however, if Kazakhstan is to compete effectively for the more limited global capital available to finance upstream activity going forward. As indicated by Kazakhstan's recent ranking, it comes in at only the 63rd spot (out of 117 countries) in the rating of E&P attractiveness developed by IHS Markit's Petroleum Economics and Policy Solutions (PEPS) team. Kazakhstan's overall score of 4.09 (out of 10) in the PEPS ranking is comprised of a blend of scores representing oil and gas (above-ground) risk, country E&P activity and exploration success, and fiscal attractiveness. This places Kazakhstan below other large hydrocarbon-producing countries, such as Russia (see Figure 3.10 IHS Markit's E&P attractiveness ratings for select oil-producing nations in 2020).

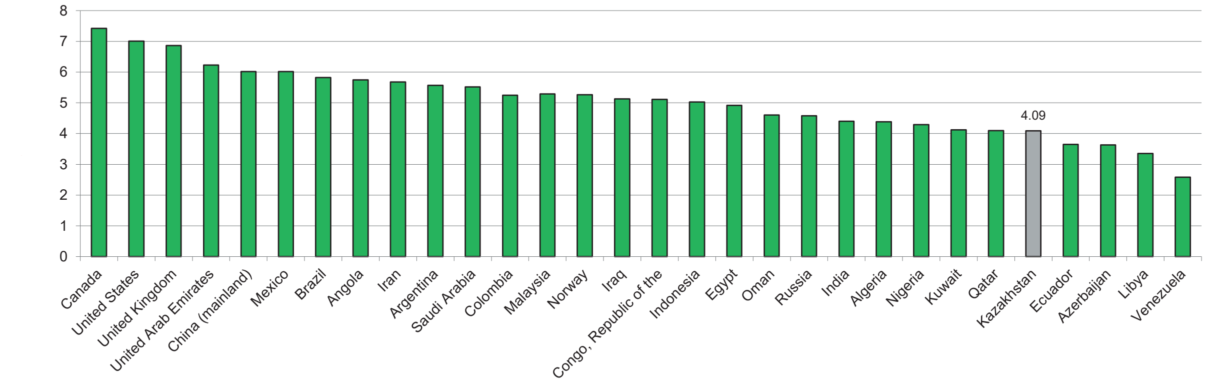
Looking more closely at the components that make up overall E&P attractiveness, it is clear that Kazakhstan suffers primarily from a low Fiscal Systems rating, which accounts for 35% of the overall score. This reflects factors such as a comparatively low rate of return for upstream investors in Kazakhstan, together with a relatively high government take. Adjustments to the country's petroleum fiscal regime may therefore be particularly critical to enable Kazakhstan to compete for investments against other mature hydrocarbon producers and regional peers.

The following sections examine the evolution of Kazakh policy in several areas of primary concern to oil producers and recent actions by the government to stimulate upstream E&P activity. We first analyze the tax regime for upstream oil projects, and then turn to two other regulatory areas impinging significantly on the E&P business climate – subsoil licensing policy and local content requirements.

19 BTC shareholders are: BP (30.1%), SOCAR (25%), MOL (8.9%), Equinor (8.71%), TPAO (6.53%), ENI (5%), TotalEnergies (5%), Itochu (3.4%), ExxonMobil (2.5%), INPEX (2.5%), and ONGC Videsh (2.36%).

20 For background on the 2017 Subsoil Code and Tax Code reforms and remaining challenges, see *The National Energy Report 2017,* pp. 69-73; *The National Energy Report 2019,* pp. 59-61; and the IHS Markit Profile *Kazakhstan: Oil & Gas Risk Country Profile, March 2021,* 11 March 2021.

Figure 3.10 IHS Markit's overall E&P attractiveness ratings for select crude oil producers in 2020



Notes: Ranking as of third quarter 2021 for 30 largest crude oil producers in 2020. The overall E&P attractiveness score is based on a weighting of the key sub-components of the rating as follows: Activity & Success Overall Rating (50%), Fiscal Systems Overall Rating (35%), Oil & Gas Risk Overall Rating (15%).
Source: IHS Markit (PEPS)

3.5.1 Fiscal terms for oil producers

Government take for Kazakhstan is classified as "high" (between 65% and 85%, according to IHS Markit methodology). Upstream producers in Kazakhstan are subject to a variety of taxes under the regular fiscal regime (see Table 3.4 Taxes applicable to subsoil users in Kazakhstan in 2021).

Three of these taxes account for a major share of total costs for the typical producer in Kazakhstan:

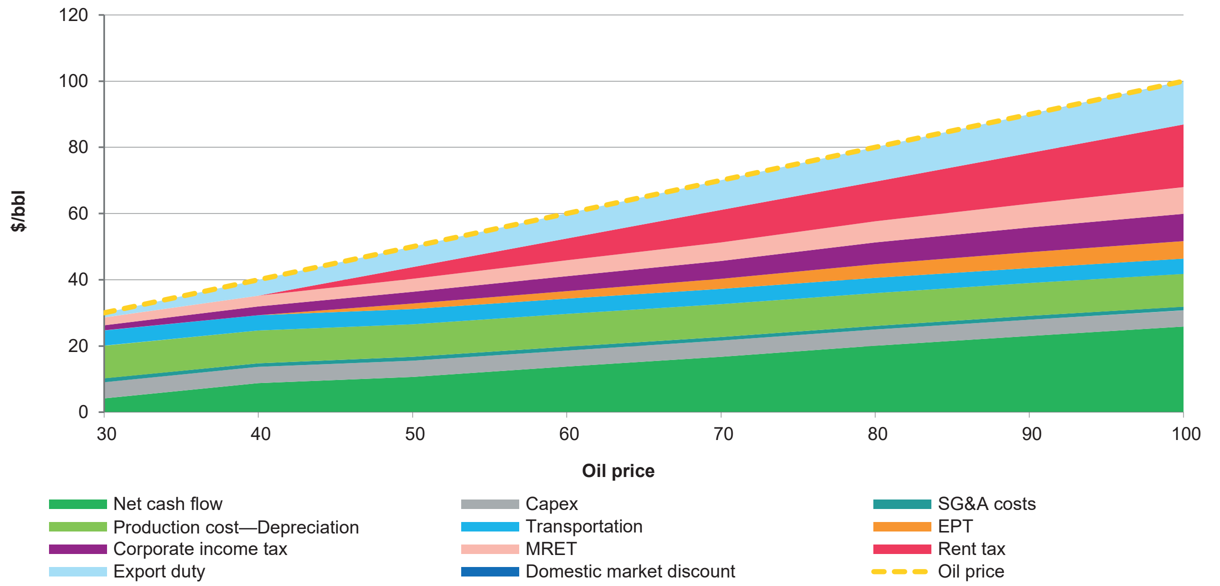
- **Mineral Resource Extraction Tax (MRET).**[21] The MRET is a royalty-like tax on crude oil and gas condensate production (and also natural gas output), and its ad valorem rate escalates depending on a company's annual production volume (but not price) – with different rates applicable depending on whether the crude is delivered to export markets or to the domestic market. Significantly, the MRET rate for crude oil exports is twice as high as the rate for domestic deliveries – ranging from 5% for smaller production volumes to 18% for larger production streams, compared with a range of just 2.5-9% for output delivered to the domestic market. The taxable base is gross revenue. For selected older fields with challenging economics, the Ministry of Energy often grants significant MRET reductions, and the MRET relief approval process for subsoil users was significantly simplified by the 2017 Subsoil Law in conjunction with the 2017 Tax Code.
- **Export duty.** The export duty on crude oil and condensate varies on a monthly basis according to a sliding scale tied to world oil prices: if the oil price is below $25/bbl the rate is zero, while if oil prices are in the range of $25-40/bbl, the duty rises from 5% of the oil price at $25/bbl to 12% of the price at $40/bbl and stays at this level until the price reaches $55/bbl, above which price the export duty rate escalates directly with the world oil price level.[22] Exports to EAEU markets are exempt from the export duty.
- **Rent tax on exports.** An unusual fiscal instrument in global practice, the Kazakh rent tax applies to the value of exported crude oil and gas condensate. The tax rate increases with the oil price once the price exceeds $40/bbl, ranging from 7% to 32%. In this respect, oil exports from Kazakhstan are subject to two types of export taxes.

Our calculation of Kazakhstan's tax take, based solely on the main statutory taxes – MRET, export duty, export rent tax, excess profit tax (EPT), and corporate income tax – increases with the oil price (and vice versa; it decreases with lower oil prices): it is below 20% of the crude oil price when the price is below $30/bbl, but rises to 40% for oil priced at $60/bbl, and increases to above 50% for crude oil prices above $100/bbl. IHS Markit estimates that for a producer exporting 100% of their output, the overall tax take as a share of oil price rises from 18% when oil is $30/bbl up to 54% when oil is $100/bbl (see Figure 3.11 Economics of Kazakhstan's oil production at different world oil prices (for 100% export)). Under the same 100% export scenario, tax take as a share of pretax cashflow is 35% when oil is $30/bbl and reaches 64% when oil is $100/bbl. Conversely, holding all other factors equal, and assuming only 20% of production is exported, tax take as a share of pretax cash flow remains at 35% when oil is $30/bbl, and reaches 60% when oil is $100/bbl

21 Kazakhstan introduced the Alternative Subsoil Use Tax (ASUT) in 2018 as an alternative to the MRET, but currently it applies only to selected technologically complex projects (continental shelf and deep horizons); for more on the ASUT fiscal regime, see Chapter 87 of the Kazakh Tax Code, accessible at https://nalogikz.kz/taxcode/2018/87

22 Kazakhstan's crude export duty rates are listed in US dollars per metric ton corresponding to oil price bands. The rates are established by the Ministry of National Economy, presented in the current legislation "On approval of the List of goods subject to export customs duties, the rate and duration of their validity, and the Rules for calculating the rate of export customs duties for crude oil and goods produced from oil"; see https://adilet.zan.kz/rus/docs/V1600013217

Figure 3.11 Economics of Kazakhstan's oil production at different world oil prices (for 100% export)



Notes: EPT = excess profit tax; SG&A = selling, general, and administrative expenses.
Source: IHS Markit

Table 3.4 Taxes applicable to subsoil users in Kazakhstan in 2021

Applicable tax	Rate/taxable base
Bonuses (signature)	Variable
MRET	0.5–18%
Excess profit tax (EPT)	0–60%
Rent tax on exports*	0–32%
Payment for compensation of historical costs	Variable
Excise tax on crude and gas condensate	0 tenge per metric ton
Alternative subsurface use tax (ASUT)	0–30%
Value-added tax (VAT)	12%
Crude oil export duty	Variable; levied per ton based on rates tied to global oil prices
Land tax	Usually immaterial for oil and gas producers
Property tax	1.5%
Environmental fees and charges	Variable
Other fees (e.g., fee for use of radio frequencies, fee for use of navigable waterways)	Variable
Other taxes and payments	Variable

Note: *0% tax rate if the global oil price is below $40/bbl.

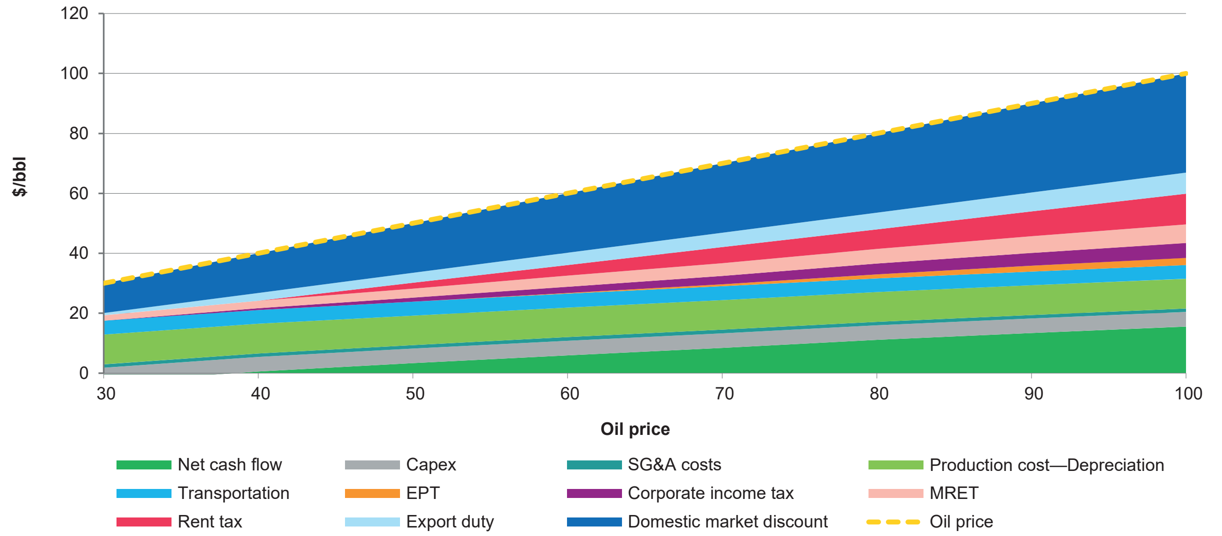
Source: Kazakhstan Tax Code

(see Figure 3.12 Economics of Kazakhstan's oil production at different world oil prices (20% export, 80% domestic sales)).[23]

23 At the same time, there are numerous significant costs that state policies impose on producers aside from direct taxes. One example is the compulsory contribution of subsoil users to R&D, amounting to 1% of production costs – a revenue stream over which oil companies may lose control entirely in coming years. While subsoil users can currently make such R&D contributions available to accredited scientific and educational institutes of their choice, in May 2021 the Energy Ministry announced plans to centralize these contributions by 2024 and use them to fund Kazakh scientific development priorities as determined by the government.

Further revisions to Kazakhstan's fiscal framework for upstream activity are currently in the planning stages. One key signpost to watch will be the outcome of the ongoing drafting of a more flexible fiscal alternative designed specifically for new oil and gas projects – named the Improved Model Contract (IMC). It offers would-be investors in new projects the option of an improved model concession contract that spells out incentivized fiscal terms in advance. The IMC would effectively complement the existing draft model concession contract (which would continue to apply for less complex upstream

Figure 3.12 Economics of Kazakhstan's oil production at different world oil prices (20% export, 80% domestic sales)



Notes: EPT = excess profit tax; SG&A = selling, general, and administrative expenses.
Source: IHS Markit

projects) currently enshrined in the Subsoil Code, and would apply to new exploration and production projects, as well as certain already discovered fields, and aims to stimulate commercial gas development. Eligibility for the IMC is defined by technical characteristics of the field or geographic location (offshore, subsalt, under-explored basins, etc.). The details of this planned reform are currently being finalized by Kazakh authorities – namely, the Energy Ministry, the Ministry of National Economy, the Ministry of Ecology, Geology, and Natural Resources (MEGNR), and the Ministry of Industry and Infrastructure Development – in consultation with a working group of the Foreign Investors' Council (an advisory organ established by order of the Kazakh government in 1998 to promote dialogue between state authorities and foreign investors). If all goes according to plan, the IMC terms will be finalized and written into Kazakh law by the end of 2021 or early 2022. While the IMC is not designed to be available to any already-producing projects, the IMC would be on offer for both yet-to-be-discovered fields and discovered but yet-to-be developed fields, subject to passing a set of published criteria qualifying such projects into one of IMC project categories.

3.5.2 Licensing policy: Online auctions initiative

Typically, the upstream contract approval process in Kazakhstan has been time consuming, involving drawn-out bilateral negotiations between the government or KMG and the investor company for exploration and production rights. However, the Subsoil Code that went into effect in 2018 made a start at addressing this issue. In particular, the procedure for awarding and finalizing contracts was accelerated and streamlined. Thus, as mentioned above, in 2019 Italy's Eni and KMG signed an E&P contract for the Abay offshore block, while LUKOIL and KMG signed a contract for the rights to the offshore Zhenis block.

In 2020, the Kazakh government took another step forward in expediting the issuance of license rights when it introduced an electronic (online) auctioning process for E&P blocks, and mandated that all auctions henceforth be held in online format. Specifically, in August 2020 the Energy Ministry announced that Kazakhstan's Subsoil Code had been amended to provide for online auctions. A larger purpose of the reform was reportedly to allow for more transparent bidding procedures and improve the competitive environment overall. With the official launch of the new system on 1 September 2020, a total of 82 onshore blocks were initially put on offer by the government via an official portal *(www.gosreestr.kz);* subsequently, in December 2020, a reduced list of 61 onshore blocks was included. Under terms of Kazakh legislation, the auction process is initiated by bidders applying for blocks of interest. According to the initial online auction rules, no more than two auctions may be held per year; each bidder is required to have a Kazakh subsidiary, take part in public hearings together with local authorities, and commit to maximize local content in project operations.

To date, a total of 15 blocks have been sold via two online auctions, in December 2020 and April 2021, while a third such auction is scheduled for November 2021. But with less industry focus on exploration, Kazakhstan has found it difficult to generate as much interest in its online block auctions as was hoped:

- **23 December 2020 auction.** Although the government initially planned to offer 10 onshore blocks in the December 2020 auction, three blocks were removed before the auction occurred in December 2020 because of a lack of bidders. Licensing of two of the auctioned blocks was cancelled in February 2021 after a delay in payment by the little-known winner – a Kazakh subsidiary of the Dutch-registered Winsple (which was subsequently banned from participating in future auctions). The five blocks that were successfully auctioned are all located in Atyrau Oblast, and the Energy Ministry received a total of around $3.5 million from the winners. The only participants in the block auctions were recently registered local or offshore entities with no previous E&P assets (see Table 3.5 Results of the Kazakh Energy Ministry's first online auction for E&P blocks (23 December 2020)).[24]

- **23 April 2021 auction.** The second auction resulted in the award of 8 blocks out of a total of 15 on offer; the remaining 7 were withdrawn due to an insufficient number of bidders. The geography of the second auction was more varied compared with the first, and included blocks in Aktobe, Atyrau, Karaganda, and Kyzylorda oblasts. Kazakhstan received around $22 million from the winners, while the highest bid was made by IC Petroleum, for a block including the Karatyube field in Aktobe Oblast.[25]

In May 2021, the Energy Ministry announced plans for several amendments to legislation governing the auctions to improve the process, and help avoid future cancellations of auction awards, including:

- a requirement that bidders pay a guaranteed fee equivalent to the initial signature bonuses;
- a stipulation that if winners refuse to take an auctioned block, the right to purchase it will be granted to the runner-up;
- elimination of the twice-yearly limit on the auction schedule.

But more far-reaching reform of Kazakhstan's upstream regulatory regime governing E&P projects likely remains a key precondition for larger-scale online auctioning of unlicensed blocks, and participation of international majors and other important upstream investors in the auctions, as sought by Kazakh authorities.

3.5.3 Local content regulations and practices

As indicated above, domestic content requirements are part and parcel of the new online auction process, and more generally constitute an overarching policy driver impacting the upstream business climate. Here too there is room for further improvement. Greater flexibility in state policies governing procurement of oilfield equipment (goods) and services as well as hiring practices would help ensure that local content targets are compatible with oil producers' continued access to international technology and innovations to help manage costs, as well as operational stability and safety.

One important recent development was the end of Kazakhstan's transition period under the terms of its accession to the World Trade Organization (WTO). By the end of this five-year period, which lasted from 1 January 2015 to 1 January 2021, Kazakhstan was required to have modified legislation related to Trade-Related Investment Measures (TRIMs), revising local content provisions in existing subsoil use contracts as well as local content guidelines for future ones. Consequently, local content requirements in contracts signed before 2011 remain in force through the contracts' duration, while the local content thresholds in contracts signed between 2011 and 1 January 2015 were supposed to be revised to 50%. Future subsoil use contracts are not supposed to include local content minimums for goods, although Article 28 of the Subsoil use law stipulates that companies should give preference to Kazakh employees. The law also limits the share of foreign specialists and managers to 50% of the employed workforce in this category, and the share of local content in work and services should be 50%. But there is also a case to be made for consideration of greater liberalization of local content rules than is strictly necessary for purposes of WTO compliance.

Current regulations often pose challenges to would-be local suppliers no less than foreign investors. In particular, given the limited buyer pool of companies outside the "Big 3," in instances where new, local industrial suppliers have emerged, it appears they often struggle with limited demand. Even when local entrepreneurs try to satisfy new orders, there are a variety of obstacles. For example:

- **Regulatory hurdles, particularly with respect to local content certifications, and constantly evolving regulations.** The 2017 Subsoil Code requires subsoil users to acquire 50% of goods and services (including electricity and transportation fuels) from the local market. But achieving this is not easy, and determination of the local content share in an upstream operator's activities requires a review of all acquired goods, services, and labor in a given year, as well as analysis of the share of Kazakh employees in the workforce (full-time employees and contractors). Generally, the local content compliance of a provider of goods or services to an upstream operator is determined by two formulas that are practically identical: one for goods and one for services. The formula is effectively the sum of various cost components divided by the total value of the contract. Two critical elements of cost components include the share of the total amount of wages paid to Kazakh employees versus total wages for the contract, as well as the presence of a CT-KZ certificate, which is a government-issued document that attests a product

24 See the IHS Markit Energy Insight *Kazakhstan's upstream investment dilemma could compel changes to E&P terms,* 30 March 2021, and the IHS Markit exploration activity monitoring *Ministry of Energy cancels sale of two blocks from first auction,* 18 February 2021.

25 See the IHS Markit exploration activity monitoring *Ministry of Energy announces winners of the 2nd auction,* 26 April 2021.

Table 3.5 Results of the Kazakh Energy Ministry's first online auction for E&P blocks (23 December 2020)

No.	Area name	Oblast(s)*	Area (sq km)	Final signature bonus, USD	% change from starting signature bonus	Work requirements	Approximate value, USD	Winner
1	Balkuduk block	Atyrau	2,689	96,150	25%	2 post-salt wells, 600 km of 2D	5,000,000	Balkuduk Munay LLP
2	Begaydar block	Atyrau	2,872	1,900,000	2,229%	2 post-salt wells, 600 km of 2D	5,000,000	SapaInvestment LLP
3	Besterek block**	Atyrau	3,041			1 post-salt well, 700 km of 2D	4,000,000	N/A
4	Deresh block**	Atyrau	5,005			2 post-salt wells, 1,000 km of 2D	8,000,000	N/A
5	Karabau block	Atyrau and West Kazakhstan Oblast	1,699	1,200,000	2,360%	2 post-salt wells, 500 km of 2D	5,000,000	Karabau Petroleum LLP
6	Koshalak block	Atyrau	2,848	80,485	0%	1 post-salt well, 700 km of 2D	4,000,000	SapaInvestment LLP
7	Sagiz block	Atyrau and Aktobe	4,962	171,690	20%	3 post-salt wells, 1,000 km of 2D	9,000,000	Tumar Petrol LLP
8	Sarayshyk block***	Atyrau	3,645	102,820,000	99,788%	3 post-salt wells, 1 pre-salt well, 500 sq km of 3D	57,000,000	Petro Qazaq LLP
9	Ushtagan block**	Atyrau	3,055			1 post-salt well, 700 km of 2D	4,000,000	N/A
10	Zaburunye block***	Atyrau	3,277	38,750,000	42,093%	3 post-salt wells, 1 pre-salt well, 1,000 sq km of 3D	63,000,000	Petro Qazaq LLP

*All located in the Precaspian basin.
**Removed in early December due to lack of bidders.
***PetroQazaq (the Kazakh subsidiary of the Dutch-registered Winsple) had to relenquish the blocks, after failing to pay the required bonus on time.

Source: IHS Markit PEPS and GEPS, Ministry of Energy RK

satisfies the "made in Kazakhstan" requirements.[26] Companies with the CT-KZ certificate are entitled to a range of benefits, namely the ability to participate in competitive tenders, as the entity (*zakazchik*) organizing the tender is required to grant a 10% proportional discount to suppliers with a CT-KZ certificate, thereby providing such providers with a competitive advantage. But receiving a CT-KZ certification requires a lengthy, expensive, and rather formalistic application process, including an independent expert review.[27] In addition, many suppliers that seek to satisfy the requirements of the "Big 3" often pursue ISO certification, in lieu of (or in addition to) CT-KZ certification, although doing so means that they may automatically fall short of the "Kazakh content" in the eyes of regulators. For the local suppliers, meeting the CT-KZ requirements, as well as the ISO certifications required by the "Big 3" – the major clients – imposes some financial and administrative burdens. Moreover, local suppliers have to pay import duties and VAT on imported components, whereas foreign suppliers providing equipment to the "Big 3" are exempt from VAT payments, under the terms of the project agreements. Local suppliers often complain that this exemption inevitably makes local suppliers more expensive and less competitive.[28]

26 https://adilet.zan.kz/rus/docs/V1800016942

27 In accordance with the Order of the Ministry of Trade and Integration of the Republic of Kazakhstan, No. 454-NK from 13 July 2021, new rules governing the process of granting CT-KZ certificates entered into effect on 1 August 2021. The new rules introduce additional reporting requirements, and requirements for the independent experts involved in assessing an entity's CT-KZ eligibility during the application process.

28 At the same time, the goal of increasing the share of local content in selected Kazakh upstream projects holds the promise of an overall reduction in costs for producers, if effectively implemented – especially given the high logistical costs currently associated with importing many of the upstream inputs that are not yet available domestically in sufficient quantity or quality. Just as Kazakh oil must travel long distances to reach export markets, much oilfield equipment must be imported from afar. In practice, this means cargo must travel thousands of kilometers by different combinations of land, air, and sea routes. Logistics chains are also subject to variable weather conditions. Increased reliance on local suppliers, where available, can help minimize the negative impact of such costs on project economics.

- **Limited number of goods and service providers.** One of the foremost challenges to enhancing local content is the extremely limited number of goods and service providers within certain equipment and service categories. On the one hand, Kazakh companies (including their JVs with foreign partners) have a relatively prominent footprint in terms of drilling services, and accounted for an estimated 70% of this market segment in 2020. At the other end of the spectrum, however, Kazakh companies' share of the project design and engineering market segment is estimated at only 20% in that year. Meanwhile, the Kazakh companies' aggregate 2020 shares of the construction, technical service and repair, and geology and geophysics segments were 40%, 65%, and 35%, respectively. The net result was an aggregate Kazakh company share of the total 2020 oilfield services market on the order of 44%.[29]

At the same time, the share of domestic content by company and industry segment continues to evolve in response to (sometimes contradictory) changes in both national and international regulations. One case in point is the legislation governing company hiring:

- **National and sub-national policy shifts in 2020, which envision a major reduction in the number of foreign employees, actually constrain overall staffing options of the oil industry (among other key sectors).** In January 2020, the Ministry of Labor and Social Protection of the Population of the Republic of Kazakhstan announced plans to reduce the total national quota on hiring of foreign personnel by 40%, with the aim of limiting the share of expatriate employees in the Kazakh economy to 0.32%.[30] In selected oblasts, akimat(y) (local governments) have actually taken proactive measures to eliminate foreign employees altogether. In January 2020, the akimat of West Kazakhstan Oblast announced that a decision was made to entirely eliminate foreign workers (primarily electric welders and wiremen) at oil fields, and the decision would be implemented over the next two to three years.[31]
- **Uncertainty over the regulatory treatment of procurement practices in the future.** The procurement procedures of the "Big 3" are not heavily influenced by revised rules in response to WTO accession and principles, and there have been no major investment projects outside of TCO's FGP-WPMP and KPO's KEP. The results of the electronic auctions have not yet led to concrete, long-term production contracts. In many respects, the new rules underpinned by WTO rules have yet to be tested, and it remains to be seen how the government of Kazakhstan will be able to support local companies through legislative changes and protectionist measures, and equally important, how local service companies will perform in a new environment, where the government will be limited in its ability to introduce protectionist measures. That said, IHS Markit anticipates demand for local services will remain relatively buoyant, but remains cautious about the use of other levers, such as import restrictions, duties, and foreign work visas, that could have a deleterious impact on new projects and the overall investment climate.
- **WTO rules also require more flexibility in the hiring of foreigners.**[32] Under the terms of WTO accession, new rules include a stipulation that up to 50% of leaders/managers of companies can be foreigners (doubling the current threshold of 25%). To the extent that technology transfer and ESG initiatives require foreigners to visit Kazakhstan for extended periods of time, the government should honor its WTO commitments and not impose additional barriers to short term intra-company or inter-company engagement.

3.6 Upstream Costs in Kazakhstan

Comparatively high upstream oil production costs render Kazakh producers vulnerable to low oil prices, and challenge future upstream investment longer term. It is estimated that oil producers in Kazakhstan need a global oil price in the range of $20-30/bbl on average to break even on their operating costs (including upstream and export taxes, and transportation expenses). By the same token, there is a high risk of some production shut-in in Kazakhstan when world oil prices drop into the $30/bbl range.[33] Similarly, calculations of full-cycle costs for new projects (incremental oil production) indicate that break-even prices at the wellhead are relatively high in Kazakhstan for developing new projects among global oil producers.

29 "Deloitte: Obzor nefteservisnogo rynka Kazakhstana v 2020 godu," *Kazservis,* January-March 2021, pp. 58-62.

30 "Na 40% sokrashchena kvota na privlecheniye inostrannykh rabochikh v Kazakhstane," *finance.kz,* 1 January 2020; accessed at https://finance.kz/news/na_40_sokraschena_kvota_na_privlechenie_inostrannyh_rabochih_v_kazahstane-1443 The quota system is further complicated by the fact that companies must apply for quota spaces in advance.

31 https://tengrinews.kz/kazakhstan_news/na-mestorojdeniyah-zko-otkazalis-ot-inostrannyih-rabochih-388657/.

32 See "Notification under article 5.1 of the Agreement on Trade-Related Investment Measures," 14 March 2016, WTO, https://docs.wto.org/dol2fe/Pages/FE_Search/FE_S_S009-DP.aspx?language=E&CatalogueIdList=228317,135750,114771,114495,61006,79979,49164,19370,49352,1839&CurrentCatalogueIdIndex=0&FullTextHash=&HasEnglishRecord=True&HasFrenchRecord=False&HasSpanishRecord=True

33 For more in-depth analysis of these cost trends, and more detailed explanation of the methodology of our cost calculations, see the IHS Markit Strategic Report *Upstream oil production in Kazakhstan: How resilient are Kazakh producers to low prices?,* 1 December 2020.

This section looks in turn at key drivers of operating costs and total costs for existing projects in Kazakhstan, and then evaluates full-cycle costs for new Kazakh projects in comparative global perspective.

3.6.1 Operating costs and total costs for producing projects

Most Kazakh oil producers do not generally publish operating costs (opex) in the traditional sense, but rather report a broader concept of aggregate "costs of realization" (*sebestoimost realizatsii* in Russian) that generally consist of seven broad components that are considered to constitute opex for oil-producing companies: employee remuneration and associated services, general taxes (such as social security and employment taxes, but excluding upstream and oil export taxes), electricity and heat, geological-technical and scientific work, raw materials, transportation within the field(s) or license area, and other field-related costs including environmental fines.

In organizing the available data on these cost components, for the period 2014-19, operating costs for a typical producer at the field averaged $7-8/bbl.[34] Consistently, the two largest cost components, accounting for almost three-fifths of total operating outlays, were (1) employee remuneration and services (32%) and (2) geological-technical and scientific work (23%). Raw materials were typically about 12%, while infield transportation and electricity cost categories each averaged around 10% of total operating costs. In terms of the "total costs" involved in producing oil and getting it to the market, we added in three additional cost components – upstream and export taxes and ex-field transportation costs. Total costs for our sample group of Kazakh oil producers were around $30-35/bbl during 2014-19. Around half of a typical producer's total costs comprise the major oil sector taxes – the MRET, export duties, and export rent tax – even at relatively low world prices. Operating costs and transportation expenses each make up around a quarter of total costs.

At the same time, the scale and structure of costs varies widely among producers, along with their resilience to low prices. The highest-cost producers' expenditures averaged nearly twice as much as those of the lowest-cost producers in our sample group.

3.6.2 Kazakhstan's position on the global full-cycle cost curve for new projects

IHS Markit's analysis of how Kazakh upstream costs compare with those in other countries, particularly for new projects (incremental production), indicates that Kazakh producers may struggle to remain competitive with their international counterparts.

Importantly, development of new oil production requires significant capex; therefore, a very useful way of analyzing oil production costs is by using so-called "full-cycle costs" at the wellhead that include opex, capex, and upstream taxation. Essentially, full-cycle costs capture the cost of finding, developing, and then producing "new" oil production capacity. The IHS Markit proprietary methodology shows these as "break-even" costs at the country level in aggregate, but actually involves analysis of individual upstream development projects within each country's portfolio; hence, they are shown as a range (see Figure 3.13 Cost curve of new global crude oil supply in selected areas to 2040).

This is essentially a forward-looking analysis, to understand the cost of developing new supply, and allows us to highlight areas where new project development is viable at current (or expected) oil prices. Reservoir data and production profiles are estimated, and drawn from the IHS Markit database, and the terms are adjusted by project, based on known information. The average (per country and/or geographical area) shown is not a weighted or arithmetic average but a selection of what a typical new oil project in that country or area (onshore/offshore) would cost in current conditions. One important caveat, however, is that our wellhead break-even prices do not include the sizable transportation costs and export duties that are incurred for Kazakh oil (or other inland producers) to reach global markets (the break-even price is calculated at the wellhead and assumes a delivery point within 50-100 km of the field).[35]

The average global full-cycle break-even price for oil (standardized, in dated Brent terms) at a 10% IRR was about $40/bbl in the first quarter of 2021. Saudi Arabia and Kuwait have the lowest typical oil break-evens of about $17-18/bbl, while Venezuelan offshore projects had the highest typical break-evens globally at around $75/bbl. Other countries on the upper end of the global curve for break-even costs include Canadian oil sands (mining) projects and Azeri and Kazakh offshore. These high- cost barrels are among the most at risk of not being developed.[36]

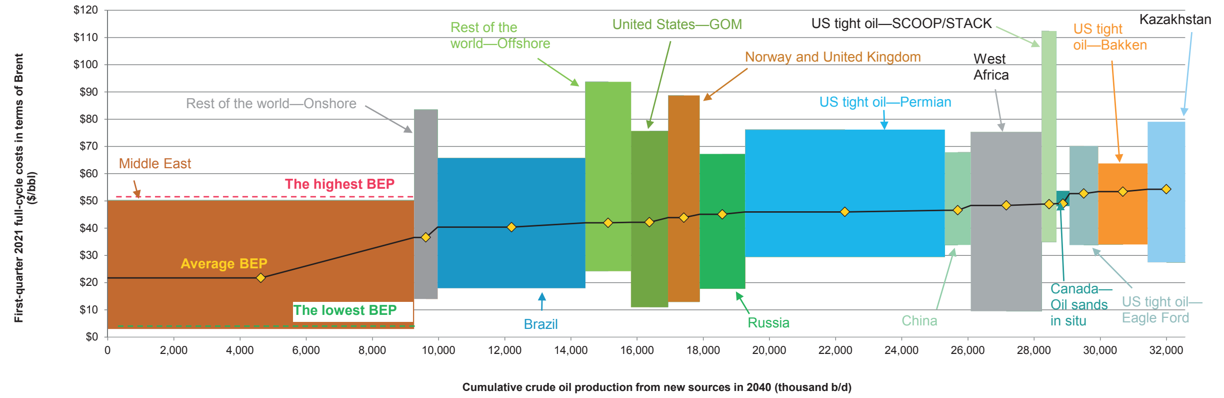
When analyzing the cost curve relative to the amount of production that is expected to be available over the next two decades, a similar story materializes from our 2020 scenario exercise for the period to 2040. The lowest-cost projects have a global average break-even cost of about $24/bbl (mostly found in the Middle East),

34 This is taken from a sample group encompassing a total of 16 producers, representative of one of four major production categories in Kazakhstan: IOC-led mega projects, fully-owned KMG subsidiaries, KMG JVs, and independent producers.

35 For more detailed explanation of the steps involved in the IHS Markit break-even cost calculation, see the IHS Markit Strategic Report *Upstream oil production costs in Kazakhstan: How resilient are Kazakh producers to low prices?*, 1 December 2020.

36 See the IHS Markit Strategic Report *Cost of Oil Report: First quarter 2021*, 13 July 2021.

Figure 3.13 Cost curve of new global crude oil supply in selected areas to 2040



Note: The cost curve's horizontal axis shows production in 2040 from new projects expected to start production between 2021 and 2040. For a selected country/region/play, the upper side of the bar corresponds to the highest BEP, the lower side of the bar to the lowest BEP, while the width of the bar represents crude oil production from new sources in 2040. New sources of oil equal any volumes from projects that were not producing as of 2020, including sanctioned projects, unsanctioned projects, and assumed discoveries. GOM = Gulf of Mexico. The Middle East includes both offshore and onshore projects in Saudi Arabia, Kuwait, the United Arab Emirates, Iraq, Iran, Oman, Qatar, and Bahrain. West Africa includes both offshore and onshore projects in Angola, the Republic of the Congo, Equatorial Guinea, Ghana, and Nigeria. Rest of the world–Onshore and Rest of the world—Offshore categories include all production from respective projects, not included in other countries or regions. The global supply shown does not include all producing areas (in part so as not to reduce clarity of the supply stack figure) and represents 89% of total global production from new projects.
Source: IHS Markit

while the more expensive projects under consideration for development have global break-even costs of well over $50/bbl. Importantly, based on just the largest 10 new conventional OPEC-country projects (in terms of expected annual production), 76% of available new supply from these countries over the next two decades has a break-even price below $20/bbl (in constant dollar terms). The results of our most recent analysis of break-even costs for the period to 2040, completed in September 2021, are generally similar, but one negative trend for Kazakhstan is an increase in the estimated break-even cost for new Kazakh conventional offshore production, on the order of $5/bbl.

In doing this global cost curve analysis over time, there are several trends that do not bode well for high-cost producers.

- First, with each subsequent iteration of this analysis, aggregate costs have typically tended to come down across the board, shifting the overall curve downward.
- At the same time, there has been a noticeable shift in expectations for more oil to come from low-cost producing areas; this also has the effect of stretching and flattening the global cost curve.
- Finally, expectations about aggregate demand also have come down.

These three dynamics all indicate that, longer term, the cost of the marginal barrel needed to meet global oil demand has been ratcheting downward.[37]

The IHS Markit cost curve methodology calculates a break-even price in first quarter 2021 at the wellhead for a typical Kazakhstan onshore project of about $50/bbl and for offshore projects at about $56/bbl, although there is considerable range around these central points. These midpoints for Kazakhstan generally place the country on the right-hand side (higher-cost end) of the global cost curve, and the high variability indicates that a sizable proportion of Kazakhstan's available incremental production is shaded toward the high end of the global cost curve. Moreover, for Kazakhstan, these full-cycle costs have been rising in recent years. As indicated above, these standardized calculated break-evens reflect only wellhead costs, and exclude long-distance transportation costs to reach export points and the export duty, both of which are sizable components of overall costs in monetizing Kazakh oil.[38]

All told, our relatively weak oil price outlook (see Chapter 1) poses a considerable challenge for new oil development in Kazakhstan. Certainly, there is always high uncertainty surrounding oil price forecasts, with the containment (or lack thereof) of COVID-19, geopolitical stability, and changing global policies relating to climate and the energy transition playing a major role in shaping demand. At the same time, world oil price trends impact Kazakh oil producers differentially depending on the share of their production delivered to export versus domestic markets. Overall, however, it appears increasingly likely that the expanding role of low-cost producers globally will constrain the ability of more expensive producers to retain (let alone grow) their market share. At the same time, enlightened policies by state authorities in such countries can go far to maintain (if not enhance) E&P attractiveness even as international competition intensifies. Several of the higher-cost producers, including Kazakhstan, have significant leeway (at least in theory) to improve the relative attractiveness of their upstream investment regimes, such as by reducing government tax take.[39]

37 The pandemic-related decrease in oil and gas project activity in 2020 initially led to falling wages and costs for materials used to develop projects, but costs then registered an increase in the first quarter of 2021, as the global economic recovery pushed up material prices, particularly steel.

38 In 2020, for example, the break-even prices at an export point required for a typical onshore expansion project and typical new offshore project in Kazakhstan were estimated to be around $57/bbl and $64/bbl, respectively.

39 One interesting example of the potential for flexible state policies to stimulate new investments in a maturing asset base was the

3.7 BAT and Digitalization in Kazakhstan: New Considerations for Oil Companies

Two emerging sets of government requirements may pose additional challenges for the Kazakh oil industry in the years ahead – the "best available technologies" (BAT) and digitalization initiatives, particularly as they relate to environmental performance. Key questions include not only the possible impacts of such measures on producers' economics but also their overall feasibility in light of geological and technical as well as market-structure considerations in Kazakhstan. Nonetheless, such issues are increasingly becoming part of the implicit "license to operate" for companies everywhere.

3.7.1 BAT

Considerations for BAT in associated petroleum gas (APG) utilization

One of the main goals of BAT is to improve upstream operations in general, while BAT initiatives are also increasingly aimed at improving the environmental performance of the upstream segment, particularly in regards to atmospheric emissions. The main source of atmospheric emissions (both of GHG and particulates) for upstream oil industry operations in Kazakhstan is the on-site use (combustion) of fuel (usually gas) in boilers, process heaters, gas turbine installations, and compressor stations; flaring of associated petroleum gas (APG) is also considered to be a major source, while fugitive emissions from wells and other installations of APG/methane are other significant sources.

Oil and gas companies participating in the Emissions Trading System (ETS) emitted an estimated 18.3 MMt CO_2 in 2020, compared with about 19.4 MMt CO_2 in 2019, and 19.6 MMt CO_2 in 2018.[40] The 2020 decline was to be expected, in connection with the pandemic-related contraction of oil production, but 2019 emissions also fell, by around 0.6%, even as Kazakh oil output reached a record high in that year. Within the ETS framework, it appears many companies were compliant with their emissions quotas, although several companies secured additional quotas in connection with capacity expansion (and higher output). During 2018-20, aggregate CO_2 emissions of all oil and gas companies in Kazakhstan amounted to an estimated 84% of the sector's ETS quota during this same period (after factoring in additional quotas), albeit with wide variation by producer.

With respect to overall GHG emissions from the oil sector, including crude oil transportation (but excluding CO_2 emissions from industry-owned power plants), GHG emissions reached 4.26 MMt CO_2e in 2019, in line with 2018 emissions, according to Kazakhstan's NIR 2021 submission to the UNFCCC.[41] General atmospheric emissions of other pollutants (particulates) appear to have followed a similar trend.

Whereas flaring of APG remains a primary source of GHG emissions for many oil-producing countries (as oil companies often flare significant amounts of APG output because of the difficulty of finding efficient utilization alternatives), Kazakhstan has made substantial progress lowering flared APG volumes and was recently among the countries with "best practice" according to this indicator (though flaring rates still vary widely among individual producers). Kazakhstan's APG flaring was reportedly only 0.39 Bcm in 2020, for a flaring rate of a mere 1.2% of total APG extraction. Between 2012 and 2020, the volume of APG flaring in Kazakhstan dropped by 61% (see Figure 3.14 Flaring of associated petroleum gas in Kazakhstan). Routine flaring has been effectively eliminated in Kazakhstan. Gas is now widely utilized on site: 20.3 Bcm (37% of the total amount of gross gas production) was reinjected last year to support oil production, and on-site consumption (other than for electricity generation) was 1.6 Bcm in 2020. Total gas processed in Kazakhstan was 30.5 Bcm in 2020, a slight decline from over 33 Bcm processed in both 2018 and 2019.

To the extent further use can be made of APG (or renewables) for field-level power generation, further reduction of emissions can be had. Most oil producers obtain power from the grid to satisfy their electricity needs. Anecdotal evidence indicates a growing demand for electricity at Kazakh oil fields in recent years given the additional waterflooding required at mature acreage in particular; so the electricity needs of Kazakhstan's legacy fields will probably only increase on a per unit basis.[42] Since much of the electricity sourced from the grid is coal-fired, greater reliance on distributed generation solutions at the oil fields could be an effective strategy for various producers to reduce carbon footprints (while perhaps leading to a reduction in overall electricity costs as well).

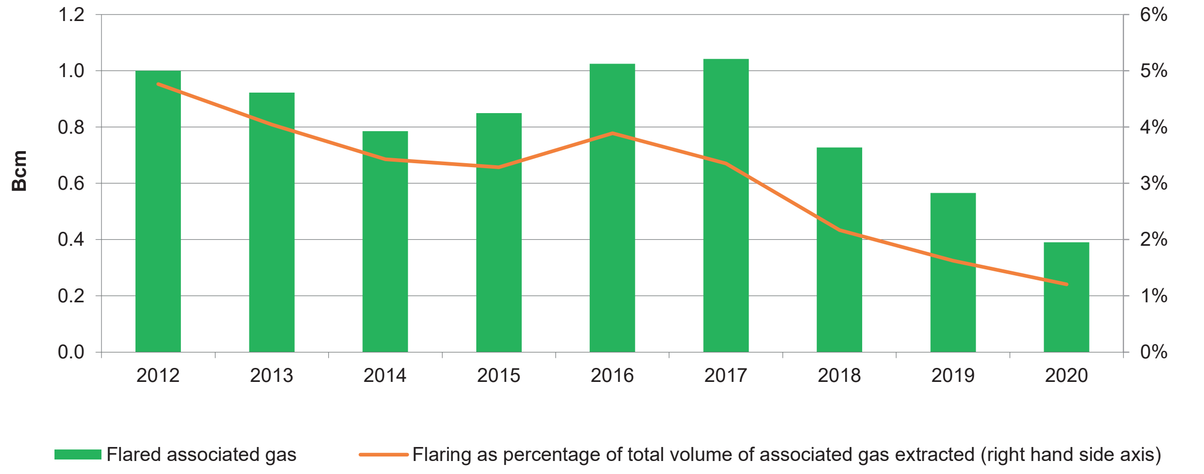
announcement earlier this year by Eni and BP of a proposed new JV to manage their existing upstream portfolios in Angola – a new commercial structure that could serve as the basis for investment in additional yet-to-be sanctioned upstream projects in the country. One key factor in the IOCs' sustained interest in Angola hydrocarbons is evidently the country's 2018 "marginal fields" legislative reforms, establishing improved fiscal terms for much of the undeveloped resource base; see the IHS Markit Insight *Africa Upstream: Eni and BP's joint ventures offer new approach to energy transition,* 14 July 2021.

40 Overall CO_2 emissions of the oil and gas companies participating in the ETS (including their upstream as well as downstream and transportation assets) are relatively small compared with aggregate emissions of participating companies in various other industries (e.g., electricity or metallurgy), and in 2020 accounted for around 12% of total emissions on the part of companies participating in the ETS.

41 GHG emissions associated with gas production and transportation were around 1.1 MMt CO_2e in 2020 or about 10% lower than in 2019.

42 Specifically, the average water cut or ratio of water produced to the total volume of liquids production (*obvodnyennost*) increased from around 53% to 60% during the period 2016-20 for companies that provided detailed operational data for NER 2021.

Figure 3.14 Flaring of associated petroleum gas in Kazakhstan



Source: IHS Markit, Ministry of Energy RK

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KMG's upstream BAT initiatives. KMG has embarked on a variety of ambitious programs designed to reduce APG flaring and other environmental emissions; for example, replacing its old (and less efficient) gas-processing capacity with new capacity, replacing fuel oil with natural gas (in on-site combustion), and using new generation down-hole additives to increase flow rates. KMG's emissions of CO_2 equivalent amounted to around 18 kilograms per produced barrel of oil equivalent in 2019, which compares favorably with other oil-producing companies (see Figure 3.15 Company reported upstream emissions intensity - operational indicators, 2019).[43]

APG utilization by KMG in 2020 amounted to 98%, with flaring of gas generating only about 2.2 tons per thousand tons of produced hydrocarbons; this is 24% less than in 2019 and 79% lower than the global industry average (according to the metrics given by the International Association of Oil and Gas Producers). KMG subsidiaries have achieved significant flaring reductions through implementation of various projects, including 93% utilization at EMG following installation of a hydrogen sulfide removal facility, and at MMG, where utilization of 99% of gas at the Kalamkas field is for on-site fuel needs.

KMG is also implementing projects to reduce the volume of solid waste generated by its operations as well as to reduce historical oil waste and land polluted by oil. In recent years, one focus of such activity has been the cleaning up of waste pits (landfills) used by MMG as well as KMG's OMG and Karazhanbasmunay (KBM) subsidiaries for storage of oil waste. Over the period 2016-19, operations were completed at a total of 16 pits. Land remediation at the last one was completed in 2020.[44] Newly generated oil waste from OMG, MMG, and KBM is now disposed of through third-party contractors.

43 MMG is 100% owned by Mangistau Investments B.V., a 50-50 JV between KMG and CNPC Exploration and Development Company Ltd.

44 Ten MMG landfills, five OMG landfills, and one KBM landfill were disposed of during this period.

One of the significant ways to reduce the negative impact on environment is better power management and improvement of energy efficiency. Modernization of technological equipment and the introduction of energy-saving technologies to optimize heat production and consumption, as well as additional on-site generation, are the main directions of development within KMG. The use of its own electricity generation sources to power pumps, reservoir pressure management systems, heating of pipelines, and other infield electricity-consuming facilities is a high priority. The goal of using more APG or even small-scale renewable sources at the field can significantly reduce upstream emissions. KMG consumed about 156.6 gigajoules of energy in 2020, which is 14% lower than in 2019. However, much of this decline was associated with a decrease in hydrocarbon production rather than improved efficiencies.

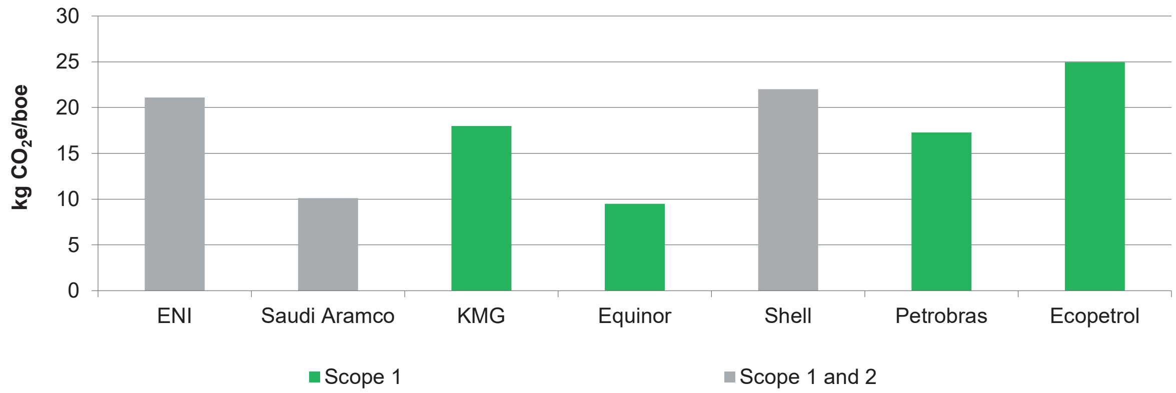
Experience of other companies with potential applicability to Kazakhstan

In recent years, several leading IOCs more actively began to introduce new solutions to reduce emissions; some of these may have some applicability at Kazakh oil fields. Key examples include initiatives that already have counterparts in Kazakhstan as well as a number of emissions reduction strategies and technologies that have not yet been introduced in Kazakhstan (e.g., CCS and CCUS measures).[45]

TotalEnergies. With respect to atmospheric emissions, between 2010 and 2020 TotalEnergies achieved its interim goal of reducing routine flaring by 80%, and has committed to discontinue such flaring at all its production

45 Carbon storage may represent an increasingly viable alternative to CO_2 emissions for various oil producers in Kazakhstan. Effective CO_2 storage capacity at Kazakhstan's oil reservoirs amounts to over 200 MMt according to one Kazakh study looking at the potential in six of the country's sedimentary basins; for an overview of this study's results, see "CO_2 storage capacity of Kazakhstan," accessed at https://presentations.copernicus.org/EGU2020/EGU2020-21554_presentation.pdf

Figure 3.15 Company reported upstream emissions intensity – operational indicators, 2019



Notes: Shell emissions refer to GHG intensities (operational control) for Integrated Gas and Upstream operations.
Source: IHS Markit, company reports

facilities by 2030. For example, in Nigeria routine flaring at company sites was reduced by 35% between 2015 and 2019, while the goal is to eliminate it altogether by 2025; APG volumes that were previously flared are now sent to a Nigerian LNG plant. To separate sulfur oxides (SOx) from the gas stream at upstream operations, the company is introducing the use of strippers, while its petrochemical plants and refineries are fitted with units that burn nitrogen oxides (NOx) and break down the compounds. The company also uses advanced digital techniques to monitor and control its GHG emissions worldwide.

In areas where company operations involve risks of water contamination, the company uses water treatment techniques to prevent untreated water from returning to the original water reservoir. The company sites that are surrounded by water have been fitted with technologies, such as the company's BIOMEM technology, which involves an innovative water treatment method using microorganisms to eliminate toxicity.

TotalEnergies also strives to reduce the amount of waste products using several different techniques. First, life-cycle assessments (LCAs) allow the company to analyze the impact of a waste product on the environment. These techniques are used because some wastes cannot be avoided. Second, the company employs industrial processes for recycling and recovery of waste products, which consist mostly of used oils or plastics that cannot be broken down further.

Chevron. Solar and wind generation is already an important source of electricity for some of Chevron's upstream operations in the United States, and the company is intent on increased use of renewables to power its core oil and gas operations worldwide. Key examples at Chevron's US acreage include solar deployments at the company's California Lost Hills (35 MW, announced 2019) and Coalinga (29 MW, operational 2014) oil fields, and a 65 MW wind project in the Permian Basin (operational 2020). A four-year partnership agreement between Chevron and the Algonquin Power and Utilities Corp., announced in July 2020, envisions development of 500 MW of renewable generation capacity to meet electricity demand at Chevron facilities in the Permian as well as Kazakhstan, Argentina, and western Australia. Under terms of this agreement, Chevron will purchase electricity directly from jointly owned projects via power purchase agreements (PPAs), while Algonquin will take the lead in designing and constructing the renewable installations.[46]

Low-carbon technologies such as CCUS are also a key element of Chevron's energy transition strategy, and the company has already made significant investments in the research, development, and deployment of CCUS. Chevron's Gorgon CO_2 injection project in northwest Australia, part of an LNG project, is one of the largest integrated CCUS projects worldwide, and is expected to reduce GHG emissions by about 5 MMt per year, with an estimated cost of $2 billion and a projected lifespan of more than 40 years.

ExxonMobil. A new division in ExxonMobil (Low Carbon Solutions) is involved in a public–private partnership to create a $100 billion CCUS hub south of Houston, Texas (the so-called CCS Innovation Zone in the Houston Ship Channel) designed to commercialize the technology and further improve it. The Innovation Zone, designed to service refining, petrochemical, and other US Gulf Coast industrial assets, will house physical CCUS infrastructure that could store up to 50 MMt of CO_2 by 2030, and 100 MMt by 2040.[47]

Rosneft. In 2019, Rosneft initiated a project to develop a hydrogeology information system with the aim of increasing the efficiency of production processes, within the wider framework of company measures for the rational use of groundwater. Rosneft is also developing technologies that

46 See the IHS Markit Headline Analysis *Chevron partnership with Algonquin highlights differing oil and gas renewable strategies,* 14 September 2020.

47 See the IHS Markit Net-Zero Business Daily News Research and Analysis *ExxonMobil unveils vision for $100-bil Texas carbon capture hub,* 28 April 2021.

will increase the efficiency of waterflooding at oilfields, and potentially reduce the volume of water required to maintain reservoir pressure; polymer flooding technologies being developed for the company's West Siberian reservoirs may reduce the need for water injections by more than half. Rosneft has also improved the reliability of production facilities, especially pipelines, with the introduction of aerial monitoring on a 24-hour basis using drones. Drones have significantly increased Rosneft's ability to detect deviations from technical norms at such facilities and reduced the time needed to respond to such issues.

LUKOIL. LUKOIL's environmental program prioritizes the reduction of atmospheric emissions from its production activities. Key measures include replacement or modernization of production equipment; use of systems for capturing emissions; increased utilization of APG; and modernization of flaring systems for sootless combustion. Another major focus of LUKOIL's environmental program is improving the use of water resources. As part of its sustainable development strategy, LUKOIL is deploying water recycling systems, increasing wastewater treatment, and reducing water losses.

3.7.2 Digitalization

Another emerging state initiative with key implications for the oil industry is expanded use of digitalization. On the one hand, Kazakh authorities themselves have stepped up adoption of digital tools in recent years (underscored by the launch of online E&P auctions discussed above). Of greater consequence for Kazakh oil producers ultimately, however, may be the new digitalization requirements for oil projects. A prime example is the information system for accounting for oil and gas condensate (ISAO) that Kazakh authorities intend to introduce within the framework of the government's overall Digital Kazakhstan program. A pilot version of the ISAO system has already been launched, and by the end of 2021 over 60% of total crude oil and gas condensate production and refining is upposed to be connected to ISAO organizations.[48]

Although detailed digitalization requirements for oil companies remain to be spelled out, key indications of the sort of action items that oil producers may need to undertake (if they have not done so already) can be found in the latest draft of the Energy Ministry's Strategy for Digitalization of the Fuel and Energy Complex of the Republic of Kazakhstan (2021-2025). Primary upstream objectives listed in this document include installation of data processing centers (*tsentry obrabotki dannykh* or TsOD) at 60% of all fields by 2023 and at 80% by 2024.

Improved application of digital technologies has also been a long-standing activity of many oil producers themselves, and several have already made considerable progress in this direction. Although oil company digitalization programs implemented to date or currently in the planning stages do not all necessarily fully align with the government's emerging agenda, several of them could serve as a partial foundation to reach official targets. Among the most instructive examples is the KMG Smart Field program, which has been under way for several years now as part of the company's overall Digital Transformation initiative. KMG first implemented a Smart Field pilot project at one of the fields of its EMG subsidiary in 2015, whereby equipment installed at the field has taken readings at all stages of the production process and transmitted well parameters to a central control center where long-term field development plans are formulated. Other key KMG examples are four initiatives that the company launched in 2020 and that KMG expects will generate benefits valued at 72.4 billion tenge (about $175 million): the Advanced Base Artificial Intelligence (ABAI) Information System, the Multifunctional KMG Shared Services Center, the Trip Management initiative, and the Engineering Simulation System at Kazakhstan Refineries.[49] Other companies, such as BP, maintain long-standing relationships with cloud-based data storage solutions such as Amazon Web Services that has allowed for more efficient data collection, storage, and intra-company distribution.

48 "Information system for accounting for oil and gas condensate launches in Kazakhstan," *Kazakhstan Newsline,* 11 May 2021.

3.8 Refining and Refined Product Market Dynamic

3.8.1 Evolution of Kazakhstan's refined product balance

The COVID-19 fallout hit Kazakh refiners' domestic and export markets hard overall, resulting in a sharp reversal of the trend of increasing Kazakh refinery throughput over 2017-19 that had been made possible by the $6 billion modernization program (completed in 2018) at all three major Kazakh refineries (the Atyrau, Pavlodar, and Shymkent plants).[50] Total throughput contracted by 7.2% to 15.8 MMt – given a contraction of both domestic apparent consumption of refined products (by 1.8% to 14.4 MMt) and product exports (by 18.6% to 2.3 MMt). With respect to the major products, the biggest declines in refinery output last year were seen in the case of kerosene (by 27.3% to 0.5 MMt), mazut or fuel oil (by 11.6% to 2.5 MMt), and diesel (by 7.0% to 4.7 MMt). In contrast, gasoline output proved relatively resilient, falling just 0.9% to 4.5 MMt (see Table 3.6 Kazakhstan's refined product balance (MMt)).

49 The ABAI system is designed to integrate all of the production data from the company's upstream division, facilitating analysis of the data via artificial intelligence, instant data visualization, and continuous remote management of production operations. Another signpost of KMG's increased emphasis on digitalization in recent years is the company's June 2019 Memorandum of Understanding with TotalEnergies envisioning joint efforts to assist state organs and other organizations in implementation of the Digital Kazakhstan program and "further development of the digitalization of the oil and gas industry"; see https://petrocouncil.kz/en/total-will-share-with-kazmunaygasits-digitalization-experience-in-the-oil-and-gas-industry/

50 Atyrau and Pavlodar are wholly owned by KMG, while the ownership of Shymkent is shared on a parity basis between KMG and China's CNPC.

With gasoline production representing a much higher share of overall refinery output as a result of refinery modernization, Kazakhstan is now basically self- sufficient in this product, and actually faces a problem of oversupply – exacerbated by the 2020 crisis.[51] Although export markets can be difficult to access, Kazakhstan has registered increasing success realizing its gasoline export ambitions over time. Total Kazakh gasoline exports in 2019 amounted to only 0.1 MMt, but in 2020 Kazakh gasoline exports soared to 0.5 MMt, albeit falling by 47% during January-May 2021. The bulk of Kazakh refined product exports nevertheless still consisted of fuel oil, which accounted for nearly 70% of total product exports in 2020 even after a contraction of fuel oil export volumes by 39.4% for the year to 1.6 MMt (see Figure 3.16 Kazakhstan's monthly exports of refined products).[52]

The 2020 Kazakh quarantine measures for the population abruptly curtailed domestic product demand starting in April. For example, KMG reported that April 2020 demand was down by 40% for diesel and gasoline year on year, and by 70% in the case of aviation fuel (reflecting record declines in both ground transportation and passenger air travel in Kazakhstan). But whereas Kazakhstan is long on gasoline, the country had to significantly increase its imports of diesel from Russia in 2020. Altogether, Kazakh diesel imports jumped 165.1% last year to 0.7 MMt. Kazakh refinery throughput could (in theory) have been higher to produce more diesel and reduce the need for imports (in keeping with a long-standing official Kazakh policy goal), but on this occasion Kazakh authorities evidently concluded that higher refinery runs to meet domestic diesel demand were too risky given the difficulty of disposing the other surplus products (including more gasoline) amid a general product glut. Kazakh policymakers nevertheless remain intent on minimizing Kazakhstan's reliance on Russian diesel, as reflected in the continued periodic imposition of bans on the import of diesel along with other products (see Figure 3.17 Kazakhstan's monthly imports of refined products).

The three major Kazakh refineries apparently managed to avoid unplanned closures in 2020, but the severe contraction of product consumption pushed refineries to operate at minimum levels during some of 2020. Several Kazakh regulatory changes introduced in April 2020 evidently helped various refiners to weather the crisis:

- **Elimination of export duties for selected products through the end of 2020, including diesel fuel, gasoline, and jet fuel.** This measure was seen as necessary to counteract the sharp drop in world oil prices in the first quarter, a decline that rendered Kazakh refined product exports unprofitable, backing up supply, and raising the prospect of insufficient oil storage facilities, which could have led to a total shutdown of Kazakh refineries.
- **Temporary bans on imports of diesel, gasoline, and aviation fuel from Russia by rail.** This policy is in line with pre-crisis measures that were designed to secure the domestic market position of Kazakh products, but these measures took on new urgency last year amid slumping domestic and international demand for transportation fuels. The April 2020 three-month ban on rail imports was subsequently extended until 1 September 2020, and in October 2020 a variety of new refined product import restrictions were temporarily enacted.

Our base-case scenario is for an ongoing rise in refinery throughput, lifting the total by around 32% to 20.9 MMt in 2050. This refining profile largely parallels our outlook for aggregate domestic refined product demand, given the relatively limited potential for incremental product exports. Aggregate domestic apparent product consumption grows by around 34% altogether during the period 2021-50 in the base case, to 19.4 MMt; diesel demand registers the biggest increase (see Figure 3.18 Outlook for apparent consumption of refined products in Kazakhstan). Diesel is already widely consumed by agricultural entities, heavy industry, and transportation in Kazakhstan, accounting for 36.1% of total Kazakh refined product demand in 2020. The trucking sector represents the chief locus of incremental diesel demand. Domestic gasoline demand is also expected to rise significantly overall during the scenario period, by 21% to 4.8 MMt, owing mainly to increased automobile fuel needs, while fuel oil consumption falls 24% to 0.7 MMt. IHS Markit does not anticipate a major shift in the composition of the trucking and light vehicle fleet towards electric vehicles; gasoline-engine vehicles, as well as vehicles with engines that run on diesel and LPGs, will continue to dominate the fleet. We expect the transportation segment to remain a major consumer of refined products longer term.

51 Atyrau and Pavlodar are wholly owned by KMG, while the ownership Even before the pandemic, there were signs of weakness in Kazakh gasoline demand; apparent consumption of gasoline in Kazakhstan dipped by 0.3% in 2019, and during the same year the national car fleet shrank by 1.7% as more cars were retired than were added.

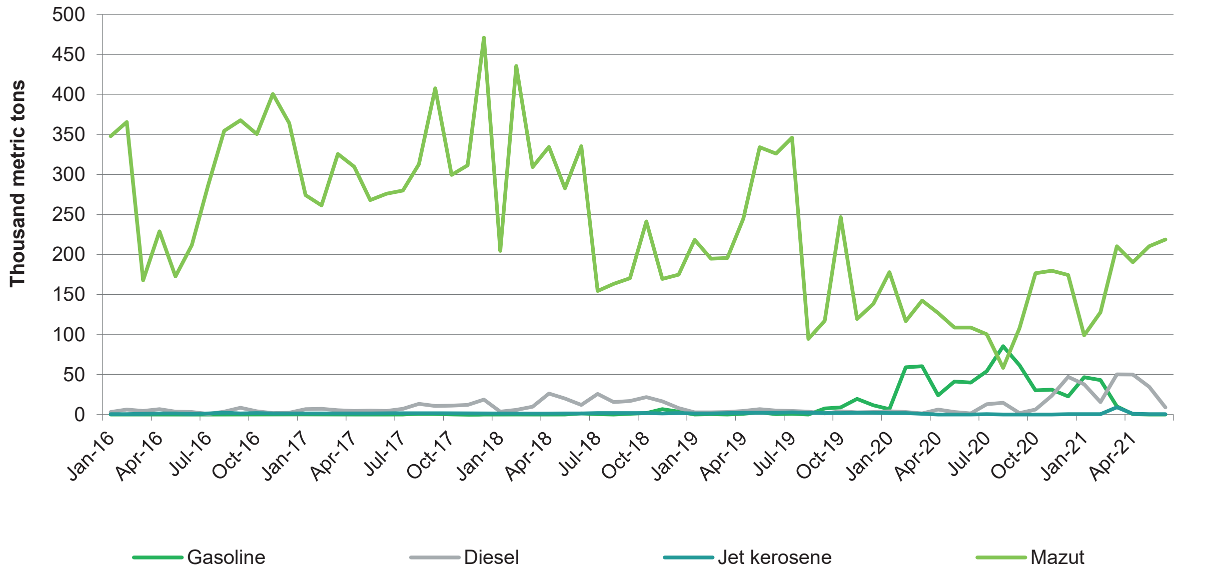
52 See the IHS Markit Insight *Turning a page: Kazakhstan became a net exporter of gasoline in 2020, potentially prompting a shift in overall policy toward trade in refined products,* 18 March 2021.

Table 3.6 Kazakhstan's refined product balance (MMt)

	2015	2016	2017	2018	2019	2020	Percent change 2019-20
Throughput	14.5	14.5	14.9	16.4	17.0	15.8	-7.2
Output of products (reported)	13.5	12.9	13.0	13.4	14.0	11.5	-18.1
Gasoline	2.9	3.0	3.1	4.0	4.5	4.5	-0.9
Kerosene	0.3	0.3	0.3	0.4	0.6	0.5	-27.3
Diesel fuel	4.6	4.7	4.4	4.6	5.0	4.7	-7.0
Mazut	4.1	3.2	3.4	3.2	2.9	2.5	-11.6
fleet	0.3	0.2	0.4	0.3	0.6	0.3	-50.2
furnace fuel	3.8	3.0	3.0	2.9	2.3	2.2	-1.3
Lubricants	--	--	--	--	--	--	
Other	2.6	3.4	3.8	4.2	4.0	3.6	-8.1
Bitumen				0.6	0.7	1.0	55.0
Petroleum coke/other residual	0.9	0.9	1.3	1.5	1.6	1.6	0.0
Losses and fuel as % of throughput	6.4	11.1	12.8	18.3	17.6	27.3	55.1
Apparent Consumption							
Total (all refined products)	11.5	12.5	12.9	14.7	14.7	14.4	-1.8
Gasoline	4.3	4.1	4.1	4.5	4.5	4.0	-11.5
Diesel fuel	4.6	5.1	4.7	4.8	5.2	5.2	-0.5
Mazut	0.1	-0.2	-0.4	0.3	0.3	1.0	279.5
Other	2.5	3.6	4.5	5.1	4.7	4.3	-9.1
Net exports							
Total (all refined products)	3.0	2.0	2.0	1.7	2.3	1.4	-40.9
Gasoline	-1.4	-1.1	-1.1	-0.6	0.0	0.5	1349.3
Diesel fuel	0.0	-0.4	-0.3	-0.2	-0.2	-0.5	160.8
Mazut	4.0	3.4	3.8	3.0	2.6	1.6	-39.4
Other	0.4	0.1	-0.4	-0.4	-0.1	-0.2	48.6
Exports							
Total (all products)	4.9	3.9	4.0	3.4	2.8	2.3	-18.6
Gasoline	0.0	0.0	0.0	0.0	0.1	0.5	848.5
Diesel fuel	0.2	0.1	0.1	0.2	0.0	0.1	184.1
Mazut	4.0	3.4	3.8	3.0	2.6	1.6	-39.4
Other	0.7	0.4	0.1	0.1	0.1	0.1	-33.8
Imports							
Total (all products)	1.9	1.9	2.0	1.7	0.5	0.9	79.8
Gasoline	1.4	1.1	1.1	0.6	0.0	0.0	-92.1
Diesel fuel	0.2	0.4	0.5	0.5	0.2	0.7	165.1
Mazut	0.0	0.0	0.0	0.1	0.0	0.0	159.5
Other	0.3	0.3	0.4	0.5	0.3	0.3	9.9

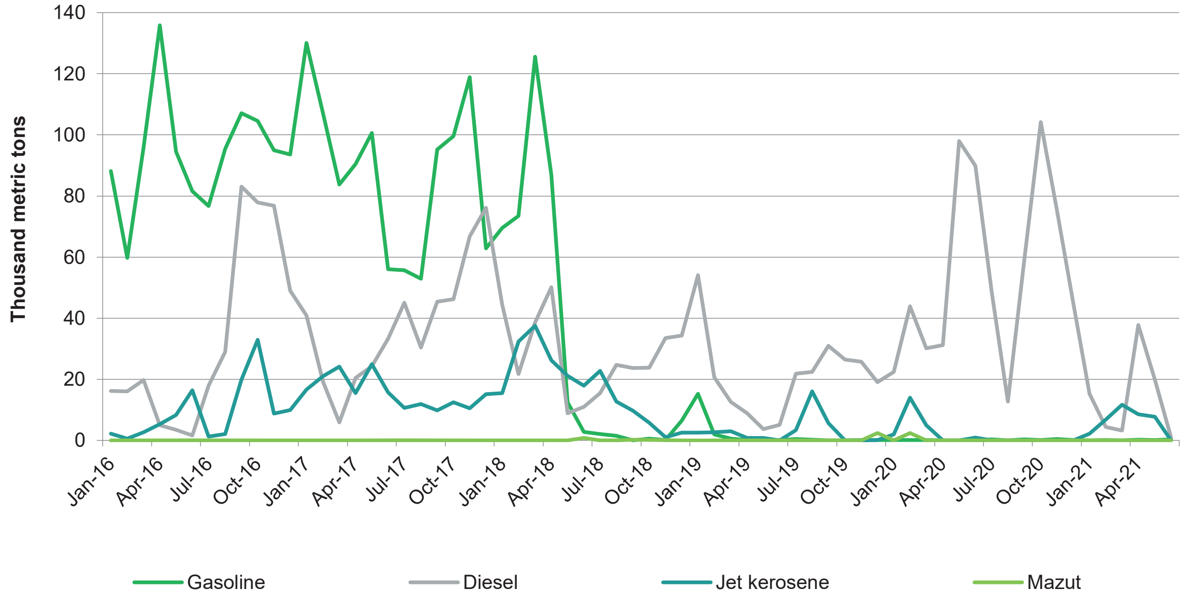
Source: IHS Markit, Ministry of Energy RK, Bureau of National Statistics RK

Figure 3.16 Kazakhstan's monthly exports of refined products



Source: IHS Markit, Bureau of National Statistics RK

Figure 3.17 Kazakhstan's monthly imports of refined products



Source: IHS Markit, Bureau of National Statistics RK

3.8.2 Domestic crude oil pricing: Cost-plus formula remains problemati

The Kazakh refining and downstream sector remains highly administered. Generally, in the domestic market, a producer (subsoil user) sells crude oil to a trader or toller at the refinery gate, so the subsoil user is responsible for paying pipeline transportation expenses to the refinery. The toller/trader assumes title of crude at the refinery, pays the designated processing fee (tenge/metric ton) to the refinery, takes the resulting refined products, and then sells them to other traders, wholesalers, and market participants.[53]

The current processing scheme (in place since 2016) guarantees refiners a generous margin, and was instrumental in financing the aforementioned modernization program, but it effectively isolates refineries from market forces, and IHS Markit concludes that the refining sector would be better served by a business model whereby refiners instead function as merchant operators. However, Kazakh refiners probably are not interested in altering the current tolling scheme over the next decade or so as they pay back sizable loans for their modernization programs. The government is also reluctant to embrace trade measures or structural reforms that could potentially put Kazakh refiners under a competitive threat (particularly if full-scale EAEU integration materializes) or lead to an increase in domestic product prices – an unfavorable political and social outcome.

It appears that the general formula for the domestic oil price in Kazakhstan is based on cost-plus; specifically, operating costs plus transportation to the refinery and domestic MRET. Although there are some nuances within this system, legally the price benchmark for domestic sales is what is published in Argus Caspian the prior week. During the period 2014-19, this official sales price was on average only 44% of the world oil price, while the average crude oil acquisition price at the refinery gate was actually slightly lower; averaging 40% of the global price during this period.

Although domestic oil prices were a higher percentage of global prices in 2020 than in 2019 – averaging around 61% of the world price level in 2020 – this essentially reflects depressed global price levels last year. Domestic oil prices averaged around 47% of world prices during the second half of 2020 and only 37% of world prices in the first half of 2021. Margins on domestic market deliveries are, in turn, much lower than on exports, essentially reflecting the overall difference in prices between the two markets (see Figure 3.19 Comparison of domestic Kazakh and international crude oil prices by month).

The comparatively low level of domestic prices versus international ones will increasingly complicate the task of securing crude oil supplies for Kazakh refineries, given the ongoing decline of legacy crude production by KMG in Kazakhstan as well as the growing share of the domestic market in total crude oil sales longer term. This challenge is already becoming acute for the Shymkent refinery, which does not have a readily available (large-scale) alternative crude supply source to replace traditional, local sources in the Turgay Basin. With production from the Turgay Basin expected to continue to decline, the key to maintaining deliveries to the refinery is the above-noted program to reverse the flow of the Kenkiyak-Atyrau pipeline. But the larger issue, longer term, remains insufficient economic incentive for Kazakh upstream producers to redirect crude from export markets to Shymkent and other refineries at low domestic prices.[54]

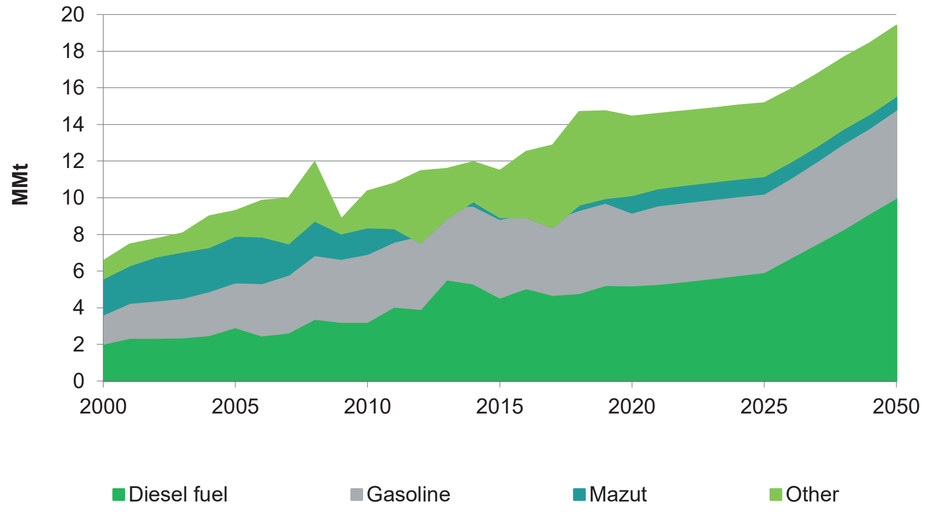
3.8.3 Domestic refined product prices and EAEU market integration dynamics

Domestic product prices remain heavily administered in Kazakhstan notwithstanding official price liberalization (Kazakhstan remains one of countries with the lowest gasoline prices in the world). This is not only a problem for Kazakh crude producers (who in effect subsidize artificially low prices at the pump through crude oil sales at prices well below world market levels), and for refined product market players in Kazakhstan (given the extremely limited retail markup). The resulting market distortions ultimately raise energy security issues for Kazakhstan because they drive the unauthorized outflow of Kazakh refined products from border regions to neighboring countries with significantly higher product prices, such as Russia and Kyrgyzstan. Kazakh policymakers try to address this issue through periodic ad hoc measures such as temporary product trade bans and other controls, but with mixed results. As noted previously, such administrative measures cannot really ameliorate the overall situation; price parity between Kazakhstan and its neighbors needs to be

53 Here and elsewhere in the text, tolling refers to the arrangement where crude suppliers pay refiners a fee to process the crude, and retain title to the resulting refined products for subsequent sale. For additional background on Kazakh domestic oil market dynamics and prices, see *The National Energy Report 2019,* pp. 65–84, and the IHS Markit Insight *Completion of Kazakhstan refinery modernization program will reduce dependence on Russian imports,* 16 November 2017.

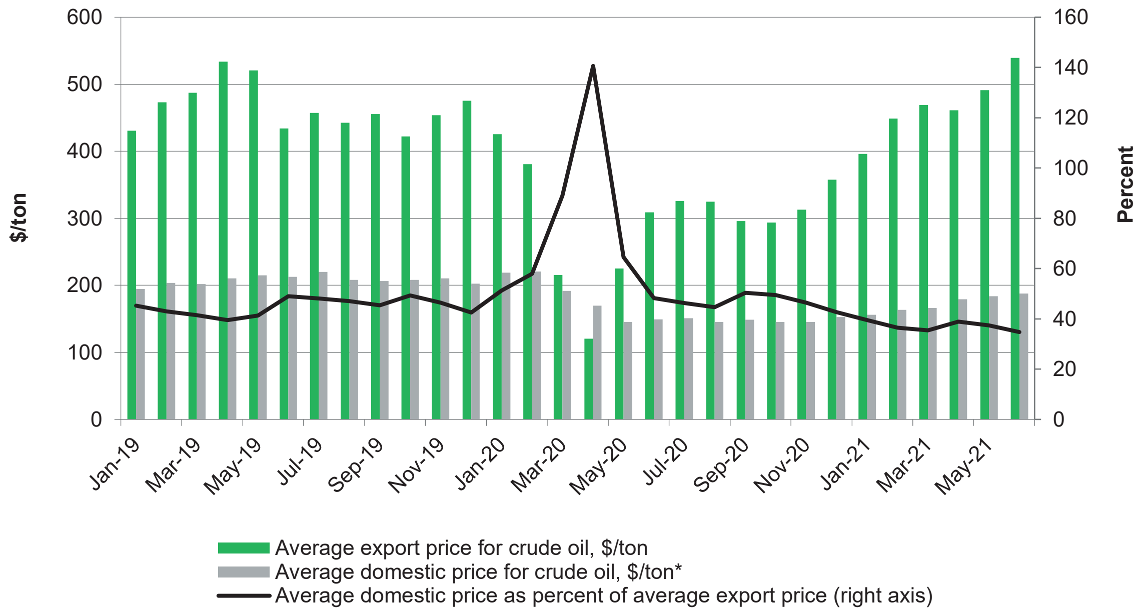
54 In contrast to Shymkent, the Atyrau refinery has the advantage of proximity to the main oil producing region of Kazakhstan, so the plant gets its crude from a variety of western Kazakh fields. But KMG's legacy regional production in this region is also declining, and the "Big 3" producers, which are the key sources of production growth, are unlikely to agree to supply crude to Atyrau or other refineries unless they can receive a competitive price. Meanwhile, the Pavlodar refinery, located near Kazakhstan's northeastern border with Russia, sources its crude from Russia because of the relative logistics. Producers in western and south-central Kazakhstan send increasing volumes (nominally) to the Pavlodar refinery as part of the swap arrangement with Rosneft on that company's exports to China. Under the arrangement, Kazakh crude recorded as deliveries to Pavlodar is directed to China within the framework of the Rosneft-CNPC swap deal, and the Pavlodar refinery processes Russian crude. However, Kazakh producers are still responsible for covering the costs for transportation to Pavlodar.

Figure 3.18 Outlook for apparent consumption of refined products in Kazakhstan



Source: IHS Markit

Figure 3.19 Comparison of domestic Kazakh and international crude oil prices by month



Note: *Acquisition price by refineries.
Source: IHS Markit

achieved by economic measures. But progress is likely to remain slow given the high social sensitivity of the domestic motor fuel price issue.

In short, the basic dichotomy between global and domestic prices – both crude oil and refined product prices – is set to continue for some time, but further liberalization of domestic prices is nevertheless likely over the next few years given the imperatives of EAEU oil market integration. Simply put, Kazakhstan will have to liberalize its domestic pricing policies more than any other EAEU member in order to achieve a common oil and refined product market by 2025, since Kazakhstan has the lowest retail gasoline and diesel price levels among the five EAEU nations (see Figure 3.20 Average retail prices of A-92 gasoline in selected EAEU countries, and Figure 3.21 Average retail prices of diesel in selected EAEU countries).

As shown by the example of the EU, regional integration tends to be most effective when member states of the common market all liberalize domestic policies and refrain from adoption of restrictive administrative mechanisms in cross-border trade. Kazakh prices will need to more closely approximate the price level in Russia for a genuine common market to materialize, since Russia has already liberalized domestic product prices and it is the largest oil producer, consumer, and exporter by far within the EAEU. At the same time, the lack of strong economic complementarity between the Kazakh and Russian economies remains a challenge to effective integration of Kazakhstan within the EAEU; both countries are major hydrocarbon producers and exporters, dependent on exports of raw materials that go mainly to global markets rather than to other EAEU member states. In contrast, the trade structure of other EAEU members is oriented more strongly toward the economic space of Russia and other neighboring countries, facilitating the EAEU market harmonization process, as they already operate largely according to Russia's general acquis.

In accordance with Article 84 of the EAEU Treaty, creation of the EAEU's common oil and refined products markets is a three-stage process. The first phase, completed in December 2018, involved agreement on the EAEU's common oil and refined products markets formation program and approval of this program by the Supreme Eurasian Economic Council (consisting of the leaders of the five EAEU member states). The second phase, currently in progress and scheduled to be completed by 2023, involves implementation of the steps stipulated in the program, including development of unified rules of access to oil and refined products transportation systems located within the member states. The third phase, to 2024, would finalize formation of the EAEU common oil and refined products market, to take effect from 1 January 2025. Key signposts of the integration progress to watch during 2022-23 include finalization of four documents needed to establish the legal basis for the EAEU common market by 1 January 2024, and thereby set the stage for a start-up in 2025:

- a treaty that officially establishes the common EAEU oil and products market;
- treaty annexes specifying uniform rules for member states to access oil and product transportation systems;
- rules governing the overall trade of oil and products within the common market;
- rules for the trade of oil and products via exchanges.

With respect to oil and product trading mechanisms, the EAEU integration project essentially involves creation of a common market between buyers and sellers of crude oil as well as refined products throughout EAEU economic space. Trading platforms are envisioned for supply and demand to interact to establish pricing, though bilateral trading between EAEU member states will also remain an option, while any trading arrangement is to be anchored in market-based pricing under terms of the common market concept.

Kazakhstan's existing trading exchange – JSC Eurasian Trading System Commodity Exchange (ETSCE) – is already serving as a laboratory of sorts to perfect oil trading mechanisms in advance of the formation of a general EAEU trading platform. ETSCE was founded in December 2008, following the lead of Russia's creation of a commodity exchange earlier that year – the St. Petersburg International Mercantile Exchange (SPIMEX) – and in August 2020 SPIMEX acquired a 5% shareholding in ETSCE with the stated goal of creating conditions "to develop electronic trading in the common market of EAEU member countries, as well as to bring Russian goods to international markets."[55] One milestone in creation of an EAEU-wide trading system was reached on 21 July 2021, when the Eurasian Economic Commission (EEC) held its first simulation of refined products exchange trading. Working with SPIMEX, EEC organized a trading session during which over 60 diesel and gasoline deals were completed. Development of EAEU exchange trading infrastructure nevertheless remains rather weak overall, and the scale of traded volumes is still small, with the result that bilateral agreements and contracts between individual EAEU states will probably continue to predominate for some time.

55 ETSCE was founded by the Financial Center of the City of Almaty and Russia's OJSC RTS Stock Exchange (the latter subsequently became part of the Moscow Exchange). For additional detail on the evolution of the ETSCE ownership structure, see "SPIMEX has acquired 5% of Kazakhstan ETS commodity exchange," 27 August 2020, accessed at https://interfax.com/newsroom/top-stories/69706/.

Figure 3.20 Average retail prices of A-92 gasoline in selected EAEU countries

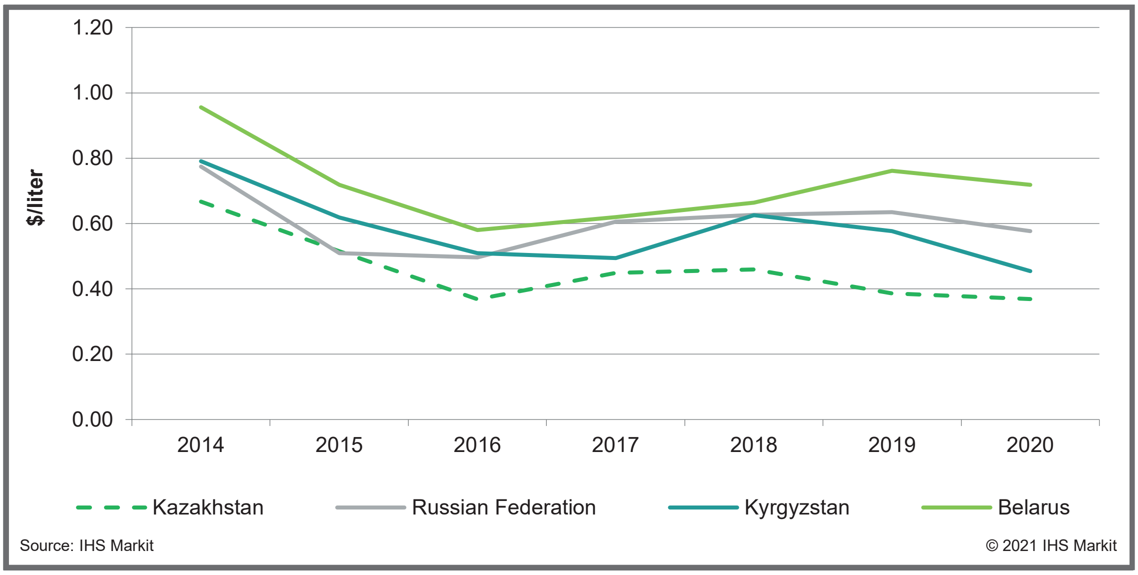
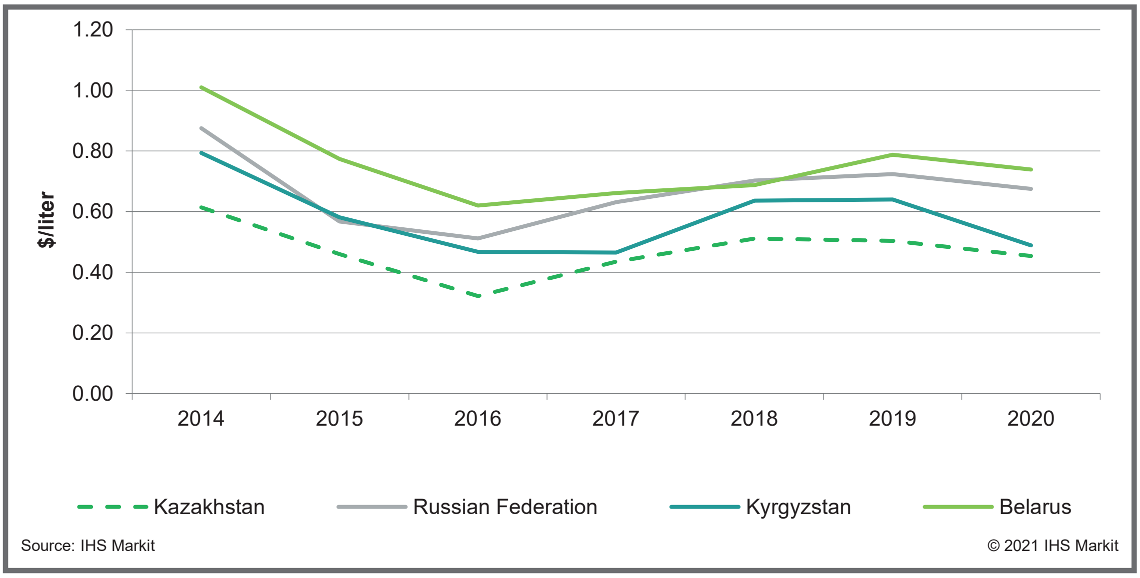


Figure 3.21 Average retail prices of diesel in selected EAEU countries



3.9 Recommendations for Kazakhstan's Upstream Oil Sector

- **Kazakhstan's OPEC+ policy should remain flexible, contributing further to Vienna Alliance actions in support of world oil prices while also ensuring that future cuts programs do not unduly constrain its own upstream development.** The "opportunity cost" of Kazakhstan's OPEC+ participation in the form of foregone production and export volumes – and lower upstream investment – may well rise in coming years. Two key trends increasing the likelihood of such a scenario in the near term are the ongoing recovery of world oil demand (albeit uneven and halting), and the prospect of significant expansion of output from selected mega projects (Tengiz and Kashagan) in the early 2020s. Longer term, the global energy transition away from hydrocarbons will change the OPEC+ calculus for Kazakhstan. Kazakh policymakers should carefully consider the impact of any planned new rounds of OPEC+ output cuts on upstream investment levels longer term when finalizing voluntary production quotas.

- **Additional reform of fiscal terms governing E&P projects should be undertaken to stimulate upstream investment and ensure Kazakhstan's global competitiveness.** Kazakhstan's relatively low ranking in global E&P attractiveness reflects a low Fiscal Systems rating in particular. To address this issue, it is necessary to stimulate increased application of more costly but impactful secondary and tertiary recovery methods. Ultimately, policymakers will likely need an expanded fiscal toolbox, including a tax alternative along the lines of the Improved Model Contract currently under development. As a matter of general underlying principle, upstream fiscal reforms should involve a shift from the current volume-based tax regime to a profits-based taxation system. The aim should be to offer investors competitive returns on investments and fiscal stability.

- **Additional incentives to stimulate processing and commercial sale of associated gas are needed.** Although Kazakhstan has abundant reserves of associated gas, much of it (up to 50%) is reinjected into reservoirs to maximize recovery of liquids. State regulation of the pricing and sales of the associated gas, implemented under the 2012 Law on gas and gas supply, significantly reduces the value of associated gas available to subsoil users and does not provide sufficient stimuli to increase processing and commercial sales of associated gas. Although improvement of gas pricing terms is being considered as part of the Improved Model Contract terms to be available to new investors, more measures are necessary to provide sufficient incentives to commercialize larger reserves of associated gas, including fiscal incentives, risk and cost sharing for gas processing facilities (especially for sour gas treatment), and other measures to reduce the cost of projects.

- **New state environmental and modernization initiatives should be formulated in such a way as to minimize any additional expenses for producers who are already burdened with relatively high costs in international terms.** For example, while parts of the government's emerging new BAT and digitalization agenda seem to complement the oil industry's own ongoing modernization drive, there is some risk that certain new requirements may impose additional, unwarranted costs on producers. In short, when crafting mandates designed to achieve environmental, digitalization, or other goals, policymakers should carefully consider these mandates' potential impacts on Kazakh producers' cost-competitiveness globally.

- **Domestic refined product prices need to be fully liberalized in order to realize EAEU common market goals, and ensure Kazakh oil producers have sufficient incentive to meet growing domestic oil market needs even as legacy sources of oil supply decline.** Greater reliance on market forces to set domestic prices is required to maintain upstream spending and stimulate new investment, since a growing share of total oil production is delivered to domestic markets. Such liberalization is part and parcel of a move to market-based domestic crude oil prices (i.e., based on the principle of export price parity), which is in turn a precondition for an attractive return on investment for all upstream players regardless of their levels of access to crude oil export markets.

- **The government should reform the current system of fines and penalties for APG, which has the effect of discriminating against hydrocarbon producers.** Kazakh authorities have made progress leveling the playing field in terms of penalties for APG emissions, particularly with a June 2021 amendment to the Code of Administrative Violations that removes discriminatory penalties related to gas flaring (making penalties related to emissions from APG flaring the same as penalties for emissions from other stationary sources). However, outsized rates for flaring remain: payments for flared gas emissions are still higher than for emissions from stationary sources, unfairly targeting the oil and gas sector.

- **Greater clarity should be provided on the scope of BAT regulations, and the timetable for implementation should be extended in the case of the most costly new technologies so as not**

to constrain oil companies' overall upstream investment programs. Mandated technologies can be exceptionally onerous, especially in cases where regulations are insufficiently clear; the required new systems can be costly, and the time allotted to implement the new technology is too short. One example is the MEGNR order of June 2021 requiring installation by 1 January 2023 of Automated Emissions Monitoring Systems at facilities that started operations before July 2021.

- **Enhanced oil recovery with CO_2 injection (CO_2 EOR) could become an integral part of emissions reductions strategies in Kazakhstan where such initiatives are deemed economical.** There are additional opportunities for injection of CO_2 to increase oil recovery and production rates. Successful application of CO_2 EOR, in a way that also reduces emissions overall, would require the upstream company to be at a stage of development suitable for EOR, and have sufficient gas for reinjection into the reservoir. Technical factors such as miscibility and CO_2 concentration in the gas stream are also important. All things considered, CO_2 EOR nevertheless appears to represent one of the most viable potential applications of CCUS technologies at Kazakh oil fields. Companies implementing such projects could also potentially tap into the global carbon offsets market; i.e., "selling" CO_2 emissions that are avoided as offsets.

- **Small-scale renewable power could be deployed for infield operations where possible and economical.** Greater reliance on renewables to provide power for field operations may significantly decrease emissions, particularly in the case of oilfield operations currently powered by coal-fired electricity purchased from the grid or where renewables can be economically deployed to displace electricity currently produced at the field from gas-fired or diesel generators. For oil producers currently lacking on-site generation, investment in renewables may also offer opportunities for improved energy efficiency compared with reliance on the grid for power.

Chapter 4

NATURAL GAS

4 NATURAL GAS AND KAZAKHSTAN'S GASIFICATION STRATEGY

Natural gas is an important tool in Kazakhstan's arsenal for combating climate change. It emits only slightly more than half (on an energy equivalent [toe] basis) the amount of greenhouse gases (GHG) as the country's most widely used fuel (coal) when consumed. Gas is abundant (in terms of reserves) and is produced in large quantities as associated petroleum gas (APG) that is extracted together with oil. And infrastructure already is in place, and is expanding, to deliver it to consumers. In addition, gas can provide pathways for the adoption of even greener fuels (e.g., hydrogen) in the future. Gas also can become even cleaner by reducing fugitive methane emissions throughout the value chain; through the use of carbon capture, use, and storage technology; by employing combined-cycle turbines to generate electricity; and through moderate blending with hydrogen. Besides substituting for coal in electric power, natural gas can also be used to displace dirtier fuels in sectors difficult to decarbonize, such as transportation (motor vehicles and ships).

Yet increased penetration of gas in the Kazakh economy is impeded by competing uses (reinjection needs to enhance oil recovery), a lack of economic incentives to produce adequate commercial supplies, and the national operator's reliance on exporting gas to sustain its operations financially. Finally, its role in the global energy transition more broadly as a "bridge fuel" is now being questioned, especially in Europe. Despite these challenges, as this chapter argues, no other energy carrier is better positioned than natural gas to curtail Kazakhstan's GHG emissions and at the necessary scale over the next two decades.

4.1 Key Points

- Between 2010 and 2020, gross natural gas production (including reinjected volumes) in Kazakhstan grew by an annual average of 4% to reach 55.1 Bcm in 2020. Commercial gas production (excluding reinjected volumes) grew at a similar rate over the past decade, reaching about 34.8 Bcm in 2020. Longer term, commercial gas supply is being pressed by burgeoning domestic demand, especially as gas displaces coal in the power segment. This is because commercial gas production is likely to be constrained due to sustained reinjection needs, and the lack of price incentives to commercialize available associated gas. IHS Markit anticipates commercial output to peak at only about 36 Bcm in 2030, before declining to about 30 Bcm in 2050. The "Big 3" producers (Tengiz, Kashagan, and Karachaganak) are responsible for 70% of the country's commercial gas supply.
- The gasification of Kazakhstan is a key strategic priority of policymakers. Thanks to substantial investment in transmission pipelines, including the Beyneu-Bozoy-Shymkent (BBS) pipeline and the SaryArka pipeline, actual (end-of-pipe) gas consumption nearly doubled over the past decade, rising from 9 Bcm in 2010 to 17 Bcm in 2020. By the end of 2020, 53% of Kazakhstan's population had access to piped gas.
- Kazakhstan's gas exports to China grew from less than 1 Bcm in 2015, to 7.4 Bcm in 2020. Exports to China provided the national gas company KazTransGas (KTG) with a source of revenue sufficient to offset its financial losses on gas sales in the domestic market. Unfortunately, exports to China are likely to be undermined in the long term by rising domestic needs combined with constrained commercial supply.
- Kazakhstan's gas sector is poised to undergo some structural changes as policymakers and KTG recognize the need to address the increasing call on gas supply. Efforts to improve the investment climate and reorganize KTG are underway. In June 2021, President Tokayev emphasized the need to improve the current model of development and management of the gas industry, including such aspects as improved investment attractiveness of the sector, increased geological exploration, improved domestic gas pricing policies, and continued gasification.

4.2 Reserves and Exploration

Kazakhstan ranks among the top 20 countries in the world in terms of its overall gas resource endowment.[1] Kazakhstan's gas reserve base as of 1 January 2020 was at 3.8 trillion cubic meters (Tcm).[2] IHS Markit estimates Kazakhstan's 2P gas reserves at 152 trillion cubic feet (4.4 Tcm). The vast majority of reserves (89%) are located

1 By international definitions for just "proven" ("1P") reserves, Kazakhstan is considered to possess 2.3 Tcm as of the end of 2020 (unchanged from 2019), or 1.2% of the global total (BP Statistical Review of World Energy, July 2021). By this measure Kazakhstan ranks fourth among CIS countries (after Russia, Turkmenistan, and Azerbaijan) and 16th in the world.

2 The reserves are reported according to the domestic definition (in categories A+B+C1+C2), which roughly corresponds to the international equivalent of proven + probable reserves. Slightly more than half (about 57%) is associated gas (held in solution with liquid hydrocarbons in the reservoir) and the remainder "free" gas. The state balance for 2020 identifies gas reserves in 255 fields.

Figure 4.1 Kazakhstan's gas sector (selected key elements)

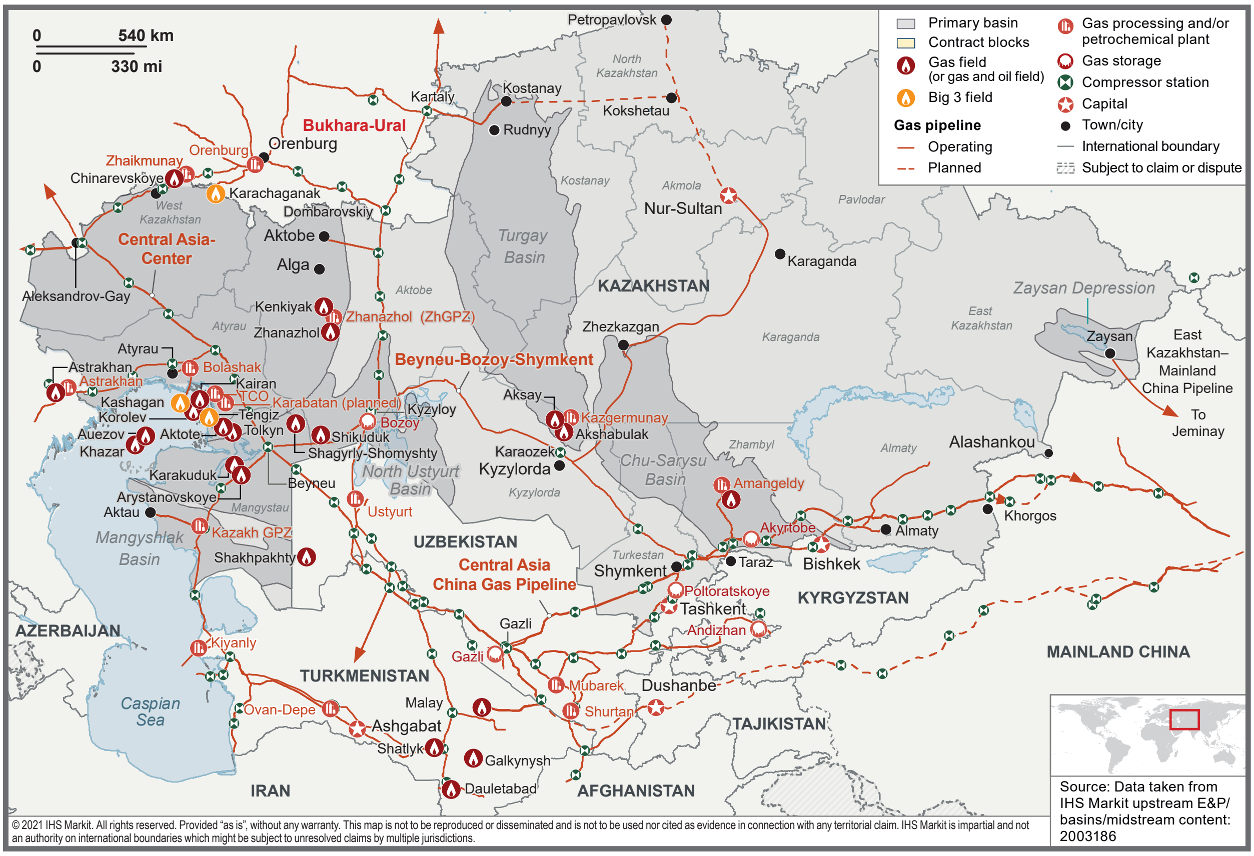


Table 4.1 Kazakhstan's 2P gas reserves by basin

Basin	Gas recoverable 2P reserves (MMscf)	Gas recoverable 2P reserves (MMcm)
Precaspian Basin	135,680,231	3,962,624
Mangyshlak-Central Caspian	7,928,665	231,561
North Ustyurt Basin	3,471,466	101,386
Turgay Basin	2,066,095	60,342
Volga-Urals Basin	1,499,790	43,802
Chu-Sarysu Basin	935,758	27,329
Zaysan Basin	165,290	4,827
North Caucasus Platform	25,000	730
Total	**151,772,296**	**4,432,602**

Note: Data as of 1 January 2019. 2P = proven+probable.

Source: IHS Markit

in the Precaspian Basin in the northern and western portion of the country, one of the world's hydrocarbon "super" basins that encompasses the three supergiant oil (with associated) gas fields – Karachaganak, Tengiz, and Kashagan – that provide the foundation for the country's current oil and gas production. In addition, two other western basins – Mangyshlak-Central Caspian and North Ustyurt – possess more than 100 Bcm of recoverable reserves and have favorable exploration potential (see Figure 4.1 Kazakhstan's gas sector (selected key elements); and Table 4.1 Kazakhstan's 2P gas reserves by basin). About 85% of gas reserves are found in a few large fields (the "Big 3" mentioned above as well as Zhanazhol and Imashevskoye), albeit at considerable depth (up to 5 km) and often with high sulfur content, both of which complicate field development and production.

4.3 Natural Gas Production and Outlook

Natural gas production in Kazakhstan is largely shaped by the fact that most of the gas produced in the country is associated gas—i.e., is produced as a by-product of oil production, with a large share of gas output coming from the Karachaganak field, designed to extract liquid hydrocarbons (e.g., gas condensate). Given relatively high gas processing costs and low (domestic) gas sales prices, most producers prefer to reinject gas to enhance oil production, rather than sell gas to the national gas company KTG.[3] This leads to a paradox of sorts: (a) large quantities of associated gas need to be disposed of, yet (b) commercial supply is relatively tight. As Kazakhstan's domestic gas consumption grows, the need to incentivize commercial gas supply is now becoming increasingly urgent, both to support domestic gasification (a key element in the country's drive to cut air pollution in big cities and to reduce GHG emissions as part of its energy transition strategy) as well as to ensure quantities for export that recently have represented the main source of profitability for KTG.

Kazakhstan's natural gas production (gross extraction) has been increasing in recent years, by almost 2% to 56.4 Bcm in 2019, following sizable increases (14.1%) in 2017 and (4.8%) in 2018 (see Table 4.2 Kazakhstan's natural gas balance 2010-20 (Bcm/y)). Gas output since late 2016 has been boosted mainly by growth in (gross) output at Kashagan, as associated gas production there has been ramping up following the restart of oil production. However, in 2020 the combined effects of a domestic economic downturn associated with the COVID-19 pandemic, OPEC+ caps on oil production (see Chapter 1), and intermittent pandemic-related production curtailments at major fields (such as Tengiz) resulted in a slight decline (-2.3%) in gross gas output, to 55.1 Bcm. Commercial production (gross output minus reinjection) in Kazakhstan has been on the rise since 2010 (24.6 Bcm), although in 2020, the national total volume was about 7% lower than in 2019 at 34.8 Bcm.

Gas production levels in Kazakhstan are determined in large part by liquids-driven upstream operations. The "Big 3" projects accounted for 79% of Kazakhstan's gross gas production in 2020, and about 70% of "commercial" gas production, as these three projects have considerable reinjection needs (see Figure 4.2 "Big 3" share in commercial gas production in Kazakhstan). Reinjection (albeit on a smaller scale) also occurs at several smaller producers in Kyzylorda and Mangystau oblasts.

Gross gas production from the top gas producers in the country (the three mega-projects, plus CNPC-AktobeMunayGaz and KMG's wholly owned subsidiaries) accounted for 50.1 Bcm (or 91%) of the national total in 2020.[4] The remaining 9% of gross gas output is produced by so-called independent (smaller) gas producers (mirroring a similar situation in oil production).

IHS Markit's base-case outlook for Kazakhstan's natural gas production to 2040, reflecting mainly growing liquids output, expects that gross gas output will expand by about 26%, to around 70 Bcm/y. Gross output will likely peak in 2030 at 76 Bcm/y, before entering a period of steady decline (see Table 4.3 Kazakhstan's natural gas balance: IHS Markit base-case outlook to 2050 (Bcm/y)). Between 2020 and 2040, almost all of the net increase in gross gas output (14.4 Bcm) is expected to come from Kashagan (12.6 Bcm), Tengiz (3.2 Bcm) and Karachaganak (1.8 Bcm), while gross output from other sources (primarily mature fields) is slated to decline by around 3.2 Bcm.

Despite the anticipated uptick in gross output, commercial volumes will likely peak somewhat sooner, in the late 2020s, at around 36 Bcm/y, before declining slightly due to sustained high reinjection needs, limited gas processing capacity, and challenges to commercial use posed by low producer and end-user prices. Commercial production from the "Big 3" is expected to be relatively flat; Karachaganak's commercial gas output remains stable through 2040 at about 9.5 Bcm/y, while Tengiz's commercial gas deliveries will continue at around 9.5 Bcm/y through 2035. At Kashagan, commercial gas output in the IHS Markit base-case outlook rises to 8 Bcm by 2030 (after completion of a new 2 Bcm/y gas

3 Kazakhstan reinjects 30%–40% of its associated gas output (37% in 2020) to maintain reservoir pressure, so only about 60% of its gross gas output is potentially available as commercial volumes for distribution to consumers, export, or in-field use as fuel.

4 In addition to its subsidiaries, KMG holds shares in each of the "Big 3" mega projects, and when these are taken into account, its total output in (in equity terms) amounted to about 8.2 Bcm, or around 15% of national gross gas production, in 2020.

Table 4.2 Kazakhstan's natural gas balance 2010-20 (Bcm/y)

	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020
Production (gross)*	37.1	39.5	40.1	42.4	43.2	45.3	46.4	52.9	55.5	56.4	55.1
Production (commercial output)**	24.6	25.2	25.3	25.5	25.6	28.4	30.3	34.7	38.0	37.6	34.8
Imports	4.0	4.1	4.5	5.2	4.0	4.9	5.8	5.1	5.7	8.8	4.3
Exports***	14.5	16.0	12.8	13.1	11.6	13.3	12.8	16.8	19.1	19.4	16.7
Net exports	15.6	15.1	14.8	14.6	13.2	16.4	17.2	20.7	22.9	21.6	17.9
Apparent consumption (commercial gas)	16.7	17.8	16.8	17.4	17.3	20.7	22.4	22.9	24.7	26.0	26.0
Consumption (end-of-pipe deliveries)****	9.0	10.1	10.5	10.9	12.4	12.0	13.1	14.0	15.1	15.9	17.1

Notes: *Including re-injected volumes; **Gross production minus re-injection; ***Exports include KPO sales to KRG; ****Amount reported as consumption (end-of-pipe deliveries) by the Ministry of Energy RK

Source: IHS Markit

Figure 4.2 "Big 3" share in commercial gas production in Kazakhstan

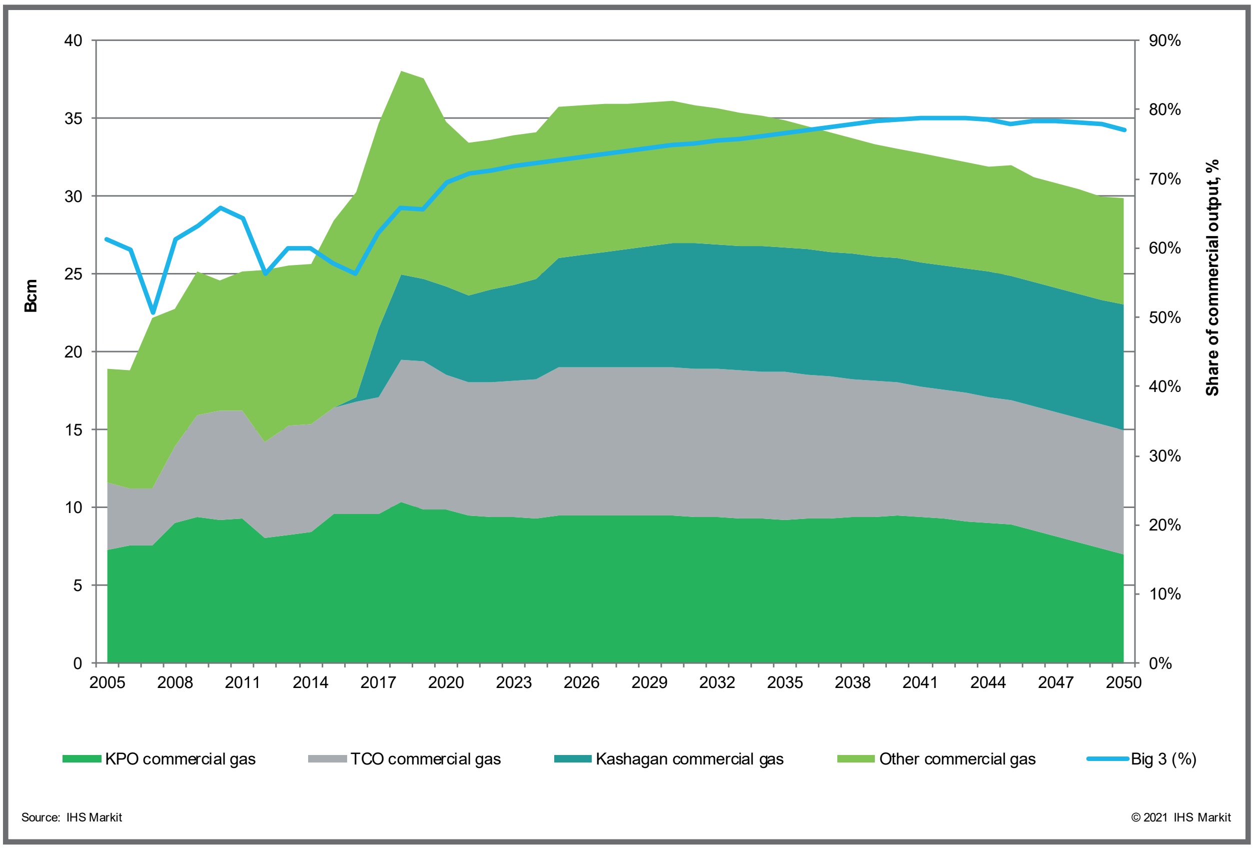


Table 4.3 Kazakhstan's natural gas balance: IHS Markit base-case outlook to 2050 (Bcm/y)

	IHS Markit forecast										
	2020	2021	2022	2023	2024	2025	2030	2035	2040	2045	2050
Production (gross)*	55.1	55.7	58.3	60.8	63.4	67.9	76.0	72.7	69.5	59.2	52.2
Production (commercial output)**	34.8	33.4	33.6	33.9	34.1	35.8	36.1	34.9	33.1	32.0	29.9
Imports	4.3	5.0	5.4	5.7	6.1	6.1	6.5	7.4	10.3	11.9	12.8
Exports***	16.7	17.5	17.2	17.0	16.7	15.2	14.5	11.8	11.3	10.2	7.8
Net exports	17.9	16.3	16.4	16.4	16.5	18.0	16.5	12.3	8.1	4.8	0.7
Apparent consumption (commercial gas)	26.0	25.8	25.9	26.1	26.2	26.7	28.1	30.5	32.1	33.7	34.9
Consumption (end-of-pipe deliveries)****	17.1	17.1	17.3	17.5	17.6	17.8	19.6	22.6	25.0	27.2	29.2

Notes: *Including re-injected volumes; **Gross production minus re-injection; ***Exports include KPO sales to KRG; ****Amount reported as consumption (end-of-pipe deliveries) by the Ministry of Energy RK.

Source: IHS Markit, Ministry of Energy RK

processing facility near Bolashak oil and gas treatment complex) and remains at that level through the forecast period (see Figure 4.3. Kazakhstan's gas production profile to 2050: IHS Markit base-case outlook).[5] The new gas processing plant near Bolashak, with capacity of 1.15 Bcm/y of raw gas (yielding 815 MMcm/y of dry gas) is already under construction, due to be completed by 2023. Reportedly, it's capacity could be expanded to 2 Bcm/y by 2025 and there are some discussions of increasing it further to 5 Bcm/y at a later date.

An outlook issued by Kazakhstan's Ministry of Energy for commercial gas production also indicates an uptick in commercial gas volumes by the late 2020s. The expansion of gas processing capacity at Kashagan is likely to be the main driver of this growth, although other "new" unidentified sources are also included (see Figure 4.4 Kazakhstan's Ministry of Energy outlook for natural gas balance to 2030). In the Ministry forecast, reinjected gas volumes more than double by 2030 from the current levels.

5 Kazakhstan's government and the NCOC partners are discussing a possible Phase 2 of the Kashagan project. Recently released details call for a less ambitious Phase 2 development than originally envisioned, but feature additional commercial gas. This new Phase 2 consists of two separate projects (Phase 2A and Phase 2B) that together would increase oil and condensate production to about 700,000 b/d (33 MMt/y) over a 10-year period. Phase 2A (currently under review) would increase total liquids output to 500,000 b/d (23.7 MMt/y) with an option of an additional 2 Bcm/y of raw gas supplied to an expanded KTG gas processing plant. An FID is expected in 2023, with project start-up in 2026. Phase 2B would bring NCOC's total liquids production to 700,000 b/d. An additional 6 Bcm/y of raw gas would be made available, either for a new processing plant or perhaps for TCO's existing facilities to utilize. An FID is expected in 2024, with project start-up in 2030.

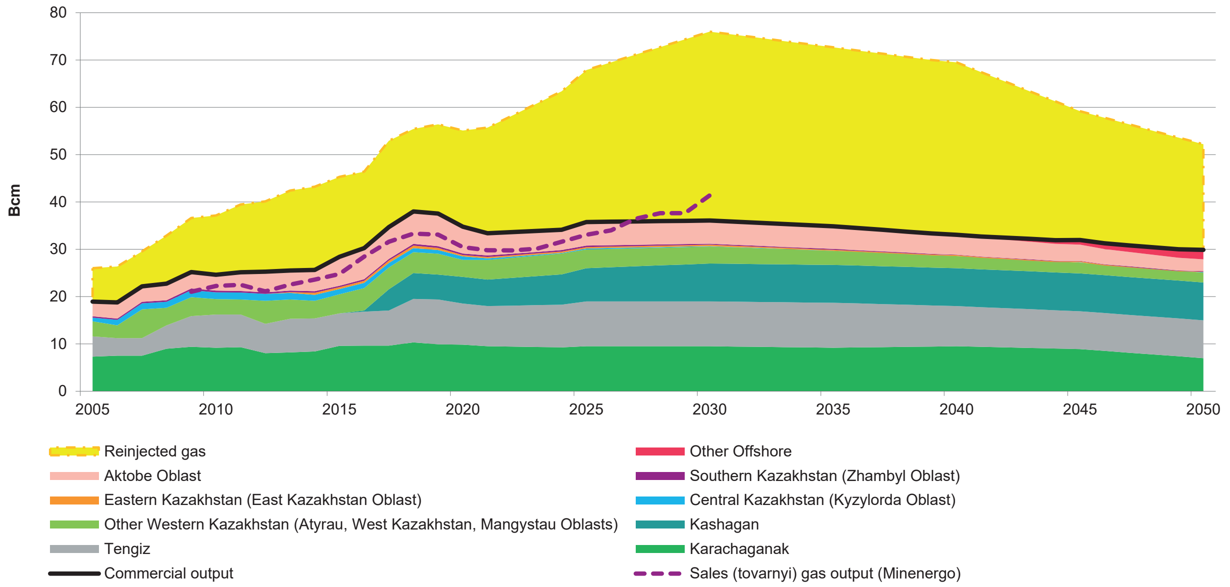
4.4 Market Structure and Legal Framework

Kazakhstan's 2017 Subsoil Code stipulates that the state's interests in the upstream natural gas sector are to be represented by the "National Company for Hydrocarbons" – a company set up by the government to conduct subsoil use activities pertaining to hydrocarbon resources. The state via the National Managing Holding Group, presumably the joint-stock company National Welfare Fund "Samruk-Kazyna" (NWF SK), should be a majority shareholder in such a company. Satisfying these criteria, KazMunayGaz (KMG) is the designated National Company, particularly with respect to its mandatory participation in developing offshore and strategic acreage.[6]

The Law on Gas and Gas Supply in January 2012 designates KMG's wholly-owned subsidiary KazTransGas (KTG) as the "national operator" for the county's single-buyer model of gas procurement, transportation, and distribution. Under the legislation, KTG not only remains the monopoly operator of all gas transmission and distribution infrastructure in the country but also has exclusive rights to purchase (associated) gas from

6 The 2017 Subsoil Code prescribes that the National Company (i.e., in practice KMG) must hold at least 50% interest in any operator of contracts awarded for offshore areas. This participation may be reduced at a later date provided that KMG maintains effective control over the decision-making process under the contract. Furthermore, KMG is expected to exercise similar rights with regards to future major field developments, which are identified as "strategic" fields in the 2017 Subsoil Code.

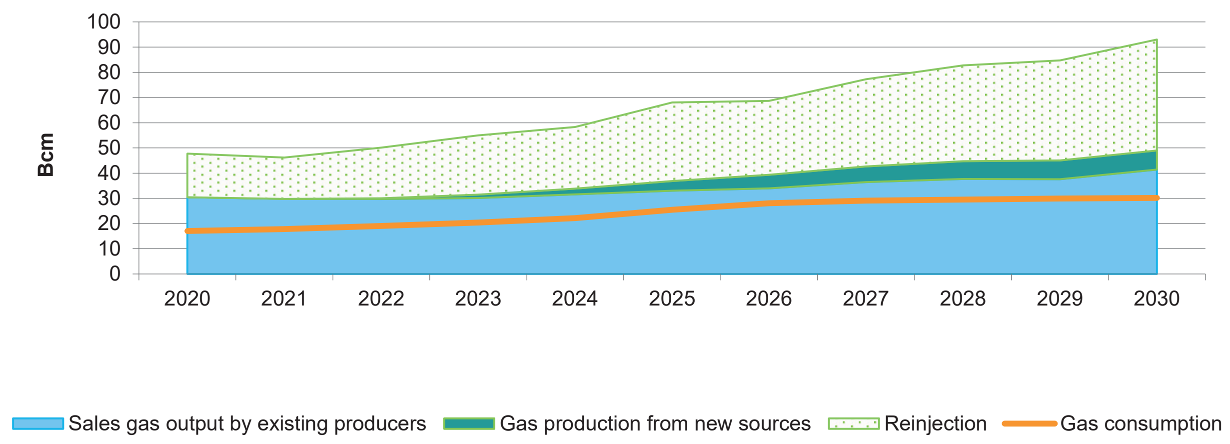
Figure 4.3 Kazakhstan's gas production profile to 2050: IHS Markit base-case outlook



Notes: For the purposes of this report, IHS Markit defines commercial gas volumes as gross gas production minus reinjected volumes; therefore, commercial production includes volumes that disappear as other upstream usage and losses. This is not the same as the volume of "sales gas" production (tovarnoye proizvodstvo) reported by the Ministry of Energy RK, which appears to exclude reinjection, impurities, and other upstream usage and losses.

Source: IHS Markit, Ministry of Energy RK

Figure 4.4 Kazakhstan's Ministry of Energy outlook for natural gas balance to 2030



Source: Ministry of Energy RK, IHS Markit producers, sell gas on the local market, and export gas.[7] As the national operator, KTG operates the country's national system of trunk pipelines and storage facilities under its subsidiary Intergas Central Asia (ICA), and maintains the network of gas distribution and sales to domestic customers through its subsidiary KTG-Aimak.

In March 2021, it was announced that KMG and the NWF SK inked a share-management agreement. The agreement enables NWF SK to more directly participate in KTG's operations, "providing support on strategic issues…such as gas price-regulation on the domestic market, upgrading and expanding the gas pipeline system, as well as furthering gasification."[8]

In June 2021, during a meeting with the gas industry officials, President Tokayev emphasized that the current model of gas industry development and management needs to be updated in order to improve the investment attractiveness of the sector, increase geological exploration, improve domestic gas pricing policies, and promote further gasification of the economy (including in the transportation sector and its deeper processing in the chemical industry). The President emphasized that, after being transferred to direct control of NWF SK, priority subsoil rights for new gas and gas condensate fields will be transferred to KTG.[9] He pointed to a strategy concept that would transform KTG into a vertically integrated national gas company with activities spanning the entire gas value chain. The president indicated that after this reorganization, KTG could pursue an IPO or a "people's IPO" as soon as 2022.

4.5 Gas Processing and Transportation

The bulk of Kazakhstan's gas output requires processing. There are five major gas processing plants (GPZs) in Kazakhstan, several smaller plants, and also an important arrangement for the processing of Karachaganak's raw (sour) gas across the border at Russia's Orenburg gas processing plant (see Table 4.4 Existing and planned gas processing plants in Kazakhstan as of 1 January 2021 (MMcm/y)). The five main plants are the older Kazakh plant owned by KMG subsidiary OMG (2.9 Bcm/y KazGPZ in Mangystau Oblast), Tengiz/TCO (approximately 9.2 Bcm/y in Atyrau Oblast), CNPC-AktobeMunayGaz (7.0 Bcm/y Zhanazhol GPZ in Aktobe Oblast), Kashagan/NCOC (6.0 Bcm/y Bolashak GPZ in Atyrau Oblast), and Zhaikmunay (4.2 Bcm/y plant in West Kazakhstan Oblast). There are several other smaller and technologically simpler plants throughout the country. The total volume of gas processed domestically in 2020 was 30.5 Bcm, a decline from over 33 Bcm processed in both 2018 and 2019.

Total nameplate processing capacity is slated to reach about 33 Bcm/y following the completion of the 2 Bcm/y plant at Bolashak. Although total processing capacity of all gas processing plants, together with the availability of Russian capacity at Orenburg GPZ, appear adequate to handle the bulk of Kazakhstan's expected volumes of gas needing processing for the next decade or so, they hide the fact that Kazakhstan will likely need more gas processing facilities for sour gas treatment. Any sizable increase in commercial gas supply would necessitate a buildout in additional complex gas processing capacity near the sources of production.

As the designated "national operator" of all gas transmission and distribution infrastructure in the country, KTG manages more than 20,000 km of trunk gas pipelines, 56 compressor stations, three underground gas storage facilities (4.6 Bcm capacity), and more than 56,000 km of gas distribution networks (see Table 4.5 Kazakhstan's trunk gas pipelines as of 1 January 2021). KTG also serves as the state representative in major gas pipelines operated by joint ventures involving foreign partners.

The national trunk gas transmission system has an aggregate transport capacity to handle up to 200 Bcm/y (see Figure 4.1). The trunk transmission system carried 112.8 Bcm in 2020, the bulk (56%) of which was actually transit gas (see Table 4.6 Gas shipments through Kazakhstan's major gas pipelines (Bcm/y)).[10] Not surprisingly, revenues from transit gas flows are extremely important to KTG's overall financial position (see below).

Two key developments in recent years have accelerated gasification in the country:

- **Completion of the 15 Bcm/y, Beyneu-Bozoy-Shymkent (BBS) pipeline established a more unified national gas network, enabling gas produced in western Kazakhstan to be delivered to southern Kazakhstan and to China via the Central Asian Gas Pipeline system (CAGP).**[11] BBS utilization expanded since its commissioning in 2013, when throughput volumes were only 300 MMcm. Volumes transported via BBS reached

7 An important exception is TCO, which under its JV agreement has the right to export gas, which it has done in the past to Russia via the CAC or Makat-Astrakhan pipelines.

8 https://www.kmg.kz/rus/press-centr/press-relizy/?cid=0&rid=818

9 https://www.akorda.kz/ru/glava-gosudarstva-provel-soveshchanie-po-razvitiyu-gazovoy-otrasli-175391

10 Unless otherwise indicated, all figures in this section are presented in the local (Russian) measure of cubic meters (Mcm, MMcm, Bcm), which contains 8,850 kilocalories per cubic meter (kcal/m^3) in gross calorific value. The IEA convention of international standard cubic meters (Mscm, MMscm, Bscm) contains 9,500 kcal/m^3. To convert from Russian normal to international standard, multiply by 0.931; to do the opposite, divide by 0.931.

11 China refers to mainland China.

Table 4.4 Existing and planned gas processing plants in Kazakhstan as of 1 January 2021 (MMcm/y)

Plant name	Location	Estimated nameplate capacity	Gas processed in 2020	Estimated capacity utilization in 2020, %	Capacity additions planned by 2030
TCO GPZ*	Atyrau Oblast	9,162	8,674	95%	0
Zhanazhol GPZ	Aktobe Oblast	7,000	4,635	66%	0
Kashagan GPZ**	Atyrau Oblast	6,000	4,132	69%	2,000
KazGPZ (at OMG)***	Mangystau Oblast	2,900	751	26%	0
Others, including****		5,826	12,281	211%	
Zhaikmunay GPZ	West Kazakhstan Oblast	4,200	624	15%	0
Total existing gas processing capacity		**30,888**	**30,474**	**99%**	**2,000**
Existing and planned gas processing capacity		**32,888**			

Notes: *IHS Markit estimate. TCO and KLPE are discussing potential construction of a 9 Bcm/y gas separation plant as part of Phase 2 in the development of the Atyrau petrochemical cluster. If Phase 2 is realized, the plant would be built in the mid- to late-2020s.

**Construction of 1 Bcm/y plant launched in 2021, to be potentially upgraded to 2 Bcm/y by the mid-2020s.

***KazGPZ is located at near OMG's production assets in Mangystau Oblast, and handles associated gas from OMG and MMG. The 921 MMcm of processed gas in 2020 includes deliveries from OMG (751 MMcm) and MMG (161 MMcm).

****Other plants (including selected field treatment facilities), besides Zhaikmunay GPZ, include Kazgermunay (Akshabulak) GPZ (150 MMcm/y), Amangeldy GPZ (400 MMcm/y), the Kozhasay Gas Processing Company LLP plant (300 MMcm/y), Kazakhoil Aktobe (300 MMcm), Borankol (326 MMcm/y), and Turgay Petroleum (150 MMcm/y).

Source: IHS Markit, Ministry of Energy RK

Table 4.5 Kazakhstan's trunk gas pipelines as of 1 January 2021

	Estimated total pipeline length (km) on Kazakh territory	Estimated throughput capacity (Bcm/y)
Central Asia–Center (CAC)	3,544	54.0
Central Asia–China Gas Pipeline (CAGP)*	1,830	59.1*
Soyuz	424	24.4
Orenburg–Novopskov	382	16.0
Bukhara–Urals**	1,175	26.0
Okarem–Beyneu	470	7.2
Beyneu–Bozoy–Shymkent	1,454	15.0
Bukhara–Tashkent–Bishkek–Almaty (BGR–TBA)**	1,585	5.8
Makat–North Caucasus	371	22.0
Gazli–Shymkent***	314	4.38

*CAGP's throughput capacity is 55 Bscm.

**Bukhara-Urals contains two parallel lines, each 1,175 km in length. BGR-TBA also contains two parallel lines, each 1,585 km in length.

***Gazli-Shymkent capacity was previously about 11.5 Bcm/y, but now it is much lower due to lack of maintenance.

Source: IHS Markit, KTG

Table 4.6 Gas shipments through Kazakhstan's major gas pipelines (Bcm/y)

	2015	2016	2017	2018	2019	2020
ICA pipelines	**84.0**	**66.8**	**76.6**	**80.134**	**73.0**	**57.8**
Domestic deliveries	11.5	12.3	12.9	13.6	13.7	14.3
Export	12.7	13.3	16.7	18.9	19.1	12.7
International transit	59.7	41.2	46.9	47.7	40.2	30.8
Russian transit (Russia-Russia)	53.1	37.0	41.4	43.9	30.7	25.7
Central Asian transit to Russia	6.6	4.3	5.5	3.8	8.9	3.8
Uzbek transit (Uzbek-Uzbek)	0.1	-	-	-	0.6	1.3
KTG pipelines	**14.1**	**16.1**	**17.7**	**23.9**	**23.9**	**23.8**
Domestic deliveries	11.5	11.8	12.8	15.0	15.1	16.0
Export	2.6	4.3	4.9	8.9	8.8	7.9
Central Asia–China Gas Pipeline*	**35.9**	**37.3**	**41.5**	**50.5**	**46.2**	**39.3**
Exports	–	–	0.6	5.2	7.4	7.4
from Kazakhstan	–	–	0.6	5.2	7.4	7.4
International transit	35.9	37.3	40.9	45.3	38.8	31.9
from Turkmenistan	30.2	32.1	36.3	37.5	33.3	28.6
from Uzbekistan	5.6	5.3	4.6	7.7	5.5	3.3
KTG equity share of CAGP shipments (50%)	17.9	18.7	20.8	25.2	23.1	19.6
BBS pipeline	**1.2**	**2.2**	**4.4**	**8.4**	**10.1**	**12.7**
KTGA						
Localized transmission networks	8.7	9.2	9.6	9.8	9.7	10.4
Major transportation pipelines	2.5	2.6	2.5	2.6	2.6	2.6
Total gas handled	**123.5**	**108.9**	**124.9**	**141.6**	**131.8**	**112.3**
Total gas handled by KTG (including 50% of AGP and BBS)	**105.0**	**89.1**	**102.0**	**112.2**	**103.6**	**86.3**
International transit, share (in percent)	**77%**	**72%**	**70%**	**66%**	**60%**	**56%**

*55 Bscm capacity; shipments reported in Bcm.

Source: IHS Markit, KTG, KMG, AGP

10.1 Bcm in 2019 and 12.7 Bcm in 2020. With BBS pipeline capacity utilization now running at about 85%, policymakers are apparently contemplating an expansion that may involve construction of another string to handle additional transit, export, or domestic market deliveries. The specifics for what gas would be shipped and to where, as well as other aspects of the pipeline project, such as ownership and financing, remain under discussion.

► **The completion of the first stage of the SaryArka pipeline in 2020, extending from the Karaozek Compressor Station (CS) on BBS to the capital city of Nur-Sultan, enabled pipeline gas to reach the capital city in 2020.** In 2020, Nur-Sultan received 4.4 MMcm of piped gas. While the 820 mm SarykArka pipeline is still being worked on to reach its full Phase 1 capacity of 2.2 Bcm/y, the plan is for the pipeline to ultimately achieve 2.3 Bcm/y capacity. First to be gasified are the boiler rooms in Nur-Sultan's combined heat-and-power plants (TETs), along with boiler rooms in the relatively low-income neighborhoods of Koktal-1 and Koktal-2 and the districts of Agrogorodok, Promyshlenny, and Zheleznodorozhny.[12] Longer term, the plan is to extend the SaryArka pipeline from Nur-Sultan to Kokshetau and Petropavlosk with a 483 km spur, and bring total capacity to 4.5 Bcm/y. The exact timing for this planned expansion, however, is yet to be determined and other gasification options for northern Kazakhstan are also being explored.

12 The Ministry of Energy plans to convert 240 boiler houses and 22,000 private homes to gas in Nur-Sultan. Overall, Phase 1 of SaryArka will bring gas to 2.7 million people in 171 settlements along the pipeline's route.

ICA operates the SaryArka pipeline under a lease agreement; the pipeline itself is owned by AO AstanaGas KMG, which is a JV between Samruk-Kazyna (50%) and AO Baiterek Fund (50%). In the IHS Markit base-case outlook, utilization of SaryArka will gradually increase, reaching about 1 Bcm/y by 2024-25. Gasification of cities in Karaganda and Akmola oblasts is challenged by economics, as gas is relatively expensive compared with indigenous coal. Due to high transportation costs, as the gas must travel across much of BBS to Karaozek and then along SaryArka, gas prices delivered to Nur-Sultan rank among the highest in the country. In 2020, the realized price of gas for industrial users, private individuals, and heat-generation facilities in Nur-Sultan was 30,310 tenge/Mcm ($74.9/Mcm), making it the second most expensive destination for domestic gas behind Turkestan Oblast (31,954 tenge/Mcm, or $77.4/Mcm). Another short-term challenge in the capital relates to the buildout of gas distribution infrastructure, although local authorities are working closely with KTG to expand the network's reach. For these reasons, the gasification of Nur-Sultan will occur gradually. It is also important to note, that under the current gas pricing mechanism, future gasification will rely on potential funds from the government budget.

4.6 Domestic Gas Consumption and Kazakhstan's Gasification Program

Abundant domestically produced coal still provides the majority of Kazakhstan's primary energy consumption, accounting for 56% of primary energy consumed in 2020. The share of gas was 24%, ranking second in importance after coal, followed by oil and petroleum products (18%). Longer term, the share of natural gas will continue to increase, chipping away at coal's share. After 2030, IHS Markit projects that the share of coal, although still substantial, will decline to less than 50%, reaching 42% in 2040; by that time the share of natural gas is expected to increase to 29%. That said, achieving this outlook requires a number of proactive policy measures.

4.6.1 Gasification

The government of Kazakhstan is actively pursuing gasification, in order to:

- more thoroughly utilize a resource that is increasingly produced (as associated gas) due to growth in oil production;
- accelerate the "greening" of Kazakhstan's energy sector – gas has a substantially lower environmental footprint compared to coal and oil – in line with its GHG emissions reduction goals, and reduce atmospheric pollution in the country;
- make the economy more competitive internationally (because of gas's potentially lower costs than certain alternative fuels);
- smooth the way for the national system's harmonization with the EAEU single market in natural gas that is planned to launch in 2025.[13]

Total investment in Kazakhstan's gasification from the national and local governments was approximately 121 billion KZT ($317 million) for the period 2015-19 and another 194 billion KZT ($547 million) is planned for 2020-23.[14] Improving and developing the country's gas infrastructure is a primary responsibility of KTG. The company invested over 112 billion KZT (about $293 million) of its own funds into Kazakhstan's gasification during 2014-19. The length of the gas pipeline distribution network increased from 27,000 km in 2014 to 61,561 km (including both high- and low-pressure lines) in 2020, while the population's access to piped gas increased greatly, from reaching 7.2 million people in 2014 to 9.8 million people in 2020. The largest distribution networks are in Turkestan Oblast (10,276 km), West Kazakhstan Oblast (7,695 km), and Aktobe Oblast (6,749 km). Kazakhstan's level of gasification rose from about 43% in 2014 to 53.1% in 2020.

The general scheme for the gasification of the Republic of Kazakhstan for 2015–30 calls for 1,600 population centers, or 56% of Kazakhstan's population, to have access to gas by 2030. Kazakhstan is therefore well on track to achieve this goal. Prior to completion of Phase 1 of the SaryArka pipeline, 10 out of Kazakhstan's 14 oblasts and two of three republic-level cities (Almaty and Shymkent) had pipeline access to natural gas. By 2030, following the full buildout of the SaryArka trunk pipeline (including distribution pipelines), at least some areas of all oblasts and the three republic-level cities will have access to piped gas.

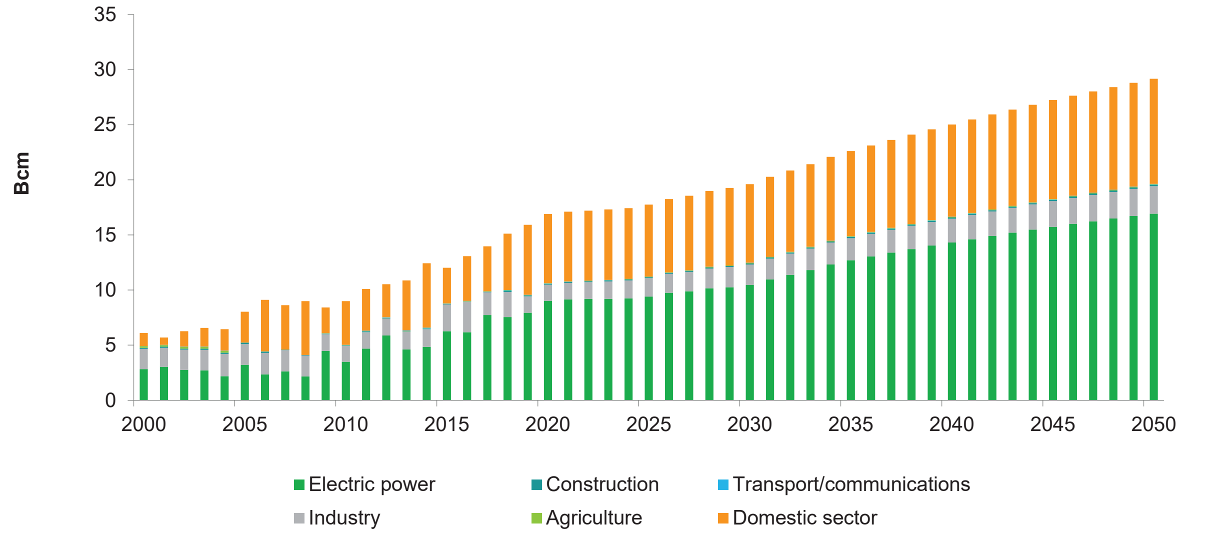
4.6.2 Historical gas consumption

Kazakhstan's end-of-pipe gas consumption reached 17 Bcm in 2020, up from 16.3 Bcm in 2019 (see Figure 4.5 Kazakhstan's natural gas consumption outlook by

13 For details, see the IHS Markit Strategic Report *A progress report on Kazakhstan's gasification program,* November 2020.

14 An exchange rate of 354 tenge/$ is applied to reflect the average over 2015-19. For the 2020-22 period, the same rate was used to maintain consistency. However, the forecasted average exchange rate during 2020-22 is 444 tenge/$, making the dollar-denominated gasification expenditure over 2020-22 equivalent to about $346 million.

Figure 4.5 Kazakhstan's natural gas consumption outlook by sector to 2050



Notes: End-of-pipe consumption; transport excludes pipelines; domestic sector is residential-commercial-municipal.
Source: IHS Markit

sector to 2050).[15] Consumption is growing in the electric power sector as well as in the residential/commercial sector, largely owing to the massive gasifi cation program. Actual gas consumption (end-of-pipe deliveries) has now exceeded the levels recorded in 1990, at 13.7 Bcm, more than tripling from a nadir of 4.9 Bcm in 1999 (toward the end of the protracted post-Soviet recession and in the depths of the Asian currency crisis).

There are effectively four regional gas-consuming "markets" in Kazakhstan, determined by such factors as sources of gas supply (indigenous production or imports) and the configuration of the national gas pipeline system. The four broadly identifiable regional gas "markets" or zones are (see Figure 4.6 Kazakhstan's domestic gas consumption (end-of-pipe) in 2020 and outlook to 2040 by consumption zone):

- The western zone, which includes Mangystau, Atyrau, and West Kazakhstan oblasts;
- The southern zone, which includes Turkestan Oblast and Shymkent city, Almaty Oblast and Almaty city, and Zhambyl and Kyzylorda oblasts;
- The northwestern zone, which includes Aktobe and Kostanay oblasts;
- The north-central zone, a nascent gas-consuming area that is only now receiving piped gas for the first time, comprising Nur-Sultan city, North Kazakhstan Oblast, Akmola Oblast, and Karaganda Oblast.

East Kazakhstan Oblast is essentially its own consuming area, with consumption organized around a small producing field that exports most of its output to China.

15 In 2020, total apparent consumption of natural gas in Kazakhstan (defined as commercial production minus exports plus imports) was about 26 Bcm. The difference between apparent and end-of-pipe consumption represents other domestic disappearance, including field and processing losses, pipeline use, changes in stocks, etc.

As much of Kazakhstan's gas production is concentrated in western Kazakhstan, gas consumption in this region has historically been robust, with gas used in power generation, industry, and the residential-commercial segment. Gasification levels in western Kazakhstan rank among the highest in the country, reaching well over 90% of its population (see Figure 4.7 Gasification levels in Kazakhstan by oblast, 2020). Consumption in western Kazakhstan amounted to 6.4 Bcm in 2020, or 37% of national end-of-pipe consumption. Oblasts in southern Kazakhstan absorbed 6.6 Bcm in 2020 (39% of consumption), while oblasts in northwestern Kazakhstan consumed about 4 Bcm of gas in 2020 (24% of consumption). In north-central Kazakhstan, gas demand has heretofore been negligible, due to a lack of pipeline access and the abundance of inexpensive coal. This is expected to gradually change, with the ramp up of the SaryArka pipeline and broader coal-to-gas switching.

The distribution of gas consumption among the various sectors of the economy has remained relatively stable, as demand across all major sectors has increased at similar rates (see Figure 4.5). Of the total amount of gas sold to (or used by) consumers in 2020 (17.0 Bcm), about 9 Bcm (53%) was used in the electric power sector to produce electricity and heat, about 1.5 Bcm (8.7%) was absorbed by industry (including feedstocks), and the remaining 6.5 Bcm (38%) was used by a combination of residential and commercial/communal consumers (the so-called "domestic" sector).

By 2030, the all-important year by which Kazakhstan aims to meet its Paris Climate targets (see Chapter 2), IHS Markit's base-case scenario envisions national gas consumption will reach around 20 Bcm, 10.5 Bcm (53%) of which will be consumed in the electric power segment.

Figure 4.6 Kazakhstan's domestic gas consumption (end-of-pipe) in 2020 and outlook to 2040 by consumption zone

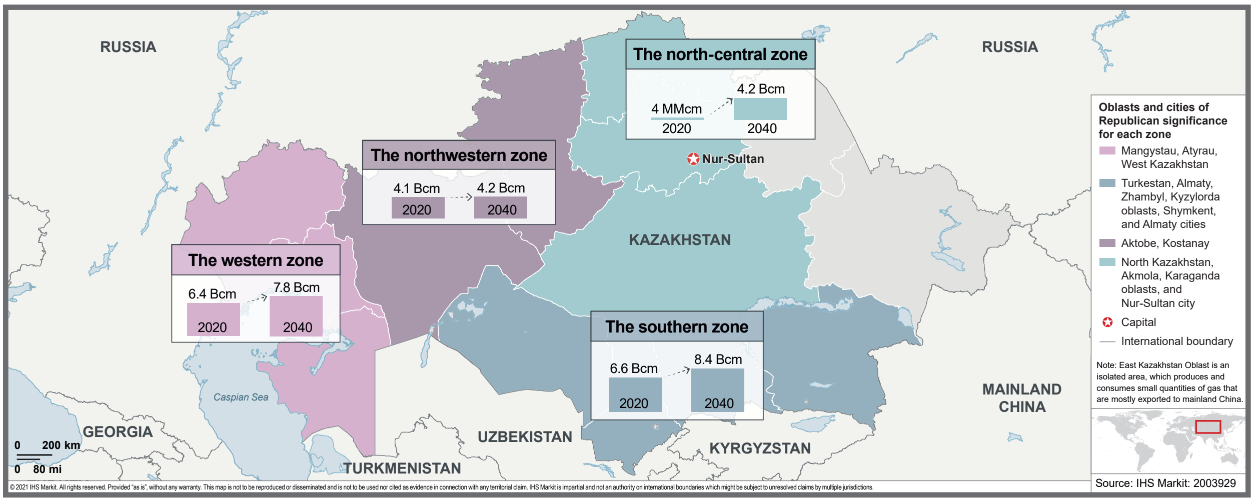
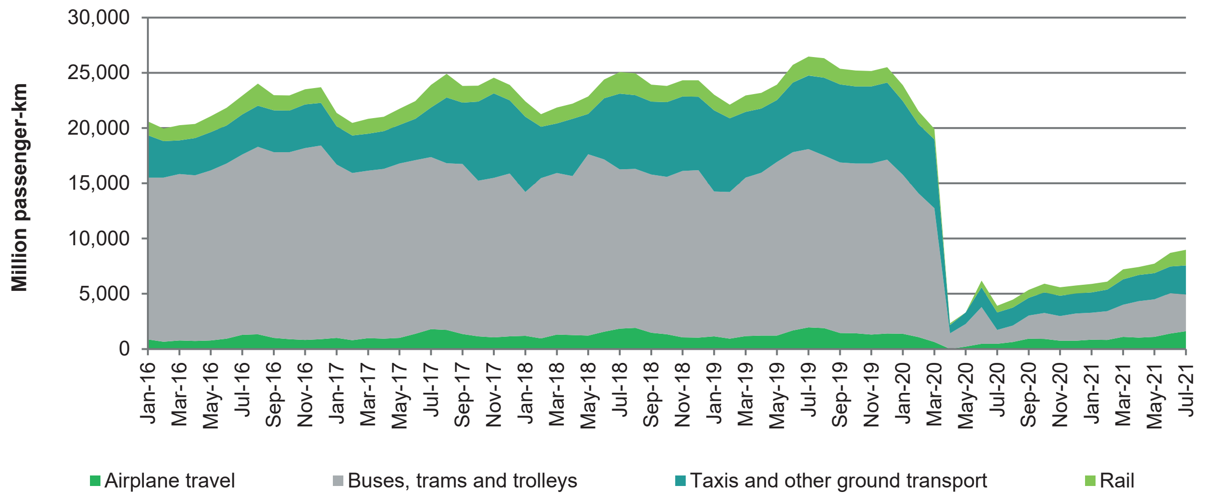


Figure 4.7 Gasification levels in Kazakhstan by oblast, 2020

Figure 4.8 Passenger transportation in Kazakhstan



Source: IHS Markit, Bureau of Statistics RK

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Gas use in the electric power segment will likely reach about 14 Bcm (57% of total gas consumption) by 2040, and 17 Bcm (58%) by 2050.

Gas consumption in the industrial sector, primarily in mining and manufacturing (including petrochemicals), is also likely to grow, albeit at a more modest pace. With respect to gas as a transportation fuel, as compressed natural gas (CNG) in municipal buses or light vehicles, or liquified natural gas (LNG) in trucking, there is some prospect for growth, although the segment has developed at a fairly languid pace in recent years.[16] LNG, for its part, has effectively made no measurable progress in recent years. Similarly, CNG is consumed only in niche transportation segments. The volume of CNG supplied to refueling stations for own-use by enterprises with vehicle fleets swelled from 157 m^3 in 2016 to 11.9 MMcm in 2017, before declining to only 2.2 MMcm in 2020. Recorded retail sales of CNG amounted to 209.4 Mcm in 2016, peaked in 2018 at 1.3 MMcm, and fell to 891 Mcm in 2020. KTG, for its part, reports that it supplied 10.9 MMcm of CNG to refueling stations (in Almaty, Aktobe, and Rudnyy) in 2019, and 42.2 MMcm in 2020 across its 16 refueling stations.

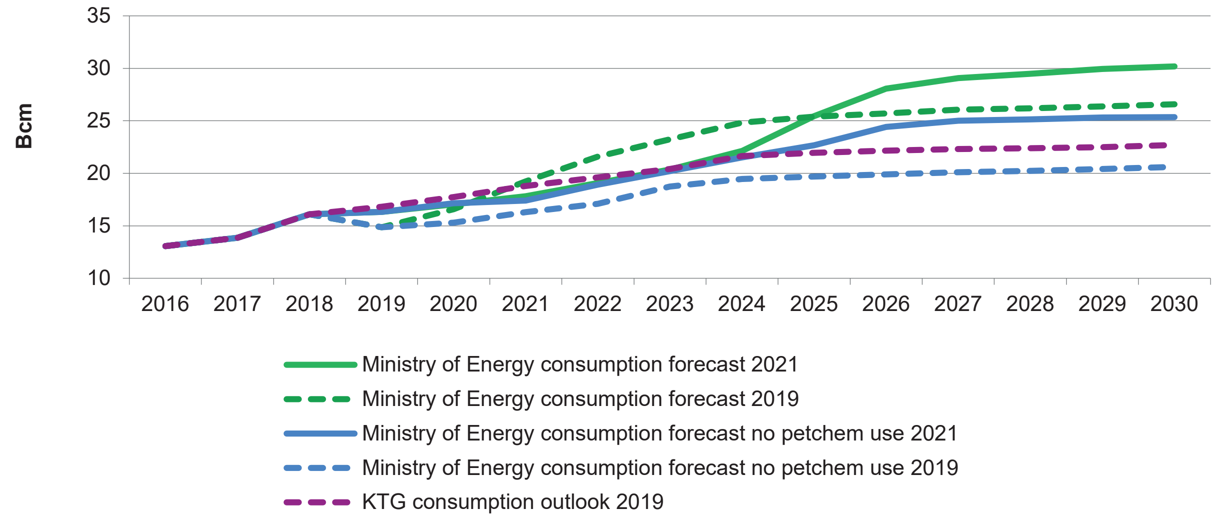
There are several reasons explaining the limited progress of CNG as a transportation fuel:

- First, CNG is primarily used in municipal transport fleets that have relatively short, prescribed routes, and this segment was growing, at least before the onset of COVID-19. Passenger travel by buses, when measured in million passenger-km, grew by an annual average of 1% between 2015 and 2019 (before contracting by 68% in 2020). The total number of buses in Kazakhstan declined by an annual average of 1% between 2010 and 2020, and by 3% between 2015 and 2020, amounting to 83,851 in 2020.[17]
- Second, Kazakhstan's relatively low gasoline and diesel prices in recent years, coupled with the costs required to convert vehicles to alternative fuels like CNG, dilutes incentives to change over. And despite some brief periods of intermittent supply shortages, gasoline, as well as diesel, has generally been well supplied in the country.
- Third, and most profoundly, the change in individual consumer behaviors brought about by COVID-19 has significant implications for the use of public transport, and by extension CNG-fueled transportation. In Kazakhstan, like elsewhere, the lockdowns and transition to remote work arrangements bludgeoned passenger transportation across all modes (see Figure 4.8 Passenger transportation in Kazakhstan). Recovery has been very slow: even during the first seven months of 2021, passenger ground transportation remained low, averaging 5,354 million passenger-km per month. Given the fact that public passenger transport, rather than freight transportation, is the main market

16 See Chapter 5.3.2. *Use of natural gas in transportation and other potential uses for natural gas* in the *National Energy Report 2017*. In 2017, Global Gas Group was actively pursuing the gasification of Nur-Sultan city and surrounding regions in the north by erecting regasification terminals; one was built at Nazarbayev University. However, since then, it appears progress on this front has stagnated, and the construction of the SaryArka pipeline effectively diminishes the need for regasifi-cation infrastructure that would handle imported LNG from Russia.

17 Promoting CNG as a fuel in private, individual vehicles is a far more uncertain proposition. Private car ownership declined from a peak of 4 million light vehicles in 2014, to 3.87 million by the end of 2020, and 3.84 million by 1 July 2021. By 1 January 2021, 89% of all light vehicles had gasoline-fired engines, while only 0.1%, 8% and 0.01% had engines fueled by gas (CNG), mixed (LPGs, gasoline and diesel), and electric engines, respectively.

Figure 4.9 Changes in official Kazakhstan's gas consumption outlooks to 2030



Source: Ministry of Energy RK, IHS Markit, KTG © 2021 IHS Markit

for CNG use, prospects for future growth in this segment remain contingent on a rebound in public transportation.[18]

4.7 Domestic Gas Consumption Outlook and Future Import Needs

Longer term, as a result of increased emphasis on gasification in the residential segment, coupled with government pressure to reduce coal consumption in the power sector, coal-to-gas switching is expected to accelerate. IHS Markit expects end-of-pipe gas consumption to exceed 20 Bcm by 2025, and reach nearly 25 Bcm by 2040 (see Table 4.3 and Figure 4.5). In light of relatively flat commercial production longer term and barring substantial changes in domestic end-user and producer gas prices to incentivize commercial supplies, imports from Russia in the north, and from Uzbekistan and Turkmenistan in the south, will continue to play a key role in satisfying overall domestic gas demand.

The Ministry of Energy has increased its outlook for gas consumption in the economy compared with its 2019 outlook, assuming a relatively rapid build-out in methane-based petrochemicals, a significant increase in gas consumption from the power sector (displacing coal at existing plants and building out new gas-fired plants), more residential consumption, and some coal-to-gas switching by some industrial plants (see Figure 4.9 Changes in official Kazakhstan's gas consumption outlooks to 2030). According to the Ministry's forecast, aggregate gas consumption will reach just over 30 Bcm in 2030, with consumption by existing consumer categories accounting for about 22 Bcm of the total. The rest of the gas will be consumed by new projects in the power sector (around 4.5 Bcm) and industry (mainly petrochemicals). In the power sector, new gas demand is expected to emerge in the south of the country, mainly in Almaty and Turkestan oblasts and Almaty and Shymkent cities. Key gas-based petrochemical projects included in the forecast are the those of the United Chemical Company (UCC) and WestOilGas (see section 4.8 below).[19]

Imports remain important in domestic gas consumption. According to operational data, Kazakhstan's gas imports amounted to 11.2 Bcm in 2005, but declined between 2007 and 2018, reaching a nadir of 3.7 Bcm in 2009 (see Table 4.7 Kazakhstan's natural gas exports and imports by destination 2015-20 (Bcm/y)).[20] Much of these imports are delivered through a swap scheme with Gazprom as part of deliveries of Karachaganak gas to Orenburg.

Total gas imports in 2020 fell dramatically, to 4.3 Bcm, according to operational statistics. The sharp downturn in imports in 2020 occurred due to a near collapse in

18 See "On approval of the Action Plan to expand the use of natural gas as a motor fuel for 2019 – 2022," https://adilet.zan.kz/rus/docs/P1800000797/history.

19 The four UCC projects are Karabatan Utility Solutions LLP, Kazakhstan Petrochemicals Industry LLP, KLPE LLP in Atyrau Oblast, and Ammonia Carbamide in Zhambyl Oblast. EuroChem and Zhaik Petroleum projects are also included in the forecast.

20 There are generally two sets of gas trade data in Kazakhstan: customs data and operational data. Customs data are reported by the Bureau of National Statistics under the Ministry of Economy. These data are sourced from customs invoices and documents submitted by the exporting and importing entities. Operational data, in contrast, are provided by the entities directly involved in gas trade and movements, particularly ICA and KTG. Throughout the report, operational indicators reflect data sourced from these operators, which appear to more closely reflect actual physical cross-border gas flows.

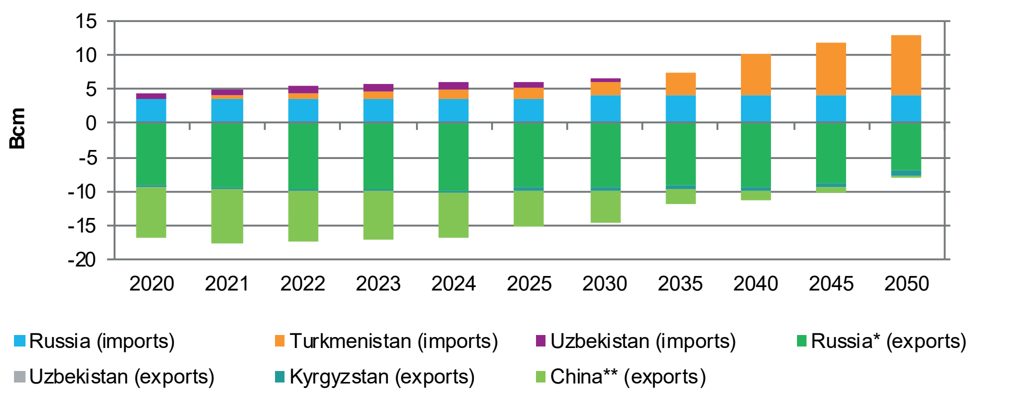
Table 4.7 Kazakhstan's natural gas exports and imports by destination 2015-20 (Bcm/y)

	2015	2016	2017	2018	2019	2020
Pipeline						
Karachaganak-Orenburg	9.6	9.6	9.6	10.3	9.9	9.9
Turkmenistan-Kazakhstan-China (CAGP+East Kazakhstan)	0.6	0.5	0.6	5.2	7.4	7.4
Total exports (customs data)	**21.5**	**21.6**	**25.6**	**26.5**	**25.6**	**18.8**
Total exports (operational data)	**13.3**	**12.8**	**16.8**	**19.1**	**19.4**	**16.7**
FSU Countries	**12.7**	**12.4**	**16.2**	**13.8**	**11.9**	**9.4**
Non-FSU Countries	0.6	0.5	0.6	5.2	7.4	7.4
China*	0.6	0.5	0.6	5.2	7.4	7.4
Total import (customs data)	**5.8**	**6.9**	**6.3**	**14.6**	**15.8**	**9.7**
Total import (operational data)	**4.9**	**5.8**	**5.1**	**5.7**	**8.8**	**4.3**
Russia	1.7	2.9	3.0	3.2	5.1	3.4
Central Asia (Turkmenistan and Uzbekistan)	3.2	2.9	2.1	2.5	3.7	0.9
Net exports	**8.5**	**7.0**	**11.8**	**13.4**	**10.6**	**12.4**

Notes: Data for Kazakhstan's exports to Russia from 2011 are taken from Russia's reported receipts of Kazakh gas; total exports are taken from the Bureau of Statistics RK, creating a discrepancy. *Kazakh volumes first injected into CAGP pipeline in 2017; main export flow to China (through CAGP) continues to be augmented with small volumes from East Kazakhstan Oblast.

Source: IHS Markit

Figure 4.10 Kazakhstan's natural gas exports and imports by destination: IHS Markit base-case outlook to 2050



Notes: *Starting from 2011, data for Kazakhstan's gas exports to Russia are taken from Russia's reported receipts of Kazakh gas. **Kazakh volumes first injected into CAGP pipeline in 2017; main export flow to China (through CAGP) continues to be augmented with small volumes from East Kazakhstan Oblast.

Source: IHS Markit

Uzbek imports, as well as a 32% contraction in recorded physical Russian imports, from 5.1 Bcm to 3.4 Bcm.[21] In 2020, Kazakhstan imported small volumes of Turkmen gas (104 MMcm) for the first time since 2017.

In the future, IHS Markit expects that Kazakhstan will continue to rely on gas imports, from Russia and increasingly from Turkmenistan (as opposed to Uzbekistan), to satisfy domestic gas needs. Longer term, as gas demand is poised to outpace the growth in commercial gas output, total imports are projected to increase to about 6.1 Bcm in 2025 and remain at approximately that level through 2035. After 2035, total gas imports are projected to increase further, reaching 10.3 Bcm by 2040. While Kazakhstan will remain a net gas exporter through 2040, thanks in large part to KPO deliveries to the Orenburg GPZ, Kazakhstan is expected to become a net gas importer by 2045 (see Figure 4.10 Kazakhstan's natural gas exports and imports by destination: IHS Markit base-case outlook to 2050).

4.8 Development of Kazakhstan's Gas–based Petrochemical Industry

Kazakhstan has access to substantial gas-type feedstocks that could be utilized for petrochemical production, as discussed in previous NER iterations. Kazakhstan currently has facilities that cover the three principal petrochemical segments (olefins, aromatics, synthesis gas/inorganics).

- The aromatics complex at the Atyrau refinery (ANPZ) was commissioned in 2016 as part of a $1.33 billion modernization program and can produce either high-octane (K-3 or K-4) gasoline or aromatics (up to 133,000 metric tons of benzene and 496,000 metric tons of paraxylene or xylene), depending on domestic needs. Paraxylene output from the aromatics complex reached 118,644 metric tons (24% capacity utilization) in 2019, and was 210,000 tons in 2020 (42% capacity utilization). Benzene output amounted to 26,607 metric tons (20% capacity utilization) in 2019, and 43,000 metric tons in 2020 (33% capacity). Output contracted in 2021 for both products, as domestic demand for gasoline rebounded, and light product output was again prioritized over petrochemicals. In 2019 and 2020, some of the paraxylene and benzene were exported to China through SOCAR's Kulevi port in Georgia (Black Sea); longer term, this may become a key export route for petrochemicals from Kazakhstan.
- The Neftekhim LLC plant is adjacent to the Pavlodar refinery and has the capacity to produce up to 48,000 tons of polypropylene annually. In 2020, the plant produced 18,000 tons of methyl tertiary butyl ether (MTBE) and 40,000 tons of polypropylene. Nitrogenous fertilizers (ammonium nitrate) are produced by Kazazot in Mangystau Oblast and Kazfosfat in Zhambyl Oblast.
- Total production of petrochemical products amounted to 359,000 tons in 2020. Of this, only 73,000 tons (20%) was consumed locally, and the rest was exported to China and Europe. Owing to Kazakhstan's small population and the nature of its industrial base, petrochemical demand is relatively low, which means that any sizable new petrochemical project will inevitably target exports.

Kazakhstan's petrochemical sector is progressing with the ongoing construction of Phase 1 of an "integrated gas and chemical complex in Atyrau." Phase 1, with a capex of $2.63 billion, will produce eleven types of polypropylene primarily for export, using domestically-sourced propane as feedstock.[22] The plant will include a propane dehydration (PDH) unit, using CB&I's catofin technology to convert propane into propylene (about 503,000 metric tons/y). Lummus' Novolen gas-phase technology will convert the propylene into polypropylene, producing up to 629,000 metric tons annually. The project operator is JV Kazakhstan Petrochemicals Industry Inc. (KPI Inc.), a JV between UCC (99%) and Almex Plus (1%), although KMG is overseeing the facility's construction under a trust management agreement. Construction on the plant was about 90% complete in August 2021, with completion scheduled for October 2021. The plant is slated to be commissioned in the first quarter of 2022.

Phase 2 of the "Integrated complex" has yet to be officially sanctioned. Phase 2 calls for the construction of a $1 billion, 9 Bcm/y gas separation unit (GSU) located at TCO that would extract up to 1.7 MMt/y of ethane, and 400,000 metric tons of propane/butane mix (comprised primarily of propane), and return the methane (around 7 Bcm/y) to TCO. The extracted propane/butane mix would feed into a 1.25 MMt/y ($6.9 billion) plant that would produce ethylene and then polyethylene, primarily for export.

Phase 2, which is overseen by KLPE, a JV between UCC (99.9%) and TOO Polymer Production (0.1%), has already completed a pre-FEED study. KLPE is apparently in the process of selecting a technology license provider and FEED contractor, aiming to commission the project by 2026. However, several issues remain outstanding. First, while discussions between TCO and KLPE have continued, and the two parties have signed an agreement on the basic conditions for the design of a GSU,

21 Russian imports (reported by Russia as exports to Kazakhstan) were 3.4 Bcm in 2020.

22 Project operator KPI will source propane mainly from TCO. In September 2021, KMG and TCO inked an agreement for TCO to supply up to 550,000 metric tons of propane annually to KPI Inc.

fundamental questions over gas pricing and arrangements have yet to be resolved.[23] Nonetheless, TCO and KLPE continue to work together on formulating the technical project documents. While TCO will likely finance the $1 billion GSU, it remains unclear if KLPE will finance the remaining $6.9 billion or so, or if another external investor will be involved. Over the years, KLPE and the Ministry of Energy have courted various investors. At one point, Austrian company Borealis was slated to participate in Phase 2, but withdrew from the project in May 2020, citing market uncertainty driven by COVID-19. In October 2021, NWF SK, KMG and SIBUR Holding signed framework cooperation agreements for petrochemical projects in the National Industrial Petrochemical Technopark special economic zone. The parties determined the conditions for creating joint ventures based on the integrated gas-to-chemicals complex, including a polyethylene plant construction project (Phase 2) and a polypropylene plant currently under construction (Phase 1). SIBUR's stake in both JVs will be 40%, and its participation in the JVs will take effect after all the necessary regulatory approvals are obtained, and the polypropylene production complex is commissioned.

IHS Markit anticipates that Phase 2 is unlikely to gain much momentum until the mid-2020s, after TCO FGP-WPMP is commissioned. Also, by that time Phase 1 of the petrochemical complex will be in operation, providing the essential "proof of concept" to justify future petrochemicals expansion in Kazakhstan.[24]

In addition, KMG and Tatneft are moving forward with a planned $800 million butadiene rubber plant. If realized, the plant would come online in 2025 and produce up to 170,000 metric tons of isobutane to yield 186,000 metric tons of butadiene rubbers annually. The butadiene plant would utilize inputs (primarily butane) from TCO. The butadiene rubber would be sent to a tire plant in Karaganda to produce tires for export.

However, despite the litany of proposed petrochemical projects outlined by the Ministry of Energy, IHS Markit does not anticipate a prolific expansion in gas-based (methane) petrochemical development in Kazakhstan. Realization of the aforementioned projects is unlikely to alter Kazakhstan's gas demand outlook substantially. This is because Phase 1 of the Atyrau Petrochemical Complex and the proposed KMG-Tatneft butadiene plant will rely on NGLs (primarily LPGs in the form of propane and butane), rather than natural gas (methane), as feedstocks. Kazakhstan is a sizable producer and exporter of LPGs. Its LPG production amounted to 3.2 MMt in 2019, 42% of which was produced by TCO. In 2020, preliminary data suggest LPG output was about 3.3 MMt.

23 https://ucc.com.kz/news/na-tengize-postrojat-stanciju-po-separacii-suhogo-gaza/

24 Transportation costs remain a major stumbling block for overall project economics and netbacks. Although low-cost associated gas theoretically makes feedstock costs in the country fairly attractive, the logistics costs of moving product to a demand hub are likely to absorb most, if not all, of the revenue generated from product sales.

4.9 Natural Gas Exports: Historical and Outlook

While Kazakhstan's customs statistics indicate a broad list of export destinations for Kazakh gas, these data reflect customs declarations, rather than physical (or even contracted) flows reported by KTG (so-called "operational" exports). In reality, Kazakhstan is not a major gas exporter, sending gas only to neighboring (regional) countries, namely Russia, China, Kyrgyzstan, and small volumes to Uzbekistan (see Table 4.7). While Russia remains the main "export" destination for Kazakh gas, thanks to the KPO-KRG arrangement, Gazprom also plays an intermediary role in Kazakhstan's gas exports to Uzbekistan and Kyrgyzstan.

IHS Markit estimates Kazakhstan's operational gas exports in 2020 at 16.7 Bcm, a decrease of 14% from 19.4 Bcm in 2019.[25] Of this, 9 Bcm was sent northward to Russia. The bulk of this is raw (unprocessed) gas from Karachaganak to the Orenburg GPZ. Small amounts of gas also were exported to Kyrgyzstan (0.3 Bcm) and Uzbekistan (0.1 Bcm) in 2020. After Russia, the second largest export destination was mainland China, to which deliveries held steady in 2020, at 7.4 Bcm, despite the COVID-19 pandemic (see text box: Central Asian gas exports to China). Most of Chinese gas exports traverse the CAGP system.[26]

Gas exports from Karachaganak to Russia are conducted under a special arrangement with Gazprom. Nearly all of Karachaganak's raw (high-sulfur) gas output (that is not reinjected) is sent across the border to Russia for processing at Orenburg GPZ under a long-term agreement, with KRG playing a key intermediary role.[27] The agreement with Gazprom also supplies some of the processed gas back to the Kazakh domestic market via a swap arrangement. In this respect, Kazakhstan's imports of KRG gas under the swap volumes, and by extension, KPO's commercial gas output, are integral to Kazakhstan's overall gas balance.[28]

In addition to KPO, small volumes of Kazakh gas (from TCO, Nostrum) are transported northward to Russia viathe CAC and Soyuz pipelines. TCO gas exports amounted to 3.7 Bcm in 2019 and 2.5 Bcm in 2020.[29]

25 Official data from the Ministry of Energy, ICA, and KTG differ from IHS Markit estimates.

26 A small volume (0.3 Bcm in 2019) is exported to China via the 110 km Zaysan-Jeminay pipeline in eastern Kazakhstan, which has been in operation since May 2013. The pipeline, owned by Guanghui Energy, supplies gas from Tarbagatay Munay to a small LNG plant producing vehicle fuels in Xinjiang province, China.

27 KazRosGas (KRG) is a joint venture between KMG and Russia's Gazprom formed in 2007. In June 2015, KPO and KRG extended their gas trading deal through 2038, securing an outlet for KPO's gas production through the end of the PSA.

28 See KMG Base Prospectus issued 3 April 2018.

29 See ICA annual report 2020.

Central Asian gas exports to China

A key development for Kazakhstan's gas industry was the commencement of large-scale natural gas exports to mainland China via CAGP in October 2017.[30] By 2018, mainland China had emerged as a major destination for Kazakh gas, receiving 5.2 Bcm. On 12 October 2018, the partners inked a five-year contract to 2023 for the export of up to 10 Bcm/y of gas via CAGP. Due to COVID-19 and the associated drop in gas demand in early 2020, PetroChina sent a force majeure notice to its suppliers to reduce or delay gas shipments. Kazakhstan, along with other Central Asian states, was asked to reduce export volumes by 20-25% in March 2020 and Kazakhstan officially confirmed that it had complied with this request. Despite this, Kazakh exports held steady for the full year at around 7.4 Bcm. In contrast, Uzbekistan, which is confronting a series of upstream issues, ultimately curtailed exports the most of the three Central Asian gas suppliers. Although KTG seeks to export as much as 10 Bcm/y through 2023, Kazakhstan's gas balance does not support such high levels of exports. The IHS Markit base-case scenario envisages Kazakhstan's exports to China decreasing sharply in the 2020s and 2030s (see Figure 4.10).

Another consideration for Kazakh gas exports to China, and Central Asian gas flows to China more broadly, centers around changes in China's gas market. On 9 December 2019, China Oil and Gas Pipe Network Corporation (PipeChina) was officially registered in Beijing as an independent national pipeline company responsible for the operations of key oil and gas midstream infrastructure and new construction in China. The establishment of the national pipeline company, coupled with other energy reforms and the rollout of new tariff-setting policies starting in 2022, has implications for CNPC's trade strategy, particularly with respect to future gas pipeline volumes.[31] CNPC has been willing to absorb financial losses on Central Asian gas transportation within China, given its status as a national energy company, its mandate to ensure supply security, and to support its existing midstream and upstream investments in Central Asia. But given the midstream reforms in China, the company is no longer able to profit from pipeline tariffs that can offset losses incurred from long-distance pipeline shipments.[32]

Significant transportation costs to China render Central Asian gas generally less competitive than spot LNG imports, some contracted LNG imports, and Russian pipeline gas in the Beijing-Tianjin-Hebei (Jing-Jin-Ji) region and Shanghai markets.[33] However, given unprecedented tightness in the global LNG spot market in 2021 that led to a record spot LNG price rally, Central Asian gas has become more competitive than in the past few years (see Figure 4.11 Comparison of delivered prices of imported gas by source in key Chinese regional markets in 2021). Longer term, IHS Markit anticipates that Central Asian imports will struggle to stay competitive given the overall abundance of LNG globally, even though they will remain a part of the supply diversification strategy pursued by China. But the abovementioned pipeline reforms mean that Chinese companies will be more reluctant to invest in additional Central Asian import gas routes, such as CAGP Line D (which was not slated to transit Kazakhstan). However, it appears that KTG is exploring ways to expand its export/transit capacity to China via BBS.[34] IHS Markit expects that gas flows through the three existing strings of the CAGP will operate at relatively full capacity, mainly transporting Turkmen gas.

Reflecting a tightening domestic gas balance, the IHS Markit base case projects Kazakhstan's overall operational exports by 2040 to decline by 27% relative to 2020 levels, to about 11.3 Bcm. Russia remains the major export destination (for processing Karachaganak gas), while exports to China decline substantially by 2040. This "export versus domestic market" dynamic will strain KTG's finances (see below).

30 In June 2017 a memorandum of understanding (MOU) between KMG and CNPC was signed for the purchase of up to 5 Bcm/y of natural gas for one year (from October 2017 to September 2018). The actual sales agreement, also concluded in June 2017, was signed by KTG and a wholly owned subsidiary of CNPC, PetroChina International Company Limited.

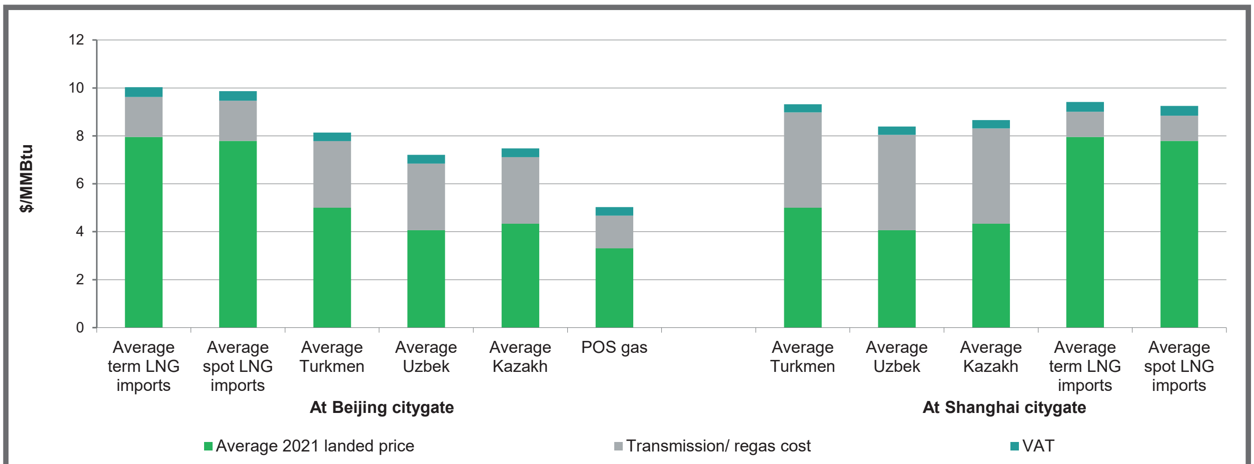
31 See IHS Markit Insight, *China to update pipeline tariff setting rules,* April 2021.

32 In 2018, for example, CNPC reported 24.9 billion yuan ($360.9 million) in losses from gas imports, with Central Asian imports contributing the lion's share of this.

33 The Power of Siberia pipeline's southern extension within China has not been completed, so Russian piped gas has not reached Shanghai yet.

34 In September 2021, KTG Chairman Kairat Sharipbayev informed President Tokayev about preliminary plans to construct a second line of BBS, which would reportedly serve as a transit route for Turkmen gas deliveries to China.

Figure 4.11 Comparison of delivered prices of imported gas by source in key Chinese regional markets in 2021



Notes: The POS south section within the Chinese territory is not completed yet, so Russian gas has not reached Shanghai. VAT = value-added tax.
Source: IHS Markit

4.10 Gas Pricing in Kazakhstan

State regulation of the wholesale price of commercial gas is carried out by the Ministry of Energy and the retail price by the Ministry of National Economy (via KREM, its monopoly regulation agency). The regulation of retail prices by the latter body has effects that extend far upstream, however, affecting the entire value chain.

4.10.1 End-user prices

Kazakhstan's State Committee for Regulating Natural Monopolies (KREM) regulates end-user gas prices by region and customer type (residential versus industrial). Its approach is guided not strictly by energy policy per se, but broader macroeconomic considerations. The government inflation target is perhaps the major factor guiding KREM's gas pricing approach, as it seeks to keep aggregate price appreciation within 20% of the prescribed inflation corridor. In 2021, given that the overall inflation rate target is 4-6%, end-user prices for energy and other utilities (gas, heat, power, railway transportation, and water) thus should account for roughly 1 percentage point of that overall inflation level. In 2020, Kazakhstan's inflation was recorded at 6.8%, exceeding the target of 4%, while average end-user prices for gas supplied to the population actually contracted 8% in dollar terms (or 1% in tenge terms, from 18,808 tenge/Mcm to 18,635 tenge/Mcm).

4.10.2 Wholesale gas prices

Regional wholesale ceiling prices are determined annually and are in effect between 1 July and 30 June of the following year. According to the official rules for determining ceiling wholesale gas prices, regulated prices in Kazakhstan cannot increase by more than 15% annually, although this rule may have to be relaxed in the future.[35] In June 2021, KREM increased regulated ceiling wholesale gas prices (effective 1 July 2021) by an average of 9.3% across all oblasts and cities, except in East Kazakhstan Oblast. Although this is an upward adjustment, it effectively returns the prices to the levels of 2018-19.[36]

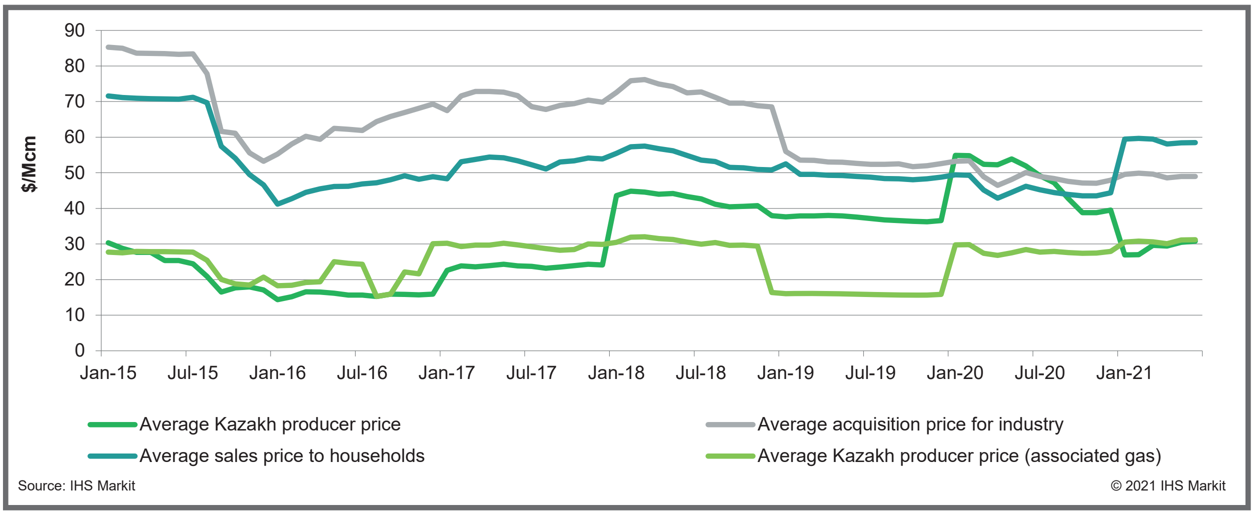
4.10.3 Producer prices

Producer prices – the prices subsoil users (i.e., upstream producers) receive – are individually negotiated between producers and KTG, the natural monopoly in Kazakhstan's single-buyer model, and ultimately approved by the

35 See Order of the Minister of Energy of the Republic of Kazakhstan No. 209 of 15 December 2014 "On approval of the Rules for determining the ceiling prices for the wholesale commercial gas sales in the domestic market of the Republic of Kazakhstan and the ceiling prices for the liquefied petroleum gas sold within the framework of the plan for liquefied petroleum gas supply to the domestic market of the Republic of Kazakhstan outside electronic sales platforms", as amended on 30 March 2020. https://adilet.zan.kz/rus/docs/V1400010120.

36 Effective 1 July 2019, regulated ceiling wholesale gas prices were reduced on average by 12%, with the cuts ranging from 0% to -23%, depending on the oblast, and remained at that level through 30 June 2021. Starting 1 July 2021, the regulated wholesale prices grew across all jurisdictions except East Kazakhstan, with increases ranging from 3% to 15%.

Figure 4.12 Monthly trends in domestic gas prices in Kazakhstan



Ministry of Energy. Theoretically, natural gas producer prices are supposed to be determined by rules established in the Law on Gas and Gas Supply (2012), which includes a "cost-plus" price component, codified in Article 15:

- Production cost ($/Mcm) + processing cost ($/Mcm)
  - + transmission tariff to point of sale to KTG ($/Mcm)
  - + profit margin (< 10%)[37]

KTG wields significant power in negotiating gas prices, and because low regulated end-user prices pressure all aspects of the domestic gas value chain, producers often end up selling gas at a price that barely covers costs, or forces them to incur a loss. In 2020, the average producer price for natural gas was $48/Mcm, and by June 2021 it was down to $30.8/Mcm (see Figure 4.12 Monthly trends in domestic gas prices in Kazakhstan). The average producer price for associated gas was $28/Mcm in 2020, and $31.2 in June 2021.

Low producer gas prices offer little incentive for upstream players to increase their commercial gas sales to KTG, or pursue new gas developments. Introducing measures to increase commercial gas production is actively under discussion between the government and various industry groups, particularly within the framework of the improved model contract. IHS Markit considers introduction of such measures to be a positive development that could potentially ameliorate the looming commercial gas supply shortage longer term. We also reaffirm the recommendation articulated in previous iterations of the NER – prices across the value chain need to increase.

37 Kazakhstan's Law on Natural Monopolies and supporting rules issued by KREM establish a methodology to calculate an acceptable profit rate for gas transportation companies (KTG and subsidiaries) based on their regulated asset base, which reflects their expenditures and investment programs. In practice, determination of end-user prices still follows a "cost-plus" approach where an acceptable profit rate is believed to be no more than 10%.

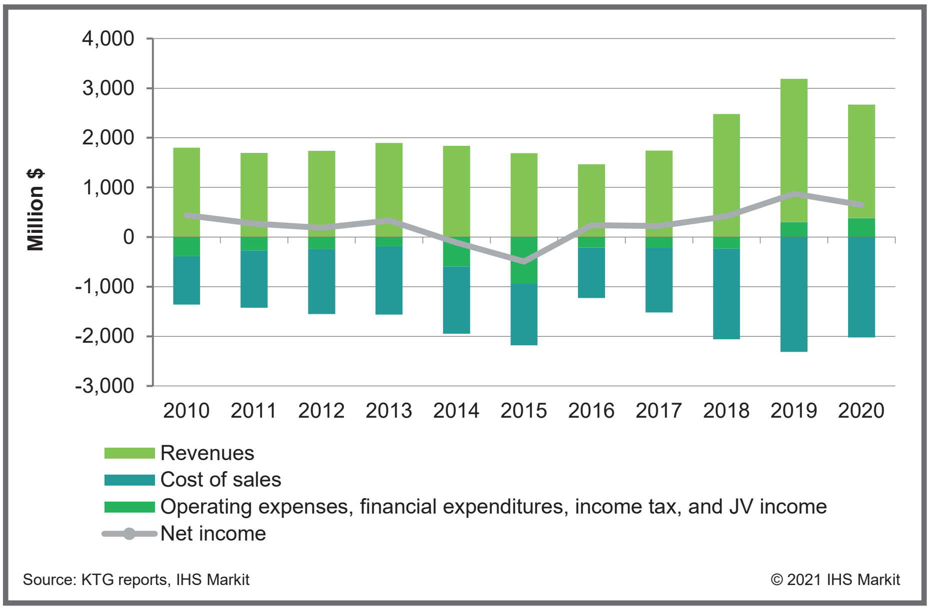
4.10.4 Role of the national operator KTG and government regulations on pipeline tariffs

The Law on Gas and Gas Supply essentially puts Kazakhstan's gas production at the disposal of a single national operator through administrative means and specifically empowers KTG to develop the domestic market and pipeline infrastructure on the basis of revenues it derives from sales on domestic and international markets. This administrative arrangement reflects the fact that the bulk of gas production in Kazakhstan occurs as a by-product of liquids production, and thus gas supply does not respond to (gas) market conditions directly. Government policy also appears to be aimed at having the state-owned entity capture any upside from higher domestic end-user prices and export prices, while maintaining a single channel for exports so as to balance the near-monopoly conditions in the two neighboring gas-purchasing countries, Russia and China.

While this type of market structure has generally functioned adequately thus far, it clearly is under increasing pressure as the country's gasification program gains momentum. Domestic gas demand is growing but the producer base has little incentive to pursue gas development for its own sake, rather than associated with liquids extraction, in their upstream endeavors. The major obstacle is that wholesale and end-user gas prices in Kazakhstan remain regulated by KREM at relatively low levels, and there is widespread political resistance to increasing them. Depressed end-user prices force market participants throughout the gas value chain to cross-subsidize their gas market operations with other activities.

KTG generates financial losses in its basic business of selling gas to domestic consumers. Between 2014 and

Figure 4.13 Consolidated financial results for KTG



2020, the company incurred a total of 429.6 billion tenge ($1.043 billion) in losses on domestic gas deliveries; and in 2021 they are projected to reach 158.8 billion tenge ($374 million). However, since 2016 the company has managed to generate positive net income in its overall operations. The turnaround in profitability for the company was not a result of a major improvement in its main business activity (i.e., domestic gas sales) but was due entirely to additional revenues from expanded gas exports to China (since 2018) and higher gas transit (since 2016) (see Figure 4.13 Consolidated financial results for KTG).[38] But continuing expansion of the distribution network from the gasification drive means that the unprofitable segment of KTG's business will continue to grow, while export volumes are likely to shrink or at best stagnate given the constraints on available supplies of commercial gas in Kazakhstan. Thus, while KTG is anxiously working to increase the availability of domestic gas supply, it is also focused on improving the current model of management of the gas industry (see Section 4.4 above).

4.10.5 Pipeline tariffs

KREM also regulates pipeline transportation tariffs for domestic gas deliveries. Tariffs for domestic deliveries via the ICA system are set for up to five years ahead, but KTG subsidiary ICA has a right to request a review and change of tariffs in accordance with Article 22 of the Law on Natural Monopolies. The ICA tariff of 2,333.3 tenge/Mcm ($5.7/Mcm) went into effect on 10 December 2020. However already in 2021, the tariff was revised upward to 4,551 tenge/Mcm (approximately $10.65/Mcm) for 2021, to cover the additional costs involved with the operation of the SaryArka pipeline.[39] A simple analysis of expected domestic throughput volumes and SaryArka construction costs indicates that the new ICA tariff needs to be around 4,500 tenge/Mcm ($10.3/Mcm) to retire SaryArka costs over about 10 years, or around 3,500 tenge/Mcm ($8.2/Mcm) to cover the costs over 20 years.

Currently, tariffs for domestic shipments on most trunk pipelines are set by the regulator as postage stamp–type tariffs (tenge/Mcm) that do not reflect distance. However, this is likely to change in the future, as there are active discussions about the need to have the tariff structure reflect the distance gas travels. For example, as of 1 January 2021, the BBS tariff was set at 1,200.15 tenge/Mcm/100 km ($2.8/Mcm/100 km, without VAT) or 15,964 tenge/Mcm ($37.66/Mcm), as opposed to the flat 16,574 tenge/Mcm ($43.5/Mcm) in prior years (applicable on both exports and domestic deliveries).[40] The new tariff is in effect through 2024. The revised BBS tariff lowers

38 Gas sales (including from exports) remain KTG's primary source of revenues (84% in 2020) rather than transportation services.

39 The revised ICA tariff was converted to dollars using the June 2021 exchange rate of 427 tenge per dollar.

40 The rate of 15,964 tenge/Mcm is apparently calculated based on the distance along the Bozoy-Shymkent segment only, and does not include the Beyneu-Bozoy segment. For details on the BBS gas transportation rate, see the BBS report entitled "Otchet o deyatel'nosti SEM po predostavleniyu reguliruemykh uslug pered potrebitelyami za 2020 god Otchet o deyatel'nosti SEM po predostavleniyu reguliruemykh uslug pered potrebitelyami za 2020 god ["Отчет о деятельности СЕМ по предоставлению регулируемых услуг перед потребителями за 2020 год"], accessed 19 June 2021, at https://bsgp.kz/ru_RU/%d0%b4%d0%be%d0%ba%d1%83%d0%bc%d0%b5%d0%bd%d1%82%d0%b0%d1%86%d0%b8%d1%8f/%d0%b4%d0%be%d0%ba%d1%83%d0%bc%d0%b5%d0%bd%d1%82%d1%8b/.

the cost of gas delivered to Nur-Sultan via the SaryArka pipeline, since the gas travels only 944 km of BBS (64% of the distance) to CS Karaozek, and not the pipeline's entire 1,477 km length to Shymkent.

KTG-Aimak adjusts distribution tariffs more frequently, sometimes biannually, to reflect ongoing investments in expanding local distribution infrastructure. Over the past year, KTG-Aimak's domestic tariffs were established on different dates for different oblasts, with some oblasts seeing rises in their tariffs, while in others, tariffs remained stable. There appears to be a general effort to increase tariffs to cover investments in gasification. For example, the transportation tariff for Nur-Sultan was set at 4,107.87 tenge/Mcm ($9.6/Mcm) from 1 November 2020 but increased by 50% to 6,158.63 tenge/Mcm (about $14.4/Mcm) beginning on 1 June 2021. In 2021 the simple unweighted average KTG-Aimak distribution tariff increased by 7% year on year to 4,751 tenge/Mcm ($11.4/Mcm).

Unlike tariffs for domestic deliveries, gas transportation tariffs for international transit via ICA and other KTG-operated pipelines are established through bilateral negotiations and are not subject to regulation by KREM (in accordance with May 2015 amendments to the Law on Natural Monopolies). As already stated, Gazprom and ICA negotiate the tariff for the transit of Uzbek and Turkmen gas to Russia, which is currently set at $2/Mcm/100 km. The tariff for shipments to China via CAGP (or Asia Gas Pipeline [AGP] on Kazakh territory) is $3.58/Mcm/100 km. The CAGP tariff has not been altered in recent years and will likely remain stable over the near term. The transit fee for exporting gas by TCO (or the few other Kazakh producers with the right to export) also are negotiated with ICA. For TCO, it is $5/Mcm/100 km, while KRG's transit tariff is $2/Mcm/100 km.

Beyond the increases already instituted in 2020-21, IHS Markit does not expect a dramatic rise in most domestic gas transportation tariffs through the mid-2020s, which will likely move in tandem with inflation and reflect mainly maintenance expenditures over the near term. There are no major new pipeline projects that are likely to take FID before 2023 that would add a lot of new capex to the tariff base, although KTG is exploring construction of the second string of the BBS pipeline.

4.11 EAEU Single Gas Market and Gas Price Harmonization

Creation of common oil and gas markets between the member states of the Eurasian Economic Union (EAEU) – Armenia, Belarus, Kazakhstan, Kyrgyzstan, and Russia – is planned to occur around 2025. This is a challenging objective, as currently energy trade among these countries is governed mostly by special bilateral trade agreements that cover volumes and terms, pricing, and other issues, such as export duties. Although work on the common market is proceeding, major issues remain unresolved, such as the issue of transportation tariffs.[41]

As Kazakhstan accedes to the rules of the EAEU common gas market, end-user gas prices between Kazakhstan and the Russian Federation would need to be harmonized, as part of a general movement toward integrated open markets. IHS Markit expects that domestic prices in Kazakhstan will converge with the domestic prices in Russia rather than vice-versa, given that gas production, trade, and the size of the domestic market in Russia are so much larger than in any other EAEU members, including Kazakhstan.[42] Given that Russian prices are higher than those in Kazakhstan, this indicates a substantial increase in Kazakhstan's end-user gas prices.

Russian domestic gas prices are differentiated by consumer group and price zones, depending on transportation distances from the main producing region in West Siberia to consumers. Kazakhstan's policymakers would need to decide with which Russian pricing zone to harmonize, especially in western Kazakhstan.[43] IHS Markit assesses that Kazakhstan should harmonize its natural gas prices with those in Russia's gas-producing regions (e.g., Yamal-Nenets Okrug) and not with the higher prices in European Russia's consuming regions, such as the neighboring Saratov Oblast (see Figure 4.14 Price outlook for natural gas consumed by industry in western Kazakhstan (Atyrau Oblast): Harmonized with Russia's Yamal-Nenets Okrug). Such an approach would allow Kazakhstan's manufacturing industry to remain competitive within the broader EAEU economic space, and make for a less rapid (although still significant) adjustment in consumer prices. Under an EAEU integration scenario, industrial gas prices in Kazakhstan would appreciate by about 12% annually during 2021–25 to reach parity with those in Russia's gas-producing regions.[44] Harmonization with Russian prices would also help KTG achieve cost-recovery in the domestic segment, and potentially, incentivize new upstream activity.

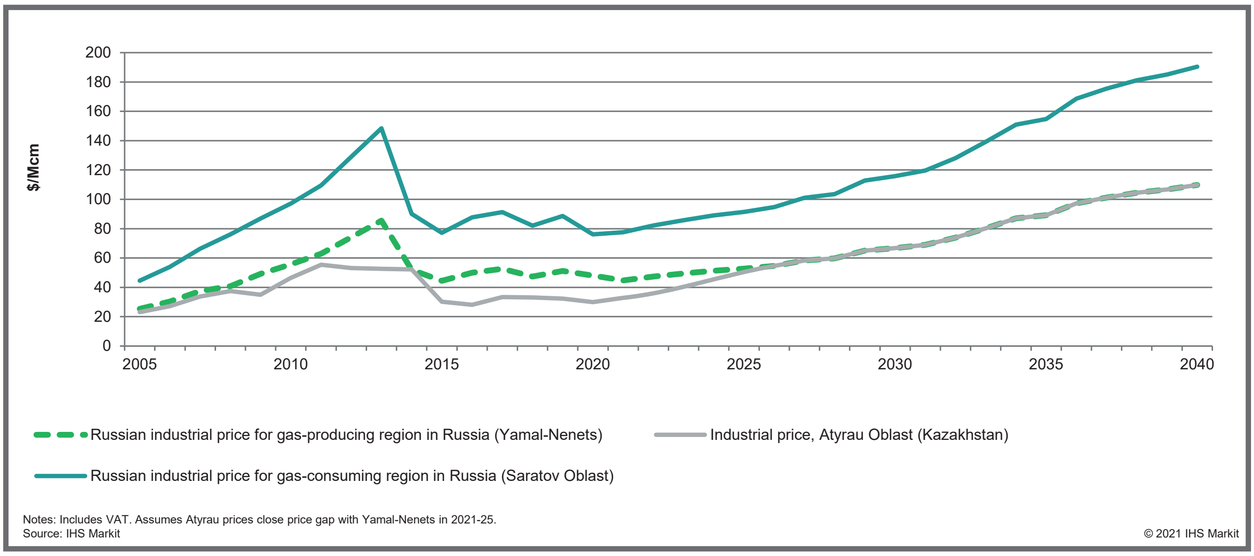
41 The main point of contention involves whether a uniform transportation tariff should be set across the EAEU that would not be higher than that currently set in Russia, or if national governments should determine tariffs inside their own boundaries that apply equally to all gas being shipped.

42 In 2020, Russian gas production stood at 692.3 Bcm, gas consumption (end-of-pipe) was 428 Bcm, and total exports were 251 Bcm.

43 In Russia, as in Kazakhstan, prices for industrial consumers located in gas-producing regions are much lower than prices for enterprises in more distant, non-producing regions, mainly because of the transportation component.

44 In 2021, wholesale end-user gas prices in Kazakhstan increased by an average of 9%.

Figure 4.14 Price outlook for natural gas consumed by industry in western Kazakhstan (Atyrau Oblast): Harmonized with Russia's Yamal-Nenets Okrug



Although the potential negative public response to higher prices remains salient in the minds of politicians and regulators alike, what is not as evident is that Kazakhstan has some of the lowest utility rates (for gas and electric power) in the world (expenditures account for only 3% of average household income in most oblasts). This is very low compared to developed country markets (22–23% in the European Union) and several large emerging markets (5–8% for Russia, and 10–12% for India). The potential for modest rate hikes in Kazakhstan is evident even in closely analogous markets (Azerbaijan and Turkey, both at 8–10%). A decision to continue with administrative management of domestic energy prices will have hidden costs, including inefficient resource use and the possibility of a chronic supply shortage. Pricing disparities already apparent in the domestic market will be exacerbated by EAEU gas market integration.

4.12 Environmental Issues in Gas Transportation and BAT

4.12.1 Global methane emissions from the natural gas sector

Overall, electricity and heat production globally account for 25% of total GHG emissions, whereas the energy supply sector (defined as fuel extraction, refining, processing, and transportation) accounts for about 10%.[45] And among these GHG emissions, roughly 76% is CO_2, with methane (16%) a distant second.[46] Methane (CH_4) accounts for a similar share (10–15%) of total energy sector emissions.

Yet, while it is not dominant in either of these emissions categories, methane has outsized importance as a greenhouse gas due to its high and immediate climate-altering potency. Although short-lived in the atmosphere – about 12 years compared to hundreds of years for CO_2 – methane is much more efficient at trapping radiation. Its global warming potential (GWP) is variously defined as about 30 times that of CO_2 on a 100-year timescale, or about 90 times on a 20-year timescale.

After emissions from natural sources (termites, wetlands) and agriculture/waste (landfills, sewage), energy production and delivery constitute the third most important source of methane emissions globally. And within the energy sector, the contributions from coal and gas production to methane emissions are comparable, accounting for 43 MMt (31%) and 42 MMt (32%), respectively, of total energy-sector methane emissions.[47] However, *within oil and gas operations* methane is the largest single component of GHG emissions.[48] For these reasons, as

45 https://www.epa.gov/ghgemissions/global-greenhouse-gas-emissions-data#Sector
46 https://www.epa.gov/ghgemissions/global-greenhouse-gas-emissions
47 IHS Markit Strategic Horizons *Global climate: understanding the methane balance,* 12 March 2020.
48 https://www.iea.org/reports/methane-tracker-2020/methane-from-oil-gas

well as global experience that shows targeted methane abatement efforts can yield significant and rapid emissions reductions, methane abatement has become *the* primary focus of efforts to reduce GHG emissions in the oil and gas industry.

Within the oil and gas industry, the major source of methane emissions *upstream* is associated with oil production and associated gas extraction (venting and leaks), and only secondarily from upstream natural gas operations.[49] In the *downstream* oil and gas segment (transmission, storage, distribution, and combustion) it is mostly leakage from the gas operations (leaks from pipelines and compressors and incomplete combustion in equipment) that are responsible for methane emissions. The relative contributions of upstream and downstream segments to methane emissions varies substantially by country because of the different mix of activities.

Looking at the global gas industry alone (without oil), roughly two-thirds of methane emissions (28 MMt/y) are generated in the upstream versus one-third (14 MMt/y) in the downstream.[50] Yet in countries such as Russia, with long pipeline systems, this ratio can reverse, with pipelines alone accounting for over three-fifths (61%) of total gas sector emissions. The International Energy Agency's (IEA) Methane Tracker project identifies Russia as the world's leading methane emitter from combined oil and gas operations.[51]

The bulk of atmospheric emissions (GHG and particulate emissions, but mainly methane) from the natural gas transportation and storage segment generally stems from fuel use in compressor stations, controlled venting during maintenance and repairs, as well as fugitive emissions and leaks (from valves, connectors, flanges, etc.).[52] Some of these emissions are technically unavoidable, while others are preventable, such as those from degraded coating on pipes, leaks from improper or irregular maintenance, poor operational practices and technical systems in place, and use of older, inefficient compressors. The largest factor determining pipeline emissions is the overall amount of gas handled in the system followed by the length of the pipeline network; i.e., the more gas a system handles either in volume or distance, the larger the volumes of methane emissions.

Globally, natural gas pipeline operators rank fugitive emissions and leaks among the most pertinent environmental issues, and are devoting substantial resources to not only accurately measure the frequency and intensity of leaks, but also to develop best practices and technologies to avoid them altogether.[53] In the United States, the Environmental Protection Agency (EPA) estimates that 19% of methane emissions in the oil and gas industry stem from the natural gas transmission and storage segment, which translates to 0.57% of total GHG emissions in the US from human activity.[54] In the EU, methane emissions generated from fugitive natural gas discharges amount to 0.5% of total EU GHG emissions, and 27% of all fugitive emissions.[55] According to current estimates, 54% of methane emissions in the international energy sector as a whole are fugitive emissions from the oil and gas industry, despite the fact that oil and gas operators now generally have a variety of mitigation measures that can be implemented at relatively low cost.

Midstream gas operators have undertaken various operational and environmental initiatives to reduce methane leakage, and to improve their overall environmental footprint. The impetus for reform is often provided by changing regulations governing emissions and waste, although companies have also successfully taken on voluntary emissions reduction goals. For example, in the US, the EPA's voluntary Natural Gas Star program reported its participating companies decreased methane emissions from transmission and storage facilities by 44% from 1990 to 2016 due to reduced compressor station and fugitive emissions, despite a 43% percent increase in US natural gas consumption during the same period.[56] Additionally, the ONE Future Coalition program in the US unites more than 45 natural gas companies working together to voluntarily reduce methane emissions across the natural gas value chain to 1% (or less) by 2025.[57]

49 Upstream leakage from gas production is a consequence of poor well management or poor management of flowback fluids from hydrofracturing operations in production from tight sands and shales.

50 Comparatively, the upstream oil sector generates around 34 MMt/y of methane emissions, compared to less than 1 MMt/y in the downstream sector; see *Global climate: understanding the methane balance,* 2020.

51 https://www.iea.org/reports/methane-tracker-2021

52 Although compressors at most production sites worldwide are powered using natural gas, in some fields, such as Groningen (Netherlands), they are now all electrically powered, eliminating the potential for leaks associated with on-site fuel use. If such electricity is generated by renewable energy or a low-carbon source, the net emissions reduction can be substantial.

53 See PG&E Corporation's 2018 Super Emitter leak abatement program, and the "Reducing methane emissions: Best practices guide equipment leaks," published by the Methane Guiding Principles group, https://methaneguidingprinciples.org/best-practice-guides/.

54 https://www.epa.gov/natural-gas-star-program/estimates-methane-emissions-segment-united-states#Transmission. Methane emissions from the natural gas transportation and storage segment account for 5.7% of all US methane emissions, which (total US methane emissions) in turn account for 10% of all GHG emissions from human activities in the US. Thus, the gas transportation and storage sector accounts for 0.57% of all GHG emissions in the US.

55 Fugitive emissions are defined as intentional or unintentional releases of gases from anthropogenic activities that in particular may arise from the production, processing, transmission, storage, and use of fuels. Emissions from combustion are only included when they do not support a productive activity (e.g., flaring of natural gases at oil and gas production facilities).

56 https://www.ingaa.org/38582.aspx

57 https://onefuture.us/

In the EU, regulatory initiatives curbing methane emissions in key sectors were adopted in 2009, halving energy-sector methane emissions from 1990 levels by 2020. The Oil and Gas Methane Partnership under UN auspices reports that participating companies "collectively reported some 25,000 tons of methane emissions avoided" over 2016-18, or an equivalent of removing "at least 134,000 passenger cars from the roads annually."[58]

Leak reduction efforts in the midstream sector can be grouped into the following broad categories:

- **Pipe repair and replacement.** Refurbishment of older distribution networks with modern polyethylene pipes is key to reducing emissions. In these old – sometimes very old – distribution grids, leakage into the soil from fine cracks and worn joints eventually enters the atmosphere. Locally, the leaks are harmless - methane is not toxic, and concentrations from this source do not reach combustible levels in the air – but collectively they are an identifiable source of GHG emissions. Pipe replacement can be a long-term and costly process, but it is being pursued systematically in almost all parts of the world where cast-iron pipes are still in service.
- **Compressor maintenance.** In the gas transmission business, some industry practices currently still allow venting from compressors when they are taken out of service for maintenance. Yet techniques are available to "seal in" the methane by using nitrogen (an inert gas) during maintenance. Major intercontinental long-distance pipelines can significantly reduce emissions by using these modern processes. Russia, for example, has made major strides in recent years by adopting these techniques.
- **Leak monitoring and detection.** Equipment that risks leakage can now be continuously monitored – by means of drone surveys, or by "laser nets" that cover an installation, such as a compressor station, that may be susceptible to such risks. Other monitoring detection technologies include infrared (IR) leak imaging cameras (using a variety of measurement tools such as a vane anemometer, hotwire anemometer, turbine meter, and hi-flow sampler), and implementing a wet seal degassing emissions recovery system. Measurement from dedicated satellites is also being developed.

4.12.2 Kazakhstan's midstream company efforts to reduce methane emissions

In Kazakhstan, data on methane leaks are not readily available or are not reported uniformly. The difficulty in accessing information means that policymakers and energy officials often are not fully aware of the problem, and potentially, its scale. Therefore, resources should first and foremost be devoted towards detecting and measuring leaks, and ensuring timely, accurate, and accessible reporting.

Kazakhstan's 2021 National Inventory Report (NIR) to the UNFCCC indicates that methane emissions from the energy sector as a whole amounted to 0.54 MMt, almost a threefold reduction compared to 1.5 MMt in 2000. KMG, ICA, and KTG-Aimak reported total methane emissions of 5.4 MMt CO_2e in 2018, or 36.7% of its total GHG emissions during that year. For its pipeline transportation segment (oil and gas pipelines), methane emissions were reported at 4.4 MMt CO_2e, or 81% of total KMG emissions.[59] Thus, the midstream segment in Kazakhstan is both the greatest source of gas-industry methane emissions and the area that affords the greatest opportunity for improvement, particularly with respect to fugitive emissions.

In Kazakhstan, natural gas transportation companies (KTG and its subsidiaries ICA and KTG-Aimak) are focused on reducing emissions of all types in accordance with national legislation and internal company objectives. ICA and KTG-Aimak generally focus on three areas of activity governed by national regulations: so-called "atmospheric emissions" (including methane) monitored by MEGNR (see Chapter 2), water use and wastewater disposal, and waste generation and disposition.[60] ICA, in particular, has achieved some success in reducing the overall environmental impact of its activities in recent years (see text box ICA and KTG-Aimak Environmental Remediation Activities).

ICA and KTG-Aimak Environmental Remediation Activities

- ICA's total atmospheric emissions amounted to 68,945 tons in 2018, 82,377 tons in 2019, and 70,000 tons in 2020 (well below its permitted level of 222,000 tons in 2020). The resumption of Turkmen gas transit to Russia through ICA's network in 2019 appeared to be a major factor for the jump in 2019, as more gas was burned

58 Oil and Gas Methane Partnership (OGMP): Third-Year Report, accessed 20 July 2021, https://www.ccacoalition.org/en/resources/oil-and-gas-methane-partnership-ogmp-third-year-report

59 In 2019, the company's CDP report did not give absolute methane emissions numbers, but indicated that methane emissions per 1,000 toe of produced hydrocarbons declined by 16% compared to 2018 (*Otchet po vybrosam parnikovykh gazov* KMG, 2019). For 2020, KMG reported the following Scope 1 methane emissions for each of its segments to CDP: upstream 58,725 tons CH_4; midstream 120,744 tons CH_4; and downstream (primarily oil refining) 56,255 tons. KMG's 2020 methane reporting includes its Romanian and Georgian assets as well.

60 CO_2 emissions are monitored and regulated separately by Zhasyl Damu under Kazakhstan's emissions trading system (ETS).

during the operation of gas compressors on the CAC pipeline system that previously had been largely idle. Also, that same year, ICA carried out a substantial amount of planned maintenance and emergency repair work that added to emissions. ICA reported that methane's share in overall atmospheric emissions was 98% in 2019, and it is reasonable to assume that the share of methane in the company's emissions was similar in 2020.[61]

- ICA's water consumption totaled 364,700 m^3 in 2020, down 4% from 378,200 m^3 in 2019, but nearly on par with 2017 levels of 364,300 m^3. ICA attributes the decline in water use in 2020 to the implementation of water-saving measures that reduced leakage. Despite this overall progress, analysis of entity-level water consumption reveals that the savings were not uniformly achieved. Water demand swelled over threefold in ICA's Kyzylorda subsidiary to 3,000 m^3 and increased by almost 4% in Aktobe. This was more than offset by the 18,500 m^3 decline in aggregate water use in Aktau, Atyrau, Shymkent, and Taraz. The increase in water consumption at the Kyzylorda and Aktobe subsidiaries was due to additional (new) compressor stations.[62] In tandem with the decrease in overall water consumption, ICA was able to minimize wastewater discharge, which declined from 33 tons in 2018 to 29.8 tons in 2019, and to 28.1 tons in 2020; this was due to upgrades in water purification equipment.
- ICA's solid waste generation *(obrazovanie otkhodov)* averaged 1,214 tons annually in 2018–20.
- ICA's overall energy consumption amounted to 692,077 tons of standard fuel (coal-equivalent) in 2020, down 4.6% from 725,427 tons in 2014. Relatedly, overall electricity consumption contracted 23% in 2019, and a further 15% in 2020 to reach 71.576 million kWh.
- In terms of energy savings, ICA reports that in 2020 energy savings resulting from efficiency measures amounted to 12,041 tons of standard fuel, including: natural gas – 10 MMcm (worth 159.6 million tenge) and electricity 1.534 million kWh (worth 23 million tenge).[63]
- KTG-Aimak's atmospheric emissions amounted to 55,788 tons in 2018, and fell to 53,331 tons in 2019, the most recent year for which data are available. This reduction materialized despite a rise in domestic gas deliveries. The company's industrial waste averaged around 800 tons annually over that same period, while wastewater discharge remained at about the same level.[64]

The drive to mitigate methane leakage across the entire oil and gas value chain, including the gas midstream, has been led by the national oil and gas company KMG. In 2014, with the support of Kazakhstan's Ministry of Energy and Norway's Agency for Environmental Protection, KMG initiated a large-scale program to identify opportunities to reduce methane emissions through projects designed to enhance detection and measuring at KMG subsidiaries and JVs. As part of this effort, KMG joined the Global Methane Initiative (GMI) in 2017, and initiated pilot projects in Mangystau Oblast. And for the first time in 2019, KMG reported its emissions as part of the Carbon Disclosure Project (CDP), including CO_2, methane, and nitrous oxide (N_2O) for 2018.

In the midstream gas sector, ICA has carried out a variety of modernization improvements, including repairing the anodic protection along pipelines, replacing hundreds of kilometers of older pipes, and installed video surveillance in its Uralsk subsidiary.[65] The company's 2021-25 goals, as determined by an audit carried out by Energy Partner LLP, center on a variety of energy efficiency improvements that generally align with the goals of BAT implementation under the new EcoCode. Such initiatives include optimizing compressor station operations and electricity use, repairing sections of lines without causing major gas leaks, installing newer cathodic stations, and monitoring network-wide water, electricity, and natural gas consumption.

Although ICA discusses methane emissions in detail in the context of environmental review reports on specific pipelines and compressor stations, it does not consistently report total company methane emissions.[66] Still, the company typically notes in its reporting that methane constitutes 95-98% of its atmospheric emissions. Indeed, in 2020, ICA carried out seven projects to eliminate (gas) leaks in the Aktau network (3 projects), Atyrau network (2 projects), and Shymkent network (2 projects). KTG-Aimak provides less information about its leak reduction

61 ICA Annual Report 2019, page 60.
62 The newly commissioned compressor stations in the Kyzylorda subsidiary were the CS Karaozek, CS Korkyt-Ata, and the CS Aral, while in Aktobe it was the CS Ustyurt.
63 ICA 2020 Annual report, p. 116.
64 During 2017-19, KTG-Aimak reports savings of over 22,000 m^3 of water. http://www.ktga.kz/company/ecology-management/
65 ICA also replaced 88 stop valves in 2018, 56 stop valves in 2019, and 42 in 2020.
66 For example, ICA notes that the maximum level of leaks at CS Ustyurt ranged between 0.12 and 0.20 normal m^3 (nm^3)/minute, and no more than 31 nm^3/h. At CS Turkestan and CS Aral (Saksaulsk), gas leakages were reported to be no more than 0.53 nm^3/h.

efforts. Its website states that on average the company emits around 9,632 tons CH_4 and 8,561 tons CO_2 annually.

Comparing ICA's GHG emissions with other pipeline operators remains rather complicated because of inconsistent reporting and data. Available data on ICA's CO_2 and particulate emissions seems to indicate that atmospheric emissions generated by ICA and KTG-Aimak are generally in line with those of other gas pipeline operators in Eurasia, after standardizing for the size of the pipeline network and overall volumes handled in their respective pipeline systems (see Table 4.8 Comparison of environmental and operational indicators for selected gas-transportation companies in Eurasia and Europe). For example, after taking into account that ICA's methane emissions (which are not included) make up 95-98% of its total GHG emissions, its GHG emissions intensity would appear to be on the same order of magnitude as Gazprom's for its transportation and storage operations.

4.12.3 Experience of BAT in other markets and potential applicability to Kazakhstan's gas segment

As in several important areas of environmental policy, the EU is playing a leading role in the regulation of emissions from the natural gas midstream. The EU policy focus is now shifting from targeting primarily CO_2 emissions to addressing other GHGs, particularly methane. The Impact Assessment of the EU 2030 climate target plan found that methane will remain a dominant non-CO_2 GHG in the EU.[67] Current EU policies target a 29% reduction of non-CO_2 GHG emissions in the EU by 2030 compared to 2005 levels, but policymakers are looking to improve these targets.

In October 2020, the EU released a strategy to reduce methane emissions in key emitting segments, including the energy sector, which is responsible for 19% of methane emissions in the EU. The key tenets of the strategy are to improve measurement, verification, and reporting of methane emissions. The European Commission (EC) is now considering legislation for obligatory improvements in detection of leaks and pipeline repairs as well as introduction of a ban on routine flaring and venting. The EC is also planning to create an international methane emissions observatory in partnership with the UN's Environment Program, the Climate and Clean Air Coalition (CCAC), and the IEA. The emissions measurement, verification, and reporting efforts will not rely on manual measurements or calculation alone, but will leverage satellite data; the EC intends to tap the EU's Copernicus earth observation satellite program to help "detect global super-emitters and identify major methane leaks."[68]

The EC is leading the Oil and Gas Methane Partnership (OGMP) together with CCAC and the Environmental Defense Fund (EDF).[69] The new OGMP 2.0 framework adopted in November 2020 aims to set a "new gold standard reporting framework that will improve the reporting accuracy and transparency of anthropogenic methane emissions in the oil and gas sector." To support global climate targets, OGMP 2.0 set a goal of achieving a 45% reduction in the industry's methane emissions by 2025, and a 60-75% reduction by 2030.[70]

With respect to BAT in Europe, implementation is not yet mandatory for the European midstream sector. Pipeline operators presently are simply responding to national regulations governing emissions. In Russia, however, Gazprom, did introduce BAT measures across its pipeline system. The company has installed shut-off and control valves on gas production unit (GPU) process equipment and outgassed low-pressure pipelines during planned maintenance periods, both of which are practices utilized by ICA. In other instances, in an effort to reduce methane emissions as part of BAT, Gazprom withdrew gas from pipeline sections under repair and diverted it to another pipeline leveraging a mobile CS.[71]

Kazakhstan's gas pipeline operators KTG, ICA, and KTG-Aimak have identified several environmental areas of concern in their respective plans submitted to MEGNR.[72] In terms of the three main areas of environmental pollution – atmospheric emissions, water use and wastewater disposal, and waste management – KTG-Aimak, for example, highlighted the need to optimize the operations of electrically driven gas compressor units, and enhance the efficiency of compressor stations. ICA's audit identified the need to optimize CS loads, conduct repair work without releasing methane into atmosphere, and

67 https://eur-lex.europa.eu/resource.html?uri=cellar:749e04bb-f8c5-11ea-991b-01aa75ed71a1.0001.02/DOC_2&format=PDF

68 https://ec.europa.eu/commission/presscorner/detail/en/ip_20_1833. It is also worth noting that there are other, private-sector companies that track emissions at the facility level using satellites, such as GHGSat Inc. European IT company Kayrros also maintains a tool that leverages data from Copernicus Sentinel-5P and Sentinel-2 missions, along with algorithms, to detect individual methane emissions from space.

69 OMGP now includes 62 companies with assets on five continents representing 30% of the world's oil and gas production.

70 https://ec.europa.eu/info/news/oil-and-gas-industry-commits-new-framework-monitor-report-and-reduce-methane-emissions-2020-nov-23_en

71 "Methane emissions management in Russia: Gazprom case study," by Dr. Konstantin Romanov, Head of Division, Secretary of Coordination Committee for Sustainable Resource Management, Gazprom, https://ec.europa.eu/info/sites/default/files/energy_climate_change_environment/events/presentations/speaker_intervention_-_gazprom.pdf.

72 See the companies' Planned Activities available on the MEGNR website, http://prtr.ecogosfond.kz/otchety-rvpz/, as well as ICA's Annual Report 2020.

Table 4.8 Comparison of environmental and operational indicators for selected gas-transportation companies in Eurasia and Europe

	2018	2019	2020
Intergas Central Asia (ICA)			
PM (particulate matter) atmospheric pollution (thousand tons)	69	82	70
Waste (thousand tons)	1	1	1
GHG emissions (thousand tons CO_2e)	589	795	701
Pipeline transmission system length (thousand km)	20.7	20.7	20.7
Gas handled through system (Bcm)***	80	73	58
PM emissions intensity (tons/MMcm transported)	1	1	1
GHG emissions intensity (tons/MMcm transported)	7.4	10.9	12.1
PAO Gazprom*			
PM (particulate matter) atmospheric pollution (thousand tons)	1,707	1,699	1,357
Waste (thousand tons)	139	151	157
GHG emissions (thousand tons CO_2e)	97,520	93,650	77,610
Pipeline transmission system length (thousand km)	172.6	175.2	176.8
Gas handled through system (Bcm)	693	679	625
PM emissions intensity (tons/MMcm transported)	2.5	2.5	2.2
GHG emissions intensity (tons/MMcm transported)	141	138	124
UkrTransGaz			
PM (particulate matter) atmospheric pollution (thousand tons)	18	21	31
Waste (thousand tons)**	3	6	3
GHG emissions (thousand tons CO_2e)	4,392	4,492	251
Pipeline transmission system length (thousand km)	33	33	33
Gas handled through system (Bcm)***	87	90	56
PM emissions intensity (tons/MMcm transported)	0.2	0.2	0.6
GHG emissions intensity (tons/MMcm transported)	51	50	5
Gazprom Belarus			
PM (particulate matter) atmospheric pollution (thousand tons)	23	22	25
Waste (thousand tons)	5	6	12
GHG emissions (thousand tons CO_2e)	320	320	450
Pipeline transmission system length (thousand km)	8	8	8
Gas handled in system (Bcm)***	63	61	56
PM emissions intensity (tons/MMcm transported)	0	0	0
GHG emissions intensity (tons/MMcm transported)	5	5	8
Gazprom Armenia			
PM (particulate matter) atmospheric pollution (thousand tons)	69	62	46
Waste (thousand tons)	0	0	0
GHG emissions (thousand tons CO_2e)	2,460	1,960	1,630
Pipeline transmission system length (thousand km)	2	2	2
Gas handled in system (Bcm)	2	3	3
PM emissions intensity (tons/MMcm transported)	28	24	18
GHG emissions intensity (tons/MMcm transported)	1,000	769	627

	2018	2019	2020
Gazprom Kyrgyzstan			
PM (particulate matter) atmospheric pollution (thousand tons)	4	3	2
Waste (thousand tons)	0	2	0
GHG emissions (thousand tons CO_2e)	90	70	40
Pipeline transmission system length (thousand km)	1	1	1
Gas handled in system (Bcm)***	6	7	7
PM emissions intensity (tons/MMcm transported)	1	0	0
GHG emissions intensity (tons/MMcm transported)	14	10	6
PSG (PGNiG, Poland) (excludes Yamal-Europe pipeline)			
PM (particulate matter) atmospheric pollution (thousand tons)	405	404	255
Waste (thousand tons)	4	4	2
GHG emissions (thousand tons CO_2e)°	102	107	102
Pipeline transmission system length (thousand km)	11	11	11
Distribution network (thousand km)	186	191	195
Gas handled in system (Bcm)***	12	12	12
PM emissions intensity (tons/MMcm transported)	34	35	22
GHG emissions intensity (tons/MMcm transported)	9	9	9

Notes:

*Includes only PAO Gazprom's transportation and gas storage activities within Russia.

**In 2020 Naftogaz Group reported total generated waste without a breakdown by subsidiary. IHS Markit assumes that UkrTransGaz share of waste generated out of the company total remained at 2019's share of 2.3%. In 2020, total waste generated by Naftogaz Group was 132,900 tons, versus 259,600 tons in 2019.

***Includes transit volumes

° Atmospheric emissions reported for PGNiG, rather than for PGNiG's distribution subsidiary, PSG. GHG emissions reflect emissions from PSG's downstream operations (distribution, storage, and trade). All PGNiG emissions data, excluding GHG emissions, originally reported in Megagrams (Mg), which has a 1:1 conversion factor to metric tons.

Source: IHS Markit, company reporting

to conduct regular pipeline inspections to identify and eliminate gas leaks.

In addition to measures taken as part of these plans, the companies are also actively engaged in international certification efforts.[73] KTG-Aimak, for example, recently completed an audit certifying its compliance with ISO-14001 Ecological Management requirements (involving annual emissions monitoring and compliance as well as risk management assessments).[74] ICA, likewise, has passed recertification of the ISO-14001 and also instituted an energy efficiency and savings policy that has been certified under the ISO 50001 international standard for Energy Management.[75]

73 KTG's company policy requires all of its subsidiaries to adhere to international and national standards via compliance with various management system certifications.
74 http://www.ktga.kz/company/ecology-management/
75 https://www.iso.org/iso-50001-energy-management.html

4.13 Recommendations for market development, reserves growth, and harmonious integration into the EAEU common market

- **As noted in previous National Energy Reports (2015, 2017, and 2019), low prices constitute the foremost barrier to growing commercial gas supply.** Kazakhstan's policymakers must come to terms with the fact that prices throughout the value chain, including producer prices and end-user prices, need to increase for commercial gas supply to grow beyond what is already pre-programmed.
- **The government and members of the Foreign Investors Council (FIC) have been working diligently to devise a series of incentives forinvestors that would help boost commercial gas production in the country.**

IHS Markit encourages the government to embrace the recommendations promoted by the FIC, and incorporate these changes into the terms for new field development (i.e., the framework of the improved model contract).

- **Policymakers in Kazakhstan should consider offering a series of incentive packages, similar to the suite of incentives offered for renewable energy projects, to investors and entities developing gas-fired generation.** Current economic and pricing conditions in Kazakhstan do not support shifting to gas from coal.
- **While the tariff for BBS was adjusted for distance – a positive development – it appears there are no plans to abandon the current postage-stamp method for most ICA pipeline tariffs.** Because of the great distances involved in Kazakhstan's gas transportation, IHS Markit encourages KREM to incorporate a distance basis into the tariff for the ICA network; this would drive greater efficiencies in gas deliveries and further incentivize domestic market development.
- **IHS Markit urges the government to make an effort to educate regulators in the Ministry of Economy, particularly KREM, on the economics of the gas sector so that a constructive dialogue can ensue with officials from the Ministry of Energy and MEGNR.** While KREM's charter is to safeguard the interests of the people by patrolling the activities of natural monopolies, its ultimate decisions must be guided by facts and economic reality.

4.13.1 Recommendations on BAT for atmospheric emissions

The introduction of any new technology or technique, including those classified as "BAT," requires careful consideration of company-specific technical constraints, climatic conditions, national and local regulations, and cost factors. There are no "one-size-fits-all" solutions, and technologies are rapidly evolving. For ICA, KTG, and KTG-Aimak, the introduction of BAT presents an opportunity to accelerate already-launched initiatives, modernize operations, and reduce their respective environmental footprints.

While the BAT conclusions included in the IGTIC's BREFs and company-level benchmarks used for the issuance of IEPs have yet to be published, IHS Markit anticipates that IEP benchmarks and BAT plans will likely target (1) atmospheric emissions, (2) energy efficiency, (3) water use and disposal, and (4) tangentially, vis-à-vis technological recommendations, industrial waste. With this in mind, IHS Markit presents the following recommendations and considerations for BAT implementation in Kazakhstan's gas transportation sector, so it focuses mainly on fugitive methane emissions.

- **A supportive regulatory environment is critical. ICA has already formulated an action plan to improve energy efficiency and achieve other environmental goals.** But financing expenditures related to these programs require KREM approval. KREM has historically resisted upward adjustments to regulated tariffs. IHS Markit strongly encourages KREM to accept proposed upgrades and modifications presented within the BAT framework as legitimate components of companies' investment programs, and ultimately incorporate such investments into the regulated tariffs. It will be extraordinarily challenging for ICA and KTG-Aimak to implement a comprehensive BAT program without the ability to recoup their investments through upward adjustments in regulated tariffs.
- **A robust digital infrastructure for data collection, monitoring, and analysis is integral to identifying methane leaks, executing a rapid repair response, and preventing future incidents**. Policy efforts in the EU and US targeting methane emissions focus on digital technologies, particularly with respect to emissions detection. And in many ways, digitization is the necessary prerequisite for modernization, as the overwhelming majority of new technologies deployed throughout the energy value chain are designed to operate in a digital world. Since 2015, KTG and the EBRD have partnered to introduce supervisory control and data acquisition (SCADA) technology to KTG's network. The introduction of SCADA to KTG's entire network, including KTG-Aimak and ICA pipelines, would be a productive first step towards enhancing KTG's ability to monitor its emissions footprint and build the foundation for additional enhancements in the future. Longer term, greater use of cloud-based data storage could play a critical role in streamlining communication between business units to allow for a rapid response. Greater operational digitization must be supported by investments in employee training, and the establishment of an organized workforce structure and systems to manage the data feed.
- **The Government of Kazakhstan could alleviate the costs of introducing BAT to companies by establishing a country-wide emissions monitoring service levering satellite detection services.** This would follow the example of the EC and allow for the collection of emissions data in real time by the MEGNR, potentially leading to shorter reaction times. The subsequent distribution of this data would promote transparency and accountability, while reducing the costs of monitoring for individual enterprises. If budgetary factors are a consideration, the government could initially establish this service

for natural monopolies only and then gradually widen the scope. This may require a shift in Kazakhstan's regulations to accept satellite-detected emissions as valid.

- **Reducing methane leaks requires frequent leak surveys through a digital mobile and stationary survey technology together with related employee training.** In 2018, PG&E, a utilities company based in California, shifted its leak survey schedule from a four-year to a three-year cycle. At the time, PG&E expected a more frequent survey cycle would reduce small-scale methane leaks by as much as 20% annually.[76] PG&E also partnered with Picarro to develop mobile technology to detect small-scale leaks, employed Differential Absorption Lidar (DIAL) LiDAR aerial surveys to inspect parts of its transmission system to identify leaks, as well as SCADA visibility and control points to monitor pressure and flow. Also essential is a robust training program that teaches employees how to identify leaks and carry out repairs. One study found that 50% of incidents in pipelines in western Kazakhstan, for instance, were caused by human error.[77]

- **To further reduce methane leaks, ICA and KTG-Aimak could contemplate adopting best management practices and replacing outdated circuit breakers.** In the United States, gas pipeline operators found that replacing a gas-fired starter expansion turbine in compressors and generators with an electric motor starter helped reduce the frequency of failed starts and lowered methane emissions.[78] Such an endeavor, however, requires electrification of the gas pipeline. And in some markets, notably in California, local governments have banned the use of SF_6 components (e.g., circuit breakers) in pipelines, in an effort to reduce potential these emissions. Companies are working with technology providers (Hitachi, Siemens, and GE) to formulate safe and effective components devoid of SF_6 by the mid-2020s. Dry seals have also been shown to reduce methane leaks, if installed properly and operated under the proper conditions.[79]

- **ICA and KTG-Aimak could consider reducing methane leaks by improving threaded connections and pipefitting specifications.** In other countries, some companies have found installing improved seals below the riser valve, and putting on improved thread sealant, have effectively reduced emissions.

- **More robust and frequent data disclosures on environmental activity and initiatives will instill accountability and allow for independent, third-party analysis.** Currently, ICA, KTG, and KTG-Aimak do not regularly publish GHG emissions data, including their methane emissions. Data transparency would enable third-party analysis and also increase public accountability. Disclosure of climate-related impacts is becoming the norm in oil and gas activities worldwide, and it is only appropriate that Kazakhstan's gas operators also adopt a more transparent disclosure disposition.

- **Reporting of absolute methane emissions will promote transparency.** Reporting companies should publish absolute GHG and methane emissions (e.g., in cubic meters or metric tons of methane) in sustainability reports, specifying the geographical, operational, and ownership segments to which the total applies. Converted measures, such as CO_2e or intensities (CO_2e/boe of production) can enhance but should not replace reporting of the original absolute emissions. If conversions are used, they should be qualified with warnings about possible subjectivity. This method would preserve the baseline number for the reader (e.g., investor, government agency) to convert as they deem appropriate and would enable straightforward comparison of historical numbers from prior years. Best practice for reporting methane intensity would be to use it in addition to, rather than instead of, reporting absolute methane emissions.

76 Pacific Gas and Electric Company Attachment 1 2018, "Leak abatement compliance plan executive summary and templates."

77 R.E. Khasanov, "Problems of protective coatings of pipelines on the example of main gas pipelines of western Kazakhstan," Neftegazovoye delo, 2014, t.12 No.1, http://ngdelo.ru/article/view/864

78 There have also been instances when gas starters could be replaced with air or nitrogen as a means to reduce emissions (https://www. epa.gov/natural-gas-star-program/replace-gas-starters-air-or-nitrogen).

79 https://www.epa.gov/natural-gas-star-program/replacing-wet-seals-dry-seals-centrifugal-compressors

Chapter 5

COAL

5 KAZAKHSTAN'S COAL SECTOR

Coal is Kazakhstan's most important fuel source, being both abundant and inexpensive to produce. Production dynamics have long been more closely tied to domestic demand trends (particularly electric power generation), as opportunities for exports remain rather limited. Given the current acceleration in the energy transition globally (and in Kazakhstan), and heightened efforts to reduce atmospheric carbon emissions, Kazakhstan's coal industry is looking for a way forward. Its likely long-term trajectory seems to be a managed gradual decline rather than one of growth. That said, the slope of that decline will depend on such factors as the pace at which natural gas and other lower carbon energy sources can be substituted for coal in electric power generation, demand in export markets, and advancements in carbon capture, utilization, and storage (CCUS) technologies that affect coal's atmospheric emissions intensity.

5.1 Key Points

- Coal is expected to remain an important energy source for Kazakhstan's economy, particularly in electricity generation, through at least 2040. In the IHS Markit base-case outlook, the share of coal in Kazakhstan's primary energy demand declines from 56% (in 2020) to about 51% in 2030 and 42% in 2040, gradually giving way to natural gas, renewables, and (after the mid-2030s) nuclear generation.
- Fears of a significant drop in coal output due to the COVID-19 pandemic's impact on the overall economy in 2020 did not materialize. Gross coal production contracted by only 1.4%; domestic apparent consumption declined slightly (0.9%), mainly in industry; and exports declined much less than had been feared, by 3.2% year on year.
- Longer term, demand for Kazakh coal, both in the domestic economy and by foreign consumers, is projected to decline, albeit slowly. Kazakhstan is seeking to grow exports, but this is challenged not only by overall pressure to reduce coal consumption in key export markets, but also by long distances to market, poor coal quality, and disagreements with transit countries.
- Kazakhstan's coal industry's plans to deal with the energy transition are still at a relatively nascent stage, but similar to other major coal producers, the current emphasis is focused on reinvigorating development and attracting new investment. The idea of shifting to value-added coal products is gaining momentum over efforts to expand exports, however. A number of reforms are being implemented, although none are expected to be "game changers" in terms of the industry's general prospects going forward; these are intrinsically linked to the international drive to reduce global GHG emissions.

5.2 Organizational Structure and Legal Framework

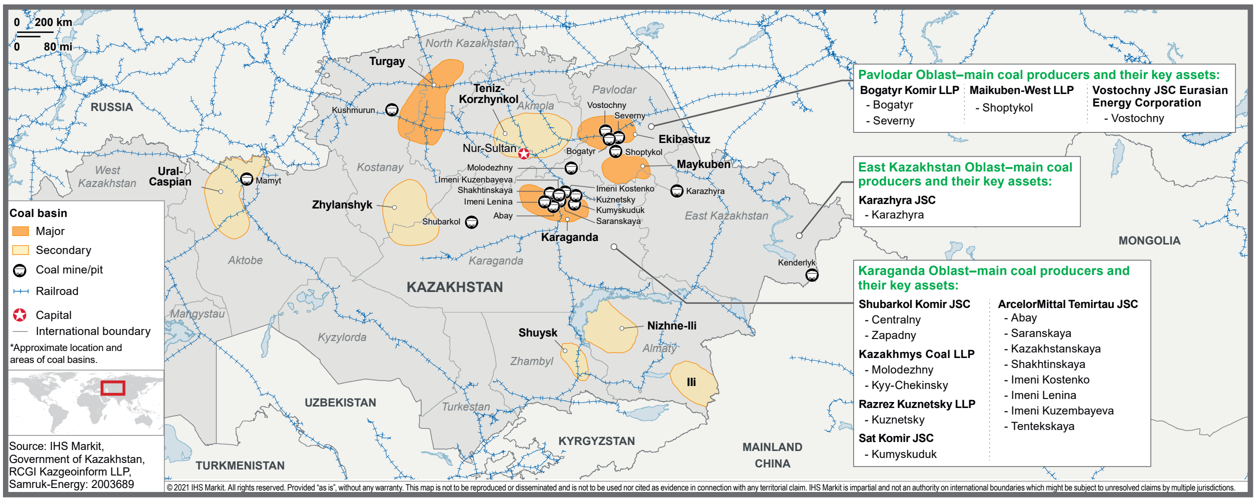
- Kazakhstan's coal industry is currently the main supplier of energy to the domestic economy, accounting for 56% of the country's primary energy consumption in 2020. Kazakhstan is engaged in almost the entire spectrum of coal production, ranging from lignite and sub-bituminous coal production for power generation to the mining of metallurgical coal and production of coke for blast furnace operation. The industry currently is exploring ways to diversify its output into value-added byproducts, such as tar, gases, solvents, and activated charcoal. Unlike other major energy sectors such as natural gas, oil, and uranium, there is no "state company" or "national champion" in the coal sector. Rather, the coal industry's organizational structure is fairly decentralized, with 25 companies currently listed by the government as engaged in coal-mining operations; still, nearly three quarters of national output is accounted for by four large entities (see below). Mine-industry regulation is guided by Kazakhstan's 2017 Subsoil Code, and is primarily overseen by the Ministry of Industry and Infrastructure Development. Recent amendments to the Tax Code and Subsoil Code and the launch of the new Ecology Code all have implications for the coal industry's operations going forward (see below).

5.3 Reserves

With the equivalent of "proven+probable" (A+B+C1) coal reserves listed at 29.4 billion tons across 49 deposits (recoverable "balance sheet" reserves are listed at 33.7 billion tons), amounting to 2.4% of the world's total, Kazakhstan is a major resource holder, as well as a world-class producer and consumer of coal.[1] The country possesses the tenth largest reserves of coal globally, sufficient to last over 230 years at current rates of production. Bituminous and sub-bituminous coal (the two types categorized as "hard coal" in Kazakh nomenclature) account for roughly two-thirds of Kazakhstan's reserves,

1 The reserves figures reported as of 1 January 2019 by Kazakhstan's Geological Committee. Proven reserves are generally taken to be those quantities that geological and engineering information indicates with reasonable certainty can be recovered in the future from known reservoirs under existing economic and operating conditions.

Figure 5.1 Kazakhstan's coal basins and key production sites*



with the remainder consisting of lignite (or "brown coal"). The largest coal basins are located in the central and northern parts of the country: Ekibastuz (10 billion tons), Karaganda (6.9 billion tons), and Turgay (5.9 billion tons) (see Figure 5.1 Kazakhstan's coal basins and key production sites). Deposits in the Ekibastuz Basin in particular stand out in terms of the low cost at which they can be produced; the seams are thick and located near the surface, making them easy to work using regular surface mining methods. Although Kazakhstan's coal reserves are large, most coal has high moisture content and relatively low heating values, as well as high ash and sulfur content. The latter means that their combustion (if untreated) is associated with – in addition to GHG emissions – substantial emissions of particulate matter and sulfur dioxide. At Ekibastuz the ash content is particularly high (42-44%), and the specific structural properties of the coal have rendered enrichment uneconomic. This limits its ability to penetrate many export markets (e.g., the European Union) in which stringent emissions controls or coal standards are enforced. An exception to this general situation is the Shubarkol Basin, where coals have much lower ash and sulfur levels (5-15% and 0.5%, respectively) and a higher heating value (5,600 kcal/kg).

5.4 Coal Production and Exports

5.4.1 Production

In 2020, Kazakhstan ranked eighth in the world in coal production, with an aggregate coal output of 109.2 million metric tons (MMt), a 1.4% decrease from 2019 (see Table 5.1 Kazakhstan's coal production (MMt)).[2] Fears of a significant drop in coal output due to the COVID-19 pandemic's impact on the economy did not materialize. The 2020 level of output remained basically in line with average annual coal production over the past decade (roughly 109 MMt/y), ranging between a high of 115.7 MMt in 2012 to a low of 98.6 MMt in 2016. Production serves mainly the domestic market. Most of the output (95%) is considered "hard" coal (although much of it is actually sub-bituminous), of which 9.7% (or 10.1 MMt) was coking coal, used in metallurgy.[3] In 2020, 87.4 MMt of coal was consumed domestically, while exports amounted to 22.4 MMt (see Table 5.2 Coal balance for Kazakhstan (MMt)). Kazakhstan imports an insignificant quantity of coal (0.6 MMt in 2020), mainly in minor cross-border trade.

Most of Kazakhstan's coal is mined in Pavlodar and Karaganda oblasts, where 2020 production amounted to 100.7 MMt, representing 92% of the country's output. In Pavlodar, coal is mined from the Ekibastuz Basin at three giant open-pit mines – Bogatyr, Severny, and Vostochny – while in Karaganda (Karaganda Basin) it comes from several open-pit mines – Borly, Shubarkol, Saryadyr, and Kushoky (see Table 5.3 Kazakhstan's main coal producers). Additionally, underground mining occurs mainly in the Karaganda Basin (supporting local metallurgy) and lignite production is concentrated in the Maykuben Basin in Pavlodar Oblast. Most of the remaining output is from East Kazakhstan (mainly Karazhyra (formerly Yubileynoye) mine). But over the past decade, production of coal for local consumption has sprung up at smaller open-pit mines in Aktobe, Almaty, and Turkestan oblasts.

2 The reported total is for run-of-the-mine output. The total does not include coal concentrate, as is the Kazakh statistical practice. Coal concentrate is a product of processing (in washeries) that removes impurities such as stone and dirt. Coal concentrate production in Kazakhstan was 3.9 MMt in 2020.

3 ArcelorMittal Temirtau, in Kazakhstan's Karaganda Basin, is the only company that produces coking coal.

Table 5.1 Kazakhstan's coal production (MMt)

	1990	1995	2000	2005	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020
Kazakhstan (total)	**131.6**	**83.3**	**74.9**	**86.6**	**106.6**	**111.4**	**115.7**	**114.6**	**109.3**	**102.6**	**98.6**	**107.9**	**114.1**	**110.7**	**109.2**
Hard coal	128.0	79.5	72.4	82.1	99.3	103.0	107.9	107.7	102.4	97.1	92.8	101.8	107.6	104.8	103.9
Coking coal	29.6	11.6	n.d.	n.d.	11.7	11.5	11.3	11.7	11.7	10.9	n.d.	10.9	10.8	10.5	10.1
Lignite	3.4	3.7	2.4	4.5	7.3	8.4	7.7	6.9	6.9	5.5	5.8	6.1	6.6	5.9	5.3
Coal concentrate	n.d.	n.d.	n.d.	n.d.	4.4	5.1	4.9	5.2	5.3	4.7	4.5	4.4	4.3	4.3	3.9

Note: n.d. = data not reported.

Source: IHS Markit, Bureau of National Statistics RK

Table 5.2 Coal balance for Kazakhstan (MMt)

	2015	2016	2017	2018	2019	2020	Percent change, 2019-20
Coal production (hard+lignite)	102.6	98.6	107.9	114.1	110.7	109.2	-1.4
Coal consumption (apparent)	74.8	74.8	80.9	91.6	88.3	87.4	-0.9
Coal exports	28.0	24.0	27.1	23.4	23.1	22.4	-3.2
Outside the Former Soviet Union	4.1	2.7	4.5	2.2	1.7	0.3	-85.3
Former Soviet republics	23.9	21.3	22.7	21.2	21.4	22.1	3.3
Coal imports	0.2	0.2	0.1	0.8	0.7	0.6	-15.3
Outside the Former Soviet Union	0.0	0.0	–	0.0	0.0	–	-100.0
Former Soviet republics	0.2	0.2	0.1	0.8	0.7	0.6	- 15.3

Source: IHS Markit, Bureau of National Statistics RK

Table 5.3 Kazakhstan's main coal producers

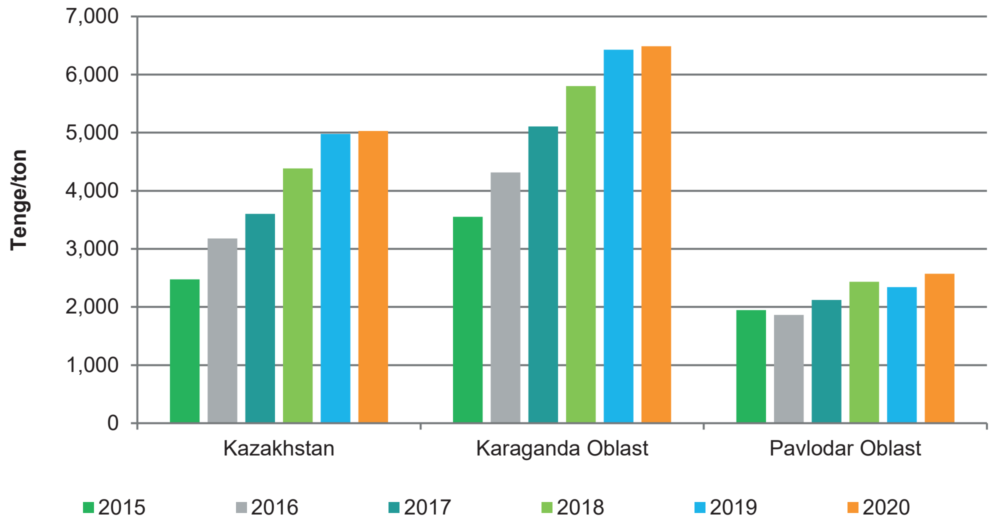
Entity	Oblast	Owner	2020 output (thousand metric tons)*	Share in Kazakhstan's total coal production	Mines
Bogatyr Komir LLP	Pavlodar	Samruk Energy (50%) and UC RUSAL (50%)	43,338	40%	Bogatyr coal pit, Severnyy coal pit
Vostochny JSC "Eurasian Energy Corporation"	Pavlodar	Eurasian Resources Group (ERG)	27,600*	25%	Vostochnyy coal pit
Shubarkol Komir JSC	Karaganda	ERG (100%), including: JSC "Eurasian Energy Corporation" (50%) SHK EURASIAN HOLDING B.V. (50%)			Central coal pit; Western coal pit
ArcelorMittal Temirtau JSC	Karaganda	ArcelorMittal	10,212	9%	Abayskaya, Saranskaya, Kazakhstanskaya, Shakhtinskaya, Tentekskaya, imeni Kostenko, imeni Lenina, imeni Kuzembayeva
Kazakhmys Coal	Karaganda	KCC B.V. owns 99.9%	7,681	7%	Borly (Molodezhny coal pit) and Kuu-Chekinsky coal pit
Karazhyra JSC	East Kazakhstan	E. Ogay (24.95%), V. Ogay (24.95%), E. Ogay (20.10%), V. Dzhumanbaev (20%), E. Nigmatullin (10)	6,427	6%	Karazhyra (formerly Yubileynoye)
Maikuben-West LLP	Pavlodar	Premier Development Company LLP	4,835	4%	Maikuben coal pit at Shoptykol deposit
Razrez "Kuznetskiy" LLP	Karaganda	Coal Holding Company PTE ltd (50%), Coal-Field Investment Company PTE Ltd (25%), Terra Mineralls ltd (25%)	189	0%	Kuznetsky coal pit

Entity	Oblast	Owner	2020 output (thousand metric tons)*	Share in Kazakhstan's total coal production	Mines
Firma "Rapid" LLP	Karaganda		148	0%	
Mining Company "Sat Komir" JSC	Karaganda	SAT & Company JSC	366	0%	Kumyskuduk coal pit at Verkhnesokursk deposit
Others		Companies including Ugolnyy Resurs, Angrensor Energo, Saykan, Madina	8,433	8%	
Total			**109,229**	**100%**	

Note: *Some 2020 output numbers are estimates; 27,600 thousand tons is the total output for all ERG entities (Vostochny JSC and Shubarkol Komir JSC).

Source: IHS Markit, Ministry of Industry and Infrastructural Development RK, Samruk-Energy

Figure 5.2 Average annual hard coal producer prices in Kazakhstan by region



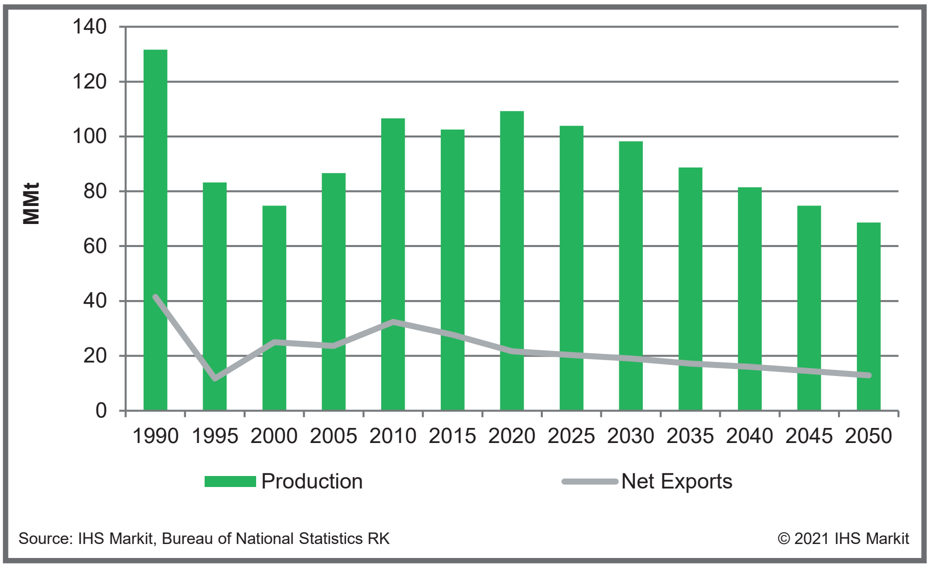
Source: IHS Markit, Bureau of National Statistics RK

According to the Ministry of Industry and Infrastructure Development, around 25 coal-producing entities operate in the country, although nearly three quarters of national output is concentrated at four operations administered by Bogatyr Komir LLP, Vostochniy JSC "Eurasian Energy Corporation," Shubarkol Komir JSC, and ArcelorMittal Temirtau JSC (see Table 5.3).[4] Kazakhstan's largest producer is Bogatyr Komir LLP, which mines the gigantic Bogatyr pit in the Ekibastuz Basin. In 2020, it produced 43.3 MMt, accounting for approximately 40% of national output. Bogatyr Komir is implementing a new "in-pit crushing and conveying system" (IPCC), including a stockyard and train loading station and a coal quality measuring system at the mine. The project will significantly reduce dust emissions as well as operating costs and is expected to be completed in 2022. The second-largest producing company is the Eurasian Resources Group (ERG), which accounts for about a quarter of national output through two holdings: Eurasian Energy Corporation JSC (EEC) and Shubarkol Komir JSC.

Three additional producers collectively account for little over one-fifth of production: the ArcelorMittal Temirtau Coal Company (underground mine production in the Karaganda Basin), Kazakhmys Coal LLP, and Maykuben-West LLP. In East Kazakhstan Oblast, Karazhyra JSC is responsible for about 6% of national output. An important factor affecting coal production in Kazakhstan are the prices that producers obtain when marketing their output in the domestic market. Partly because coal production costs, especially in large open-pit mines where large rotary excavators are used, are very low, the prices producers receive are also fairly low. Unlike other types of fuels such as natural gas, LPGs, electricity and heat, or even (indirectly regulated) refined products, Kazakhstan's coal prices are not directly regulated. However, the Ministry of National Economy and the Ministry of Trade and Integration monitor coal pricing and oversee trade, including sales on the commodity exchanges. Prices obtained by producers have generally increased over the period 2015–20 (see Figure 5.2 Average hard coal producer prices in Kazakhstan by region).

4 The State Statistics Agency, however, currently lists only 15 companies as engaged in coal-mining operations.

Figure 5.3 Kazakhstan's coal production and export outlook



Over the longer term, Kazakhstan's coal production is expected to decline, albeit slowly, reflecting challenges in increasing exports (see below), national commitments to reduce greenhouse gas (GHG) emissions, greater gasification and renewables penetration, and the high uncertainty that surrounds the development of coal-based chemicals and other alternative coal uses (such as coal gasification, synthetic liquid fuels production, and coal-water slurry). In the IHS Markit base case, coal output declines on average by 1.5% per year to 2050, reaching about 98 MMt in 2030 and 69 MMt in 2050 (see Figure 5.3 Kazakhstan's coal production and exports outlook).

5.4.2 Exports

Over the past decade, Kazakhstan has exported roughly one quarter of its annual production, although this share has been gradually shrinking. In 2010, exports were around 31% of output, but the share had fallen to around 25% mid-decade, and to only about 20-21% since 2018. In 2020 total exports amounted to 22.4 MMt, or 21% of production. However, the dip in 2020, about 3% year on year, was fairly modest compared with initial expectations at the onset of the COVID-19 pandemic (see Table 5.2). However, this number conceals diverging dynamics in different export markets.

Historically, Russia has been the primary export destination for Kazakh coal. In 2020, exports to Russia still accounted for 86% of total exports, or nearly 20 MMt of coal (down 2% year on year; see Table 5.4 Kazakhstan's coal exports by country (thousand metric tons)). Most of the Russian coal exports are from the Ekibastuz Basin, reflecting a historical arrangement whereby several power stations across the border in the southern Urals and West Siberia (Russia) were designed to burn Ekibastuz coal.[5] In addition, about 0.6 MMt/y of coking coal from the Karaganda Basin was exported to iron and steel plants and other industrial facilities in Russia in 2020.

Not surprisingly, the other countries of the Former Soviet Union (FSU) outside Russia represent the second-largest export destination for Kazakh coal exports, accounting for 12% (or 2.8 MMt) of total exports in 2020.[6] Exports of Kazakh coal to these countries actually increased by an impressive 39% in 2020, albeit from a small base. Kazakhstan exported about 0.9 MMt of coal each to Kyrgyzstan and Ukraine in 2020, and another 0.9 MMt to other FSU states (namely Belarus and Uzbekistan).[7] Exports to Ukraine would likely have been even larger if it were not for a dispute with Russia over coal transit to Ukraine (see below). ArcelorMittal also exports about 800,000 metric tons of coking coal to its steel plants in Ukraine.

Outside the FSU, Kazakh coal exports fell dramatically, by 81%, in 2020 and amounted to only about 0.3 MMt, or a mere 1% of total exports. China was the largest importer of Kazakh coal in the non-FSU category at nearly 0.2 MMt in 2020, a fourfold increase versus 2019. Still, this increase could not offset declines in exports to Europe – Switzerland and Cyprus, in particular – even as Kazakhstan increased exports (in small volumes) to other European countries (the United Kingdom, Greece,

5 Currently, Russia's Reftinskaya GRES, Troitskaya GRES, Omsk TETs-4, and Omsk TETs-5 power stations use imported Ekibastuz coal.

6 Kazakhstan's statistics uses the term CIS (Commonwealth of Independent States) in referring to these countries collectively, even though Ukraine and Georgia withdrew from the organization some time ago, and Turkmenistan is not a full member.

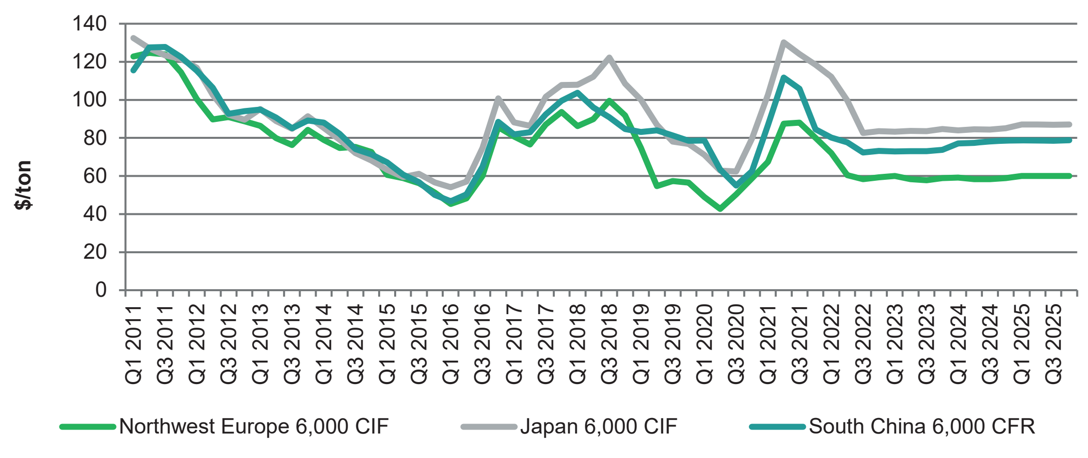
7 Coal exports to Belarus likely were ultimately destined for Ukraine, as Belarus does not have any coal-fired generation of its own.

Table 5.4 Kazakhstan's coal exports by country (thousand metric tons)

	2017	2018	2019	2020	Share in total exports	Percent change, 2019–20
Russia	20,905	19,608	19,776	19,353	86%	-2%
Kyrgyzstan	1,075	928	744	957	4%	29%
Ukraine	404	371	790	905	4%	14%
Belarus	158	188	356	695	3%	95%
Uzbekistan	65	109	122	235	1%	93%
China	–	1	39	173	1%	341%
Poland	5	41	22	53	0%	139%
United Kingdom	18	18	5	11	0%	133%
Turkey	–	15	11	5	0%	-52%
Greece	–	–	–	3	0%	
Georgia	1	–	3	2	0%	-18%
Latvia	–	28	12	2	0%	-83%
Azerbaijan	1	1	–	–	0%	
Moldova	2	1	–	–	0%	
Cyprus	181	191	447	–	0%	-100%
Finland	3,450	695	–	–	0%	
Switzerland	761	1,184	774	–	0%	-100%
Japan	108	9	–	–	0%	
Total exports	**27,136**	**23,387**	**23,101**	**22,395**	**100%**	**-3%**

Source: IHS Markit, Bureau of National Statistics RK

Figure 5.4 Quarterly average international thermal coal spot prices and medium-term outlook



Source: IHS Markit

Poland).[8] Lower exports to Europe in 2020 were largely due to lower demand from the pandemic and record low coal prices mid-2020, when even the most competitive global coal producers had to shut in production (see Figure 5.4 Quarterly average international thermal coal spot prices and medium-term outlook).

8 Exports to Europe tend to be limited to Shubarkol coal, which meets Europe's specifications for ash and sulfur content and heating value.

However, Kazakh coal exports to Europe had been waning even before the 2020 pandemic, pressured by low natural gas prices, higher renewables generation, and overall European climate policies to eliminate coal generation and associated GHG emissions (see Chapter 2). Additionally, Kazakh coal is challenged by its high moisture, ash, and sulfur content, which limits its ability to be exported to many markets. Transportation costs from landlocked Kazakhstan are also significant. Kazakhstan's coal exports to non-CIS countries between 2017 and 2019 contracted by 70%. Finland, one of the largest coal export destinations, imported about 3.5 MMt of Kazakh coal in 2017, but stopped imports completely in 2019.[9]

In addition to the general market factors weighing upon Kazakhstan's coal exports, two special situations involving transit through Russia have impeded trade in recent years with third-country customers.

Dispute over coal transit to Ukraine

In June 2019, a dispute emerged between Kazakhstan and Russia over Kazakh coal being shipped by rail across Russia to Ukraine. In that month, Russia instituted a system restricting coal shipments via its territory through a permitting system. The issue developed against a backdrop of worsening relations between Russia and Ukraine that eventually extended to coal trade. From 1 June 2019, in response to additional sanctions imposed by Ukraine on Russian companies, officials, and goods, Russia imposed a permit-controlled export regime for Russian coal deliveries to Ukraine and began applying the same sort of permit restrictions on Kazakh transit coal as well.[10] Kazakhstan argued that such restrictions were not applicable to transit coal and other transit cargo according to the basic principles of the Treaty on the Eurasian Economic Union (EAEU), which is supposed to ensure the freedom of transit of goods. In practice, the restrictions began to be applied to Kazakh transit coal destined for Ukraine almost immediately (from July 2019). In October 2019, the Eurasian Economic Commission concluded that Russia was creating obstacles to Kazakh coal transit counter to the rules governing the EAEU market.[11] Rather than lifting the restrictions, Russia agreed to increase Kazakhstan's monthly quota for coal transit to Ukraine from 90,000 metric tons per month (imposed since July 2019) to 140,000 metric tons per month. However, at the time, Minister of Trade and Integration of the Republic of Kazakhstan, Bakhyt Sultanov, remarked that the proposed allotment still did not cover the transit volumes requested by Kazakh coal exporters. Given the complex political factors involved, the issue of coal transit to Ukraine is likely to remain an underlying impediment in this trade going forward.

Persistent port and railway bottlenecks, especially in the Russian Far East

Even before the dispute over Ukrainian transit coal came to the fore, Kazakhstan had been trying to work out an arrangement with Russia for Kazakh coal to reach Europe and Southeast Asia by accessing coal-loading facilities at Russian ports.[12] In 2017, Kazakhstan proposed an arrangement that would facilitate such access, but Russia ultimately rejected it, and the compromise that was offered ultimately went nowhere. Later, in 2018, the two countries again failed to sign an agreement on any additional transportation guarantees for Kazakh coal to move across Russia and out to export markets via Russian seaports.[13] Russian coal producers and regulators have argued that Kazakh coal already is subject to the same rules as Russian coal. Therefore, offering any additional guarantees would effectively discriminate against Russian producers. Conversely, Kazakh coal producers point to the lack of clearly defined rules stipulating access to services in seaports, which results in a lack of guarantees from month to month that their coal will be shipped and not blocked in favor of Russian coal or for other reasons. Capacity at the coal export terminals has been constrained, so there is real competition between Russian and Kazakh coal shipments for export loading capacity.[14] In addition to clogged ports, rail infrastructure more broadly in Russia presents another potential chokepoint for Kazakh coal transit. Although the EAEU Treaty clearly stipulates equality of access to rail infrastructure and services, transportation capacity along some of the main rail routes to Russia's eastern seaboard continues to be limited, and its expansion remains one of the key priorities of the long-term development program

9 By 2029, Finland plans to ban coal use for energy generation (heat and power), likely implying no coal imports at all.

10 The new regime required that exports of certain goods into Ukraine (including coal and selected oil products) be specifically approved by Russia's Ministry of Economic Development.

11 According to the Association of Mining and Metallurgical Enterprises of Kazakhstan (AGNP), between July and October of 2019 Kazakh shippers applied for permits to ship 716,000 metric tons of Kazakh coal to Ukraine, but less than half of this volume (320,000 metric tons) qualified for permits to transit Russia. Kazakhstan estimates the resulting monthly losses for the country's enterprises at $11 million.

12 With the creation of EAEU in January 2015, exports of Kazakhstan's coal (and other goods) in the eastern direction became economically feasible (at least in theory) because of the applicability of Russia's unified internal rail tariffs to Kazakhstan's goods transiting to third countries, including via Russian seaports.

13 In 2018, Russia approved a request from a Kazakh company to take 50% control of the Port of Vysotsk coal stevedore, near St. Petersburg, with a capacity of 8 MMt/y. In 2020, the Port of Vysotsk handled 6.8 MMt of coal exports.

14 See the IHS Markit Strategic Report *Russia Watch: In search of new demand: Russian energy producers restrategize as market challenges multiply,* 15 January 2020.

of the Russian Railways corporation (RZD). Over the past decade the Russian coal industry has undergone a major reorientation toward export markets in general, and Asia in particular, as domestic coal consumption has declined; this has been accompanied by considerable modernization and expansion.[15] This has put pressure on several points along existing rail infrastructure going east at the same time as Kazakhstan's coal producers have also been looking to grow exports in that direction. Russia's rail export capacity to the west does not appear constrained to the same degree. RZD readily adjusts its rail rates (in the range allowed within its purview) for coal according to prevailing export prices (in Europe) and margins earned by coal exporters. In prior years, RZD offered lower rates on rail to certain western ports to encourage shipments in that direction. For example, in 2019, to attract rail deliveries to ports on the Baltic Sea and Poland, RZD offered a steep discount (up to 60%) on tariffs for Kazakh thermal coal exports in those directions. However, the reality is that demand has shifted toward the east (Asia), and the capacity allocated for Kazakh coal going west has remained underutilized.

Thus, as problems with transit to Ukraine emerged in the second half of 2019, representatives of Kazakhstan's coal industry appealed directly to Kazakh Prime Minister Askar Mamin for intergovernmental assistance, in negotiating with Russia to facilitate greater access to markets in Southeast Asia, India, Japan, and South Korea. In September 2019, the presidents of Kazakhstan and China announced a preliminary transit agreement for Kazakh coal (up to 2 MMt/y) to move by rail through the Dostyk/Alashankou border crossing via mainland China on to the port of Lianyungang for further export to Southeast Asia.[16] However, export statistics do not report any coal exports to Asia (other than China) over the past two years. The COVID-19 pandemic most certainly complicated any possible shipments along this route: during 2020, China significantly restricted train traffic from Kazakhstan to China and in March 2021, Kazakh Railways instituted a ban on trains going to China via the Dostyk/Alashankou border crossing in order to alleviate a backlog of train cars at the border.[17]

Export outlook clouded by challenges to competitiveness

Over the longer term, Kazakhstan's coal exports are projected to decline, albeit slowly, reflecting a general retrenchment in global coal demand; we forecast them to contract to around 19 MMt/y in 2030 and 16 MMt/y in 2040 (see Figure 5.3). There is concern about a more rapid weakening of Russian demand for Kazakh coal (by the mid-2020s) given that some of Russia's generating capacity designed to burn Ekibastuz coal is becoming obsolete and in need of replacement. Additionally, Russian coal producers, particularly from the Kuznetsk Basin, are eager to supplant Kazakh imports, not to mention the significant inroads made by Russia's natural gas in the region. Still, we expect that given its intrinsic economic competitiveness, Kazakh coal will be able to maintain this market over the next decade or even longer. It will take time to carry out upgrades to this generation capacity, which likely will need to be done one plant at a time. Kazakhstan has ambitions to export more coal to China, although this is challenged not only by the relatively low quality of the coal, the difficult logistics, and the high cost of transport (China's main coal consumption centers are in the east, while its own coal is mined inland, in western China), but also by China's own abundant coal reserves and the expectations of peak coal demand in China as early as 2025, given a moderation of economic growth, environmental concerns, and structural change in the economy. Further, Xinjiang Province, which borders Kazakhstan and is closer to China's major eastern demand centers, is expected to become the second-largest net coal exporting region in the country. Finally, coal demand is gradually moving closer to the mine mouth (to northern and western China), facilitated by sending coal-fired power via ultrahigh-voltage (UHV) transmission lines to other regions. One option for Kazakhstan that merits further consideration is the export of higher value-added (and lower-bulk) coal products (tar, gases, solvents, and activated charcoal) that can better withstand the relatively high transportation costs to this market.

Exports to Europe are constrained by poor coal quality, long transportation distances, and plummeting demand for coal. Only Shubarkol coal meets the European Union requirements for ash content and calorific value, and so the prospects for greatly expanding thermal coal exports appear quite limited.[18] Low European gas prices and higher recent EU Emissions Trading System (ETS) (carbon) prices in Europe have kept gas quite competitive with coal in power generation.[19] In 2020, for the first time in European history, more power was generated from renewable energy sources (38%) than from fossil fuels (37%), driven by a ramp-up in new solar and wind power projects. While there are no official updates to Europe's coal phase-out schedule in light of COVID-19, several coal-fired plants in Spain and Italy have closed

15 See the IHS Markit Strategic Report *The "new economics" of Russian coal,* August 2007.

16 The port of Lianyungang lies near the mouth of the Qiangwei River in northern Jiangsu Province in eastern China.

17 In November 2020, the number of trains admitted from Kazakhstan into China fell by about a third compared with a year before, from 16 to 11 trains per day.

18 Kazakh industry officials indicate that they could produce up to 14 MMt/y of Shubarkol coal.

19 See the IHS Markit Market Briefing *European competitive fuel price report,* March 2021.

down earlier than planned as plants struggled to remain profitable amid the pandemic. And even though there will likely be some post–COVID-19 demand recovery, the European demand loss should be viewed as essentially permanent.

Regionally, there is some potential for increasing exports to neighboring markets in Central Asia, such as Uzbekistan and Kyrgyzstan, as both countries plan to maintain or even slightly grow coal-fired generation in their overall generation mix. Coal exports to Ukraine could clearly increase, as well, if the transit disagreement with Russia is resolved; but export potential is still rather limited given the overall logistics and specific properties of Kazakh steam coal. Finally, although coal demand in South Asia (Pakistan, India) is expected to remain resilient, any potential Kazakh exports to these markets will face strong competition from such global seaborne exporters as South Africa (providing nearly two-thirds of Pakistan thermal coal imports in 2020), Indonesia (62% of Indian imports), Australia, Russia, and the United States.

5.5 Global Coal Demand Overview

Globally, coal demand is expected to grow slightly in 2021 and 2022 (to ~6.26 billion tons in both years) over depressed levels in 2020 (6.11 billion tons), as many national economies return to growth after an aggregate 3.5% decline in global GDP in 2020 due to the COVID-19 pandemic. However, the recovery is expected to be constrained and uneven, both as a result of renewed spikes in infections associated with new variants of the virus (e.g., in East Asia, South Africa, and United States) as well as idiosyncratic developments in particular markets. A primary example of the latter is a trade dispute between China and Australia, with the Chinese government imposing restrictions on the import of Australian thermal and metallurgical coal (as well as other commodities) starting in the autumn of 2020. In response to the ongoing dispute, Australia thus far has (successfully) diverted its coal to other markets (especially India), whereas China has managed to secure adequate supplies from alternative suppliers, such as Indonesia – although production bottlenecks there (due to heavy rainfall) and in Colombia and South Africa have contributed to near-term tightness of supply globally. The re-orientation in trade flows has clouded the near-term demand growth picture and reverberated through a market that clearly faces challenges.[20]

20 IHS Markit *Steam Coal Forecaster,* April 2021.

It should be remembered that suppliers had no issue in 2019 with meeting even higher total demand levels (6.42 billion tons), and there were only a handful of mine closures globally in 2020. Thus, given that there has been little change in global production and export capacity, once near-term supply bottlenecks are overcome and inventories normalize, it is difficult to see how the supply side could not accommodate the expected demand growth going forward.

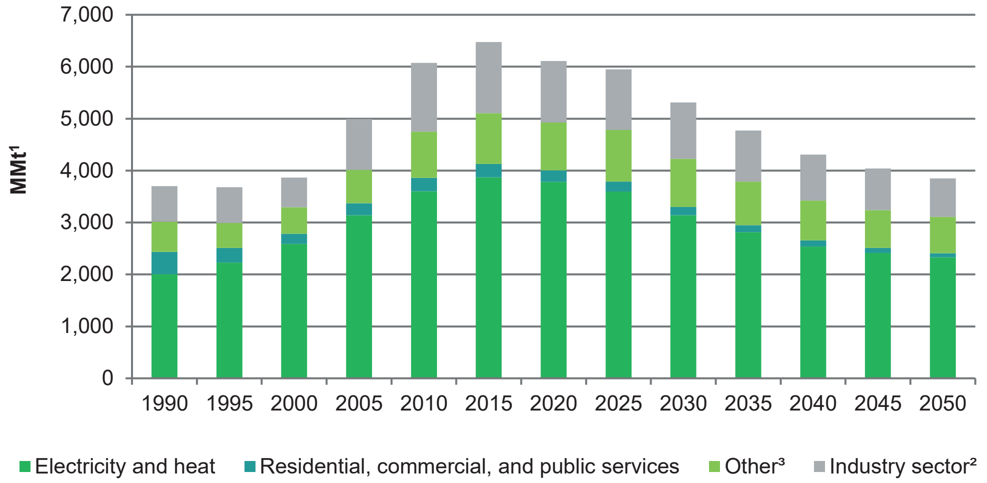
Further, according to the new IHS Markit base-case scenario (Inflections), after 2022 coal demand is expected to decline steadily – from 5.95 billion tons in 2025, to 5.31 billion in 2030, to 4.31 billion tons by 2040 – driven primarily by a lower outlook in a number of key demand centers, namely Europe, Japan, South Korea, Taiwan, India, and even mainland China.[21] Although the stories will differ by country, competition with other energy sources and deliberate limits on consumption are expected to substantially lower overall demand, particularly in the electric power sector where pressures to lower GHG emissions will arise earliest and be most intense (see Chapter 2). IHS Markit projects global power sector demand for coal will be nearly 20% lower in 2030 than at present and more than 35% lower in 2040 (see Figure 5.5 Global coal demand by sector).

5.6 Coal Transportation

Rail transportation tariffs in Kazakhstan are regulated by the Committee for the Regulation of Natural Monopolies of the Ministry of National Economy of the Republic of Kazakhstan (KREM), with tariffs for coal typically set lower than the average for all rail-transported goods, given coal's significant share (25%) in the overall volume of rail shipments and its status as a socially important good. The rail transportation tariff includes three components: services related to the provision of railway infrastructure for transportation, locomotive traction services, and provision of wagons (freight cars). Rail transportation services are regulated and from 2021 are differentiated by route type (electrified or not), whereas rail car services were deregulated in 2017. Locomotive traction services are regulated, but from 2021 there are differentiated tariffs

21 For the outlook in each of these demand centers, see IHS Markit Global Steam Coal Market Service *Thermal coal seaborne imports and exports outlook to 2050,* June 2021. As described in Chapter 1, the Inflections scenario portrays a world that is responding more proactively than our previous base-case scenario (Rivalry) to key turning points in international geopolitics, national political and economic priorities, business and individual behaviors, and the financial criteria of investors and lenders. The COVID-19 pandemic is seen as an "accelerator" of many of these changes, some of which had been under way for some time, but have become primary drivers of global political, economic, and business affairs now and in the years to come.

Figure 5.5 Global coal demand by sector



Notes: (1) 6,000 kilocalorie per kilogram energy content. (2) Includes feedstocks. (3) Includes energy sector uses, distribution losses, and statistical differences. Negative numbers may indicate use of synthetic fuels.

Source: Historical data from the International Energy Agency, projections from IHS Markit © 2021 IHS Markit

for different traction types (electrified/non-electrified) as well as by fuel types. According to Kazakhstan Temir Zholy (KTZ) – the Kazakh national rail company – the tariff for locomotive traction using oil products (diesel) exceeds that for coal by 4.6 times. In December 2020, KREM approved new tariffs on cargo shipments by rail for 2021–25, indicating that the average tariff will increase by 13% in 2021, with coal and grain tariffs increasing by only 4–6% (basically in line with projected inflation).[22] Additionally, within KTZ, freight operations have been officially separated from passenger transport; the cross-subsidy that passenger shipments receive is now explicitly identified. In 2021, it is expected to be 55 billion tenge ($128 million).

5.7 Domestic Coal Consumption

Kazakhstan's economy heavily depends on coal; in 2020 coal still accounted for 56% of the 92 million metric tons of oil equivalent (MMtoe) of primary energy consumed in the country (see Figure 5.6 Outlook for Kazakhstan's primary energy consumption by fuel to 2050). Even as the country continues its gasification agenda and other initiatives toward fulfilling its Paris climate accord and energy transition goals, coal is expected to remain an important energy source for the economy, and particularly for lectricity generation through 2040.[23] In the IHS Markit base-case outlook, the share of coal in Kazakhstan's primary energy demand declines to approximately 51% in 2030 and 42% in 2040, giving way to more use of natural gas, renewables, and even nuclear (after the mid-2030s). In 2020, the share of gas in primary energy consumption was only 23%, ranking second in importance after coal, followed by oil and petroleum products (17%). Meanwhile, primary electricity (mainly hydropower, but increasingly wind and solar as well) and other minor fuels constituted the remaining 3% of primary energy consumption in 2020. By 2040, IHS Markit projects that the share of natural gas will increase to 29%, while primary electricity's contribution (by then incorporating nuclear power) will rise to about 7% of primary energy demand.

Kazakhstan's apparent coal consumption (production minus exports plus imports, including delivery and processing losses) has fluctuated over the past decade in a band between 74 MMt/y and 92 MMt/y. In the past three years, consumption declined slightly, from 91.6 MMt in 2018 to 87.4 MMt in 2020 (see Table 5.2). Electric power stations are the largest consumers of coal, accounting for roughly 70% of total coal consumption in 2020 (see Figure 5.7. Kazakhstan's apparent coal consumption by sector, 1990-2020).[24] The other major coal consumer is the industrial sector, particularly metallurgy/coking, accounting for roughly 20% of total

22 In 2020, Kazakhstan's inflation rate was 7.5% and for 2021 the target is 4-6%, although this is looking increasingly difficult to achieve. IHS Markit now projects 2021 inflation at 7.1%.

23 See the IHS Markit Strategic Report *A progress report on Kazakhstan's gasification program,* 4 November 2020.

24 Coal-fired generation accounted for 68% of total electricity generation in 2020. However, this share has been gradually declining, partly because of the expansion of gas-fired generation in western and southern Kazakhstan.

Figure 5.6 Outlook for Kazakhstan's primary energy consumption by fuel to 2050

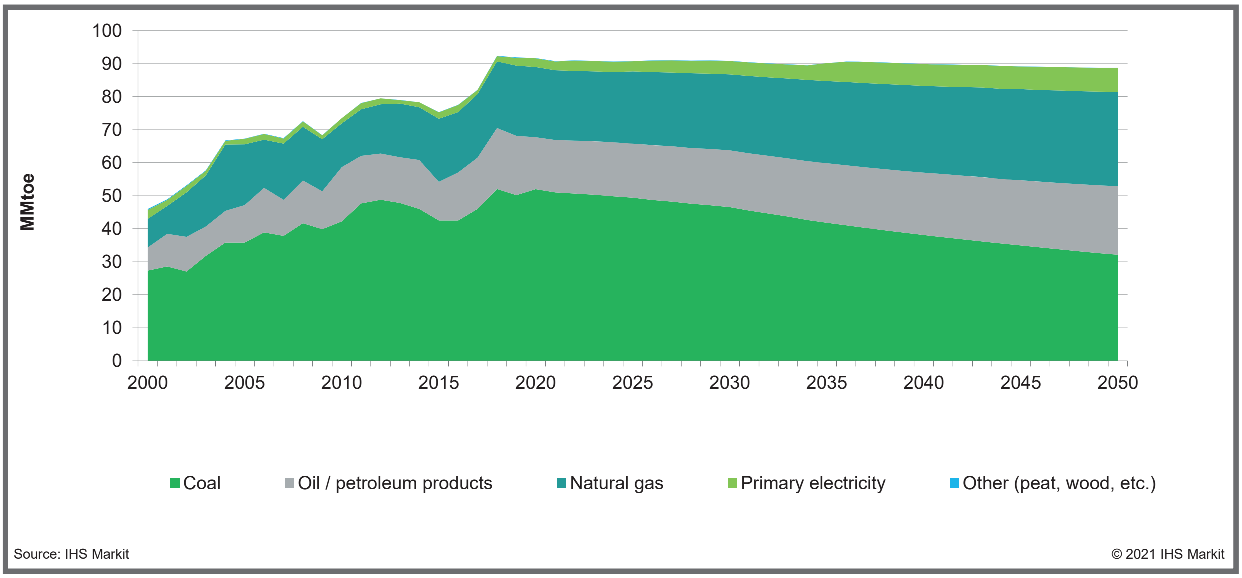
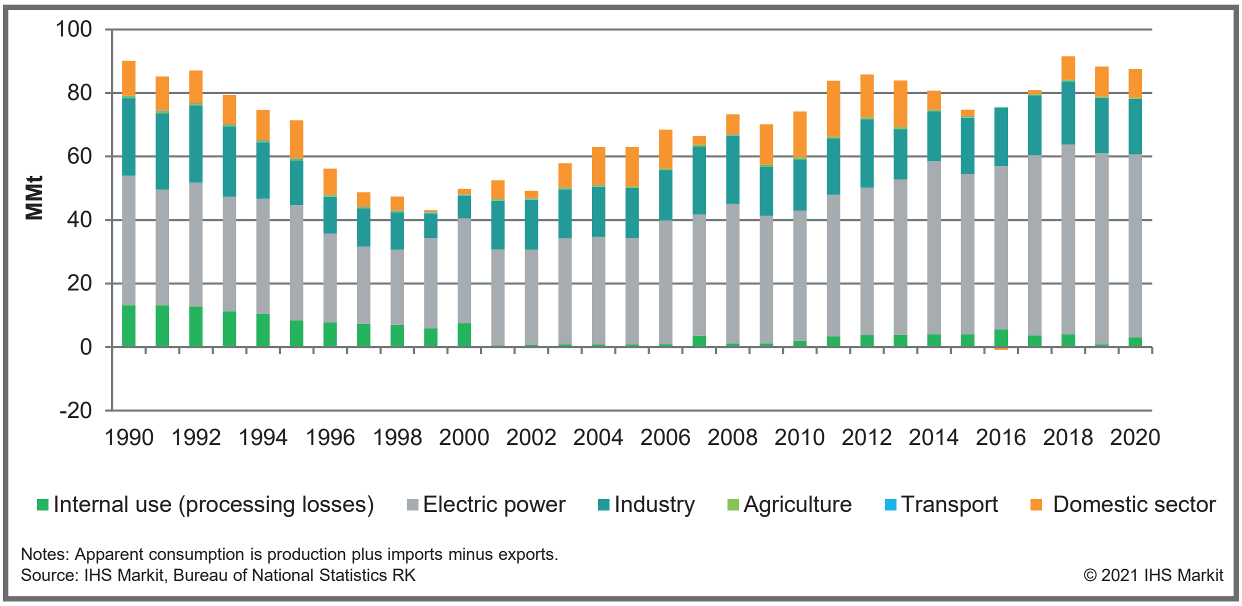


Figure 5.7 Kazakhstan's apparent coal consumption by sector, 1990-2020



demand. The share of the household and commercial sector in total consumption has declined considerably over the past decade: as recently as 2010, the sector accounted for about 20% of domestic coal demand, but in 2020 this share had fallen to about 10%. In 2020, actual coal consumption by the residential sector is estimated at around 9 MMt. Coal consumption historically has been supported by favorable prices for industrial and residential end-users. Coal purchase prices for power generation and industrial consumers are typically negotiated directly between the buyer and seller. Prices for residential and commercial consumers are determined largely (about 90%) via sales through 18 commodity exchanges; prices for residential consumers are considerably higher than for higher-volume consumers in industry (see Figure 5.8. Average annual hard coal prices for industry and residential consumers in Kazakhstan). Consumer prices reflect the low mine-mouth prices as well as rail transportation and fees (including rolling stock charges and insurance), or in the case of purchases on commodity exchanges, additional expenses such as distribution margins for wholesale and retail intermediaries that may include truck transport from the railway station to the consumer.[25]

25 According to the Ministry of Industry and Infrastructure Development, mine-mouth coal prices range between 2,000 and 6,000 tenge ($4.65–13.95) per metric ton.

Figure 5.8 Average annual hard coal prices for industrial and residential consumers in Kazakhstan

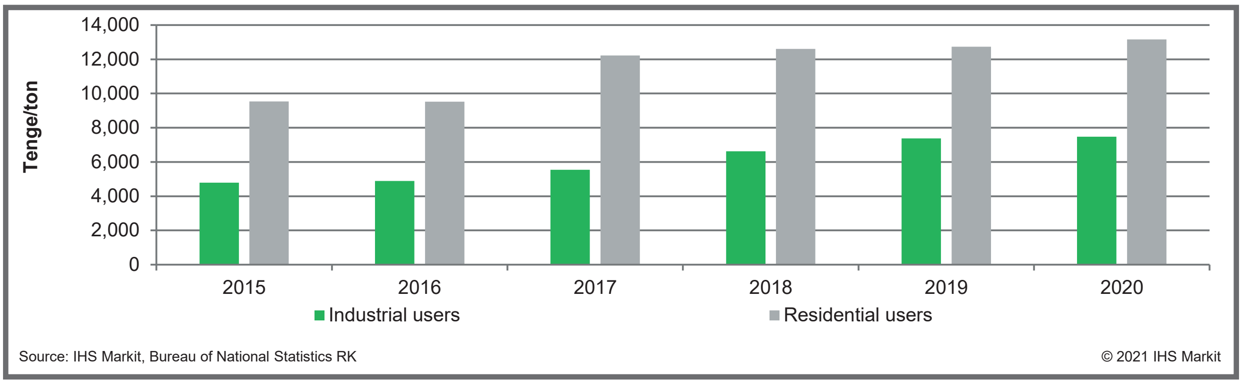
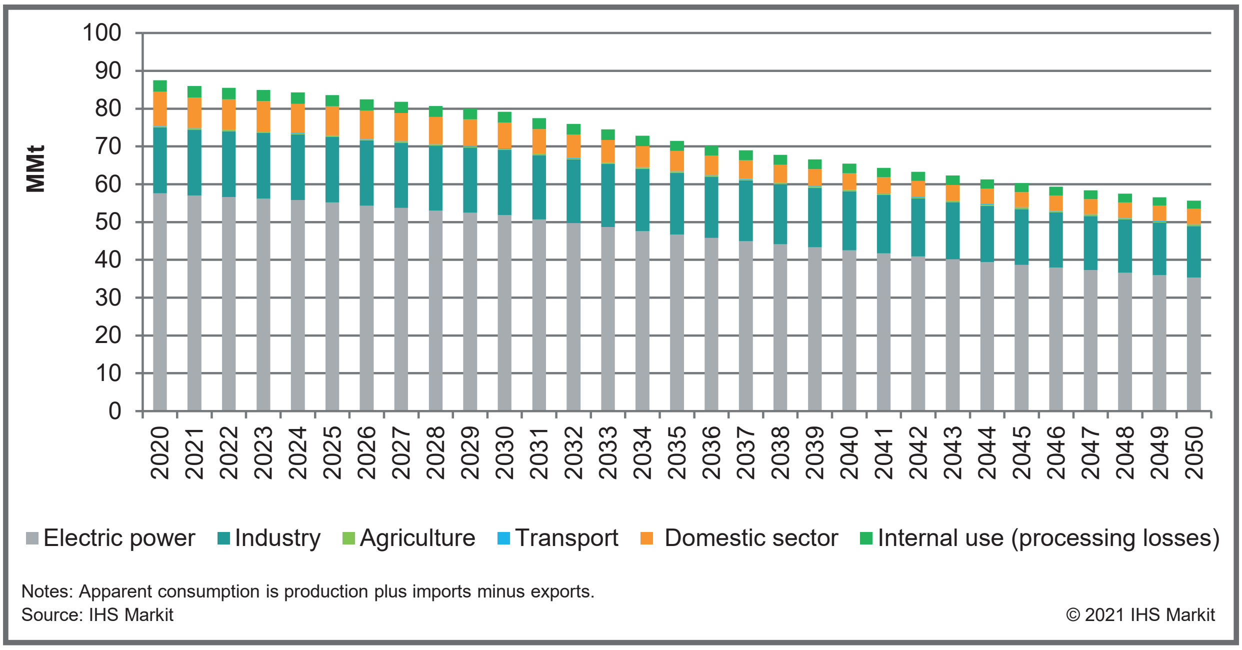


Figure 5.9 Outlook for Kazakhstan's apparent coal consumption by major sector, 2020-50



KREM regularly investigates any unusual spikes in coal prices for residential consumers. There have been periodic discussions between the coal industry and the government on directly regulating coal prices for residential consumers, aiming at keeping residential user coal price dynamics in check and prices for end users affordable. But so far, such action has not been necessary. Longer term, apparent coal consumption is expected to decline annually by around 1.5% on average through 2050 and reach about 56 MMt (see Figure 5.9. Outlook for Kazakhstan's apparent coal consumption by major sector, 2020-50). Coal consumption by the power sector likely already peaked in 2018–19 at about 60 MMt. We expect that coal demand in the sector will decline going forward, by around 1.7% annually on average to 2050, to reach about 35 MMt/y; other energy sources (natural gas, renewables, and nuclear) are expected to gradually displace coal in overall generation. Still, power sector coal demand will continue to be significant within overall national coal consumption, with its share remaining relatively steady at around 66%.

Coal consumption by industry (which mainly comprises coking in metallurgy) is forecast to decline only modestly (by around 0.8% annually) through the end of the forecast period (2050). This is likely to be accompanied by the growing use of other fuels (e.g., natural gas) in industry as well. Consumption in the residential-commercial sector will almost certainly decrease, with consumers switching to natural gas (as a result of further gasification) or to liquefied petroleum gases (LPGs) or electricity when possible, mainly for convenience, as has been the case in other industrialized countries. The share of the residential-commercial sector in Kazakh coal consumption is projected to decline steadily, from around 10% of the total in 2020 to less than 8% in 2050.

5.8 Coal Balance Outlook for Kazakhstan

Projections of Kazakhstan's coal balance out to 2050 reveal several important trends. Coal production steadily declines from the current levels of 109 MMt to 69 MMt in 2050. Apparent consumption follows a similar trajectory, falling from 87 MMt in 2020 to 56 MMt in 2050. These trends are consistent with an outlook for an economy that is gradually utilizing energy more efficiently, slowly increasing its gas consumption, and adding renewable and some nuclear generation capacity in the electric power sector (around 2035). Indeed, one of the key global trends observed in recent years inhibiting the growth in coal demand has been the declining energy intensity of economic growth, whereby lower rates of energy consumption come with GDP growth. This dynamic has been established for some time in the developed world, but is now extending to the developing world as well. China's coal demand barely increased (1.5%) over the years immediately preceding and during the early days of the pandemic (2017–19), despite nominal GDP growth over the same period of 16%; over the same period, India's growth in coal consumption, although substantial (6.7%), was outpaced by economic growth (8.9%). In these and other countries, among the more important explanatory factors are structural economic change (from heavy industry toward services), the use of more energy efficient devices (e.g., home appliances, LED lighting), switching from low-calorific to cleaner-burning fuels in the domestic sector (e.g., from coal, peat, and wood to LPGs and natural gas), and incipient solar energy adoption (see Chapter 2). In Kazakhstan, the balance of coal production and consumption appears to be closely linked to electric power generation for the foreseeable future. This reflects the inertia built into the structure of the electric power sector (where 69% of capacity is coal-fired). Even with the continued gradual growth in gas-fired power generation and the phasing in of some renewable and perhaps nuclear capacity, coal will remain the dominant fuel in the power sector through the end of the outlook period.

5.9 Notable Changes in Kazakhstan's Coal Industry since 2017

A number of important developments in the coal segment have occurred since publication of KAZENERGY's *National Energy Report 2017* that warrant some mention.

5.9.1 Cancellation of rent tax on coal exports and MRET adjustment ease process of EAEU integration

In December 2020, Kazakhstan's president signed a number of amendments to the Tax Code.[26] One of these included a cancellation of a 4.7% rent tax on coal exports, while at the same time, the mineral resource extraction tax (MRET) on bituminous coal and lignite was raised from 0% to 2.7%.[27] These amendments represent a major change for Kazakhstan, which since 2015 had resisted calls from the Eurasian Economic Commission (EEC) to cancel the rent tax on exports to EAEU countries, as it was viewed as a barrier to intra-bloc trade. Kazakhstan had insisted that the rent tax was not a duty but merely a means of taxation within the country, as the MRET rate was set at zero. Instituting MRET enables the government to recapture some of the revenue that will be lost due to nullification of the export rent tax. While the rent tax regime applied only to coal exports, the MRET now applies to all production volumes. Use of the special coefficients to regulate the MRET rates that apply to coal used in the domestic market essentially maintains prior taxation levels.

5.9.2 Roadmap for Kazakhstan's coal industry re-orients the focus to "deep" value processing

Kazakhstan's coal industry is attempting to re-invigorate its development and attract new investment. One focus has been on changes in the Tax Code, as described above, although thus far the impact has been limited. An additional step was taken in 2019, when Kazakhstan adopted the "Roadmap for the Development of the Coal Industry of the Republic of Kazakhstan for 2019-21" (the Roadmap), which includes measures to support industry development and implementation of new projects, largely focused on technological modernization. There seems to be industry-wide agreement that the future of Kazakhstan's coal industry lies in developing new applications with deeper coal processing, especially in coal-based chemicals. Kazakhstan's government is supportive of the development of "value-added" coal-based products. In 2020, it included coal enrichment in the list of activities designated as priority investment projects; these projects are to receive several tax breaks including reduced corporate income tax, land tax,

26 Law of the Republic of Kazakhstan dated 10 December 2020 No. 382-VI 3PK.

27 In certain cases, covering most domestic uses of coal, a decreasing coefficient of 0.01 applies to MRET; for more details see http://.adilet.zan.kz/rus/docs/Z2000000382#z2059

and property tax. Speaking at the first Coal Industry Forum in June 2019, Deputy Prime Minister Zhenis Kassymbek noted the importance of the coal industry to Kazakhstan's energy independence. He also stressed that the government plans to pursue a purposeful policy of stimulating "deep complex processing of coal" to obtain products with high value-added.[28] The 2019–21 Roadmap seeks to clarify and advance the future of Kazakhstan's coal industry, including increasing opportunities for coal exports, improving coal quality, and focusing on advanced coal processing and creation of value-added products. Although it conspicuously lacks details on the industry's plans to adjust to energy transition initiatives, the Roadmap does call for a careful analysis of proposed environmental legislation and its impact on the coal industry. The Roadmap also calls for identifying ways to reduce coal prices for domestic consumers, mainly by cutting out various trade intermediaries. For instance, it envisions the introduction of a digital platform for coal sales to residential consumers, spearheaded by the Association of Mining and Metallurgical Enterprises (AGMP).[29] Among the projects listed by the Roadmap as major initiatives toward the industry's modernization are:

- Construction of a semi-coking plant by Shubarkol Komir to fully supply its parent company Eurasian Resources Group's ferroalloy production operations
- Implementation of an IPCC system by Bogatyr Komir (mentioned above), including a stockyard and train loading station and a coal quality measuring system at the Bogatyr mine, the country's largest
- Construction of a coal concentrate preparation complex at Bogatyr Komir's Severny mine by 2024[30]
- Plans by Shubarkol Premium (unrelated to Shubarkol Komir) to carry out research and experimental work on processing coal into liquid hydrocarbons (diesel)
- Installation of a two-stage enrichment system at ArcelorMittal's Vostochny Central Processing Plant to increase production of coal concentrate
- A project for coal mine methane utilization by ArcelorMittal Temirtau (see below)[31]

Although it is not included in the Roadmap, another project – a new coal enrichment plant by Qaz Carbon in Karaganda Oblast to produce high-quality coal concentrate with low ash content using "wet washing technology" – is also close to realization. The plant, with a capacity of 1.8 MMt/y, is expected to launch later in 2021 and will mostly supply the Karaganda Ferroalloy Plant (operated by YDD Corporation), with the remaining output being exported.

Currently, several companies are making coal-based products and chemicals in Kazakhstan:

- Shubarkol Komir's coke plant produces semi-coke, coal tar, and coke-oven gas.
- ArcelorMittal Temirtau's coke plant produces a similar slate of products.
- ArcelorMittal Temirtau also produces naphthalene, pitch, solvents, and ammonium sulfate as coking byproducts.
- In 2020, Shubarkol Komir JSC turned out the first trial batch of activated carbon (activated charcoal).

5.9.3 New Ecology Code

Another new development with which the coal industry must contend involves the new Ecology Code that came into effect on 1 July 2021. Although the Ecology Code appears to pose more of a problem for large consumers of coal, such as coal-fired heat and power plants, there are implications for coal producers as well. Under the Code, remediation requirements for industrial facilities that have significant impact on the environment have become more stringent. The largest stationary emitters in the country included in the group of "Category I" enterprises (responsible for 80% of total atmospheric emissions monitored by the Ministry of Ecology, Geology, and Natural Resources [MEGNR]) are required to obtain mandatory integrated environmental permits (IEP) by 2025 that stipulate a commitment to implement "best available technologies" (BAT) by 2035.[32] Category I emitters that consume coal include:

- Thermal power plants and other heating units with capacity of over 300 megawatts (MW)
- Installations for gasification or liquefaction of coal with a capacity of 500 metric tons per day or more
- Installations for thermal or chemical processing of coal (or bituminous shale), including the production of carbon by high-temperature carbonization (dry distillation) of coal or electrolytic roasting (graphitization)

28 See the Association of Mining and Metallurgical Enterprises (AGMP) Portal, www.agmpportal.kz, accessed 20 April 2021, https://agmpportal.kz/budushhee-ugolnoj-otrasli-za-glubokoj-pererabotkoj/.

29 Established in 2015, the AGMP is the largest industrial association in Kazakhstan, with more than 100 companies spanning a wide array of industries from ferrous and nonferrous metallurgy, uranium mining, to coal mining.

30 Plans call for exports of 1 MMt/y of high-quality coal concentrate in 2024–25, with the volume increasing to 3.4 MMt/y from 2026.

31 On 12 March 2021, a Working Group on alternative energy sources for electric power generation was established within the Ministry of Energy, which includes coalbed methane, hydrogen, and industrial gases as areas for active consideration; a draft law on the initiative is expected in 2022.

32 For Category I enterprises below the "top 50," BAT programs (and obtaining the IEP) should be completed by 1 January 2035. By year-end 2021, 97 Category I enterprises, including the so-called "top 50" largest emitters, are expected to complete their integrated technological audits (see Chapter 2).

5.10 Considerations relating to BAT in Coal Mining

While coal's preeminent contribution to Kazakhstan's total GHG and atmospheric emissions stems mainly from its combustion in power and heat generation, coal mining (both underground and surface) also renders significant ecological impacts, including air quality, solid waste disposition, and wastewater handling. Coal mining's largest contribution to GHG emissions probably stems from the release of methane (CH_4) rather than on-site fuel use, that escapes from mines and stockpiles during mining, transportation, and enrichment of coal.

Yet the measurement of methane emissions from coal mining remains somewhat problematic. The International Energy Agency (IEA) estimates that coal mining globally is responsible for approximately 40 MMt of methane emissions annually – the largest single energy-sector source (although less than the contribution of the oil and gas industries combined). The difficulty of estimating coal-mining methane emissions is hindered by the very large variations among countries in terms of the qualities of coal being mined (in terms of chemically bound methane as well as other characteristics), the mining method (open-cast or strip mining releases significantly less methane than deep-mined coal), whether such sources as methane seeps from stockpiles of coal at the mines awaiting transportation or power stations are included in national-level calculation of methane emissions, and whether the measurements are based on what the scientific literature terms a "bottom-up" or "top-down" approach. These uncertainties of measurement remain unresolved, both at the global and national levels, and are reflected in the wide range of possible variation around the estimated benchmark for global energy-sector methane emissions (from one-third to four-fifths of the benchmark value).[33]

In addition to methane emissions from mining, on-site generators, boiler rooms, and propulsion units also used in coal mining produce the usual slate of atmospheric pollutants, including CO, CO_2, NO_2, SOx, and soot/dust/ash. Another source of atmospheric emissions comes from spontaneous combustion of coal (usually in storage or waste piles), or ignition of coal dust accumulations within a mine. This comes despite concerted efforts to reduce the frequency of such events (particularly through the practice of "rock dusting" with the dispersion of limestone dust), and increased detection and monitoring.[34]

33 See IHS Markit Strategic Horizons *Global climate: understanding the methane balance,* 12 March 2020, p. 3.

34 In 2021, Avantgarde Group, with the participation of Kazakhstani specialists, developed a system to introduce the technology for monitoring endogenous fires (caused by spontaneous coal combustion) using remote sensing of the Earth from space.

Total GHG emissions from coal production in Kazakhstan are officially estimated at 21.6 MMt CO_2e in 2019, or about 6% of Kazakhstan's total GHG emissions, marking a 9.5% decline relative to 2018, and a 51.6% reduction from 1990 levels.[35] Importantly, nearly all of coal's GHG emissions were methane. GHG emissions from this segment have hovered around 20-25 MMt of CO_2e per year since 2000, even as coal production grew considerably. It appears the bulk of emissions reduction gains materialized in the 1990s, reflecting severe contraction in Kazakhstan's coal output – which declined from 132 MMt in 1990 to 58.2 MMt in 1999. The absence of nationwide data on the coal industry's water use, solid waste generation, atmospheric and GHG emissions challenges any in-depth assessment of the sector's environmental condition. Public reporting by some individual companies does provide some indicative guidance, however.

- Samruk-Energo's Bogatyr Komir LLP reports total atmospheric emissions (presumably of all types) as 3,840 tons in 2020 (versus 3,670 tons in 2019); this represents approximately 1% of Pavlodar Oblast's reported atmospheric emissions.
- ERG's Shubarkol Komir released 4,356 tons of atmospheric emissions in 2019. Of total emissions, 9% was CO, 0.05% was methane, 4% was NOx/NO_2, 33% was SOx/SO_2, and a staggering 53% was inorganic dust.[36]
- In 2019, ArcellorMittal Temirtau's coal-production division generated 7,836 tons (8,923 tons in 2018) of dust, 1,083 tons NOx (1,017 tons in 2018) and 2,616 tons SOx (3,019 tons in 2018).

Other information comes from more anecdotal reports, such as the onset of "black snow" in Temirtau in 2018, and reports of coal-mining enterprises discharging wastewater directly into watercourses.[37] These indicate a sector with a fairly significant environmental impact.

The application of BAT is supposed to mitigate this environmental impact considerably, while increasing the

35 GHG emissions from coal mining are classified as fugitive emissions from fuels (1.B) in official UNFCCC GHG inventories; this category amounted to 9% of Kazakhstan's energy sector GHG emissions in 2019, down from 12% in 2010, and 31% in 2000. When compared to total GHG emissions, fugitive emissions from the extraction of fuels across the coal, oil, and gas sector amounted to 7% of total GHG emissions, on par with emissions from Kazakhstan's transportation sector.

36 See "Information on actual dirty particle emissions into the atmosphere" for AO Shubarkol Komir available on the Single Ecological Internet-Resource of MEGNR, http://prtr.ecogosfond.kz/2020/12/21/ao-shubarkol-komir-3/

37 Turgai Alimbaev et al. "Ecological problems of modern central Kazakhstan: challenges and possible solutions," E3S Web of Conferences 157, 03018 (2020), https://doi.org/10.1051/e3sconf/202015703018 Minister Ecology, Geology and Natural Resources meeting with community activists, https://www.youtube.com/watch?v=uWG-YIrTyl8

sector's overall efficiency.[38] But policymakers are faced with a difficult task of incentivizing coal producers to implement BAT, which typically involves considerable capital investment, and to participate in Kazakhstan's overall energy transition, even as longer term the industry is facing retrenchment, and for some of the smaller operators, even possible extinction. Furthermore, there are several structural global trends that should be taken into account when formulating the BAT reference books for coal mining:

- As European countries have moved away from coal, a substantial body of environmental-technical research has focused on best practices associated with decommissioning mines and measures to counteract abandoned mine methane emissions.
- The application of "clean coal" degassing technologies is not yet widespread, due to costs and technical feasibility.
- The global private and public sector R&D community is overwhelmingly focused on engineering solutions for a low-carbon future devoid of coal, rather than on generating cleaner practices in producing and consuming coal.

5.10.1 Ongoing environmental measures in Kazakhstan's coal extraction segment

Recent investments by coal-mining companies have focused on mitigating dust and atmospheric emissions, enhancing operational inefficiencies, and improving waste storage.

Measures to mitigate dust and atmospheric emissions

Bogatyr Komir LLP is taking steps to mitigate dust pollution from its open-pit mines, as such dust generates immediate health consequences for the company's employees. The company installed an experimental fog-forming unit that converts drainage and fresh water into a fog using a high-pressure pump. This fog then traps and settles coal dust, preventing its dissemination. The company plans to install six additional units. ArcelorMittal appears to being taking a more proactive approach to reducing atmospheric emissions, after being fined 1.395 billion tenge (about $4.1 million) in 2018 for above-quota atmospheric emissions.[39] The company has implemented air pollution prevention measures such as reconstruction and modification of its dust-collecting and ventilation installations and its flue stacks for heat and electricity units. Because of its characteristics, coal production in the Karaganda Basin comes with significant methane emissions, which the company is attempting to capture and use on-site at boilers and it has a small methane-powered electricity generation unit (1.4 MW) at one of its mines. It supplies up to 20% of the mine's electricity needs, thereby eliminating the need to use additional coal for power generation and reducing the operation's CH_4 and other emissions. At Shubarkol Komir's Central and Zapadny mines, owned by ERG, the company is deploying dust and gas collecting treatment units and other dust suppression measures. The company conducted a pre-feasibility study to capture and filter flue-stack gas emissions from the boiler facility at the Eastern mine, but decided not to pursue the project due to poor economics.

Waste and water management

With respect to solid waste disposition, in line with industry standards, both Bogatyr Komir and Shubarkol Komir store removed overburden at unused depleted sites within their respective acreage, adding chemicals and other materials to mitigate the inflow of oxygen and reduce fire risks. Bogatyr Komir also provides waste ash and slag to local entities in Pavlodar for use in road construction materials. In 2020, Bogatyr Komir supplied 10,000 tons of dry ash, but limited local demand constrains usage in this segment.

Mirroring the experience of Bogatyr Komir, at some of ArcellorMittal's coal mines, technologies have been introduced in mine reclamation that utilize production wastes; namely, overburden and slag waste. At other mines, these materials are stored in dumps or slag heaps; and at others, ash and slag are partially used in the production of cinder blocks. According to ArcelorMittal's forward-looking environmental plans, the company intends to build additional wastewater and mine water treatment facilities that will purify wastewater and produce potable water. In terms of protecting and preventing the pollution of surface water sources (streams), a number of Kazakhstan's coal mining enterprises are implementing a suite of clog-prevention and sanitary measures at their existing treatment facilities. Companies are modernizing water purification filters, cleaning and repairing settling

38 Clean coal technologies (CCTs) are a new generation of advanced coal utilization processes that are designed to enhance both the efficiency and the environmental impact of coal extraction, preparation, and use. See https://www.sciencedirect.com/topics/engineering/clean-coal-technology

39 https://informburo.kz/novosti/na-14-mlrd-tenge-oshtrafovali-amt-za-zagryaznenie-okruzhayushchey-sredy.html In 2021, the company successfully won a court cause disputing a 1.8 billion tenge fine levied against the company for similar violations; see https://kursiv.kz/news/kompanii/2021-03/amt-ne-budet-vozmeschat-ekologicheskiy-uscherb-na-18-mlrd-tenge

tanks, and rehabilitating pumps. Cleaning water through electrolysis, in addition to physical-mechanical methods of wastewater treatment, is used to reduce the concentration of pollutants from mine effluent. To reduce wastewater discharges, Shubarkol Komir treats industrial effluents at its sewage treatment plants at its Central and Zapadny mines. One investment that is not necessarily geared towards reducing waste but improves efficiency is the Bogatyr Komir LLP's in-pit crushing and conveying system (IPCC). The system is used for the extraction, transportation, blending, and railcar loading of coal. Provided by Germany's ThyssenKrupp and on track for commissioning in 2022, the in-pit crushing and conveying mechanism will effectively cut out several intermediate steps associated with delivering coal from the mine to the loading point. The previous system involved nine steps while the continuous mining technology will only involve five. Less handling of the coal will inevitably contribute to a reduction in dust and overall energy use.

5.10.2 Experience of other countries and potential applicability to Kazakhstan

International experience in modernizing coal mining operations highlights several important dynamics. For operating mines, the overall environmental measures focus on mitigating wastewater runoff and overall air pollution that affects the surrounding area. These projects tend to be fairly narrow in scope, especially in countries that already have robust and widely-enforced national environmental regulations (such as Germany).

Wastewater treatment

Germany's Mitteldeutsche Braunkohlengesellschaft (MIBRAG) is a significant producer of brown coal (lignite). To mitigate wastewater discharge, MIBRAG employs a state-of-the-art water purification system at its United Schleehain open-cast mining site. The system treats approximately 60 m^3 of wastewater per minute, ultimately discharging only clean water into a nearby river, with no environmental impact.[40] China's Shenhua Energy Company, that country's foremost coal mining enterprise, sends used mine water through permeable underground rock formations for natural cleansing in parts of its mines that are not involved in active mining operations. This naturally purified water is later circulated through conventional industrial wastewater treatment facilities, but the use of natural purification initially enables the company to reduce the energy intensity of its operations.

IT solutions and technologies

Shenhua Energy also leverages other technologies based on IT to increase efficiency, promote employee wellbeing, and mitigate environmental impact. Such solutions include "smart" mines, which employ intelligent long-wall mining, intelligent integrated application platforms, and mining robotics.[41] The company also deploys robots in selected mines to detect gases and other harmful pollutants. Robots are especially prominent at abandoned mines.

Methane management

As already noted, coal mining, especially at underground mines, generates substantial fugitive methane emissions.[42] Active coal mine methane management, laid out in various BAT reference books, includes measures such as pre-mining degasification, recovery and oxidation of ventilated methane, and flooding of abandoned coal mines. Another management strategy is utilization of coalbed methane for power and heat generation. Some of these measures are already employed by ArcellorMittal at some of its mines in Karaganda Oblast. Some of these same measures are used in Russia by SUEK at its S.M. Kirov and Komsomolets mines. In 2020, SUEK utilized about 2% of its total methane emissions for on-site heat and power generation. The use of thermal oxidation technologies to dilute the concentration of ventilation air methane (VAM) can also be important in mitigating emissions.[43] While not a new technology, regenerative catalytic oxidation (RCO) and regenerative thermal oxidation (RTO) were first applied commercially to VAM at BHP Billington's West Cliff site in 2007. Another effective and economical way to control mine methane emissions is to capture the gas by means of boreholes before methane even enters the mine workings. This technology is beneficial for mines with substantial methane. The coalbed methane that is drawn away can be used commercially as natural gas. Similarly, pre-mine drainage at sites could make a significant contribution towards mitigating methane emissions from surface mines.[44]

40 The company's other environmental activities include archeological preservation and nature and species protection.

41 http://www.csec.com/zgshwwEn/mtbd/ywtxListContent.shtml

42 The amount of methane released depends on the mining methods, coal rank, and coal seam depth. Due to the relatively higher gas content in deeper seams, more methane is emitted from underground coal mining than in open-pit mining. And the greater the depth, the higher the methane release tends to be.

43 VAM is believed to be the largest source of mining emissions.

44 www.epa.gov/sites/default/files/2016-03/documents/cmop-methane-recovery-surface-mines-march-2014.pdf

5.10.3 Key recommendations

- **Reducing dust is a serious challenge for the coal-mining industry.** There are a variety of technical solutions that can be more widely deployed in Kazakhstan to reduce dust. Along with expanding the use of fog-forming units to suppress dust (which is currently only experimental), the use of chemical reagents together with water can also greatly increase dust suppression. Reagents can reduce the use of water by a factor of ten, while at the same time increasing the overall efficiency of suppression. Other simple measures to reduce dust and soot involve installing rotary wire brushes along the side of conveyor belts; this provides regular cleaning, and is most effective when combined with regular maintenance of the conveyor systems. Installing scrubbers in the stageloader/crusher area can also help mitigate dust emissions. Such practices are already being used in Kazakhstan, but BAT should seek wider adoption and adherence.
- **To reduce haulage dust and dust along intake roads, mines should also consider using surfactants, hydroscopic compounds, or other binders and resin-based products in these areas.** International experience with these substances, applied together with water, have yielded a measurable and improved impact in emissions and visibility. Such measures, when complemented with alterations to transportation schedules within the mine, can curb atmospheric dust emissions significantly.[45]
- **The emission limit values (ELVs) governing emissions in the IGTIC's forthcoming BAT reference books for coal mining in Kazakhstan should present targets that are attainable while also driving meaningful improvements.** Some independent analysis of ELVs under the previous EcoCode argued that these were set too generously, fundamentally removing any incentive to improve operations with BAT implementation.[46]
- **BAT compliance for coal producers, and subsequent issuance of integrated environmental permits, should include greater use of monitoring technologies to guide preventative measures.** International experience demonstrates that agile monitoring and detection systems within mines, as well as throughout the overall producing area, are among the more effective ways to prevent and mitigate most environmental issues. This could include the expanded use of on-site waste sampling equipment to track acid mine drainage, for example. This can also include shifting to newer, more energy efficient monitoring alternatives, especially those that are integrated into broader digital solutions. For example, low-power portable laser methane detection and alarm instrument monitors are being developed that use tunable laser absorption spectroscopy to replace the more traditional and less-efficient catalytic methane detection systems.[47] There are a variety of emerging technical options within this space, leveraging lasers and other digital solutions.
- **Kazakhstan's coal producers have already initiated some waste "recycling" programs, such as selling ash to local municipalities or using coal waste, that reduce ultimate disposal.** Such programs should be sustained and encouraged under the new BAT rollout.
- **Regulators should consider some kind of fiscal incentives that encourage mining companies to pursue on-site methane utilization where it is technically feasible, such as for generating heat and electricity.** Recognizing that there are several technical conditions that shape the feasibility of methane recovery and use, the economics of these projects is often the main factor driving companies to reject these endeavors. Improving their economics should help drive implementation.
- **Kazakhstan's policymakers could also consider pushing measures to reduce the density of emitted mine methane through VAM mitigation techniques, such as RCO, RTO, and others.**
- **To make water use in coal mining not only cleaner but more efficient, Kazakhstan's coal mine operators should consider introducing more thorough water treatment technologies like those used elsewhere, such as in Germany and China.** These technologies not only reduce water use and reduce operating costs, but prevent the release of pollutants into the environment – not only pollutants that enter the water directly but also those that damage the soil and foul the air during subsequent evaporation. Large industrial entities, like coal mining, should help utilize water resources in a rational and effective way.

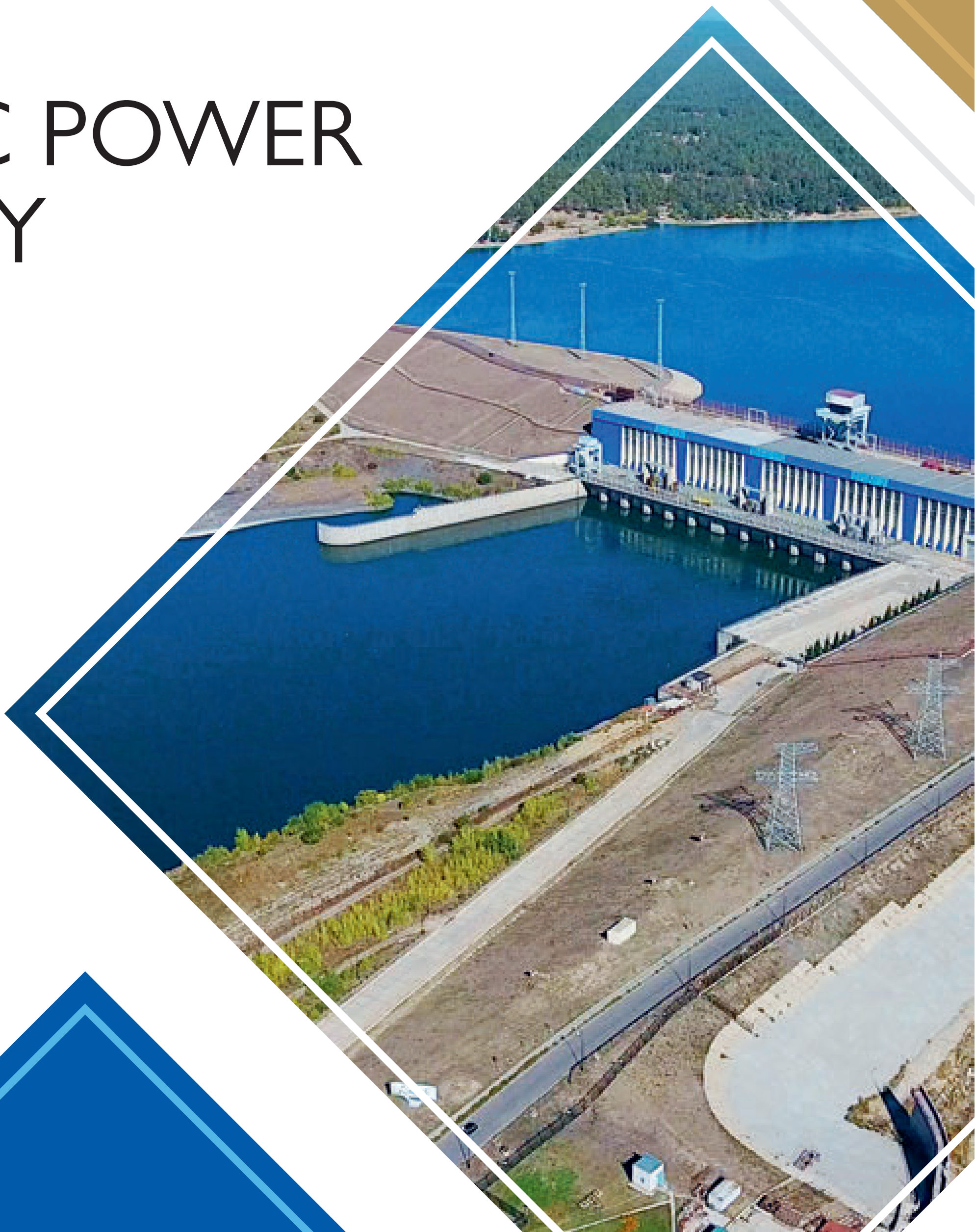
45 Jay F. Colinet et al. "Best practices for dust control in coal mining," US Department of Health and Human Services, January 2010. For an example of a company providing dust control solutions, see EcoLab, https://www.ecolab.com/offerings/road-dust-control

46 See "Enhancing competitiveness in the mining sector in Kazakhstan," OECD, 2018.

47 https://www.spiedigitallibrary.org/conference-proceedings-of-spie/11340/113401M/Coal-mine-low-power-laser-methane-detection-and-alarm-instrument/10.1117/12.2548071.short?SSO=1

Chapter 6

ELECTRIC POWER INDUSTRY



6 ELECTRIC POWER INDUSTRY

BY AVANTGARDE AND SEEPX ENERGY

6.1 Key points

Kazakhstan has the largest fuel and energy complex in Central Asia. The relatively easy accessibility of coal (mostly mined using an open pit method) and the developed transportation infrastructure together attribute to the low cost of electricity, which in its turn serves as a foundation for the competitiveness of the country's economy and is an important social consideration. Nevertheless, Kazakhstan's use of coal as a primary fuel for the electricity and heat energy production in the country has a significant consequence for the environment and climate. Consequently, Kazakhstan is pursuing a policy of gradually replacing coal with natural gas and renewable energy sources. Several strategic documents, including Kazakhstan's "Development Strategy to 2050" and "The green economy concept" set the ambitious targets to substantially reduce the share of coal generation, and form the foundation of a new energy policy in Kazakhstan.

Part of this energy policy was the 2014 adoption of an effective renewable energy legislation that facilitated high level of investment stability and enabled for the commissioning of more than 1,466 MW of wind and solar power plants and about 114 MW of small hydro power plants over a seven-year period. This meant Kazakhstan almost achieved its 2020 renewables (RES) output target indicator of 3% of the total power output in the energy system. The introduction of the market mechanisms for the selection of renewable energy projects in 2018 facilitated a decline in the average renewable electricity price (wind by 14% and solar by 55%) to a level comparable with the price of a gas-fired generation. However, the development of intermittent energy sources dependent on weather and time of day for their output intensifies the existing problem of Kazakhstan's energy system balancing and stability, providing there is a shortage of flexible capacity.

Another energy policy area deals with the challenge of modernising electric power plants and electricity grid, due to the high degree of equipment wear and tear. The new Environmental Code sets an ambitious task of modernising power plants and significantly reducing emissions by shifting to the principles of the best available technologies (BAT).[1] The Nationally Determined Contributions under the Paris Climate Agreement impose significant obligations on Kazakhstan to decarbonise its economy and the electric power industry, yet the achievement of which depends on the pace of reforming the price setting policies and revising the mechanisms facilitating the stability of investment in the sector. Despite the government's targeted efforts to modernise generating and grid assets, the industry is characterised by a significant degree of depreciation of fixed assets, a relatively low generation efficiency (33–35%), a high share of network transmission losses (8.3%), as well as a shortage of flexible capacity for intra-day balancing. The development of renewable energy sources, the modernisation of the energy infrastructure and the introduction of BAT all contribute to an increase in the cost of electricity, the growth of which is restrained by the government to the parameters of the country's economic and social development strategy. The market-based instruments intended to reduce electricity prices have no tangible effect, whilst the administrative and regulatory mechanisms controlling the power and heat energy prices growth are not sufficiently flexible and transparent, which altogether leads to imbalances and underfunding of the industry.

Finding the ways of achieving a balance between the cost of energy, reliability of supply, and environmental sustainability is the subject matter of this chapter. The ways to reform the power sector and revise the energy policy proposed in this chapter aim at reaching this balance in the most transparent manner using various economic and market instruments.

6.2 The electric power sector key findings

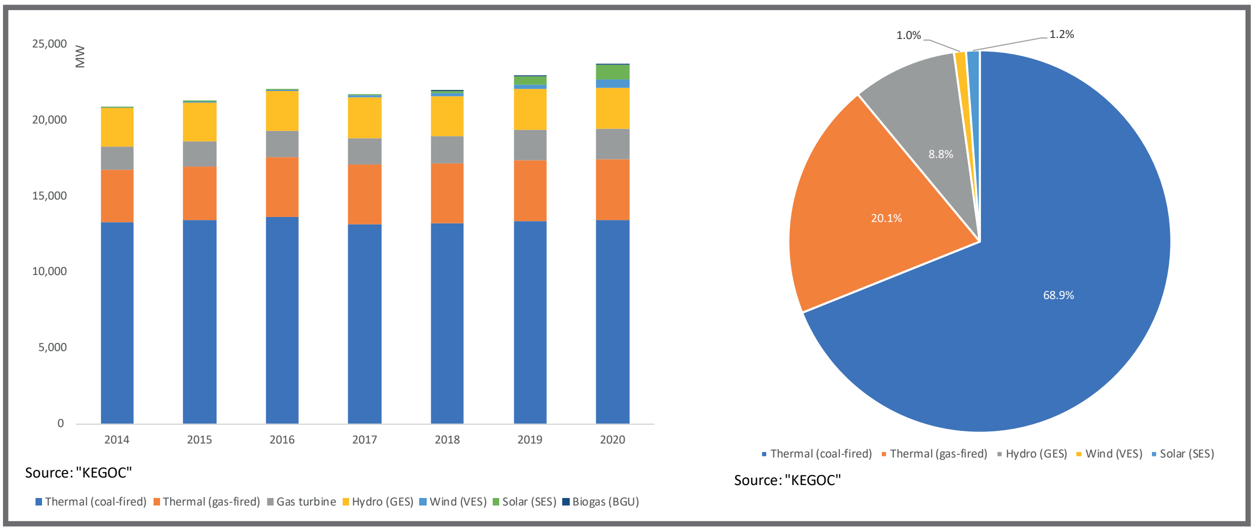
On 1 January 2021, the installed capacity of Kazakhstan's power plants according to the system operator (KEGOC) reached 23.6 GW, the bulk of which (over 82%) some 19.4 GW are thermal power plants (abbreviated in Russian as TES [from *teploelectrostantsia*]), out of which 13.4 GW are coal-fired and 6 GW are gas-fired.

There are 68 TES, of which 41 are a specific soviet era thermal combined heat and power plant design operating in Kazakhstan (abbreviated in Russian as TETs [from *teploelectrotsentral*]) that also provide heat energy to the population and industrial consumers, 6 condensing power plants, 15 gas turbine and 6 gas engine generating plants (abbreviated in Russian as GPES). In terms of renewable energy sources, there are 47 hydroelectric power plants (abbreviated as GES in Russian) of which 41 are relatively small,[2] as well as 29 wind turbine power plants (abbreviated in Russian as VES) and 45 solar power plants (abbreviated in Russian as SES) and one biogas plant (abbreviated in Russian as BGU).[3]

1 The Environmental Code of 02.01.21 describes BAT as "the best available techniques".

2 The hydro power plants with installed capacity of up to 35 MW.
3 According to the Ministry of Energy data.

Figure 6.1 Changes to the installed capacity and structure of electricity production by fuel type.



The development of the oil and gas complex in the west of the country has led to a gradual increase in the share of gas generation in the energy balance, whilst the legislative framework adopted since 2014 in support of renewable energy sources facilitated an increase in the renewable capacity, which, according to the legislation includes wind, solar, small hydroelectric power plants, and biogas power plants. Yet, since 2021, following the amendments to the legislation, the status of renewable generation has been assigned to waste-to-energy plants as well (with 100.8 MW due for commissioning)

In general, between 2014–21, the installed generating capacity increased by 2.8 GW (13%), out of which 1.6 GW were renewable energy sources, see Figure 6.1.

Regionally, Kazakhstan's energy system is divided into three zones – the interconnected North and South energy zones (hereinafter North Zone and South Zone), connected by three 500 kV lines, and an isolated West Zone (hereinafter West Zone). The energy zones fuel-base defines the type and fuel-mix of generating assets.

- The West Zone is the home to the country's key oil and gas fields, hence the TESs there only run on natural gas. Notably, some of the power plants that operate in the West Zone are power supply sources for oil and gas exploration only and do not supply electricity to the grid. In addition, Atyrau power node is connected to the UES Russia's IES South (Astrakhan power node) by the means of 110 kV lines, whilst West Kazakhstan province is connected to UES Russia's IES Volga by the means of three of 220 kV lines.
- The North zone is a home to the major coal mines, including "Bogatyr" coal mine, one of the largest in the world. The coal power plants form the foundation of the North Zone generating capacity and include all coal condensing power plants (traditionally abbreviated in Russian as GRES [from *gosudarstvennaya raiyonnaya electrostantsia*]),[4] and hydropower plants located in Eastern Kazakhstan. North Zone has excess capacity. About 70% of the country's total generating capacity is located in the North Zone. The developed network infrastructure of 220-500-1150 kV HV lines, including those connecting Unified Energy System of Kazakhstan (UES Kazakhstan) to UES Russia's Siberian IES, enable for the power transit to South Zone and power exchanges with UES Russia. The North Zone is also home to Kazakhstan's major industrial power consumers, in particular the mining and metallurgical industries.
- The South Zone is power deficient. In terms of power consumption, the residential segment has the highest share in this zone, whilst the generating mix is varied and includes both coal and gas-fired generation, as well as hydropower capacity. Notably, the South Zone has been leading the development of small-size hydropower plants. The South Zone power deficit (some 13,531 million kWh) is met by flows from the North Zone. In relation to the climate agenda, the zone is most favourable for developing solar and wind generation. However, existing problems with intraday balancing, in the absence of flexible capacity, prevent the South Zone from maximising on its environmental potential. The largest gas condensing power plant, Zhambyl GRES, is amongst the other key assets in the South Zone. Notably, since 1992 it has been operating on a substantially reduced load (capacity utilisation rate of 17% in 2020) due to issues

4 GRES is a type of condensing thermal power plant that produces electric power only.

Figure 6.2 The energy infrastructure map. Kazakhstan Source: SEEPX Energy Ltd.

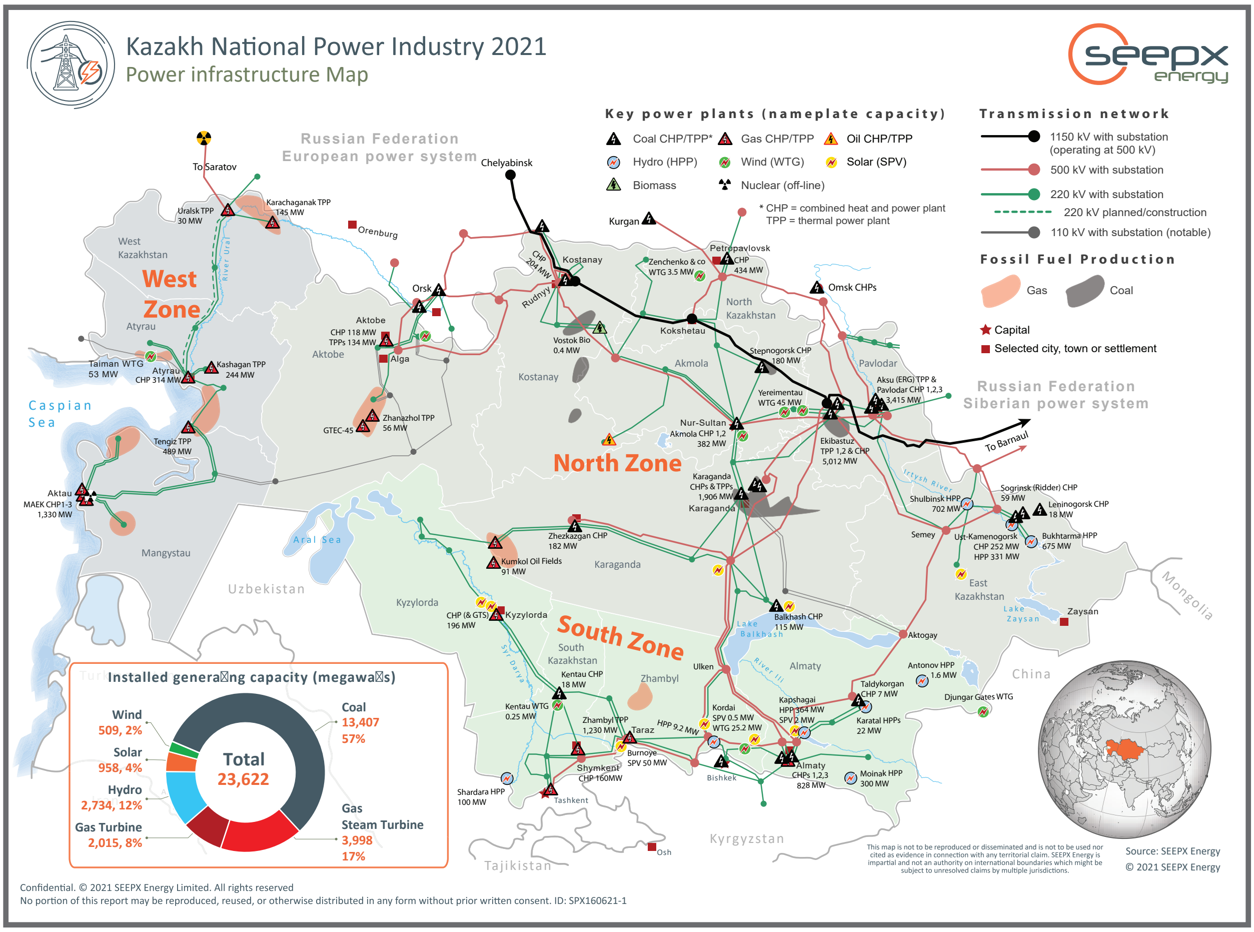
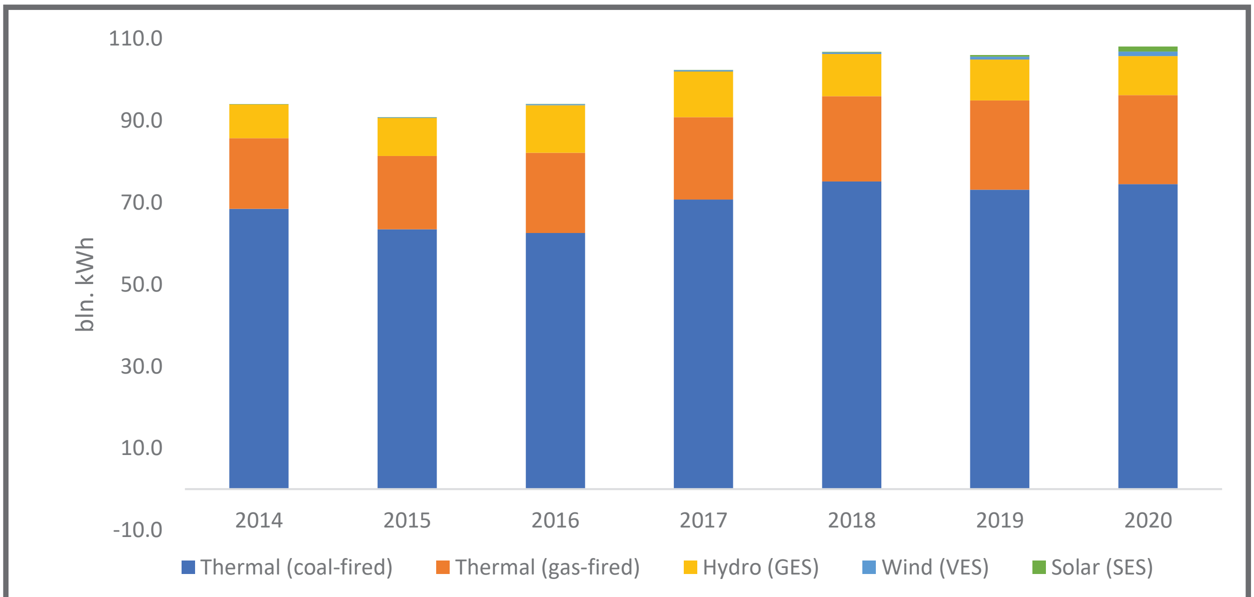


Figure 6.3 Structure of electricity production in 2014–2020



Source: KEGOC

with natural gas supply (initially from Uzbekistan). At that, the commissioning of the Beyneu-Shymkent main gas pipeline in 2015 did not help resolve this GRES' load level. Despite the power deficit in the South Zone, this gas-fi red asset remains deeply underutilised due to competition from the lower electricity prices from coal-fi red power plants in the North Zone.[5]

The varied distribution of generating capacity contributes to the overall imbalances between the energy zones. For example, the installed capacity of the North Zone is 15.9 GW, whilst in the South Zone it is just 4.2 GW. And although the power deficit in the South Zone is met by the three "North-South" 500 kV transit lines, the power lines regularly experience overloads.

At present, the country's Ministry of Energy is exploring various options for unifying the West Zone with the South and North energy zones, but even the shortest 500 km connection (Atyrau-Aktobe) requires significant investments (see Figure 6.2).

Kazakhstan is the ninth largest country in the world, so the electricity transmission along the extended electricity grid is characterised by relatively high losses. The electric grid infrastructure operated by the national operator of transmission lines KEGOC consists of 220–500 kV lines that cover the distance of over 26 thousand km, whilst regional network operators' lines, 10/6–220 kV, extend for more than 250 thousand km. The extensive electricity grid infrastructure is amongst the reasons for the high level of losses (more than 10%).

The electric power industry in Kazakhstan also includes the production and transmission of heat energy. The sources of the heat energy are 41 TETs, 63 large boiler houses and 2,200 small boiler houses (notably, about 60% of the district heating supply is met by the TETs). The heat energy is transported along the heating networks (main and district) with the total length of more than 12 thousand km. High heat energy losses during heat energy transportation are common and can reach 30% (although the official statistics state they are 17%). In addition, the heat energy sector is characterised by the low efficiency of heat energy sources and a high degree of wear and tear of the main equipment (the average wear of heat energy networks in Kazakhstan is 59%).

6.2.1 Electricity production

In 2020, electricity production in Kazakhstan totalled 108.09 billion kWh, which was 1.9% growth versus 2019, according to the system operator (KEGOC). Notably, in 2020 all energy zones demonstrated the growth in power output – North Zone by 1.4 billion kWh, South Zone by 0.6 billion kWh, and West Zone by 0.1 billion kWh.

In the structure of generation, coal-fired power plants accounted for 68.9% of total output in the country. Gas-fired power plants produced 20.1%, hydropower plants 8.8%, whilst wind and solar power plants generated 1.0% and 1.2% of electricity, respectively, see Figure 6.3.

Since 2014, the total electricity production in Kazakhstan has grown by 15% (14.2 billion kWh), whilst the share of output by coal-fired power plants has decreased from 72.9% to 68.9%, following an increase in renewable and gas-fired generation. Notably, in 1990 the share of coal output was over 80%. At that, large energy and industrial groups account for more than 58.7% of electricity production in Kazakhstan.

The TES' operation involves electricity consumption for the plants' own needs, for water treatment and supply systems, fuel preparation, pumping, and compressor equipment. And whilst the power consumption for own needs by the coal-fired KES (GRES) accounts for 5–6%, for TETs, which also produce heat energy, the power consumption for own needs accounts for 11–17%. Notably, the modernisation of equipment and optimisation of operation could create efficiencies insofar as reducing electricity consumption for own needs.

Following the respective investment commitments, Kazakhstan's thermal power plants constantly undergo capital maintenance, but mainly of turbine equipment, see Figure 6.4. Thus, the total capacity of TES turbines installed after 1991 is 9.1 GW or 47% of the total installed capacity.

Despite a significant level of sectoral investment, the renewal of TES' fixed assets does not take place to the full extent, especially when it comes to boiler equipment, the average service life of which exceeds 40 years.

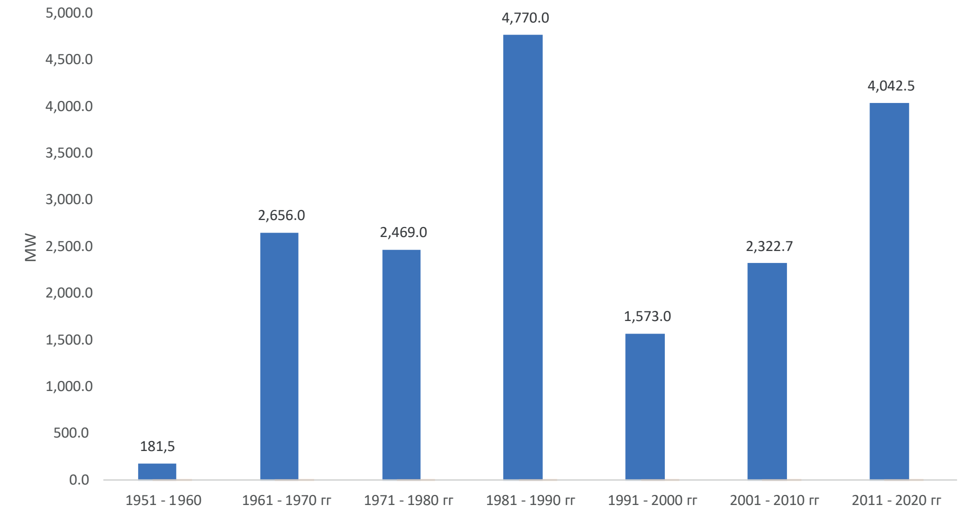
The high level of pollution and the power industry's negative environmental impact remain as significant challenges. To meet the international commitments on the greenhouse gas (GHG) emissions reduction by 2030 under the framework of the Paris Agreement, Kazakhstan plans to integrate the GHG reduction measures into the operation of the hard-to-abate coal-fired generation (that cannot be decommissioned due to risks to the reliability of electricity and heat energy supply), for instance, through energy efficiency and energy saving measures, such as reduction of fuel consumption per unit of power output.

6.2.2 Transmission and distribution of electric energy

The 500–220 kV electricity grid infrastructure is a backbone of the National Electricity Grid (NEG) that enables electrical connections between the country's regions as well as with the power systems of neighbouring states. The NEG is operated by KEGOC. The country's regional power transmission is performed by 196 energy transmission companies (abbreviated in Russian as EPOs from *energoperedayushiye organizatsii*), including

5 The power deficit in the South energy zone is approximately12.7 billion kWh. By increasing the Zhambyl GRES load to 80% can reduce the deficit in the zone by 6 billion kWh.

Figure 6.4 TES turbine launches, MW



Source: Companies' data

19 regional power network companies (abbreviated in Russian as REKs), and power supply companies (abbreviated in Russian as ESOs) that supply electricity to the retail consumers.

The energy transmission companies (EPO) could be any company that employs their own power networks for power supply to the consumers, for example, KazTransOil, and National Company Kazakhstan Temir Zholy (KTZh). The NEG facilitates electric power transmission from the energy producers (that have a grid connection for the power output into NEG) to the wholesale consumers (distribution grid companies, large consumers) connected to this grid.

The total volume of electricity transmission in 2020 through KEGOC's grids amounted to 43.6 billion kWh, whilst through the REK's networks it was 43.3 billion kWh, notably the total volume of electricity losses amounted to 7.51 billion kWh. The high level of losses is a result of extended network infrastructure, see Table 6.1.

Table 6.1 – The length of the KEGOC network infrastructure and part of REK.

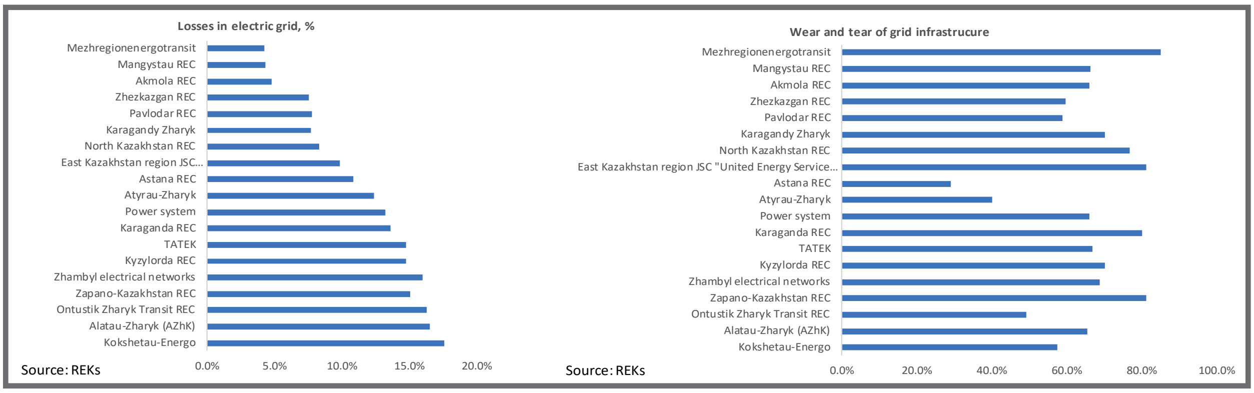
Voltage	length, km	
	KEGOC	REKs
1150 kV (under 500 kV parameters)	1,421.2	0.0
500 kV	8,288	0.0
330 kV	1,864.1	0.0
220 kV	14,694	1,428.2
110 kV	352.8	22,857.2
35 kV	44.1	27,082.2
10 kV	92.6	51,315.9
6-0.4 kV	18.7	47,613.1

KEGOC combines the functions of the operator of the National Electric Grid and a system operator.

In the context of a successful energy sector reform and aspirations for technological progression of Kazakhstan's energy system (adherent to the goals of innovative, highly technological and low carbon development) the role, the sphere of interests and motivation of the System operator are expected to be solely on the most effective ways of managing the energy system modes, balances and future planning. In other words, an independent System operator cannot be responsible or have a vested interest in the operation of either generating assets or the network, whilst a network company (devoid of the System operator's functionality) should not have an impact on operational modes, balances or future of the energy system planning.

In the context of the future energy system planning, rather than placing greater emphasis on the continued construction of the network infrastructure and retention of sufficient transmission load (for the purpose of minimising transmission losses, for example) an independent System operator's role evolves to include responsibility for selecting generating capacity with the parameters needed for the energy system (flexibility, environmental sustainability, and innovation), advancing the distributed energy sources (both production and consumption) or the energy system functionality, that would enable for the greater integration of consumers into the operation of the power system through the use of demand response, as well as new technologies (including the industrial energy storage, upon sufficient maturity) and technological solutions (automation of processes and digitalisation), the decisions

Figure 6.5 Losses in REK's networks (left) and depreciation of fixed assets (right).



Source: REKs

Source: REKs

upon which are already required in the interests of the energy system.[6]

The planned substantial increase in the share of renewable capacity in Kazakhstan's energy system will force a change in planning their modes of operation. An independent System operator will be faced with the challenge of employing various balancing resources, developing production output forecasting technologies, involving demand response, as well as reinforcing and expanding the grid. In addition, an independent System operator' equidistance from other market participants (besides the network company) could help transform the role of conventional thermal generation with the penetration of renewables. Once a primary source of energy, the thermal power plants' role is to become a resource for balancing the power production and consumption, frequency control and stand-by reserve generation.

The System operator's role in the context of future energy system planning presumes the functionality for the development of the future energy system documents (publicly validated programme and scheme), open discussion and validation of technology-related decisions (on the generating capacity output, consuming equipment, integrating new technologies, and decommissioning of energy assets). With this regard, it is of utmost importance that the System operator develops and maintains a mathematical energy system model to have access to real time data on the energy system performance and future energy system planning. For example, this model will help account for technological, economic, and environmental parameters of generating equipment and other resources participating in the capacity market. In addition, this functionality could facilitate a shift from the norms that define demand and supply parameters during the capacity auction towards probabilistic factors based on the energy system' actual parameters.

The concerns relating to the reliability of the power system operation as consequence of KEGOC's unbundling is unduly justified. The unbundling prerequisites for the System operator to improve the quality of the power system management and future planning. In addition, since the energy system management will be the System operator' sole responsibility the rules on information disclosure should be amended to facilitate better information disclosure on the operation of the energy system and the System operator's transparency. Both will improve transparency and control over the tariffs' growth.

The high level of losses (in REK's) and the depreciation of fixed assets are the main challenges for the network infrastructure in Kazakhstan. In 2020 the power transmission losses in networks operated by KEGOC amounted to 2,767.9 million kWh (5.7%), whilst the losses in the networks operated by REKs amounted to 4,739.5 (10.9%), see Figure 6.5. At the same time, the degree of the power grid equipment wear and tear in the networks operated by REKs remains high (65% on average) despite the fact that, according to the companies' data, the annual investments amount to about 30% of the required revenue.[7]

The digitalisation of the electric grid is viewed as the means for reducing losses, optimising operational modes, and improving the reliability of power supply. According to KEGOC reporting, the company has already embarked on the project of "Automating the Unified Energy System of Kazakhstan Management" under the "Digital Kazakhstan" state programme, that focuses on three areas: the automated frequency and capacity

6 The unbundling of the System operator functions from those of the National operator of transmission improves the management of the energy system's modes as the grid company (effectively acting as a System operator) and pursuing the goal of the most efficient mode for the grid operation (to minimise losses, for example), could cause inefficiencies for generation and the energy system overall. More so, the integration of renewable assets by the grid without the whole system planning and assessment by the System operator represents a substantial risk for the energy system. In addition, the construction of excessive grid infrastructure at the expense of generation and/or discounting other promising technologies and solutions could pose a real threat to the efficient operation of the energy system in 15–20 year horizon.

7 The assessment of the network companies' cost efficiencies and investments effectiveness falls outside the scope of this Report. Yet, the efficiency of costs and effectiveness of investments in Kazakhstan will depend on whether Kazakhstan could successfully improve the tariff-setting methodologies for the grid companies' required revenues and the end consumers' tariff (accounting not only for the reliability of electricity supply and minimum indicators of service quality, but also the innovative development of the segment, with the achievement of environmental goals). See chapter 6.3.6.

control(abbreviated in Russian as ARChM); the centralised automatic emergency response system (abbreviated in Russian as CSPA); the synchrophasor WAMS/WACS technologists.[8] The latter was integrated by KEGOC in 2019–21 for the monitoring and forecasting of electrical modes and control of stability margins on three North-South 500 kV transit lines.

For the next decade, the unification of the West Zone with the North and South zones is the main grid infrastructure development project for Kazakhstan. The connection is considered via one of the options listed below:

- The North-West 500 kV AC line Atyrau-Aktobe (500 km).
- The North-West DC line Atyrau-Zheskazgan (1,400 km).
- The West-South DC line Beyneu-Shymkent (1,500 km).

For economic and technical reasons, the first two options connecting the West Zone with the North Zone assume the power transmission from the surplus North Zone to the West Zone. Yet, under these options, the coal-fired power plants in the North will supply electricity to the western region with developed gas generation and several gas fields that operate their own large gas-fired power plants. The North-West options are less appealing given the overall goal of reducing the share of coal-fired power plants' output and the availability of excess capacity in the West Zone. Also, it would be essential to achieve the projected technical and economic parameters of transmission load for the effective operation of the planned transmission lines, otherwise the underutilisation of the lines will result in both significant losses during the electricity transmission and the breach of projected technical and economic parameters.

Building a line from the West Zone to the deficit South Zone will mimic the route of the natural gas line Beyneu-Shymkent. The implementation of this option will require strengthening of the grid and the construction of additional gas-fired generation in the West Zone. This could involve revamping MAEK and equipping it with the modern combined-cycle units, which, provided an increase in gas supplies to this power plant, will make the power supply from the West Zone to the power-deficient southern regions possible, whilst increasing the flexibility of the West Zone and the share of gas generation in the overall energy balance.

Overall, the construction of new power transmission lines, the tasks of reducing the wear and tear of the power grid infrastructure, and the challenge of digitalisation (for losses reduction amongst other things) will require an increased level of investment and a tighter control over the efficiency of spending. In this regard, the industry reform with the subsequent transition to the incentive methods of tariff setting warranting profitability and return on investment for the companies in this sector should be accompanied by an increased independent control over the efficiency and effectiveness of spending.

8 KEGOC is also working on introduction of the smart power system attributes, in particular, the local automatic emergency response systems, the digital relay protection and automation devices (RZA), the dispatch control and data collection system (SCADA), an automated system for commercial metering of electricity (ASKUE), the controlled shunt reactors 500 kV , phase – shifting devices, fibre-optic communication systems, unmanned aerial vehicles, etc.

6.2.3 Electricity consumption

The power consumption in Kazakhstan only exceeded 1990 levels in 2018, see Figure 6.6. Notably, during the soviet era, a substantial share of power supply originated from Russia and Central Asian countries, whereas at present Kazakhstan is a net exporter of electricity (0.7 billion kWh).

According to the system operator Kazakhstan's power consumption in 2020 reached 107.4 billion kWh, which was 2% higher than in 2019. Despite the restrictions imposed on the economy by COVID-19, the increase in electricity consumption was registered in all energy zones: in the North Zone by 2.1%, in the South Zone by 2.7%, and in the West Zone by 0.6%. Notably, when 2020 electricity consumption is compared to that of 2019, on a monthly basis there is no obvious dip during the period of quarantine, see Figure 6.7.

Between 2014–20 the largest increase in electricity consumption was registered by the North Zone, amounting to 9.5 billion kWh, whilst in the South Zone power consumption increased by 3.4 billion kWh, and in the West Zone it grew by 2.6 billion kWh, see Table 6.2.

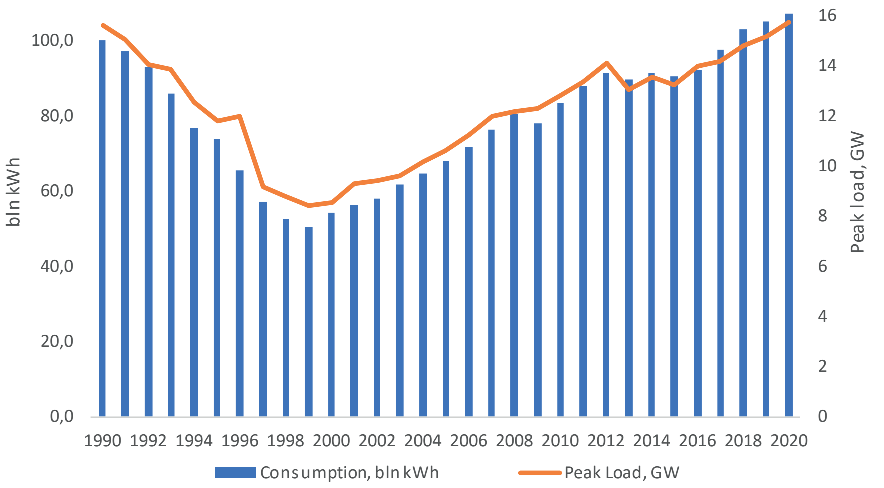
The electricity consumption growth of 57% in the Aktobe province is a consequence of oil and gas project development, as well as other industrial projects including rail and beam plant and Aktobe Ferroalloy Plant (that was put into operation in 2014 by "TNK Kazchrome" and has the most powerful DC furnaces in the world [72 MW]). The 47.1% growth in electricity consumption in the Atyrau province during this period is associated with the Kashagan field's output increase (from 0 to 15.1 million tons of oil) and the expansion of the Tengiz field.

Notably, electricity consumption is dominated by Kazakh industry (57.9%), whilst the share of housing and utilities (abbreviated in Russian as ZhKH from *zhilicshno-kommunalnoye hozyaistvo*) accounts for 22.3%, see Figure 6.8.

The power consumption by large industry in 2020 reached more than 35.5 billion kWh, with the strongest growth exhibited by Aktobe Ferroalloy Plant (1,683.2 million kWh) in this period. The largest decline (-59.8%) in electricity consumption in 2020, as expected, was recorded at KTZh (-2.0 billion kWh) due to restrictions imposed during the pandemic.

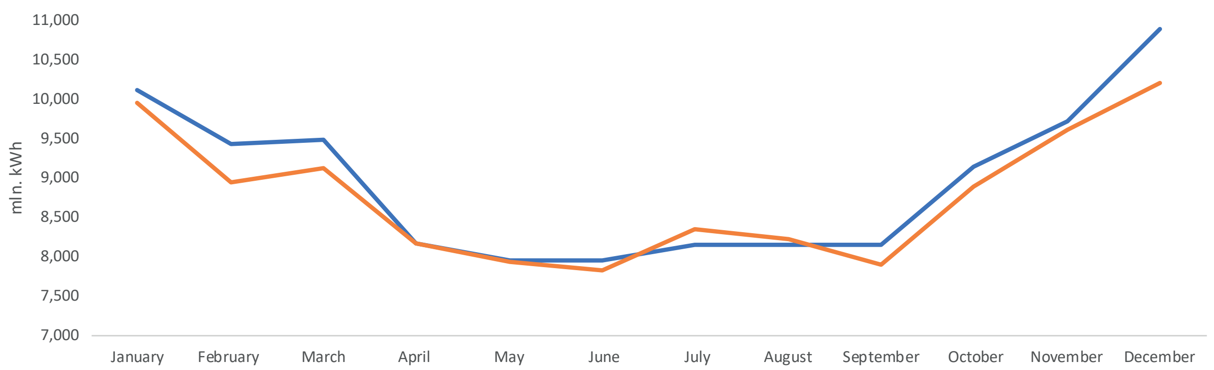
The growth in electricity consumption in Southern Kazakhstan (Almaty and Turkestan provinces) is mostly associated with population growth. In the city of Almaty and the Almaty province the population increased by

Figure 6.6 Electricity consumption and peak capacity load 1990-2020.



Source: KEGOC, NER 2019 data

Figure 6.7 Monthly electricity consumption 2019–20.



Source: KEGOC

Table 6.2 The growth in electricity consumption by province in 2014–20

	Provinces	2014	2015	2016	2017	2018	2019	2020	Changes
North	East Kazakhstan	8664	8523	8530	8563	9080	9339	9204	6,2%
	Karaganda	15433	15712	15786	16695	17319	17991	18460	19,6%
	Kostanay	5473	4688	4599	4689	4782	4786	4615	-15,7%
	Pavlodar	17363	16975	17611	18654	19433	19527	20731	19,4%
	Akmola	7996	8061	8285	8645	9141	9209	9196	15,0%
	North Kazakhstan	1704	1643	1685	1731	1800	1764	1665	-2,3%
	Aktobe	4232	4798	5272	5900	6301	6437	6647	57,1%
South	Almaty	10168	9917	9960	10446	10977	11351	11367	11,8%
	Turkestan	4148	4090	4270	4646	4953	5097	5211	25,6%
	Zhambyl	3898	3782	3191	3802	4321	4473	4948	26,9%
	Kyzylorda	1642	1605	1592	1658	1689	1760	1760	7,2%
West	Mangystau	4898	4978	5011	4956	5237	5111	5023	2,6%
	Atyrau	4251	4272	4711	5537	6185	6350	6255	47,1%
	West Kazakhstan	1791	1804	1808	1931	2009	1998	2256	26,0%

Figure 6.8 The structure of electricity consumption by industry (2018 estimate).

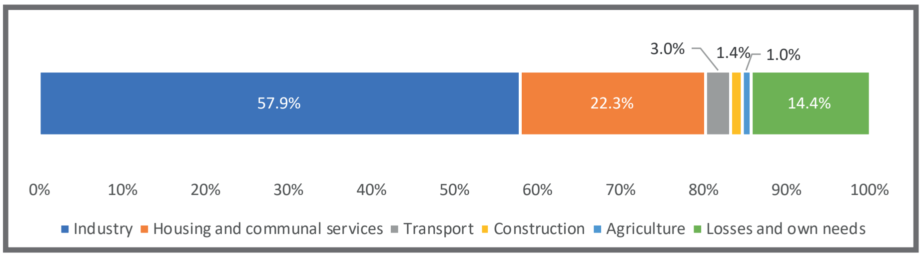
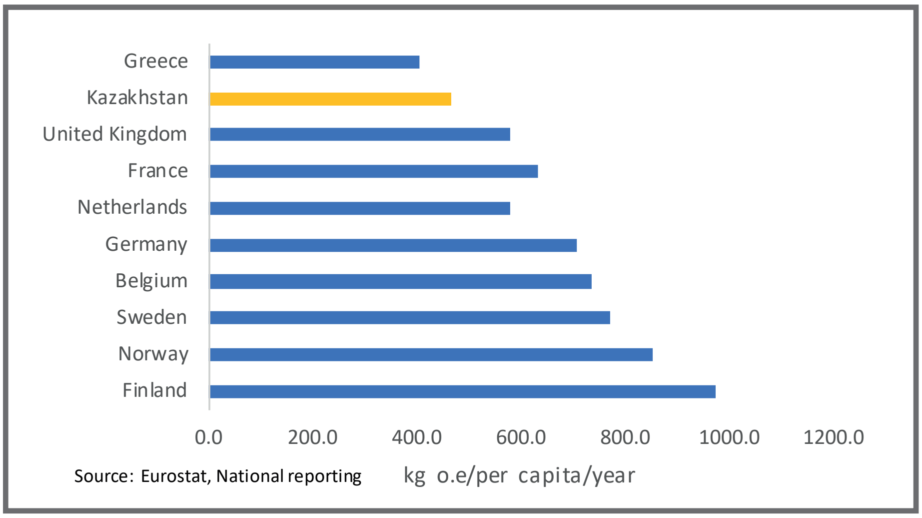


Figure 6.9 Energy consumption by households kg oil. e. per person per year (2018)



485 thousand people, whilst in the Turkestan region and the city of Shymkent by 325 thousand people during this period. Notably, despite the low cost of energy, the power consumption by households (per person per year) in Kazakhstan is significantly lower, than in the EU countries, see Figure 6.9.

The relatively low power consumption by households in comparison to the EU is largely a consequence of the centralised district heating and hot water supply. The systemic efficiency of heat energy supply from the TETs affects residential power consumption. At the same time the low electric intensity (low level of electric devices' penetration) of Kazakh households creates a certain reserve for the electricity consumption growth in the future.

Meanwhile, the power consumption growth in Kazakhstan largely depends on the rate of industrial production growth and the global commodity markets, since most exported products are raw materials and semifinished products, namely, oil and oil products, natural gas, metal ores, and alloys.

At the same time, the electricity consumption in Kazakhstan could find support from the emergence of new industries and consumption formats. Thus, a new trend in electricity consumption in Kazakhstan has emerged from business activities related to cryptocurrencies. The low cost of electricity and the availability of the coal-fired KES (GRES) capacity reserves led to the emergence of large cryptocurrency mining centres in Kazakhstan. In 2021, Kazakhstan ranked third in the world after China and the United States in cryptocurrency mining with a total share of 8.2%.[9] Notably, cryptocurrency mining in most countries is a grey area and it is very difficult to assess the volume of electricity consumption by this industry. Moreover, Kazakhstan's policy on digital financial assets and currencies has not been fully formulated.[10] This means that any measures that might tighten regulation on the issuance and circulation of digital unsecured currencies could have a negative impact on the power consumption outlook for this industry. The Government of Kazakhstan has already approved the introduction of a special tax on cryptocurrency mining from

9 Based on the University of Cambridge estimate, the power consumption by cryptocurrencies mining globally is about 130 billion kWh, therefore, the power consumption by this industry in Kazakhstan could be estimated at 10 billion kWh. However, this estimate seems to be too high and the power consumption by cryptocurrency mining is likely to be significantly smaller.

10 See Law of the Republic of Kazakhstan No. 347-VI «On Amendments and Additions to the certain legislative acts of the Republic of Kazakhstan on the Regulation of Digital Technologies» dated June 25, 2020; "Rules on informing about digital mining activities", Order No. 384/НҚ of the Minister of Digital Development, Innovation and Aerospace Industry of the Republic of Kazakhstan dated October 13, 2020; Civil Code of the Republic of Kazakhstan and the Law of the Republic of Kazakhstan "On Informatisation".

1 January 2022.[11] Moreover, the changes to the power market rules and possible restrictions imposed on power companies for electricity supply to digital mining centres are being discussed.[12]

This presents a challenge given the significant difference of generating capacity distribution by energy zone and issues with the north-south transmission congestion, the power system efficient operation planning, accounting for growing consumption disparity. Another challenge for power consumption forecasting is related to the shifting peak electricity consumption, owing to the increased frequency and duration of temperature fluctuations and anomalies caused by climate change.[13]

6.2.4 Industry regulation and pricing policies

The key state bodies, responsible for the regulation and price setting policy in the electric power sector are:

The Government of the Republic of Kazakhstan

The operation of the electric power industry in Kazakhstan is governed by the norms of the Law of the Republic of Kazakhstan “On the Electric Power Power Industry”. The law defines the principles of the electric power sector operation, the approaches to setting prices for the energy producing companies, the structure of the electric and heat energy markets, the functions of the sector entities.

In accordance with the Law “On the Electricity Industry”, the government of the Republic of Kazakhstan develops the main direction for state policy in the electric power industry.

The Ministry of Energy

In accordance with the legislation the responsibility for executing the state policy in the electric power industry is assigned to the Ministry of Energy with a list of more than 80 competences of which is defined by the law “On the Electric Power Industry”.

In the context of tariff regulation and pricing policy in the electric power sector, The Ministry of Energy is responsible for setting the power price caps for electric power, the price caps for balancing, and the price caps for capacity. In addition, the Ministry of Energy sets individual capacity tariffs for existing and newly commissioned power plants.

11 The tax would be calculated based on the electricity consumption – KZT1 per 1 kWh of electric energy consumed during digital mining.
12 The drafts of the legislation to limit mining https://legalacts.egov.kz/
13 The abnormal winter temperatures in 2021 in the Northern Hemisphere led to the shutdown of a number of critical facilities for the global economy as a consequence of the Texas energy crisis. https://www.power-technology.com/features/the-great-state-of-texas-explaining-the-power-crisis-and-what-happens-next/

The Committee for the regulation of natural monopolies (KREM) of the Ministry of National Economy

KREM executes the state regulation and control of natural monopolies. It sets tariffs for the following services for natural monopolies:

- Electric power transmission and/or distribution.
- Production, transportation, distribution and/or supply of the heat energy.
- Technical dispatch of electric power into the grid and for consumption.
- Electric power production and consumption balancing.

Since 2009 Kazakhstan has been applying price caps for the price of electric power. The introduction of the price caps for power generating companies has been an attempt to resolve the challenge of generating capacity inadequacy by modernising the country’s generating assets in the shortest possible time. In exchange to receiving a higher price cap, each power plant committed to a 2009–15 investment plan. The price caps were subject to annual upward adjustments so to maintain the investment attractiveness for the industry. In 2009–15, under this “tariff-for-investment” price-cap scheme, the power sector attracted about USD 6.8 billion for the expansion, modernisation, and overhaul of existing power plants. By the end of 2015, the tariff-for-investment scheme was completed, successfully facilitating about 3,000 MW of additional generating capacity for the overall power system.

In 2016, to replace the “tariff-for-investment” price-cap scheme, Kazakh policymakers planned to launch a capacity market, however its launch was postponed until 2019. This meant that the government was forced to maintain the price cap system. The new price caps were set at 2015 levels for the subsequent three years (2016–18), however the investment variable was replaced with the cost of renewable power by including the latter into the price caps of conventional power plants.

Notably, according to the renewables’ enabling regulation, the conventional power plants are conditioned as buyers of electric power and purchase renewable power from the financial settlement centre RFTse (RFTse for RES) in proportion to their share of output.

Following the launch of Kazakhstan’s capacity market in 2019 and subsequent changes to the wholesale market legislation, the consumers’ power price changed to accommodate the two variables: the price cap for the electric power set by groups of energy producing companies (the tariff for electric power) and the price for the services of maintaining the electric power capacity ready to generate (the capacity tariff).

The capacity tariff for the wholesale consumers is made up of the sum of the following costs:

- The cost of the newly commissioned capacity.
- The cost of modernised capacity or of the capacity undergoing expansion.
- The cost of TETs capacity in the volume necessary to meet the heat load schedule.
- The cost of capacity selected during the centralised annual trade.
- The Single Buyer's costs.

The sum of the total costs, accounting for the Single Buyer's commission (abbreviated in Russian as RES RFTse from *raschetno-financoviy tsenter podderzhki vozobnovlyayemykh istochnikov energii*), are divided by the total amount of absolute peak consumption load for the coming year (calculated from the total amount of consumption during the peak hour). A single capacity price that derives from these calculations is set in tenge/MW/month.

Notably, there are neither transparent nor market mechanisms for selecting and determining the capacity price for the modernised capacity or for the power plants undergoing expansion. The Ministry of Energy defines the terms as well as the capacity price for such projects on a case-by-case basis following the recommendations by the Council of the Kazakhstan Electricity Association, acting as a Market Council (Sovet Rynka in Russian), in accordance with the decree by the Ministry of Energy). The Market Council's executive committee (*presidium* in Russian) predominantly includes representatives of the energy companies, which deprives the committee of objectivity when passing decisions on the energy producing companies' investment projects, that in the end of the day would be paid by the end consumers.[14]

The launch of the capacity market was accompanied by the adoption of the Ministry of Energy's decision to reduce the capacity price cap to 590 thousand tenge/MW per month instead of the previously announced capacity tariff price cap of 720 thousand tenge/MW per month. In addition, the electricity price caps in 2019–20 excluded a profit margin. Altogether, these decisions had a negative impact on attracting investment into generating assets in Kazakhstan.

The restrictions imposed by the Ministry of Energy at the capacity market resulted in a lack of market incentives to reduce capacity prices during the centralised trade. The effect that the centralised capacity trade has had on the capacity price reduction is limited to 0.7%, which defeats the purpose of the competitive capacity selection, see Table 6.3. A lack of the capacity market target-setting (encapsulated in Russian word "tselepolaganiye" that means the place of the capacity market in resolving the energy trilemma and the role it will play in the whole energy system evolution) reduces this mechanism to the of distribution capacity revenue between the power plants, rather than the competitive selection of capacity and investments into assets with the needed characteristics and technological parameters of equipment.

Table 6.3 The capacity market 2019–21

	Billion tenge		
	2019	**2020**	**2021**
Modernisation and expansion	9.30	22.51	20.50
Purchase from TETs	17.62	16.67	17.12
Centralised capacity trade	35.15	43.31	41.94
Total purchase volume	62.07	82.49	79.55
The effect from centralised trade	2.863	0.965	0.297
% of the market	8.1%	2.2%	0.7%

The decision to launch the capacity market with the price constraints described above, as well as the administratively capped annual amount of funds that could be used for the modernisation and overhaul of the power assets at individual tariffs have resulted in a significant reduction in the level of investments into the power plants since 2019 (the capacity market launch), see Figure 6.10.[15]

The 2021 amendments to the legislation on the electric power industry intended to single out the costs associated with the purchase of renewable power by the conventional power plants within the price caps.

From July 2021 the wholesale market consumer price consists of the following:

- The end-consumer electricity tariff, which includes the price cap set by the groups of energy producing companies and the allowances to support the use of renewable energy sources (these two components are the tariff for the electric power).
- The tariff for services ensuring the capacity readiness to meet demand (the capacity tariff).

The growing weight of renewable support on the conventional power plants' finances has been behind a shift of the RES allowance into a separate cost category. The share of the costs associated with the purchase of renewable output in the total costs for conventional power plants has increased from 2–3% to 10–14% over the five years.

Over the past decade, the power generating sector has been the testing ground for a variety of tariff policies: from the free market price formation to the introduction of the "tariff-in-exchange for investment" scheme, from setting the price cap without profit margins to the inclusion of the cost of renewable energy into the price caps, and finally singling out the allowances within the price caps that support the use of renewable energy.

14 It would be prudent for the Market Council's Executive Committee to include other market representatives to reflect their position and protect their interests. Otherwise, the Market Council represents solely the interests of the energy producing companies.

15 The national project for the development of the electric power industry, Measure 1. Increasing the investment allowance into the electric power industry above the level of 2015 within the framework of the investment agreements with energy producing companies for the modernisation, expansion, overhaul and (or) upgrade of the power plants under the framework of the capacity market.

Figure 6.10 Investments into power plants between 2009–21

Source: companies' data, RFTse for RES

To ensure the progressive development of the electric power industry it is important to define the long-term tariff policy and assign the powers relating to the setting and approval of all tariffs in the electric power industry to a single state body.

The heat energy sector

In Kazakhstan the electric power industry also includes the heat energy sector, since 60% of the heat energy is produced by the power plants (TETs). The cogeneration of electricity and heat energy by TETs in Kazakhstan falls under dual regulation by both the Ministry of Energy (that sets the price caps for the electric power) and by KREM that sets the heat energy tariffs.

Climate change in Eurasia and its impact on energy consumption

The fallout from the Texas energy crisis, which was caused by the abnormally cold weather in February 2021, was not only significant for this state, but for the global economy (following the shutdown of the largest microchip and micro schemes production facility). It has demonstrated the importance of accounting for climate change during the energy systems' planning.

The global warming caused by the anthropogenic increase in the greenhouse effect (IPCC, 2021) is characterised by faster warming in polar and temperate latitudes compared to tropical (the so-called "polar enhancement").[16] In addition, a more rapid trend in warming is observed over land compared to the ocean, due to the lower energy intensity of evaporation.[17]

In Eurasia, the average rise in atmospheric temperatures reduces the recurrence of abnormally low temperatures and increases the recurrence of abnormally high temperatures.[18] Thus, in 1950–2018 the number of abnormally warm days in Eurasia increased by 2–8 days per decade, whilst the number of abnormally cold nights decreased by a comparable 2–8 days. At that, the greater increase in hot days is observed in the west of the continent, whilst a greater decrease in cold nights – in the east of Eurasia.

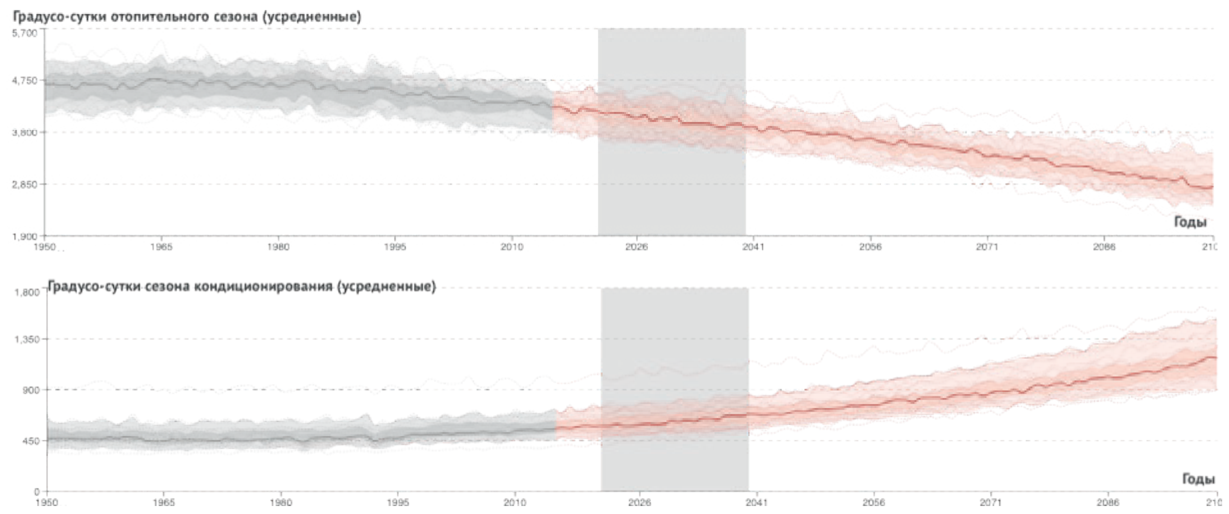
The extended periods of abnormally cold or abnormally warm weather are of particular interest. Statistically, there is a significant increase in the overall duration of abnormally warm periods (by 1–4 days for each decade since 1950) and a much weaker decrease in the abnormally cold periods (0–1 day per decade) in Eurasia. Notably, in the south-east of the United States the duration of cold periods has practically not changed during 1950–2018, so the abnormally cold February 2021 in Texas did not contradict the aspects of regional climate change.[19]

In general, whilst abnormally cold periods are becoming rarer, they will continue to be a climate feature of the temperate latitudes in both North America and Eurasia in the coming decades.

The Coupled Model Intercomparison Projects (CMIP) 6, which models the earth's sensitivity to future climate changes and that has become the foundation for the 6th Intergovernmental Panel on Climate Change (IPCC) report (IPCC, 2021)[20] demonstrates that the warming trend will continue

16 Bekryaev, R. V., Polyakov, I. V., and Alexeev, V. A., Role of Polar Amplification in Long-Term Surface Air Temperature Variations and Modern Arctic Warming, Journal of Climate 23 (2010) 3888–3906.
17 Sutton, R. T., Dong, B., and Gregory, J. M. (2007), Land/sea warming ratio in response to climate change: IPCC AR4 model results and comparison with observations, Geophys. Res. Lett., 34, L02701
18 https://archive.ipcc.ch/report/srex/
19 Doss- Gollin J. et al 2021 How unprecedented was the February 2021 Texas cold snap? Environ. Res. Lett. 16 064056.
20 https://www.carbonbrief.org/cmip6-the-next-generation-of-climate-models-explained

Figure 6.11 Predicted changes in the degree – days for the heating season and the cooling (air conditioning) season.



Source: http://interactive-atlas.ipcc.ch/

over the coming decades. From the middle of the 21st century this trend will either plateau, following the SSP 126 sustainable scenario of the socio-economic development, or will continue to increase following the SSP 585 scenario of active reliance on hydrocarbons.

The climate change impact on energy consumption will be particularly evident on the reduction during the heating season and an increase in cooling (air-conditioning), that could be expressed in the relevant degree – days. In Eurasia this change will be notable with the easing of the frosts, see Figure 6.11.

The Figure shows changes to the duration of degree-days under the SSP 585 assuming the active reliance on hydrocarbons averaged by Eurasian regions according to the CMIP 6 project calculations. The dotted lines refer to the data form various scenarios, whilst the red line refers to the median value.

It is important to account for the climate changes whilst planning the energy systems' operation.

Due to the social importance of the heat energy price, the state restricts the heat energy tariff growth through KREM, which expresses itself in setting the heat energy tariffs below the costs. At the same time, TETs are experiencing price competition from the coal-fired KES (GRES) power plants.[21] The electrical efficiency for electricity production at KESs (GRES) is physically higher than that at TETs, but the fuel energy utilisation ratio at TETs is 70–80% due to the associated heat energy production. The efficiency of using TETs instead of a combination of a boiler house and a KES (GRES) has been proven scientifically and empirically by the fact that the total resource costs at TETs are lower for heating and power supply purposes in the northern cities with a population of more than 100 thousand people.

Unlike the electric power industry the heat energy supply involves three variables: production, transportation (inclusive of the distribution and supply of heat energy) and consumption of heat energy.[22]

The heat energy market operates at the retail level only, at that, in practice consumers are unable to choose their heat energy suppliers. The heating networks and the boiler houses tend to be on the balance sheets or under management of municipal administrations. This measure was forced on them to enable direct investments into updating the heating networks infrastructure. A standalone law "On the heat energy supply" is under development and will introduce a separate regulation for the heat energy supply industry. It will optimise the planning of heat energy loads and operating modes for the heating networks with the possibility of introducing heat pumps for utilising waste energy.

Notably, the low cost of energy resources, that increases the payback period for the energy saving and energy-efficiency projects, is amongst the factors that constrain the pace of the power and heat energy sectors' modernisation.

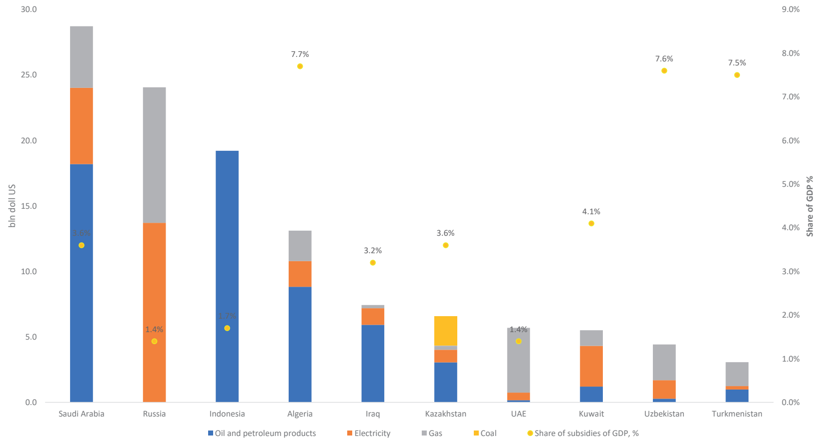
By setting the electricity price caps at the level of net cost of power production, or just below it, means that the power plants are deprived of means to invest into energy efficiency projects and modernisation projects (unless the latter are included into the capacity market investment projects).

The practice of suppressing the energy resource prices means Kazakhstan in fact subsidises them. In a 2019 rating

21 The efficiency of electricity production by KES (GRES) tends to be higher than that of TETs. However, due to the additional heat energy production TETs have an extremely high fuel utilisation factor (the overall efficiency for the electricity and heat energy output)

22 According to the definition in the current legislation, the electric power industry includes the production, transmission, distribution and consumption of electricity and heat energy.

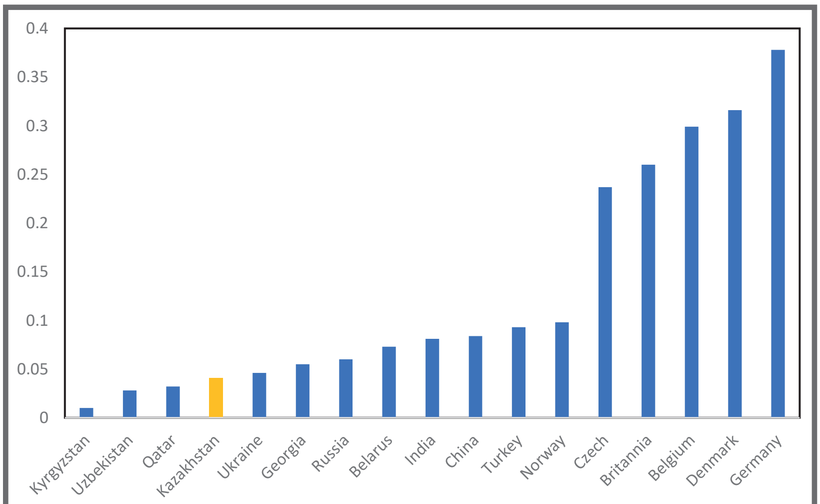
Figure 6.12 Subsidies for domestic energy consumption in oil and gas exporting countries*



Source: IEA, Value of fossil-fuel sabsidies by fuel in the top 25 contries

*See https://www.iea.org/data-and-statistics/charts/value-of-fossil-fuel-subsidies-by-fuel-in-the-top-25-countries-2019

Figure 6.13 The cost of electricity by country (in tenge/kWh)



Source: www.globalpetrolprices.com

by the International Energy Agency (IEA), Kazakhstan was eleventh in the world in terms of energy resource subsidies, which amounted to USD 6.6 billion or 3.6% of the country's GDP. At the same time, Kazakhstan was the only country in the ranking with coal subsidies (USD 2.2 billion), see Figure 6.12.[23]

According to the IEA methodology, subsidies are defined by the difference between domestic and global prices, accounting for price parity. The coal price subsidies primarily include railroad transportation which is at the expense of other commodities (metals, oil and oil products). The price subsidies of natural gas, petroleum products and coal are underpinned by the electric power and heat energy tariff regulation. The energy resource subsidies impact power prices in Kazakhstan which remain one of the lowest in the world, see Figure 6.13.

At the same time, there has been a growth in the conventional power plants' average price of electricity. Thus, the average price cap in 2019 was about 6.5 tenge/kWh, whilst in 2020 it increased to 7.6 tenge/kWh, which was predominantly linked to the increase in costs for the support of renewable energy resources.

The seven-year price caps that were meant to send long-term price signals to the investors have been reviewed regularly to account for the growth of costs associated with the support of renewable generation, as well as inflation, increases in the cost of fuel, equipment, and payroll.

Summarising the above, under the current tariff regulation with non-functioning market mechanisms, the prospect of a new large-scale modernisation program, let alone the power industry's energy transition, seems feasible only subject to the power industry reformation within the shortest possible time.

23 https://www.iea.org/data-and-statistics/charts/value-of-fossil-fuel-subsidies-by-fuel-in-the-top-25-countries-2019

6.2.5 The wholesale electricity market analysis

The electricity market in Kazakhstan consists of the two levels: the wholesale and retail electricity markets.

At the wholesale market, Kazakh power plants sell electric power to energy-supply organisations and wholesale consumers. The wholesale electricity market consists of a:

- Decentralised market where electricity is sold under bilateral agreements.
- Centralised market where during the exchange-based trade electric power is traded at a spot market including day-ahead and intra-day trading, and the power supply for medium and long-term periods.
- System services and auxiliary services market.
- Wholesale capacity market.
- Balancing market.

The wholesale market participants are:

- Power plants or energy producing organisations , that supply electricity to the wholesale market in the volume of at least 1 MW of average daily capacity, and are equipped with an automated system for commercial metering of electricity (ASKUE).[24]
- Consumers of electric power who purchase electricity at the wholesale market in the volume of at least 1 MW of average daily capacity and are equipped with ASKUE.
- Power transmission companies with characteristics corresponding to the above bullet.
- Power supply organisations that do not have their own power grids and that purchase electricity at the wholesale market to resell it in the amount of at least 1 MW of average daily (base) capacity.
- The system operator (KEGOC).
- The operator of a centralised electricity trade (KOREM).
- The Settlement and Financial Center for the Support of Renewable Energy Sources (abbreviated in Russian as RFTse from *raschetno-finansovy tsenter*). RFTse is a Single Buyer at the wholesale capacity market and a settlement centre.

Building on the 2020 results, one cannot help noticing some dysfunctionality in all the wholesale electricity market mechanisms. The centralised electricity trade has been reduced to a minimum (the share of contracts signed during the centralised trade is about 1% of total generation), the capacity market projects' selection has not resulted in lower capacity prices and the selection of capacity during the centralised trade lacks competition, the capacity market projects for modernisation and expansion of the power generating assets lack the necessary funds enabling the transition to the Best Available Technologies (contrary to Kazakhstan's environmental policy), the balancing market has not been launched and continues to operate in a simulation mode. And the investments into modernisation of existing power plants have decreased several times below the levels of investments prior to the introduction of the capacity market (see Figure 6.10).

To improve one's understanding of the wholesale market dynamics, according to the Register, there are 359 wholesale electricity market participants, of which: 19 are REKs, 114 – power plants (including 57 RESes), and 225 consumers, of which 26 are ESO. The renewable power plants do not have to operate on the electricity market directly, since they sell electricity through a Single Buyer (RFTse for RES).

The structure of electricity production in Kazakhstan is as follows: the large energy holdings Samruk Energo, CAEPCO, and KKS account for about 41.2% of power generation. The industrial groups that happen to own generating capacity (ERG, Kazakhmys, Kazzinc, and Arcelor Mittal) account for 24.6% of the power output. The state-owned power plants produce 10.7% of the electric power, whilst the renewable plants that supply electricity through RFTse account for 2.4% of output. The generation owned by oil and gas companies is 4.1% of total generation, whilst the independent power plants account just for 17.9% of the total electricity generation in the country, see Figure 6.14.

When state price control is taken out of the equation, the structure of the electricity market, as well as the number and affiliation of the market participants, would indicate that the market operates as an oligopoly.[25]

Under such a model, the limited number of producers do not create effective market mechanisms sufficient for the competitive regulation of electricity prices, whilst the limited number of buyers at the electricity market, some of whom are affiliated with electricity producers (REKs, ESOs), do not create sufficient competitive downward pressure on the electricity price.

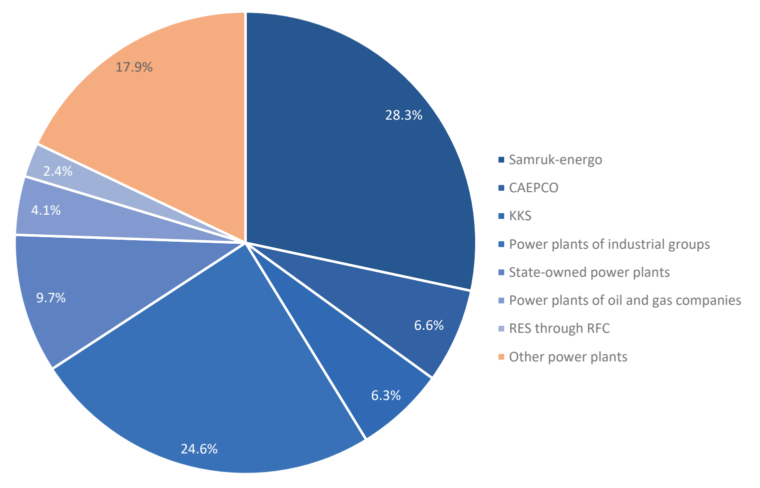
As a result, the implementation of free competitive market principles at Kazakhstan's electricity market has a muted effect, therefore, a revised approach should be considered. For example, a Single Electricity Buyer could facilitate a more flexible regulation of producers' electricity prices with a mandate to enable modernisation, improve reliability, and low-carbon development of generating assets.

Notably, the positive effects are achieved in markets without stringent price regulation and with a sufficient number of independent participants competing for market share or a more optimal price. Under the circumstances when the price is controlled administratively, and a limited group of the market players control both supply and demand, the market mechanisms for power generation require an

24 The automated commercial electricity metering system (AMR or ASKUE in Russian) – is a metering system that facilitates the remote storage and processing of data and information on the power consumption or output of electricity into the grid.

25 The oligopoly refers to a market structure with an imperfect competition with an extremely limited number of suppliers/sellers.

Figure 6.14 The structure of electricity production by ownership



Source: companies' data

alternative. The Single Electricity Buyer mechanism may turn out to be more effective if there is a competitive selection of electricity suppliers, considering the trilemma of the electric power industry development. In this case, accounting for the long-term power industry targets, it would be possible to form a mechanism for the selection of electricity suppliers with the help of an information system that would optimise the merit order based on a variety of parameters, such as greenhouse gas emissions reduction, fuel consumption minimisation, and least final cost of electricity supply.

The centralised electricity market.

The centralised electricity market represents an exchange-based platform for the short to medium-term electricity trading (spot trading for the day-ahead, week-ahead, month-ahead and quarter ahead), as well as long-term (up to one year). In 2020 the share of centrally traded power was less than 1% of total electricity production, see Table 6.4. Of course, prices formed in this way cannot serve as objective market price indicators. Notably, in previous years, the share of centralised trade reached 28%. This drastic decline has been the consequence of Ekibastuz GRES-1 and Ekibastuz GRES-2 withdrawing from the market following changes to Samruk-Energy's electricity selling policy.

An efficient operating electricity spot market is a necessary element of a developed competitive electric power market since it facilitates the formation of a variable part of the daily schedule. However, due to the peculiar workings of the wholesale electricity market in Kazakhstan, the spot market is still in its infancy. Amongst the main reasons for the underdevelopment of the spot market is the high share of oligopolies in the electricity market (60% of electricity is supplied by five energy companies) and the lack of price volatility due to state regulation of the price caps for power generation. Additionally, there is a lack of individual responsibility for the non-compliance with the planned production and consumption daily schedule, as well as the infeasibility of competition between the different type of regional power plants (for example, regional TETs, and KES [GRES], or KES [GRES] and GES [hydropower]).

Exchange-based markets are an integral part of most global energy markets. Effective functioning energy exchanges are, first of all, a transparent price regulator, since the price of the spot market is influenced by all external and internal factors integral to the market. At the same time, exchange trade in Kazakhstan did not gain momentum for the following reasons:

- The spot trade in Kazakhstan is used to improve the electricity prices in the bilateral agreements, which does not reflect the purpose of a spot market. As for medium and long-term trade, since the legislation prohibits the sale of electricity exceeding the price caps, the bilateral auction with marginal prices is not feasible. The currently used countertrade method has been modified to account for the above legislative restrictions but does not adhere to the exchange price setting method.
- The absence of the billing and settlement system for medium and long term trade means the market participants run the risk of breaching contracts with regards to the payment or power supply, which is a departure from the general principles of the exchange-based market. The availability of a settlement system (a clearing centre) is one of the key aspects of an exchange-based trading system for any commodity. The clearing centre can operate as part of an exchange and as a separate structure, subject to the national legislation. However, in accordance with the legislation, the administrator of the centralised trade in Kazakhstan, KOREM, is not allowed to clear and settle payments following the centralised trade transactions for the medium and long-term.

Table 6.4 The share of centralised trade compared to the electric power production in 2016–20.

	2016	2017	2018	2019	2020
Electricity production (mln. kWh)	94,076.5	102,383.6	106,797.1	106,029.8	108,090
The spot trade volume (mln. kWh)	1,048.6	318.7	211.69	350.32	190.29
Share of spot trade (%)	1.10%	0.30%	0.20%	0.30%	0.18%
Medium and long-term trade volume	9,206.9	28,641.1	21,049.1	175,97.5	939,289
Share of medium and long term trade (%)	9.79%	27.97%	19.71%	16.60%	0.87%

- Amongst other challenges over the medium and long-term is the absence of the obligation to sign a power supply agreement. This means that the registration of a trade at the auction does not mandate signing a power supply agreement between the seller and the buyer. It does not warrant the parties' mutual responsibility for power delivery, timely payment of delivered power, including the seller's liability towards the buyer in case of emergency failure to supply power.

The long-term centralised trade, with this regard, has no economic sense for wholesale market participants as on the one hand it prohibits sellers from selling power at prices above the approved price cap, but on the other hand, have no incentives to hedge the risks associated with singing power purchase agreements and subsequent delivery.

The balancing market

The balancing market, which could smooth out daily deviations from scheduled, was due for launch in 2008, but continues to operate in a simulation mode. Kazakhstan is preparing to launch its balancing electricity market from 2022. The need to launch a real time balancing market from next year was emphasised at a government meeting on 6 February 2021, when discussing the development of the renewable energy sources in the country.

However, despite operating the balancing market in a simulation mode for over ten years, Kazakhstan failed to resolve certain issues that would enable its integration into the structure of the wholesale electricity market. The generation structure lacks enough flexible capacity to balance fluctuations in daily electricity production and consumption. This is an acute problem, which is only getting worse with every year. The structure of generating capacity in Kazakhstan historically meets base-load demand during the day, whilst the peak demand is met by Russian and Central Asian power systems. The development and commissioning of intermittent generation has exacerbated this issue further, see Figure 6.15

Kazakhstan's system operator has noted that "the capability for UES Russia to balance UES Kazakhstan's deviations have been exhausted. The UES Kazakhstan's deviations from the agreed dispatch schedule can reach as much as 1,300 MW, which threatens the separation of the power systems and the subsequent development of systemic accidents involving the mass restrictions to consumers' power consumption. The Russian side has issued an official complaint for the systematic violation of the conditions for the parallel operation of the two power systems by UES Kazakhstan and announced it was forced to shift to the UES Russia independent operation from the UES Kazakhstan. This problem has been brought up to the attention of both governments".[26]

The need to develop flexible generation in Kazakhstan has been talked about for several years, but the market has not sent sufficient price signals for building flexible generation. The tenders for constructing flexible generation were not announced at the launch of the capacity market, furthermore there is no mentioning of the need to create conditions for flexible generation and its further operation at the electric power market in the legislative acts until late 2020.

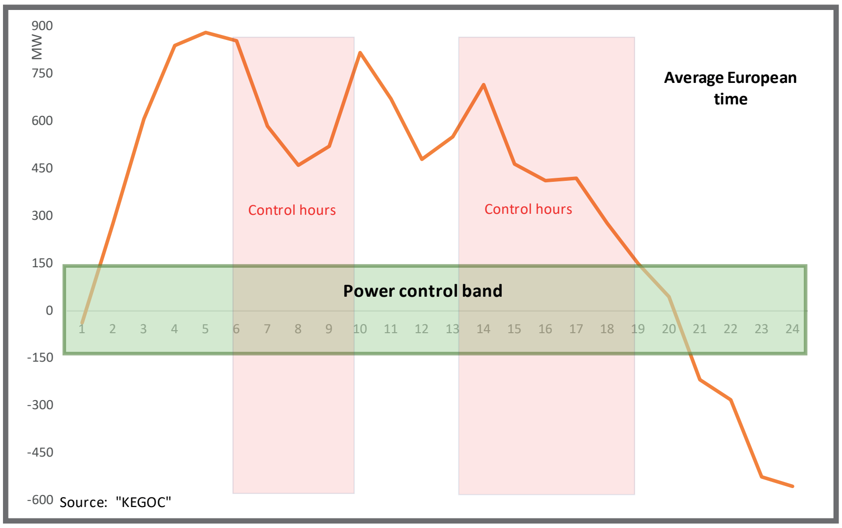
Notably, in December 2020 state bodies approved changes to legislation facilitating the development of flexible generation. On 7 December 2020, the amendments to the Law "On the Electric Power Industry" mandated the development and construction of flexible generation; the first auctions for which are scheduled for December 2021. However, even if we assume the auctions' success and the commissioning of these power plants on time, the earliest the flexible capacity will enter the system would be 2025, upon the commissioning of gas-fired power plants and in 2027 with the commissioning of hydropower plants.

To involve power plants into balancing power in the energy system, Kazakhstan initiated a project for integrating an automatic frequency and capacity control at the power plants (abbreviated in Russian as ARCHM from *avtomatizirovannoye regulirovaniye chastoty i moshnosti*), including Ekibastuz GRES-1 and hydropower plants – Bukhtarminsk, Ust-Kamenogorsk, Shulbinsk, and Moinak GESes. Whilst this project will maximize the use of available flexible capacity, this generating capacity is insufficient to balance the whole energy system.

The lack of balancing capacity would cause significant price volatility at the balancing market. We assume, the planned introduction of the price caps for the generators' balancing power is to mitigate this circumstance. Whilst this initiative will help curb the electricity prices' growth, the administratively set tariffs cannot send objective price signals and reflect the real cost of balancing in

26 KEGOC Report 2021, on balancing UES Kazakhstan.

Figure 6.15 The volumes of fluctuations purchased and sold at the border of the UES Kazakhstan and the U
Russia at peak load day on 12 January 2020.



Kazakhstan. The balancing prices should fully reflect the generators' real costs for electricity generation in real time, and account for profit.

Considering that prior the launch of flexible generation in Kazakhstan, some of the peak load in the power system will be met by Russia's power system, and purchased from the Russian generators, it will be paid by Kazakhstan's consumers at the marginal price of the Russian balancing market. The planned balancing market pricing policy of setting the price caps for balancing electricity by groups of energy producing organisations raise doubts about further development of market relations, as well as attracting investments into the power generating sector.

The issue of equipping the wholesale electricity market participants with the necessary commercial infrastructure – an automated system for commercial metering of electrical energy (abbreviated in Russian as ASKUE)remains unresolved. Currently, more than a third of consumers of the wholesale electricity market do not have – an automated system for the electric power commercial metering. Most likely, the launch of the balancing market will incentivise the market entities to address this issue. Summarising the above, the lack of commercial balancing system in the power sector:

- Restrains further development of renewable energy and makes the goals for increasing the share of renewable energy in the structure of generation difficult to achieve.
- Creates no economic incentives for the wholesale market participants to comply with the daily schedule, i.e., there is no targeted distribution of imbalances in the power system.
- Creates no incentives for the energy producing companies to sell electricity during peak hours.

The capacity market

According to the current legislation, all subjects of the wholesale electricity market are required to participate in the capacity market. However, the industrial groups with own-generation and large consumers have the right to supply capacity from their own power plants, which reduces the number of capacity market participants that take on the capacity market costs.

The benefits of the capacity mechanism for power plants are that the assets selected for the supply of capacity receive revenue regardless of the demand (if the fact that the plant is ready to generate is confirmed by the system operator [SO]), thereby providing long-term guarantees and a high level of revenue stability. All costs relating to the commissioning of new generation, expansion and modernisation of existing power plants are distributed equally amongst all wholesale buyers (except for the industrial groups representing the largest consumers).

The operating power generating companies that pass the certification of their generating units' electrical capacity by the system operator are allowed to participate in the capacity market.[27] Essentially, this implies defining the volumes of capacity ready for supply by confirming the range of the electrical loads and the declared parameters of the generating plants with the actual values. This approach does not adhere to the electric power industry's innovative and low-carbon development goals, since it implies the capacity market access to the maximum number of existing power plants.

The current capacity market rules do not impose requirements to the technical parameters of the power plants' equipment due for selection (for example, the steam pressure indicators, the year of the main equipment commissioning, the rate of load fluctuations, the type

27 See "The rules for the organisation and operation of the electric capacity market", Appendix to the order of the Minister of Energy of the Republic of Kazakhstan of 7 November 2018 No. 439, Approved by the order of the Minister of Energy of the Republic of Kazakhstan on 27 February 2015 No. 152.

of fuel, turbine technologies, performance indicators, and environmental parameters), therefore the System operator does not utilise the capacity market mechanism for addressing the whole system goals on improving efficiency, increasing flexibility, forced modernisation, and decarbonisation.[28] With this regard, to support the power industry progressive development, the Capacity Market Rules could be reviewed and extended with the requirements for the power equipment technological parameters.[29] The requirement of such parameters only for investment projects (for the reconstruction, expansion, and modernisation of existing power plants) is insufficient and limits the rate of technological renewal and innovative development of the sector.[30] The lack of long-term target-setting (*tselepolaganiya*) for both the electric power industry and the capacity market and the capacity selection under price control has limited the effectiveness of this market instrument.

For comparison, from 1 January 2020, according to the European Parliament resolution of April 2019, and updates to the previously adopted documents regarding the functioning of the Electricity and Capacity Markets in the European Union (EU) (in 2009–16), the capacity market mechanisms are viewed as last resort and require validation of reasons and goals.

The regulatory and procedural changes at the EU's electricity market aim at creating the electricity market signals that could stimulate better flexibility, support the power plants' decarbonisation and innovation in support of the EU's goals to achieve the continent's carbon neutrality by 2050. From 1 January 2020 the capacity market access is restricted to the EU power plants that pollute the atmosphere. The power plants with the emissions exceeding 550 grams of CO_2 /kWh that have not participated in the capacity mechanisms will not get access or receive capacity payments starting from January 2020. Access to the capacity market for power plants that have already been selected to provide capacity for the next four years after 2020, with emissions exceeding 550 grams of CO_2 /kWh, will be closed from 2025.

28 For comparison, the competitive selection of generating capacity in Russia (abbreviated as KOM) excludes generating equipment with a live steam pressure of 9 MPa or less, consisting of a turbine unit with a steam turbine (steam turbines) and its main parts produced earlier than 1967, except if the utilisation rate of the installed capacity of such a turbine unit for the year preceding the selection was more than 8%.

29 "The target indicators are set for each year in the investment agreements for the modernisation, expansion, reconstruction and (or) renewal of generating capacity, namely: the fuel to power/heat energy ratio, the available electrical capacity; the service life of the main generating equipment; the wear and tear of the main generating equipment; and environmental targets». See the Law of the Republic of Kazakhstan dated of 9 July 2004 No. 588-II «On the Electric Power Industry» (amended and supplemented on 19 April 2019), article 15-4, paragraph 6.

30 "The investment agreements for modernisation, expansion, reconstruction and (or) renewal of capacity set annual target indicators for the following parameters: specific consumption of equivalent fuel for the supply of electric and (or) heat energy; available electrical power; service life of the main generating equipment; the degree of deterioration of the main generating equipment; environmental indicators «. See the Law of the Republic of Kazakhstan dated 9 July 2004 No. 588-II «On the Electric Power Industry» (as amended and supplemented on 19 April 2019), article 15-4, paragraph 6.

6.3 Structure and target-setting for the reforms

The transition of Kazakhstan's electric power industry towards a cleaner and more sustainable future is difficult to realise, when the reference point for its development is the *Concept for the fuel and energy sector long-term development of 2014.*[31] According to the Concept, whilst Kazakhstan aims at "increasing the share of renewable power generation to 30% by 2030" it also plans to "maintain a significant share of electricity production by coal-fired power plants in the total production of electricity". The intention to achieve Kazakhstan's climate targets solely through the integration of renewable energy, whilst maintaining the conventional architecture of the power system (both in terms of generating assets and network infrastructure) and without setting the more ambitious goals for the sector's innovative development and the reform of its institutions can be explained by the fact that in 2014 the reliability and affordability of supply until 2030 were the higher priority tasks than the sector's "green agenda". Notably, Kazakhstan's "Green Economy Concept" does not represent a power industry document, as it sets sustainable goals for the economy as a whole, only referencing the general outline of changes in the energy industry.

Nevertheless, the global initiative for transitioning the energy-intensive industries and the energy sector to the path of sustainable development, that gained momentum after 2015, meant that **the key global drivers** for the transformation of the electric power industry were set in 2016:

Sustainable development – setting decarbonisation targets and the goals for improving air quality contributed to the emergence of new technologies in the energy system, including low-carbon distributed generation, energy storage; electrification of heat supply and transport.

Costs' effectiveness – the industrial development strategies that pursue cost-effectiveness and innovative development stimulate the emergence and development of smart grids and smart technologies, as well as the integration of demand response into the energy system.

Safety of power supply – not only implies reliability of electricity and heat supply, but also the integration of digital systems for monitoring and forecasting load and cyber security systems.[32]

31 See: "The Concept for the fuel and energy sector development in the Republic of Kazakhstan to 2030 (Resolution of the Government of the Republic of Kazakhstan dated 28 June 2014 No. 724).

32 For example, the KEGOC's project on the implementation of synchrophasor technologies (WAMS/WACS)

The transformation of consumer behaviour under the influence of the "green" agenda – the desire to reduce the cost of electricity and heat energy stimulates the use of behind the meter technologies for electricity and heat consumption, supports demand response, creates prosumers of electric power, and enables a transition to new types of transport (electric cars, electric bicycles).

New formats of doing business at the market and within the industry – requires separating the network operator functions from that of the system operator; allows for the emergence of demand aggregators and efficiency aggregators at the retail market; supports microgrids, including those based on industrial energy complexes; and forces energy sales companies at the retail market to compete for the end consumer through tariff and quality of supplied electricity (with green credentials).

These global drivers should be accounted for when forming long-term goals for the development of the energy system and the directions of necessary reforms.

The system approach to the electric power sector planning

In contrast to the soviet era planned economy, the power systems in developed countries evolved in a decentralised manner on the basis of market competition, without the use of long-term planning. The climate change agenda and emerging environmental crises made it necessary to introduce long-term planning methods and certain central planning, with the introduction of non-market pricing mechanisms ("green" renewables tariffs, trading the GHG allowances etc.). The risk of this approach is the possibility of imbalances and inaccuracies in planning, since the decisions are made not on the basis of special scientific and technical research, but often for political and even populist reasons.[33] An example of such an approach is the proposal to use hydrogen in the EU's gas transportation system instead of natural gas. Such a proposal does not stand up to scientific criticism since the embrittlement of steel by hydrogen makes it impossible to use the gas networks for hydrogen transportation long-term. Kazakhstan has been able to partially preserve a systemic approach to the energy sector planning and retain state control over a significant number of energy assets (through state ownership or subsidiaries of the national company the National Welfare Fund Samruk-Kazyna). This means it can develop and implement a program for the energy sector development built on the principles of long-term planning and supported by the scientific and technical evidence.

6.3.1 The power industry's goals and challenges

Following the global trends, long-term target-setting and a clear definition of the goals and challenges in Kazakhstan's electric power industry will make it possible not only to map out the directions of the reforms, but also to make realistic assumptions about the future energy system's functionalities. The tasks and challenges faced by Kazakhstan's power sector could be summarized as follows:

Tasks

- Low carbon development of the electric power in-dustry and sector contribution to the achievement of the Paris Agreement goals
- Reliability of power supply
- Reliability of heat energy supply
- Investments attraction into power generating assets
- Innovative development and digitalisation of the pow-er sector
- Affordability of electricity and heat energy

Challenges

- High wear and tear of fixed assets (50 – 70%)
- High level of losses during power transmission (up to 9%)
- High environmental impact and high carbon intensity
- Low sector flexibility and balancing
- The low level of investment effectiveness
- Impact of rising electricity costs on social stability
- Lack of operational transparency in the industry and lack of data accessibility

In terms of the impact that the growing cost of electricity has on social stability, it should be noted that the residential costs associated with utility bills (electricity, heating, water supply, household waste removal) in Kazakhstan are amongst the lowest in the CIS countries. The ratio of utilities' cost to the average wage is the lowest in Kazakhstan (11.8%), compared with 12.2% in Uzbekistan, 13% in Belarus, and 17.1% in Russia.[34]

33 The study by the Carbon Market Watch shows that the surplus profits of the corporations in Europe deriving from the sale of allowances and accounting for the costs of the free allowances exceeded 24 billion euros and were ultimately generated at the taxpayers and consumers' expense.

34 https://www.energyprom.kz/ru/a/monitoring/kommunalka-i-koshelyok-sredi-stran-sng-oplata-kommunalnyh-uslug-menshe-vsego-byot-po-semejnomu-byudzhetu-imenno -v-kazahstane

6.3.2 Vision and target setting for the industry

Up until 2020 Kazakhstan's policy for the power sector has been to maintain the sector's status quo (*business as usual*), whilst passing separate laws and implementing isolated initiatives. The improvement of certain processes (such as shifting to auctions for renewable energy sources) was accompanied by a stringent price control policy that deprived the sector of financial incentives for the sector's technological and innovative development, both generation and networks (especially distribution). The capacity market has become a form of subsidy paid to existing coal-fired capacities, rather than a tool for selecting capacity fit for the energy system that faces an energy transition. The development of the grid infrastructure, as well as decisions on technological development of the energy system, are dictated from the standpoint of the electric grid company, KEGOC, rather than an unbiased system operator. The adoption of the new environmental code and the program for the transition to the principles of the Best Available Techniques (BAT) are separate initiatives that are disconnected from the *whole energy system approach* for the long-term development of the energy industry and the electric power industry, in particular.

A whole energy system approach to the development of the electric power industry within the framework of the energy transition implies the development of a portfolio of options for the transition to more sustainable (including clean) energy resources in all areas of their use (electricity, heat supply, transport) and the creation of a matrix of their application and subsequent evolution in the best interests of the end users, commercial sector, and industry. This means developing new policies and adjusting existing regulations and all available market mechanisms and economic instruments to stimulate the achievement of the set goals. **Thus, the first step for the electric power industry in Kazakhstan will be to agree upon the coherent vision for the power sector in accordance with the country's low-carbon and innovative development strategies already approved politically. At the same time, it will be important to define the outline of technological requirements and functionalities of the future power system architecture from the standpoint of a whole system approach to the energy sector development and considering technical, governance, commercial and social factors.**

The clear understanding of the power sector's vision and the power system architecture (key characteristics) by 2030-40-60 is essential not only for Kazakhstan as a whole to develop the pathways for reforms, to assess the cost of the electric power industry decarbonisation, and to change business models (by the power sector participants), but also for Kazakhstan's international partners who are already concerned about the carbon content of imported products.[35]

Based on the tasks and challenges and taking into account key global trends, the vision and pathways for Kazakhstan's power industry could be expressed as:

Creating highly efficient and flexible energy system for reliable and stable power and heat energy supply, in accordance with the pace of the country's economic development, capable of facilitating the sector goals of low carbon development by 2050, whilst ensuring a just (social) energy transition and centred around the needs of the end consumer.

The key functionalities of such power system will include:

- Enabling conditions for the power system operation that would simultaneously address the goals of environmental sustainability, efficiency and cost effectiveness, and reliability of power supply.
- Enabling conditions for the power system operation that would meet the goals of achieving environmental sustainability, efficiency, and cost effectiveness, and reliability of heat energy supply.
- Enabling conditions for incentivising investments into electric power, heat energy and network assets with the target technological characteristics in accordance with the sector's vision.
- Enabling conditions for the innovative development of the power sector.
- Enabling conditions for the use of smart grids and other power market technologies for the integration of new loads, new types of generation and energy resources/carriers.
- Enabling conditions for the maximum visualisation of the state of the power system at any time (sector digitalisation).
- Enabling conditions supporting the energy system development in a set direction through the holistic market and sector regulation with no retrospective force.
- Enabling conditions for supporting and exceeding consumers' expectations both from the reliability and quality of services, and from the functionality of the energy system.
- Enabling conditions for the constant monitoring of risks and opportunities in the operation of the power system, implementation of corrective actions,

35 According to the forecasts, the average carbon intensity of electricity produced in the OECD countries is 430 g CO_2 per kWh. To reach carbon neutrality by 2050 the carbon intensity will have to drop to 50 g CO_2 per kWh. The technologies that meet these parameters are wind and solar power plants, nuclear power plants and hydro power plants (See https://www.oecd-nea.org/jcms/pl_15000/the-costs-of-decarbonisation-system-costs-with-high-shares-of-nuclear-and-renewables). For some countries (where coal or gas generation are hard to abate) the policy framework and a system architecture assume a higher criterion of 100 g of g CO_2 per kWh.

protocols and technological regulation (including emergency situations).

The above wordings do not specify the market mechanisms. More so, Kazakhstan, like many other industrial economies' will have to develop such approach to the energy transition that would facilitate economic efficiency, support infrastructural availability, and ensure social acceptability of any changes in the electric power industry. At that, vision and target-setting, as well as the anticipated power system functionality will define the energy systems' characteristics (the structure of generating capacity, network, technological development, and fuel balance).

For example, Kazakhstan is already planning to use the Single Electricity Buyer model, as part of its "Plan of the Nation – 100 Concrete Steps" Program (step 50). Section 6.3.5 will demonstrate that despite a clearly non-market nature of this approach the Single Electricity Buyer, subject to adhering to the vision, as well as the environmental, economic, climatic and social variables, could become an effective tool in realising the above mentioned goals by the means of competitive selection of suppliers. The capacity mechanisms also must be aligned with the common industry goals, incentivising the displacement of inefficient capacity and modernisation of assets, including a shift to BAT, but on a competitive basis.

The shift to the result-oriented tariff setting methodology for natural monopolies (setting efficiency targets and cost effectiveness parameters of spending, targets for innovative development, as well as environmental sustainability) in accordance with the industry's vision and goals, that would assure profit (for electricity transmission/distribution, system services, production and transportation of the heat energy), requires changes to their target-setting, as well as fine-tuning price regulation to cover the costs associated with effective investments into new technologies and perspective areas in the interests the industry, technological architecture and end consumers' (including future consumers) in addition to the costs covering reliability and quality of power transmission and distribution.

Reforming the retail market will involve development of new tariff schemes and services, as well as industrial and economic policy initiatives that would encourage consumers to support the industry's target-setting.

6.3.3 Shifting to BAT principles

The Best Available Technologies (Techniques) [BAT] is an approach adopted by the EU, 38 OECD countries, Russia, Belarus and China as part of the policy framework for preventing and controlling industrial pollution by integrating advanced environmentally friendly technologies.[36] The BAT reference documents are the integral part of this approach covering, as far as it is practicable, best technologies available by industrial activity.

The new Environmental Code passed in 2021 provides for a gradual shift of industrial activities that fall under the first polluter category to BAT,[37] incentivised through a several-fold increase in environmental payments (2, 4, and 8 times). To offset the steep increase in the environmental payments, businesses will be forced to introduce clean technologies and receive an exemption from environmental payments for a certain period. Upon shifting to BAT and getting a subsequent approval by the Ministry of Environment the entity receives an integrated environmental permit (IEP or KER in Russian from *kompleksnoye ekologichesoye razresheniye*) and is exempted from the environmental payments for ten years. According to the data provided by utilities (generators), the environmental payments constitute 1–3% in the net cost of electricity production by the coal-fired power plants in Kazakhstan.

Several industry-specific BAT draft reference documents (BREF) have already been published including a draft of the BREF for "Large combustion plants".[38] During the first stage (from 2025) the shift to BAT principles will be put in place by the 14 largest coal-fired power plants in Kazakhstan.

For coal-fired generation the sulphur oxide remains the main (57%) polluting matter. The integration of BAT and increase in environmental payments will call for a new sulphur content standard in coal, see Figure 6.16.

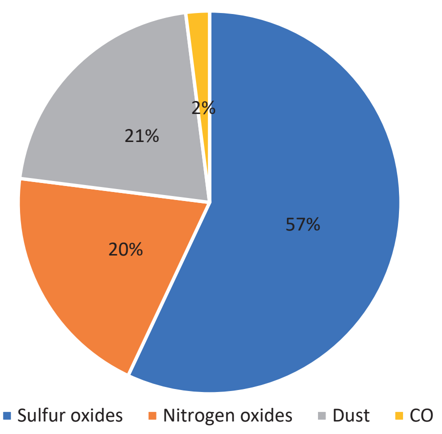
The main areas of BAT application in the power sector would be sulphur and nitrogen emissions' suppression, the installation of new electric filters for dust collection, optimisation of combustion systems, and ways of reducing the incomplete chemical combustion (CO), the emissions monitoring systems, as well other measures aimed at reducing the environmental impact. The energy-saving technologies are also mentioned in the BAT reference books. Although the main impact of BAT on

36 OECD is an international Organisation for Economic Co-operation and Development that aims at "shaping policies that foster prosperity, equality, opportunity and well-being for all". Most of its 38 member-states are countries that recognise the principles of representative democracy and free market economy that work on evidence-based international standards and solutions for social, economic, and environmental challenges https://www.oecd.org/about/

37 Businesses with the most significant environmental impact fall under the first category (out of IV), see the "Instruction on defining the category of the assets that has a negative impact on environment", the Order by the Minister of environment, geology and natural resources of the Republic of Kazakhstan of 13 July 2021 No. 246

38 See https://igtipc.org/ru/ndt/20210514-044949

Figure 6.16 The structure of emissions into atmosphere by coal-fired plants.



Source: Companies' data

utilities will be in the reduction of pollution, they will also contribute to the reduction in GHG emissions.

The level of investment necessary for shifting to BAT in the power sector is estimated at USD 3.5 billion. This is about 1.4 times higher than the total value of the electricity power sector, accounting for the revenue from the power plants, network companies, and other participants. Considering the share of environmental payments in the net cost of electricity production does not exceed 1–3%, even when increased several-fold it will not allow for offsetting them against BAT related investment. Therefore, it would be necessary to establish a mechanism that could warrant a certain level of stability for the investments into BAT. Accounting for the specific attributes of Kazakhstan's power sector, the BAT-related investments in the power sector could be realised through the capacity market mechanism, by selecting generating capacity on a competitive basis conditioned by efficiency factors.

6.3.4 Renewables support and development

The 2018 system for auctioning the renewable capacity projects has proven its effectiveness. It enabled to attract investors from 12 countries, including Kazakhstan, China, Russia, Turkey, the Netherlands, Germany, Spain, France, Bulgaria, Italy, the United Arab Emirates, and Malaysia. In 2018–20, according to the auctions' results, 58 companies signed contracts with a Single Buyer for the renewable capacity projects (RFTse for RES) totalling 1,219 MW.

The auction system facilitated commercially reasonable prices for renewable capacity, and achieved price reductions, the maximum of which for the wind generation has been registered at 30%, solar – 64%, and hydro – 19%.

To sustain this successful experience, it is important to set the long-term volumetric targets for the auction.

Whilst in 2018 the announced volume of renewable capacity due for auctioning was set at 1,000 MW, in 2019–20 it was reduced to 250 MW, and in 2021 to 200 MW. Following the Presidential Order on increasing the share of renewable energy in the country's energy mix to 15% by 2030, the annual decline in auctioned renewable capacity looks inconsistent with the policy.

Given several physical and environmental concerns associated with wind and solar, it is necessary to place greater emphasis on the development of small-size hydropower generation, when planning the renewable capacity penetration in Kazakhstan.

- The solar PV panels tend to occupy a rather large area (about 2 hectares per 1 MW).
- The manufacturing of solar panels is an energy-intensive process associated with the use of harmful and hazardous substances.
- The panels' disposal remains a serious challenge.
- The lifespan of solar panels does not exceed 25–30 years, thus, hundreds of thousands of solar megawatts, built during the *"green boom"* between 2010–20, will require large-scale disposal after 2040, which can become a serious environmental problem.

Notably plastic materials, that once considered a "green" technology of the twentieth century and enabled preservation of trees, has now become an environmental disaster resulting in "garbage" continents.[39] The EU had the foresight to develop several requirements for the disposal and recycling of solar panels, but this is an economically expensive process and not all countries will be willing to follow the EU's example. There is a risk that Asian developing countries will not be able to recycle solar panels thus posing a major new threat to the environment. Consideration should be given to a long-term renewable

39 Out of 6.3 billion tons of plastic produced since 1950 only 9% has been recycled and 15% incinerated.

auction schedule. This will both enable investors to plan forward, as well as indicate Kazakhstan's commitment to green energy.

It is advisable to hold all renewable projects' auctions when the projects are supported by documentation, including wind generation projects.[40] This approach will exclude the investors' risks associated with the renewable projects' realisation, including the need to obtain permits for connection to the power grid, develop a capacity output scheme, and resolve land acquisition issues.

It is also necessary to revise the auction price cap formation. At present, the price cap by technology is set at the level of the highest winning offers for the year prior the auction. However, given that the auction price caps are set in the national currency discounting the annual changes to the currency exchange, there is a risk of losing investors' interest in the auction.

The environmental problem, that Kazakhstan plans to tackle through renewable auctions is the disposal of municipal solid waste. The incineration of municipal solid waste to generate electricity and heat (waste-to-energy projects) in 2021 was included into legislation that supports renewable energy sources.[41] In addition, an exception to the auction rules has made it possible to recognise the auction results as valid in the event of a single participant when it comes to waste-to-energy projects. The waste-to-energy auctions that subsequently took place confirmed policymakers' fears when only a single bidder for Waste to Energy won projects in six cities of Kazakhstan with the auction price of 172.1 tenge/kWh. Notably, during the consultation, the Ministry of Ecology indicated the tariff would not exceed 100 tenge/kWh. The energy recycling of the household waste in Kazakhstan lacks a system of household waste handling (including sorting and processing). This raises concerns, let alone the demand for six waste-to-energy (incineration) plants with a total installed capacity exceeding 100.8 MW.

The efficient processing of organic waste and sewage water treatment waste is the construction of biogas power plants that process organic waste with the possibility of additional production of organic fertilizers. Despite the active livestock breeding in Kazakhstan, the number of biogas complexes remains extremely low. The last auction for a biogas plant in 2020 was declared invalid considering only one applicant. There is a need to increase incentives for the construction of biogas power plants for the integrated processing of agricultural waste.

40 According to the Renewable Auction Rules, the documentation refers to the key project parameters for the construction of a new renewable asset that includes the initial data, market research, resource potential assessment, a scheme for the capacity output and the technical conditions for the connection to the grid, etc.

41 The list of renewable energy sources was supplemented by "other fuel derived from the household solid waste used for the production of electric and/or heat energy".

Physical and chemical properties of hydrogen.[42] The record of hydrogen industrial production and use is more than 200 years old. The lighting and generator gases, which consisted of hydrogen for 45-50%, were produced by the means of pyrolysis and hydro pyrolysis from coal since 1820 to illuminate buildings and streets in the European cities. Until the 1960s gas pipeline infrastructure was developed for the use of combustible gasses in combination with hydrogen, until they were substituted by a much cheaper and practical natural gas from the residential and industrial use.

The main benefits in using hydrogen are its absolute environmental sustainability (the emissions of the water vapor), its higher heating value, as well as high efficiency (60–70%) of electricity output using the fuel cells. Hydrogen is the lightest of the chemical elements and the lightest gas, which affects its physical properties, namely the low density and low boiling point (-252.9 °C). Yet, the very chemical and physical properties of hydrogen bring about the restrictions to its use, both from technical and economic points of view.

A characteristic feature of hydrogen, that restricts its use in the existing gas pipelines, is its metals solubility thanks to its ability to diffuse through metal walls. The ultimate strength of metals decreases due to the gas porosity in metals. The hydrogen embrittlement is a result of hydrogen's impact on carbon steel.

The hydrogen production through electrolysis is associated with electricity losses and, subject to technology, is only 60–80% efficient. Notably, to produce 70 million tons of hydrogen through electrolysis will require about 3,600 billion kWh or about 10% of the world's annual electricity production.

The pressure of 35–70 MPa (or up to 700 atmospheres) is required to store hydrogen in a compressed form, whilst the compressed methane is stored under the pressure of 20–25 MPa. The storage of compressed hydrogen requires high-pressure vessels with a significant wall thickness, which means that for the storage of 1 kg of H_2, each cylinder will weigh 33 kg. Any evolution in material science could reduce the cylinder weight to 20 kg per 1 kg of hydrogen.

42 Based on the report by "Zhasyl Damu" on Hydrogen Energy

heating value is 141 MJ/kg. In a liquefied form hydrogen still has low density, as one litre of liquid contains only 71 grams of hydrogen (10 times less than petrol). Consequently, the storage of hydrogen in cryogenic form requires large capacities, which means that energy losses will be significant.

At the beginning of 2021, at least eight OECD countries and the EU have programs for the development of a hydrogen economy until 2030 with the available funding of more than USD 217 billion. However, the main technical challenges associated with the use of hydrogen in the economy remain unresolved. Some of the hydrogen programs will most likely remain unfeasible in the medium term. However, the efficiency of using the fuel cells and the high environmental sustainability of hydrogen are the foundations for the research and development of the safe and cost-effective methods of hydrogen storage and transportation.

6.3.5 A Single Electricity Buyer mechanism

An equal access for all market participants to the power market, including investors into renewables, is critical for the power sector. For this purpose, and provided there is an independent system operator, it would be necessary to facilitate a properly functioning Market Council (*Sovet Rynka* in Russian). At that, to support the sale of export products under the Single Buyer model, the industrial groups will be allowed to sign internal bilateral agreements for the supply of electric power and capacity.

The introduction of the Single Buyer model in the electricity and capacity market is hoped to:

- Shape the daily schedule for the production and consumption of electric power subject to the technological characteristics of the power plants and the unit commitment requirements.
- Launch the centralised power market trade to the upmost, including the electric power spot trading.
- Resolve the power price disparity by region.
- Smooth out the consequences of affiliation between the producers and consumers of electrical power.
- Create equal market conditions for the operation of all energy supply companies.
- Provide targeted support for low-income consumer groups during power tariffs‘ increase.

Whilst there are obvious positive aspects to this market model, there are risks associated with its implementation. The Single Buyer will accumulate all the cash flows from the electric power, capacity, and renewable energy markets. This means there is a risk of non-payments and cash deficiencies. Considering this, the payment support system with the mandatory enrolment of all market entities and access to the state financial aid, if necessary, would be essential. The introduction of this system will help attract investement into the electric power industry, as well as secure investor obligations when it comes to building new generating capacity (inclusive of renewables) in Kazakhstan.

The Single Buyer model at the wholesale electricity market will help facilitate changes to the shaping of the daily consumption and production schedule. To reduce emissions, whilst supporting the operation of hydropower plants and TETs, it is prudent to shape the daily schedule a day-ahead accounting for the technological characteristics and economic viability of unit commitment. This approach will help to establish commercially reasonable market prices for electric power by the hour and to form unform prices by region (a single price for the North and South zones and a single price for the West Zone. Once the technological unification of all three zones is completed – a single wholesale power market price).

In this regard, the status of a non-biased System operator (independent from running the operation of network infrastructure) is essential, as an organisation “equidistant” from all the power market participants. The system operator should be responsible for defining the technological parameters of the energy market model. To ensure this, the system operator must have full access to the transmission load data, the information on technological and economic parameters of the main power plants’ equipment, and be able to make the necessary technological restrictions, when calculating a single spot price. This is to facilitate both the reliable operation of the power system, but also the optimal load of technological equipment to achieve economically reasonable power market prices.

The introduction of a Single Buyer model has been discussed earlier and builds on the concept of the aggregated demand (developed by Tukenov A.A.). The model is based on the competition between groups of power plants and the daily schedule founded on the least cost of electricity supply. The key parameters of the aggregated demand model are:

- The wholesale buyers submit bids to the Single Buyer for the required volume of electricity consumption for each period (year, month, week, hour of the day), indicating only the volume of electricity without specifying the price.
- The wholesale electricity producers submit price offers to the Single Buyer for the same periods, indicating the volume of electricity for sale and the asking price per 1 kWh.
- By adding up (aggregating) the electricity volumes specified in the buyers’ non-price bids, the Single Buyer determines the aggregate demand (the total volume of bids for the purchase of electricity) for each period.

The aggregate demand is distributed among the producers of the same group in proportion to their total available capacity, thus determining the demand for each group of power plants. The selection within the group is based on the price offers with the task of minimising the cost of electricity supply. However, given the new targets facing Kazakhstan's electricity sector, the price-only selection is no longer sufficient. The Single Buyer model should consider not only the cost of electricity, but also the technical parameters of the power plants, the operating modes, the greenhouse gas emissions factors, and possibly other factors associated with the operation of the power system.

The Single Buyer's choice of the unit commitment to meet the demand could be supported by the information and computing systems capable of accounting for the cost of electricity supply, the greenhouse gas emissions ratios and other parameters of the power plants and the power system operation. As a result, the use of information systems for the mathematical optimisation of the power plants units' commitment at least cost, the greenhouse gas emissions and fuel consumption reduction, can produce a significant systemic effect.

6.3.6 The incentive tariff regulation

Similarly to other countries, electric power transmission and distribution and heat energy transportation in Kazakhstan fall under natural monopolies, therefore, the prices for these business activities are regulated by KREM. The sustained high level of electric and heating networks wear and tear suggests that tariff regulation, applicable to them in Kazakhstan, does not stimulate investment sufficiently to replace fixed assets. Despite the fact that the power network and heat energy tariff methodology refers to the basic principles of the so-called incentive tariff regulation, in practice the profit rate caps are reviewed downwards administratively.

The incentive regulation for the natural monopolies is founded on the principles of creating a high level of confidence for the parties involved in the long-term regulation and stability of the price control parameters, whilst delivering measurable benefits for the end consumers, investors, and the companies themselves. At the same time, the power network tariff regulation aims at stimulating end-consumer behaviour in accordance with the country's economic and social development strategy. The incentive tariff regulation, based on the value of the regulated asset (Regulated Asset Base or Regulated Asset Value [RAB or RAV]), was first introduced in the UK in 1995 and was subsequently adopted by many countries. The general principle of the methodology is the regulator's predictive approach (*ex-ante*) to setting the tariffs for the natural monopolies based on the assessment of the assets' value directly involved in the provision of the services, the gross revenue required for their operation and new launches, as well as the remuneration for the companies. Thus, the method estimates the value of realised investments (the capital base), operating costs for the assets maintenance and growth, as well as the income from the asset management and new investments (in the form of a regulated profit).

The Required Revenue = Operating Expenses (controlled and uncontrolled) + Depreciation + Profit + Tax

Profit = Regulated asset base * rate of return

The structure of the individual components that are included in the asset base, directly involved in the provision of the services, may vary from country to country, and in addition to the fixed assets (power lines, buildings, structures, land, office furniture and machinery, equipment, vehicles, etc.) may include current assets and assets under construction.[43]

The fundamental point of RAB methodology is the direct link between the revenue and the profit and the value of involved assets, as well as the quality and efficiency of operation. As a result, there is an investment incentive (to increase the assets' base) and a return-on-investment security.

Over the years many elements of the RAB methodology have undergone significant changes to account for the goals of low-carbon development and the need to integrate new technologies. Thus, in the UK, whilst the value of assets is still used as a foundation for the calculation of the required revenue and profit, the regulator sets the network tariffs not merely to cover the costs that would ensure the reliability and quality of power transmission and distribution, but also to ensure the efficient investment into new technologies and promising areas in the interests of the power system's overall target-setting, the vision of the energy system's technological architecture, and the future needs of the end consumers.

Following the RIIO formula, standing for **Revenue = Incentives + Innovation + Results,** the UK regulator produces measurable benefits for consumers, investors and the companies in accordance with the segment's objectives (that are embedded into the overall industry's vision).

The fundamental principle of this tariff methodology is the link between the remuneration and the results achieved by the companies during the price control period and, in case of the innovative development, during several price control periods (hence it is known as a performance-based incentive regulation). The most frequently encountered performance indicators are the duration and frequency of power supply interruptions (SAIFI and SAIDI), the penetration of innovation, sustainable development and decarbonisation, energy efficiency, and cost effectiveness (value for money). In the UK the power network companies are assessed subject to achieving primary and secondary tasks:

43 The leased assets (involved in the direct provision of services) in 60% of cases are included in operating costs. However, the connection fees, as well as any benefits (subsidies, grants, and payments) are excluded from the base, since they are not funded directly by the grid company.

The primary tasks include:

- Quality of consumer service (the degree of requests satisfaction).
- Reliability of service.
- Terms of connecting to the network.
- Impact on environment.
- Social obligations towards vulnerable consumer groups.
- Security of supply.

The secondary tasks include (the costs of implementing secondary objectives, as a rule, fall into one price control period, whilst the benefits are achieved in the subsequent periods, since they are associated with the long-term effect of improving the quality, nature, and efficiency of service):

- Network risk management (e.g., monitoring and management of load changes).
- Achieving project results from the previous control periods.
- Technological or commercial innovative solutions.

In addition, to incentivise repair and modernisation of the assets and equipment (that do not increase the asset base) and to shift the focus from the investment into new assets (capital expenditures that increase the base), the regulator employs TOTEX methodology, which allows for a partial inclusion of the costs associated with the upgrade and repair of equipment into the asset base. The TOTEX approach controls the growth of the capital base and encourages companies to spend more efficiently.

Accordingly, the companies' reporting is structured to cover the following areas:

- Reliability of power supply (including indicators of frequency, and number and duration of interruptions in the power supply).
- Speed and ease of connection to the network.
- Quality of the services provided.
- Company's contribution in supporting the socially disadvantages and vulnerable consumers.
- Measures that contributed to reduction of the GHG emissions and other impact on the environmental.
- Adherence to safety standards and safety improvements.
- Innovative development.
- Investment efficiency.

The goals of technological and, in particular, innovative development, imply a level of planning and investment that goes beyond one price control period (which is normally between 4–5 years and in some cases 8 years). In other words, investments made at the beginning of one price control period can only be realised in the subsequent price control periods. Furthermore, the power network companies' tariff regulation should facilitate conditions for a continuous improvement of the network infrastructure and value creation for the end users. In other words, the tariff regulation should facilitate innovation as part of the *business as usual* activity.

An independent audit of the costs and investments effectiveness, as well as of the network companies' operational activities ensures efficiency of this methodology. For example, in the UK, the long-term tariffs' approval takes up to 30 months and includes a multi-level audit of the companies' business plans by independent energy economists.

In Kazakhstan, the tariff setting for the network companies (and other natural monopolies) looks significantly different. Regardless of the favourable incentives embedded into the principles of tariff methodology in Kazakhstan for the network companies, the specific mechanism that is designed for its implementation, according to the "Rules of tariff setting", is devoid of both constructiveness and incentives.

The cost-plus methodology dominates the electricity transmission sector, which implies sourcing investment from the net profit and depreciation deductions and direct them towards capital expenditure. But as the network companies in practice are devoid of economic profit, there is no incentive for new investment. This explains why the law on incentive tariff regulation was passed at the end of 2018.

The same idea was reflected in the Law "On natural monopolies" (clause 5 of paragraph 2 of Article 17):

"2. The incentive method of tariff regulation provides for:

5) profit setting, accounting for the return on invested capital and rates of return on invested capital, as well as the book value of the assets of the natural monopoly involved in the provision of the regulated service, and the rate of profit calculated according to the method determined by the authorised body"

However, in practice the company's profit must be spent on the investment program, following the order of the Minister of National Economy of the Republic of Kazakhstan dated 19 November 2019 No. 90 (paragraph 637 of paragraph 4 of chapter 13) "On the approval of the Rules for the tariffs setting": *"The level of profit, included in the tariff is limited to the funds required for the implementation of the investment program and the depreciation deduction. Investments are made by the entities using their own and (or) borrowed funds. The sources of own funds are profit (net income) and depreciation deductions. The borrowed funds are repaid from the profit (net income) and (or) the depreciation deduction. The expenses for the payment of dividends to the shareholder are excluded from the profit."*

In addition, under the current natural monopolies' legislation, at the end of the price control period for the long-term tariffs, inclusive of those set using the incentive method, the companies have the right to apply for the approval of tariffs for the next long-term period. However, during the tariff approval the authorised body accounts for the actual costs incurred only during the last four quarters preceding the date of the application's submission. This, in turn, means that under the rules of incentive tariff regulation, companies are incentivised to optimise costs and generate additional profit up to four quarters prior to the filing of the new application. Whilst during the last four quarters to stop optimisation and secure the foundation for the inflated future tariff.

There could be several legislative changes to help resolve the current situation, which could be adopted separately or in combination with each other.

- Within the framework of the approved incentive tariff methodology to ensure the natural monopoly's required revenue covers the current operating costs, the return on investment and return of investment.
- The return of investment implies a long-term return of invested capital following the depreciation principles, and the return on investment is defined as the product of the rate of return (we propose WACC by industry) and the sum of the residual value of assets, assessed at the time of calculations, and a net working capital. The downward adjustment of the required revenue occurs when the company fails to achieve the target indicators of the quality and reliability of supply, as well as the technological development as defined by the authorised body.
- The inclusion of R&D expenditures and the expenditure for the demonstration of new technological and commercial solutions into the required revenue (the new ways of providing a more reliable, affordable, and environmentally friendly power supply to the end consumers) will require to fine-tune the tariff regulation's objective in such a way that the implementation of new solutions and pilot innovation projects became one of its incentives.
- At the same time, following the goals of the power industry low-carbon development, the tariff regulation should facilitate the companies' access to the new types of financial instruments (green bonds within the green taxonomy; sustainable bonds for the implementation of sustainable development projects and socially significant projects not necessarily listed in the green taxonomy; special bank financing) and account for the cost of such funds in the required revenue.
- The detailed audit of the business plans by the regulator (with the possibility of outsourcing auditors) makes it possible to establish the correct financial incentives and individual cost efficiency ratios when calculating the required revenue. To maintain the companies' confidence in the stability of regulation, in the event there is a discrepancy between the actual and estimated costs, the total established level of required revenue for the price control period is not retrospectively revised up or down. At that, the cost-efficiency ratio, without the differentiation between the operating and capital costs, set between 40–50% of the total cost, could be considered should the company achieve targets and there is no proof of intentional costs overrun.

The regulator needs to have access to financial resources to attract highly qualified independent energy-economy experts to determine realistic, measurable, reasonable, and consumer-oriented target performance indicators for the companies, as well as to deeply assess the companies' required revenue needs and their performance. In addition, the regulator will need resources to develop standards and methods of incentive regulation applicable to Kazakhstan (without distorting the essence of the methodology), making the appropriate changes in the accounting and the categorisation of costs, methods for collecting and processing information, standardising concepts, and automating processes.

Building a culture of innovation within the day-to-day companies' operations requires special attention and redefinition of cost categories. The regulator's active support of the measures that incentivise and enforce, reasonably limited in time, investments in innovative technologies with a clear definition of directions and strict selection of projects will contribute to the start of the overall transformation of the segment. At the same time, it is proposed to consider the possibility of providing state financing for innovative areas (technologies), the implementation of which poses an extraordinary risk for private or bank capital at this stage.

The drastic alteration or renunciation of the basic principles of this methodology, the substitution of methodology with politically driven decisions and or retrospective changes will constitute a regulatory failure of this initiative. Such approaches create regulatory instability and unpredictability, which affects the long-term cost of capital and makes borrowing extremely expensive. The latter discourages investment, and runs counter to the interests of consumers, investors, companies, and the sector as a whole.

6.3.7. Reform scheme

The proposed scheme of reform pathways is based on the earlier defined vision and target-setting for the development of the country's electric power sector, considering the main tasks and challenges, see Figure 6.17. The pathways for achieving the tasks include the project areas listed below:

- Replacement of equipment.
- Construction of renewable energy sources and low-carbon development.
- Construction of flexible energy sources.
- Optimisation of the power systems' operation.
- Integration of BAT.

The future of nuclear power

There are 443 commercial nuclear reactors with a total installed capacity of 394 GW in operation globally. They generate more than 2,600 billion kWh, which is 10.1% of the world's electricity production.

For more than half a century the USA has been the leader in the nuclear generating industry by installed capacity of its nuclear power plants (95.5 GW). However, since 1996 it has not commissioned a single reactor and its forward plans are limited to only 2.5 GW, whilst China has 18.2 GW of nuclear capacity under construction. The European Union countries, which once led this industry alongside the USA, have since either eliminated the nuclear energy from the future energy system (like Germany), or reduced its share in the capacity balance (like France). For example, under the framework of the German strategy the "Energy Turn" (Energiewende), the energy system predominantly relies on the output of intermittent wind and solar power plants, that are difficult to integrate into modern power systems. As a result, most nuclear power plants' development takes place in Asia, primarily in China and India.

The large-scale plans for the development of nuclear power could come across restrictions related to uranium reserves, which, accounting for planned nuclear generation globally, are estimated to last just for 90 years. However, the Russian project «Leapfrog» (Proryv in Russian) that targets nuclear fuel recycling could fundamentally change the future outlook of the global energy industry. In June 2021 Russia launched its latest fast-breeder nuclear reactor BREST-OD-300 in Seversk (Tomsk province). Kazakhstan's National Nuclear Center participated in the development and testing of this reactor's fuel cells.

The nuclear power plant currently under construction in Seversk will be the first in the world to have a closed fuel cycle, making nuclear power renewable. A particular characteristic of a fast breeder reactor is its ability to produce more plutonium than uranium and plutonium it consume, whilst the spent fuel recycling enables them to replenish their nuclear fuel with an insignificant amount of natural or depleted uranium.

According to the experts' estimates, the shift to the closed fuel cycle would force the annual demand for uranium to fall by more than 200 times. Therefore, it would take only 250 tons of uranium, instead of 54 thousand tons, to generate 2.6 trillion. kWh/year.

The nuclear energy shift to the closed fuel cycle opens possibilities for the world to meet its ever-increasing energy needs.

Purpose of reform:

- To support the policy goal for highly efficient and low-carbon power sector
- Guarantee reliability of electric power supply
- Guarantee reliability of the heat energy supply
- Attract investment into needed capacity and resources, in the needed geographical area and within the needed timeframe
- Affordability of electric and heat energy, and just (social) energy transition

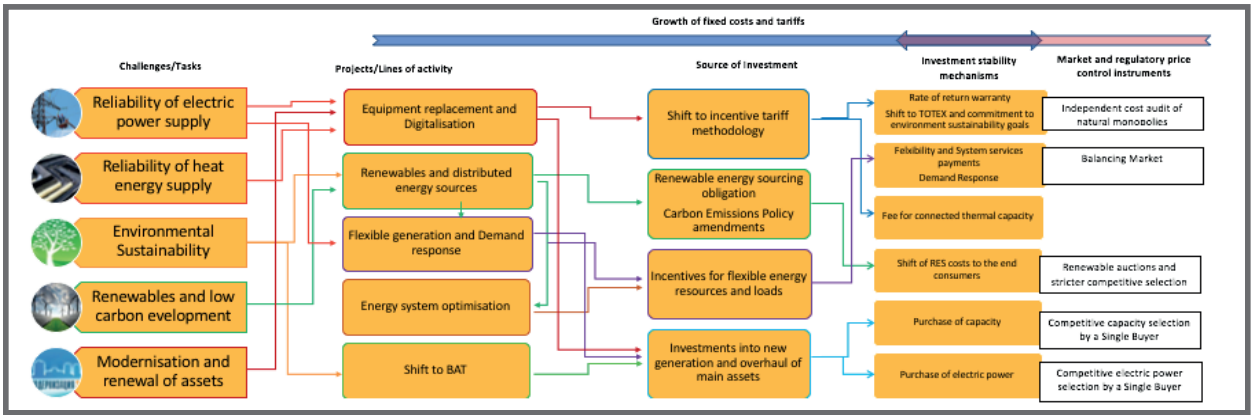
Reform challenges:

- High wear and tear of main assets
- Heat energy losses in the heating network
- High carbon intensity of the electric power sector and its impact on environment
- Poor sector flexibility (for the integration of renewables, distributed energy resources, power consumption and storage)
- Low level of investment effectiveness
- Regulatory disbalance and destructive sector regulation
- Low level of regulatory and state support of technological break through (innovative technological solutions)
- Risk of social unrest in the areas economically dependent on fossil-fuels

Key reform project areas:

- The development of a whole system consistent approach to the policy of highly efficient and low carbon power sector development inclusive of:
  - Establishing a direct link between the power sector strategy goals and the sector regulation, price formation and carbo policy
  - Integration of long term highly efficient and low carbon development targets setting into to all levels (generation, grid, consumers)
  - Identification of the key instruments/directions for increasing the power sector efficiency and its decarbonisation
- Optimisation and flexibility of the energy system
  - Unbundling of the System Operator to implement a consistent policy for the energy system transformation adherent to the long-term goals
  - Creation of regulatory conditions for the improvement of the energy system flexibility by the SO Transformation of the future energy system planning by the System operator including the provision for the technological decisions validation.
  - Digitalisation of processes and equipment
  - Development and maintenance of a single mathematical energy system model for the information on the real time energy system performance and future planning
  - Creating conditions for the «business as usual» innovative energy system development
  - Launch of the balancing market

Figure 6.17 The electric power industry reform pathways



- Creating investment incentivising conditions
  - Direct state financing of areas that require support due to current immaturity of technologies (innovative technologies);
  - Review of pricing policy and tariff setting methodologies for generation, sales and network companies
  - Introduction a levy for financing KREM
  - Providing access to green / low-carbon project financing
- Transformation of the market participants' regulation (both generation and grid) towards "incentive results oriented" and creation of incentives linked to the efficiency, innovation and decarbonisation goals.

Resources

- State funds, private investment, affordable finance
- Transformation of price-formation and sector regulation

Investment incentives:

- Incentive, result oriented tariff methodology/regulation
- Guaranteed purchase of RES power for the contractual period
- Resource flexibility incentives
- Capacity payment
- Carbon emissions trading, environmental taxes and levies

Investment incentives:

- Guaranteed rate of return for RAB regulation
- Flexibility payment
- Fee for the connected thermal capacity
- Shift of renewables' costs on to the end consumers
- Single Capacity Buyer

Market and regulatory tariffs growth control measures:

- Independent costs audit (funded by special levy to tariff)
- Balancing market
- Renewable auctions
- Capacity market
- Expansion of the System operator responsibility, transparency with regards to the management of the modes, balances and future planning. Provision of the System operator's equidistance from all sector participants.

The implementation of these power sector projects would require investments, that in turn would need the mechanisms to ensure the high level of investment stability, as well as measures to incentivise power industry entities to develop and modernise. The creation of conditions for attracting investment in the industry should be accompanied by measures to curb the overstatement of expenditures and capital investments. **For these reasons it is proposed to finance KREM through an additional special tariff premium applicable to all natural monopolies for the possibility of attracting independent auditors to check the efficiency of spending and the expediency of investments by the natural monopolies.**[44]

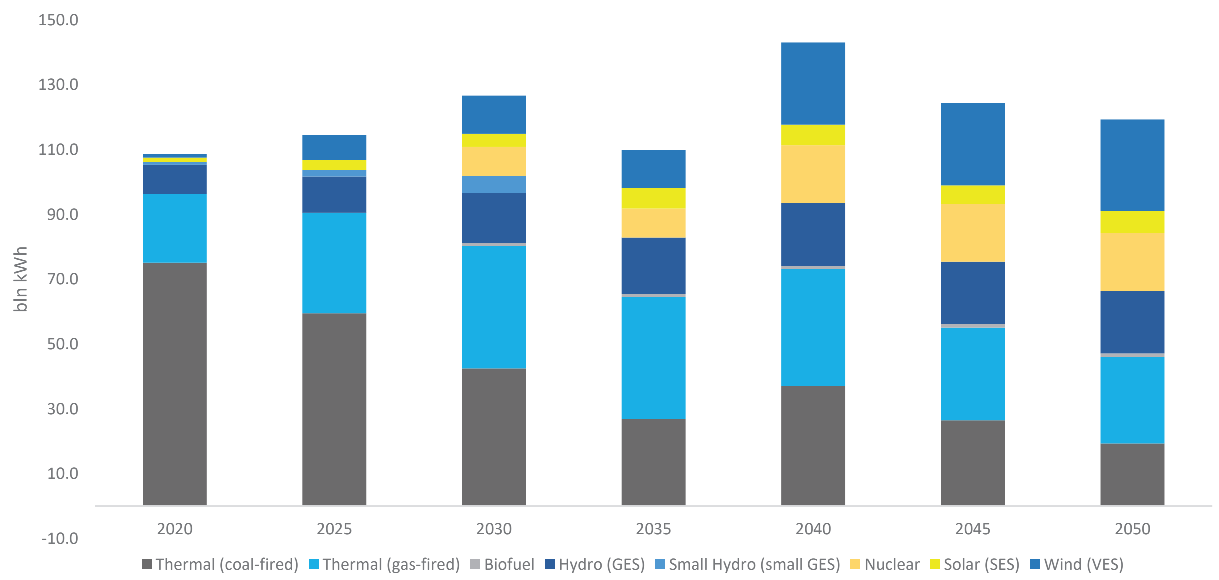
6.4 Electricity development forecasts

The power sector development forecast was calculated using the TIMES model. It is employed by the IEA as part of its ETSAP methodology for the energy scenarios and an in-depth analysis of the energy and the environment (Loulou et al., 2004).

The TIMES model generator combines two different and complementary approaches to the energy consumption modelling: a technical-engineering approach and an economic approach. TIMES is used to study possible energy scenarios for the economic development.

44 An independent source of income for the KREM may eventually help remove it from state subordination and establish and independent Regulator

Figure 6.18 The forecasted structure of electricity generation in Kazakhstan in 2025–50



Source: TIMES modelling

In the context of the proposed target-setting for the development of the electric power industry, it followed the scenario of gas-fired and hydropower generation development, according to the plans of the Ministry of Energy to 2035, as well as the commissioning of nuclear capacity, the first unit with an installed capacity of 1200 MW by 2030 and the second unit with the installed capacity of 1200 MW by 2040. The model assumes a significant increase in energy efficiency after 2040 resulting in electricity consumption decline, see Figure 6.18.

Scenario assumptions:

- The scenario assumes the availability of natural gas resources required for the development of gas-fired generation, including for the purposes of balancing variable electricity generation by wind and solar power plants.
- The decision to build nuclear capacity will be made in 2021–22, assuming the period of NPP construction will take 8–9 years (inclusive of design, survey, approval and the actual construction).

Overall, this scenario achieves the “Green-economy concept” target indicators. The modelling shows the share of low-carbon generation (by nuclear power plants and renewable energy sources) will reach 36% by 2030 and 66% by 2050.

The coal-fired generation will still be present in 2050, although its share will be gradually reduced and substituted from 69% in 2020 to 34% in 2030, and 26% in 2050. The growth of output by the coal-fired power plants from 2040 is explained by lack of firm power in the energy system. At that, it is assumed that by 2040 the maturity of CCUS technology and its economic feasibility would support its use at the coal-fired power plants. In the scenario under consideration, the coal-fired baseload generation is substituted by the commissioning of nuclear power plants and partially, by the gas-fired power plants' operation. The combined cycle technology (CCGT or PGU in Russian from p*arogazovaya turbinnaya ustanovka*) is the most efficient for operating in baseload (achieving around 60% of installed capacity).

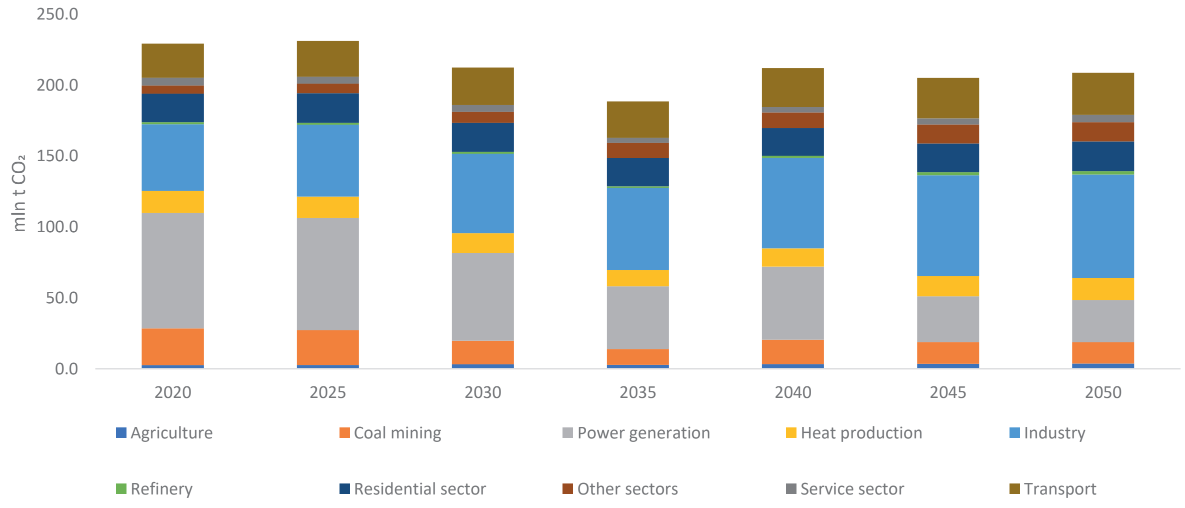
Greenhouse gas emissions will be significantly reduced even considering the growth in energy consumption, see Figure 6.19.

Significantly, there will be a decrease in the average emissions of carbon dioxide during the electricity production from 780 gCO_2 / kWh in 2020 to 215 gCO_2 / kWh by 2050.

The competitive unit commitment by the Single Buyer accounting for the average greenhouse gases emissions and other technical plants' parameters (see section 6.3.5) will facilitate the priority purchase of cleaner energy, and the coal-fired generation displacement by gas-fired power plants **(e.g., increasing the Zhambyl GRES load).**

The most critical component that will help achieve these indicators is the implementation of a new energy policy, which can be formed accounting for the proposals specified in this chapter.

Figure 6.19 – Forecast of carbon dioxide emissions in the economy in the period 2025–50



Source: TIMES modelling

6.4.1 Overview of IHS Markit's outlook for Kazakhstan's electricity sector to 2050 in the context of the national fuel and energy balance (alternative view)

The electricity sector lies at the very heart of Kazakhstan's fuel and energy balance, being both an important source of final energy demand as well as the single-largest consumer of fossil fuels. As such, it also is a large source of GHG emissions and other atmospheric pollutants. Kazakhstan's aggregate electricity generation grew by an annual average of 2.8% between 2010 and 2020, reaching a national total of 109.2 billion kWh.[45] In comparison, GDP grew by an average of 3.8% annually during this period. Aggregate electricity consumption amounted to 108.8 billion kWh in 2020 (107.3 billion kWh in the centralized grid), up by 2.6% from 2019 (including losses in generation and transmission); this occurred despite a 2.6% contraction in GDP in 2020, reflecting the effect of the global pandemic.

In our forecasting of energy demand, IHS Markit uses an integrated, demand-driven approach that involves other parts of the national fuel-energy balance. Our methodology is based on changes in activity levels in the major sectors of the economy (industry, agriculture, construction, transportation, and residential-commercial). The activity levels in each sector are, in turn, tied back to underlying GDP trends.[46]

45 A total of 108.1 billion kWh was generated by stations within the centralized grid.

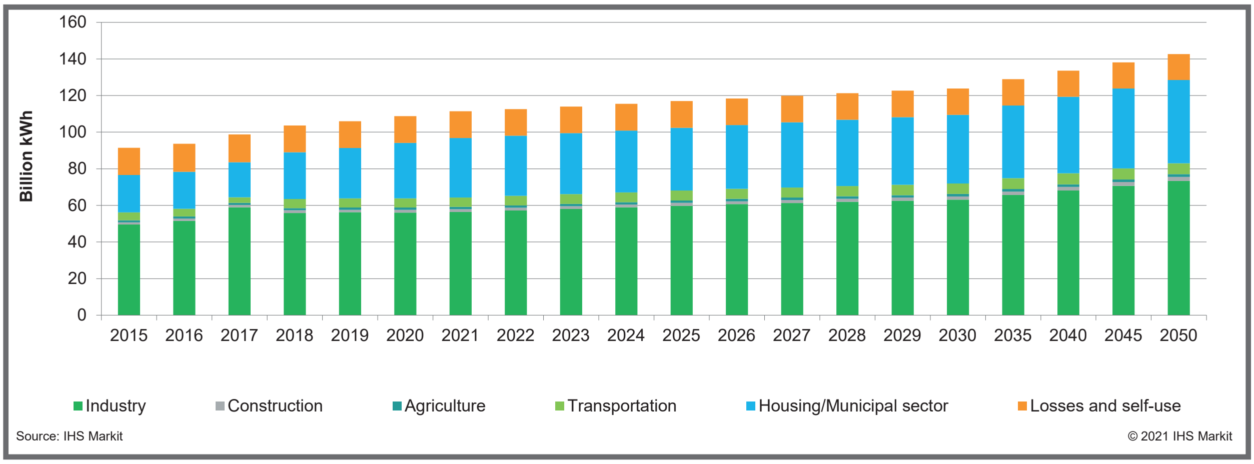
46 Five general forces are driving changes in electricity demand, including (1) economic recession and recovery; (2) changes in relative prices; (3) changes in real incomes; (4) changes in incentives for enterprise managers and other economic actors; and (5) changes in technologies.

It is the projected figures for electricity consumption that largely drive electricity production, as needed to meet demand.

We assume a set of general global political and economic conditions that align with IHS Markit's base-case or Inflections scenario (discussed in Chapters 1 and 2); these, of course, have specific implications for economic and social conditions in Kazakhstan. Our general base-case scenario assumes no dramatic, market-altering disruptive forces globally (e.g., world wars) on either the demand or supply side of markets; and on the demand side, it incorporates assumptions about long-term gains in energy efficiency – such as improved heat rates in electricity generation and rising vehicle fuel economy. Our base-case scenario also includes assumptions around sufficient investment in upstream exploration and production to meet our projections of global hydrocarbon demand, and energy demand more broadly. In turn, these give rise to certain expectations about global oil, energy, and commodity prices, and global market conditions more generally.

Importantly, our assumptions regarding expected changes in the underlying structure of the Kazakh economy remain fairly modest; i.e., we do not anticipate that Kazakhstan is going to dramatically change its underlying economic profile over the 30-year forecast period. But we do assume that certain long-term market trends continue, such as the ongoing shift from heavy industry to services, which makes the economy less energy intensive. Also woven into the analysis are underlying assumptions regarding ongoing modernization in industry and other sectors as

Figure 6.20 Electricity consumption in Kazakhstan by major sector: IHS Markit base-case outlook



new processes and equipment are introduced. The long term outlooks for Kazakhstan's population dynamics, GDP growth, and global oil prices are provided by the IHS Markit Economic and Country Risk and IHS Markit Crude Oil Markets teams, respectively. Kazakhstan's average annual GDP growth over the 2020-50 period is calculated to be 2.4% (more than doubling in absolute terms), while population growth is 0.8% per year.

To forecast future aggregate demand for electricity, consumption is first projected for the five major economic sectors in the country – industry, construction, agriculture, transportation (in this case primarily electrified rail and pipelines, as these are the main consumers of electricity within the transport sector in Kazakhstan),[47] and household-commercial-municipal use (domestic sector).[48] For example, existing macroeconomic outlooks provide forecasts of growth in gross agricultural output or construction activity. These growth rates are used to forecast agricultural and construction demand for electricity. Similarly, the forecast of transportation activity (either passenger-kilometers for urban rail, ton-kilometers of freight for electrified rail, or ton-kilometers of oil and gas shipments for pipelines) is used to forecast the demand for electricity by this sector. Household and municipal demand for electricity is assumed to have a relatively high elasticity with respect to personal incomes and consumption. As this demand segment frequently includes some service sector demand, the fairly high-income elasticity employed helps capture increased demand from small businesses and commercial activity.

Longer term, the structure of electricity consumption in Kazakhstan is anticipated to have an increasingly larger share of energy use by the services sector and households. For households, increased electricity consumption will very much depend on such factors as rates of housing construction and the pace at which electric appliances and other personal electronic devices are acquired by households. Energy prices for households must be high enough to cover the cost of production and delivery, while at the same time such increases cannot be excessive in comparison with rises in household real incomes. This shift results in a rise in the ratio of peak to average load.

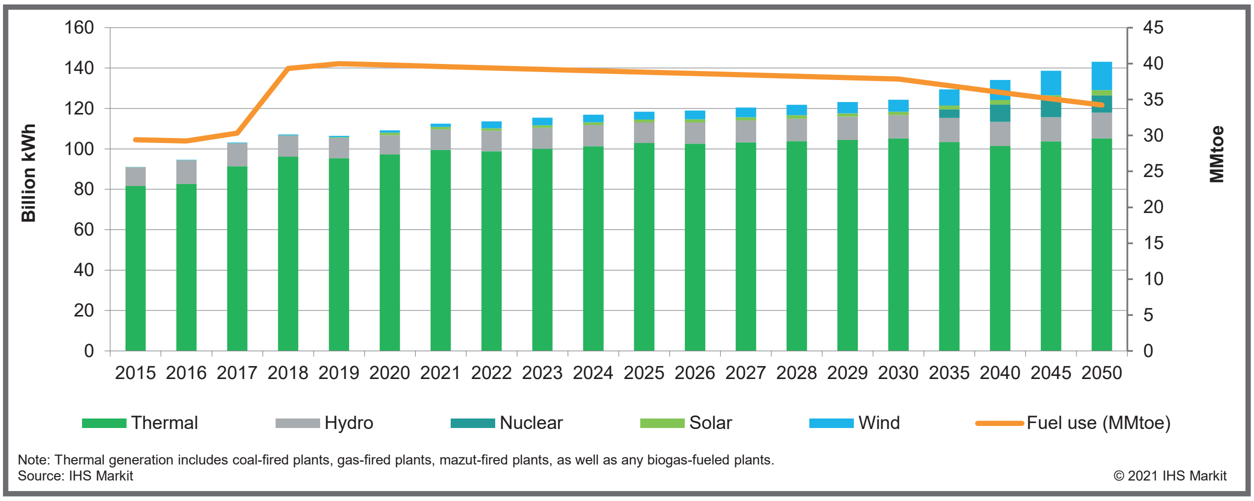
We project that Kazakhstan's aggregate electricity consumption (including production and transmission losses) will increase by an annual average of 1% through 2050, reaching 123.9 billion kWh in 2030 and 142.7 billion kWh in 2050. This is a higher growth rate than what we project for Kazakhstan's primary energy consumption, which we anticipate will actually decline slightly (the average annual change is expected to be -0.1% for Kazakhstan's primary energy consumption in 2020-50), reflecting improved energy efficiencies throughout the economy. As a result, consistent with long-established global trends associated with economic development: electricity becomes a progressively larger share of final energy consumption longer term; this reflects the fact that electricity is a very flexible and useful form of energy that can be employed in a wide variety of uses.

Total electricity consumption is slated to grow by an annual average of 2% between 2020 and 2030, but slow to only about 1% between 2030 and 2050 (see Figure 6.20 Electricity consumption in Kazakhstan by major sector: IHS Markit base-case outlook). Industry will

47 IHS Markit does not envision that electric vehicles will emerge as a major consumer of electricity over the forecast period in Kazakhstan, although their use will, of course, grow, albeit from a very small base. IHS Markit envisions electric cars remaining much less than 10% of new car sales (additions to the car fleet) even in the 2040s.

48 These categories reflect the traditional accounting breakdowns employed in statistical reporting. Electricity is not only consumed by end-users; it is also used by power stations themselves in the process of generating and also lost within the grid systems in transmitting electricity. To forecast these losses (or uses), historical ratios of transmission losses to domestic deliveries and of losses and self-use by power stations to total production have been estimated. It is assumed that these ratios gradually decline over time as the utilities reduce losses and improve efficiency.

Figure 6.21 Electricity generation in Kazakhstan: IHS Markit base-case outlook



remain the largest power consumer, still accounting for 51% of electricity use in 2050. The share of transmission losses and self-use are projected to gradually decline, falling to around 10% of apparent electricity consumption by the end of the forecast period (2050). This occurs as older plants are replaced, energy efficiency increases, and investments in distribution infrastructure materialize.

We assume that Kazakhstan will not change much over the forecast period in terms of its net electricity export position, remaining a small net exporter. Thus, the IHS Markit base-case outlook anticipates electricity generation in Kazakhstan will also grow by an annual average of 1% through 2050, reaching 124.4 billion kWh by 2030, 134.1 billion kWh by 2040, and 143.2 billion kWh by 2050 (see Figure 6.21 Electricity generation in Kazakhstan: IHS Markit base-case outlook). We expect that thermal generation will continue to play a dominant role in the country's electricity sector; the share of thermal in overall power generation, however, will decline from 89% in 2020 to 85% in 2030, 76% in 2040, and 74% in 2050. In line with Kazakhstan's 2050 goals, there will be a continued buildout in renewables – solar, wind, and hydro (and some biogas); combined, these three segments are slated in our forecast to generate 15% of power by 2030, 18% by 2040, and 20% by 2050. Despite the fairly attractive terms offered to renewable project developers at present, the ever-present challenges to successfully integrate renewable sources, due to their intermittent nature compounded by factors such as market structure issues, supply chain availability, and costs, suggest that renewables are only likely to reach a 20% threshold in Kazakhstan. That said, IHS Markit anticipates a nuclear plant (1200 MW) will come online in the mid-2030s, likely in southern Kazakhstan near Lake Balkhash, allowing the displacement of a sizable amount of coal-fired baseload generation.

Within thermal generation, we forecast a moderate pace of change from coal to gas, reflecting constraints on commercial gas supply. By mid-century, the coal-gas share in Kazakhstan's thermal generation will shift from the current 80%-20% in 2020 to something like 57%-43% in 2050.

The outlook for generating capacity is developed from the generation forecast, taking into account typical capacity utilization factors for different types of generation, changes in peak load, and retirements of older capacity. Our base case outlook is for aggregate generation capacity to reach 37 GW in 2050, of which 22.5 is thermal-fired, 1.2 GW nuclear, 3.4 GW hydro, and 10.9 GW renewables (solar and wind).

Overall, all power sector development forecasts share the following common properties: the decrease in the share of a coal-fired generation output, construction of nuclear generation, and integration of a significant share of renewable capacity. The technological progression could impact the structure of generation and the level of consumption, whilst the trend for the cleaner electric power and energy sectors will undoubtfully remain.

Chapter 7

URANIUM

7 URANIUM INDUSTRY: REVIEW AND ASSESSMENT OF NEW DIRECTIONS IN ATOMIC ENERGY

7.1 Key Points

- Kazakhstan is the world leader in uranium mine output, producing 19,500 (metric) tons in 2020 and accounting for roughly two-fifths of the world total in recent years. This reflects its vast reserves – it possesses 37% of global "reasonably assured" uranium resources that can be developed at lowest cost (<$40/kg U) – and the fact that over four-fifths of its uranium resources can be developed under the most economically advantageous and least environmentally disruptive method of extraction, in-situ leaching (ISL).
- Kazakhstan's mine production fell in 2020 by 15% relative to 2019, reflecting both a reduction in global electricity demand in the wake of the COVID-19 pandemic as well as a weak (oversupplied) market for uranium, following unprecedented growth during 2003–16. In response to the anemic market conditions, Kazakhstan, along with other major mine producers, has deliberately limited output.
- Currently nearly all of Kazakhstan's uranium mine output is exported, as the country currently does not possess commercial nuclear power generation capacity (only research reactors). Of all the stages in the nuclear fuel cycle, only uranium mining, reconversion, and fuel pellet fabrication/fuel assembly are currently undertaken in Kazakhstan. The focus on mining reflects Kazatomprom's calculation that mining is currently the most attractive segment of the nuclear fuel value chain (i.e., its global comparative advantage lies in its large ore deposits suitable for ISL-based mining).
- Although the current global uranium resource base is considered to be more than adequate to meet projected world uranium demand through 2040 under most scenarios, future investments will nonetheless be needed in most countries to bring these resources into production. Kazakhstan is well situated in this regard: it does not require a massive build-out of new infrastructure to sustain present output.
- Recent efforts to expand the uranium value chain in Kazakhstan to elements of the fuel cycle downstream from mining are driven not so much by a profit-maximization motive as by a belief that product diversification offers flexibility (in the form of increased sales options and reduced dependence on individual downstream processors) in the ultimate delivery of uranium to its consumers.
- Nonetheless, some recent initiatives toward product diversification could provide a tangible benefit, to the extent they move the country closer to being able to generate nuclear power domestically, should Kazakhstan decide to pursue this option. Most notable in this regard is the completion (in 2021), in a joint venture with the China General Nuclear Power Group (CGNCP), of construction of a unit at the Ulba Metallurgical Plant (UMP) to produce fuel assemblies for CGNCP reactors.
- Kazakhstan's President Tokayev recently announced an ambitious climate goal of carbon neutrality by 2060. In light of the country's existing research and development expertise in nuclear generation, fuel storage, and waste disposal, as well as expected limitations on the availability of commercial gas for baseline electric power generation at least over the medium term (see Chapter 4), nuclear generation should be considered as a viable option consistent with efforts to restructure Kazakhstan's power sector to meet its carbon neutrality pledge. Indeed, the government has recently taken steps in this direction.

7.2 Market Structure and Legal Framework

Kazakhstan's Subsoil Code, which went into effect in June 2018 and subsequently amended (see below), designates the Ministry of Energy as the "Competent Authority" to represent the interests of the Republic of Kazakhstan and to implement state policy in the area of subsoil use of hydrocarbons and uranium, while designating the Ministry of Industry and Infrastructure Development as the "Competent Authority" for the subsoil use of solid minerals. The Competent Authority grants exploration and production rights on behalf of the state, with subsoil use rights being allocated for a specific period subject to possible extension.

In the uranium and nuclear sector, the Energy Ministry (via its Nuclear and Power Control and Oversight Committee) sets and executes state policy, and is charged with oversight of uranium production and processing as well as (potential future) nuclear power generation.[1] Kazatomprom, which is 75% owned by the Samruk-Kazyna National Welfare Fund – is the state corporation

1 According to the Order *(Polozheniye)* on the Ministry of Energy of the Republic of Kazakhstan confirmed by Government Decree no. 994 of 19 September 2014 (and article 63 of the Subsoil Code).

that acts as an agent of the state in managing uranium assets and has the status of National Company in the uranium production industry.[2] The National Company has the authority to represent the state's interests in subsoil contracts, and to execute such contracts, and to administer the production and export of uranium and its compounds, as well as nuclear fuel.[3] Subsoil use rights may be terminated or altered by the Ministry of Energy of Kazakhstan if, for example, subsoil users do not satisfy their contractual obligations, which may include periodic payment of taxes to the government and meeting mining, environmental, and health and safety requirements. The National Nuclear Center at Kurchatov, which operates three research reactors, undertakes research and development activities.[4]

Kazatomprom operates, through its 39 subsidiaries, joint ventures, and associates, 26 uranium deposits grouped into 13 projects ("asset clusters"), all of which are located in Kazakhstan and 11 of which now involve some foreign participation (see below).[5] On an entitlement basis, Kazatomprom accounted for 55% of the uranium mined in Kazakhstan in 2020 (both through its direct production and its shares in joint ventures with foreign companies) and 22.5% of production globally.[6] Because Kazakhstan does not presently possess commercial nuclear power generation capacity (only research reactors), all of the produced uranium is exported, primarily under long-term contracts. Of all the stages in the nuclear fuel cycle, only uranium mining, reconversion, and fuel pellet fabrication/fuel assembly are currently undertaken in Kazakhstan.

The current legal framework for governing the *use* (post-subsoil) of uranium materials in the economy is based on the Law on Nuclear Energy Use (2016), which replaced a previous law (1997) that had become obsolete. The Law includes provisions that introduce expert evaluations of nuclear safety measures as well as accreditation of nuclear safety personnel. It also codifies Energy Ministry regulations for the physical security of nuclear materials, facilities, and storage; safety rules for handling radionuclides; a Nuclear Emergencies National Plan; rules for transportation of nuclear materials and radioactive substances; and regulations for the collection, storage, and disposal of nuclear waste.

7.3 Uranium Reserves and Exploration

According to the authoritative uranium "Red Book," Australia leads the world in terms of its overall uranium mineral endowment, with 28% of total *identified resources* recoverable in the category <$US 130/kg U (equivalent to $50/lb U_3O_8).[7] This is broadly considered to include all intermediate- and lower-cost resources that are feasible for commercial development under current economic conditions.

However, in terms of low-cost so-called *reasonably assured resources* that generally can be developed under higher levels of profitability (<$40/kg U and <$80/kg U), Kazakhstan leads, with 37% and 28% of the global total, respectively (Figure 7.1 World's reasonably assured reserves with cost of production <$80/kg U). In terms of all cost categories currently encompassed under the NEA/IAEA categorization (<$260/kg U), Kazakhstan possesses reasonably assured resources of 464,700 tons of uranium (tU) – 10% of the world total – of which 382,420 tons (82%) are in deposits amenable to in situ leaching (ISL), the most economically efficient and

2 On 13 November 2018, Kazatomprom made its stock market debut (raising $450 million from investors) on the London and Astana exchanges. Kazatomprom sold 15% of its stock in the dual-listing initial public offering, which valued the company at $3 billion. A secondary public offering followed in September 2019, raising an additional $128 million, bringing the "free-float" of outside shares to 18.72% of the total. And in June 2020 an additional offering raised the "free-float" to 25% of the total.

3 In 2019, a total of 24 subsoil contracts were reported by the Ministry of Energy to be in force for the exploration or production of uranium (3 for exploration only, 8 for production only, and 13 for exploration and production).

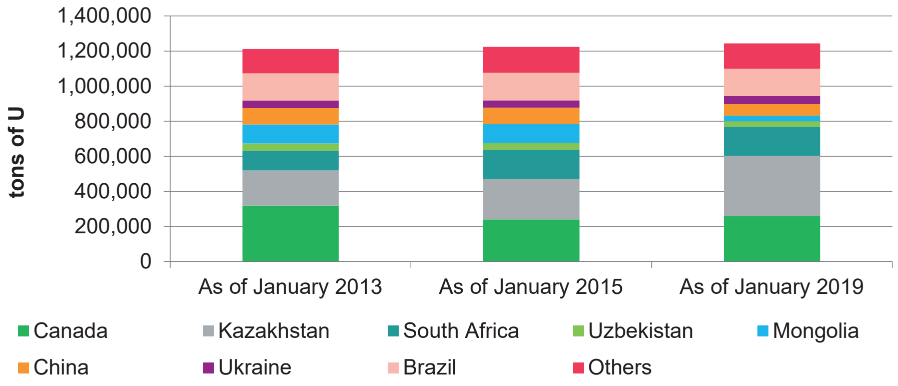
4 The National Nuclear Center at Kurchatov was established and operates in accordance with the Decree of the President of the Republic of Kazakhstan dated May 15, 1992 No. 779 "On the National Nuclear Center and the Atomic Energy Agency of the Republic of Kazakhstan."

5 In Q2 2021 Kazatomprom sold two of its subsidiary units – Astana Solar and Kazakhstan Solar Silicon LLP – via tenders for 380.6 million tenge ($887,480) and 322.8 million tenge ($752,703), respectively. The two subsidiaries produce components and solar PV modules and components (cells), respectively. A third subsidiary – KazSilicon, which produces metallurgical silicon, quartz, and microsilica – was put up for auction three times but thus far has yet to find a buyer.

6 Kazatomprom National Atomic Company, *Integrated Annual Report of Kazatomprom for 2020.*

7 The Red Book – OECD Nuclear Energy Agency (NEA) and International Atomic Energy Agency (IAEA), *Uranium 2020: Resources, Production, and Demand,* Paris: OECD, NEA No. 7551, 2020 – is the only government-sponsored publication tracking world trends and developments in uranium resources, production, and demand. It has been published biennially since 1965. It defines (p. 9) *identified resources* as uranium deposits delineated by sufficient direct measurement to conduct pre-feasibility and sometimes feasibility studies. They encompass the subcategories of *reasonably assured resources* (RARs) and *inferred resources.* For RARs, there is high confidence in estimates of grade and tonnage based on mining decision-making standards, whereas inferred resources represent lower-confidence estimates that generally require further direct measurement prior to making a decision to mine. In this report, unless otherwise indicated, we use the category of recoverable RARs (i.e., recoverable with existing technologies, with mining and processing losses taken into consideration) as the basis for assessment of Kazakhstan's uranium endowment.

Figure 7.1 World's reasonably assured reserves with cost of production <$80/kg U



Notes: Totals of 2019 related to cost range <USD 80/kgU should be regarded with some caution since certain countries do not report low-cost resource estimates, mainly for reasons of confidentiality, whereas other countries that have never, or not recently hosted uranium mining, may be underestimating mining costs.

Source: IHS Markit, World Nuclear Association, NEA

environmentally friendly method of extraction.[8] More importantly, it possesses 65% of the world's reasonably assured resources (RARs) that can be extracted through ISL. Finally, 95% of Kazakhstan's *identified uranium resources* available at <$40/kg U are associated with existing and planned production sites, 94% at <$80/kg U, and 71% at <$130/kg U. Thus, the country is not confronted with the need for the massive build-out of new mine infrastructure to sustain its present output.

Kazakhstan recently has reported increases in uranium resources in all cost categories, owing both to ongoing exploration efforts and currency depreciation. Since exploration began in 1944, at least 60 deposits have been identified in six ore provinces in the southern, north-central, and western regions of the country – Shu-Sarysu (60.2% of total resources), Syrdarya (15.2%), North Kazakhstan (17.3%), Caspian (1.8%), Balkhash (0.8%), and Ili (4.7%) (see Figure 7.2 Kazakhstan's uranium provinces and distribution of uranium reserves). In 2017–18, exploration efforts, including at the Budenovskoye and Inkai deposits in the Shu-Sarysu province and at the Northern Kharason deposit in the Syrdarya province, yielded 149,621 tU of new *identified resources* (<$260/kg U).

7.4 Mine Production and Exports

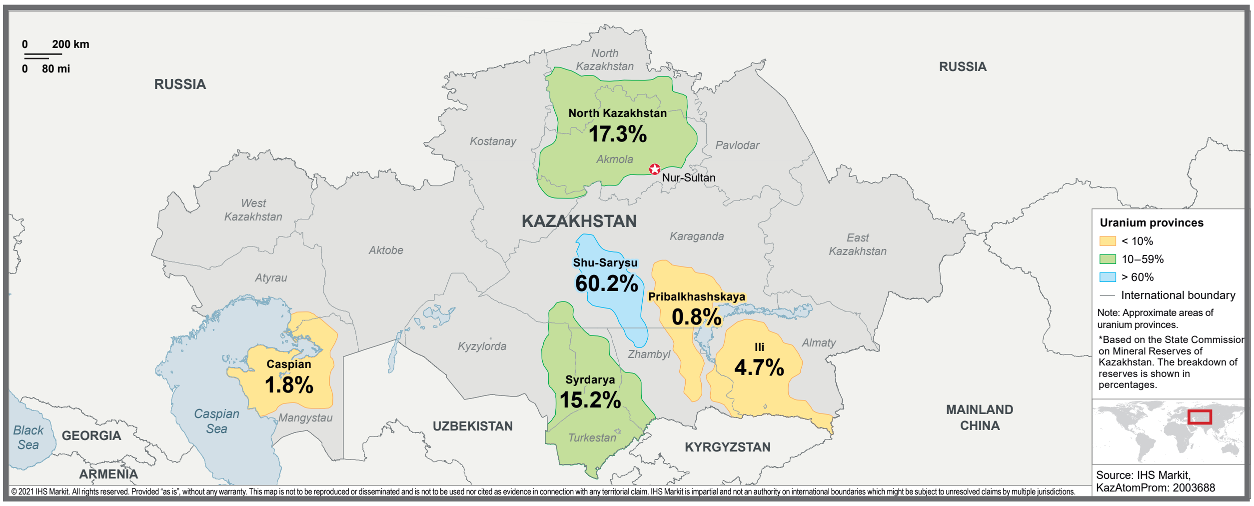
A weak (oversupplied) market for uranium, following unprecedented growth during 2003–16, prevailed during 2017–19, before worsening further in 2020 as a result of the COVID-19 pandemic.[9] Major producing countries, including Canada and Kazakhstan, have limited total production in recent years in response to a sustained depressed price environment. Global uranium mine production decreased by 15% between 2016 and 2018 (falling from 63.0 thousand tons [Mt] to 53.5 Mt), before experiencing a slight increase of 1% in 2019 (to 54.2 Mt). Uranium production cuts unexpectedly deepened with the onset of the global COVID-19 pandemic in early 2020.

As the world's leading uranium mine producer (accounting for 41% of world output in 2020), Kazakhstan has led the production curtailment. Total production fell to 19.5 Mt in 2020, a decrease of 15% relative to 2019 (22.8 Mt) (see Table 7.1 Uranium production in Kazakhstan, 2010–20 (metric tons)). This is in marked contrast to the previous trend, which saw Kazakhstan accounting for 72% of world supply growth over the period 2000–16. Regionally, almost all of current (2019) output comes from mines in southern Kazakhstan's Turkestan and Kyzylorda oblasts (77% and 19% of the total, respectively). Kazakhstan's leading

8 NEA and IAEA, *Uranium* 2020, p. 266–267. The ISL method leaches ores with sulfuric acid to yield uranium solutions, extracted directly from sandstone deposits via a system of wells, which are processed via an ion exchange technology to yield a precipitate (uranium-bearing salts). The salts are further refined to produce natural uranium concentrates. Because ISL does not bring waste rock and ore to the surface, there are no mine waste deposits or dust dispersion from them. Further, the process mobilizes less than 5% of the radioactive elements, the balance of which remain in the ground. In addition to being cost-efficient and less environmentally impactful, the ISL technology offers enhanced operational flexibility compared to conventional mining; similar to fracking in the petroleum industry, this improves the scalability of Kazatomprom's operations and allows it to ramp up or down its production in a quick and cost-efficient manner in response to evolving market conditions (a very important advantage given the current flux in global demand).

9 See KAZENERGY, *The National Energy Report 2017*, p. 160, 162–166 for background on the weakening of global market conditions during this period.

Figure 7.2 Kazakhstan's uranium provinces and distribution of uranium reserves*



uranium producer is state-owned Kazatomprom. On an entitlement basis it produced 10.7 Mt of U in 2020, accounting for 55% of the country's U mine production, and production guidance for 2021 ranges from 12.6 to 12.8 Mt (this nonetheless reflects the company's pledge to keep production 20% below previously planned levels; see below). Despite this, the bulk (82%) of Kazatomprom's uranium output is not from projects it solely owns, but rather from 11 projects in which it has an interest (usually a controlling block of shares) in joint ventures with foreign partners – involving companies from Canada, France, Russia, Japan, mainland China, and Kyrgyzstan.[10] Nine major projects each produced over 1,000 tons of uranium in 2019 and 2020, and accounted in aggregate for 86% of the country's mine output in 2020, i.e., 16.8 Mt of 19.5 Mt (see Table 7.2 Major uranium-mining companies, ownership, mines, and output in Kazakhstan, 2019-20).

The reduction in output reflects Kazatomprom's earlier announced strategy to reduce production by 10% in 2017 and 20% between 2018 and 2022 (to support global prices during a period of weak global demand – see above). But it also is due to a serious outbreak of COVID-19 domestically, which necessitated the imposition of strict quarantine measures in the industry during the period April–June 2020.

The principal export markets for Kazakhstan's mined uranium (uranium concentrate, U_3O_8) in 2018 and 2019 were in mainland China, Russia, Canada, India, France, the United States, and Ukraine (Figure 7.3 Kazakhstan's uranium exports to major countries, 2016-20). Despite the muted near-term outlook for production, Kazakhstan's exports in 2020 actually increased modestly (by 3.5%), to 27.8 Mt.[11] The increase reflects a gradual improvement in the global price environment (see below) as other major world producers joined Kazakhstan in voluntary curtailments in production (resulting in a temporary supply deficit), and the weakening of the tenge relative to the dollar: as with oil, international trade in uranium is generally denominated in US dollars, whereas most of the company's operational and capital expenditures are denominated in tenge. Reflecting the slow improvement in the supply–demand balance globally, Kazakhstan's production is expected to increase slightly in 2021, to 22.5–22.8 Mt (approximately the same level as in 2013–2014 and slightly below peak levels reached in 2015 and 2016). And on 2 July 2021 Kazatomprom, citing a gradually improving market environment, announced it would maintain output in 2023 at 2021–22 levels (i.e., between 22.5 and 23 Mt).

It should be emphasized that the focus on the upstream (mining) in the present competitive international market is a conscious decision by Kazatomprom that reflects its view of mining as currently the most attractive segment of the nuclear fuel value chain in terms of sustainable profitability and returns on capital. This is driven by its comparative advantage of large deposits of uranium suitable for ISL-based mining. The company's recent

10 Kazatomprom has developed 11 successful asset-level partnerships with Cameco, CGNPC, Kansai, Marubeni, Orano (formerly Areva), Rosatom/Uranium One, and Sumitomo, as well as the Energy Asia consortium (Japan). In terms of country participation, Russian companies are involved in six joint ventures in the republic; Japanese companies in three; French, Canadian, and Chinese in one project; and a Kyrgyz company has a small stake (0.04%) in one additional project. Kazatomprom's motivation for the granting of shares in deposits to foreigners is to obtain funding and technological expertise in exchange for a share of the output. Kazakhstan's Subsoil Code specifies that state ownership in each new joint venture must be at least 50%, although for two JVs formed prior to enactment of the Code, this share (49%, 30%) is lower.

11 This figure reflects total sales by Kazatomprom and its foreign partners. The fact that the 2020 export figure exceeds Kazakhstan's 2020 production reflects sales from inventories (see Kazatomprom National Atomic Company, *Integrated Annual Report of Kazatomprom for 2020,* p. 29).

Table 7.1 Uranium production in Kazakhstan, 2010-20 (metric tons)

	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020
Total uranium production	17,449	19,096	20,979	22,501	22,829	23,806	24,689	23,321	21,705	22,808	19,477

Source: Kazatomprom National Atomic Company

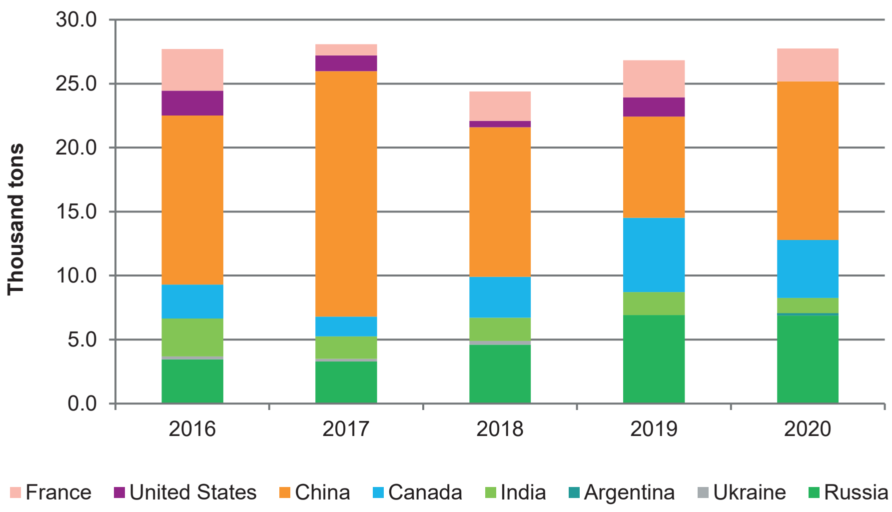
Table 7.2 Major uranium-mining companies, ownership, mines, and output in Kazakhstan, 2019-20

Company	Ownership	Mines, deposits	2019 mine output, tons U	2020 mine output, tons U
JV KATCO LLP	51% Orano (France); 49% Kazatomprom	Moinkum (sections 1 and 2) Inkai (section 1)	3,252	2,833
JV Inkai LLP*	40% Cameco (Canada); 60% Kazatomprom	Budenovskoye (section 2)	3,209	2,693
JV Karatau LLP	50% JSC Uranium One (Rosatom); 50% Kazatomprom	Akdala, Inkai (section 4)	2,600	2,460
JV Southern Mining and Chemical Company LLP	70% JSC Uranium One (Rosatom); 30% Kazatomprom	North Kharasan	2,401	2,260
JV Khorasan (Kyzylkum) LLP	30% JSC Uranium One (Rosatom); 20% Energy Asia**; 50% Kazatomprom	Budennovskoye (sections 1, 3, 4)	1,599	1,455
JV Akbastau LLP	50% Uranium One (Rosatom); 50% Kazatomprom	Central Mynkuduk, Zhalpak	1,550	1,363
MC-Ortalyk LLP	51% Kazatomprom; 49% China General Nuclear Power Group	Kanzhugan, Moinkum (sections 1 and 3), E. Mynkuduk, Uvanas	1,694	1,308
Kazatomprom- SaUran LLP	100% Kazatomprom		1,541	1,230
JV Baiken LLP	47.5% Energy Asia**; 52.5% Kazatomprom	North Kharasan	1,560	1,181

Notes: * JV Inkai LLP determined its annual production (proportional to the share of ownership) in accordance with the Sales Agreement disclosed earlier in the Kazatomprom's Securities Issue Prospectus; ** Energy Asia consists of 59.5% Japanese partners and 40.5% Kazatomprom.

Source: Kazatomprom National Atomic Company, Integrated Annual Report of Kazatomprom for 2019, pp. 69-78; Integrated Annual Report of Kazatomprom for 2020, pp. 60-73.

Figure 7.3 Kazakhstan's uranium exports to major countries, 2016-20



Source: IHS Markit, Bureau of National Statistics RK, Kazakhstan's Customs Statistics

Table 7.3 World nuclear power reactors and uranium requirements as of July 2021

	REACTORS OPERABLE		REACTORS UNDER CONSTRUCTION		REACTORS PLANNED		URANIUM REQUIRED in 2021
	No.	Mwe, net	No.	MWe gross	No.	MWe gross	tonnes U
China	51	49,569	17	18,616	38	41,785	10,814
India	23	6,885	6	4,600	14	10,500	1,080
Korea RO (South)	24	23,150	4	5,600	0	0	5,121
Turkey	0	0	3	3,600	1	1,200	0
UAE	1	1,345	3	4,200	0	0	877
Bangladesh	0	0	2	2,400	0	0	0
Japan †	33	31,679	2	2,756	1	1,385	2,344
Russia ‡	38	28,578	2	2,510	25	23,890	6,227
Slovakia	4	1,837	2	942	0	0	428
Ukraine †	15	13,107	2	1,900	0	0	1,879
United Kingdom	15	8,923	2	3,440	2	3,340	1,820
USA	93	95,523	2	2,500	3	2,550	18,295
Rest of the world	146	133,686	7	8,155	16	17,787	19,384
WORLD*	**443**	**349,282**	**54**	**61,219**	**100**	**102,437**	**68,269**

Notes:
68,269 tU = 80,506 t U_3O_8
Operable = Connected to the grid.
Under Construction = First concrete for reactor poured.
Planned = Approvals, funding or commitment in place, mostly expected to be in operation within the next 15 years.
Proposed = Specific programme or site proposals; timing very uncertain.
* World figures include Taiwan, which generated a total of 31.1 TWh from nuclear in 2019 (accounting for 13.4% of Taiwan's total electricity generation). The island has four operable reactors with a combined net capacity of 3844 MWe. A two-unit plant (Lungmen) commenced construction in New Taipei City in 1999. In February 2019 Taipower confirmed that the two units would not be completed. The two units are listed as under construction in PRIS, but were removed from WNA's database on 1 September 2020.
† Under Construction figures include a number of units where construction is currently suspended: Angra 3 (Brazil); Ohma 1 and Shimane 3 (Japan); Khmelnitski 3&4 (Ukraine).
‡ Baltic 1, a VVER-1200 unit, commenced construction in Kaliningrad in Russia in February 2012. Construction was suspended in July 2013, and in 2017 the RPV made for Baltic 1 was sent to be used in Ostrovets 2 in Belarus. The unit is shown as under construction in PRIS, but was removed from the WNA's database in November 2020.
New plants coming online are largely balanced by old plants being retired. Over 1998-2020, 103 reactors were retired as 105 started operation. However, the reactors grid connected during this period were larger, on average, than those shutdown, so capacity increased by 31 GW. The reference scenario in the 2019 edition of The Nuclear Fuel Report (Table 2.5) has 154 reactors closing by 2040, and 289 new ones coming online (figures include 21 Japanese reactors online by 2040).
TWh = terawatt hour (billion kilowatt hours); kWh = kilowatt hour; MWe = megawatt (electrical as distinct from thermal).

Sources: Reactor and electricity data: International Atomic Energy Agency Power Reactor Information System (PRIS); US Energy Information Administration; company data; World Nuclear Association estimates; IHS Markit; for uranium requirements - World Nuclear Association, The Nuclear Fuel Report (published September 2019, reference scenario forecast).

efforts to expand to other elements of the fuel cycle therefore are not driven as much by financial factors as a belief that diversification of products offers a measure of security (greater flexibility of sales options and reduced dependence on individual downstream processors) in the ultimate delivery of uranium to its consumers.

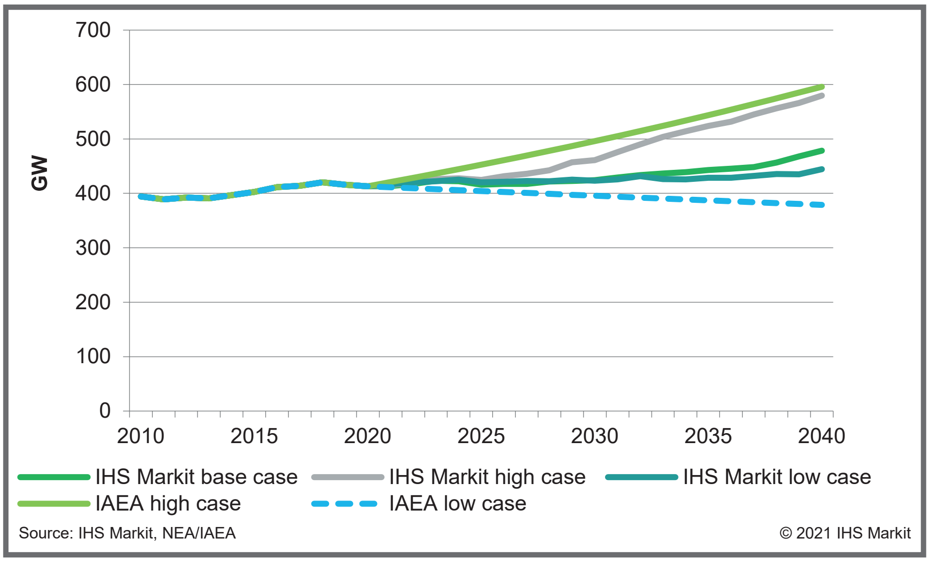
7.5 Global Uranium Market

Power generation remains the largest consumer of uranium globally, accounting for 95% of overall demand. Uranium is also used for medical and research purposes and naval propulsion (e.g., powering ice-breaking vessels, submarines).[12]

In May 2021, a total of 443 commercial nuclear reactors were operating worldwide, with an aggregate capacity of 394.2 gigawatts (GWe, electricity output capability as distinct from thermal), requiring about 68 Mt of uranium annually; another 54 reactors were under construction, with an aggregate capacity of 61.2 GWe (see Table 7.3

12 See KAZENERGY, *The National Energy Report 2017*, p. 164. Data on uranium demand for nuclear weapons production are not available, but the amount is now believed to be negligible relative to consumption during the Cold War era.

Figure 7.4 Global nuclear generation capacity outlook by scenario



World nuclear power reactors and uranium requirements as of July 2021). The global commercial reactor fleet generated 2,657 terawatt-hours (TWh) of electricity in 2019, compared to 2,563 TWh in 2018. In 2019, nuclear power and renewables worldwide combined generated more electricity than coal for the first time. Because of the considerable flux in policies announced in several countries regarding the future of nuclear power (involving rates of commissioning of new and decommissioning of old reactors), future world nuclear capacity out to 2040 is subject to a wide range of estimates: from moderate growth above the current level in the IHS Markit low-demand scenario (444 GWe) to roughly 596 GWe in the IAEA high-demand case (see Figure 7.4 Global nuclear generation capacity outlook by scenario).[13] Based on these estimates, world annual reactor-related primary (mined) uranium requirements are projected to range between roughly the current level (68 Mt U) to well over 100 Mt U annually in 2040.[14]

Despite the wide range in estimates for future uranium demand, the current uranium resource base is considered to be more than adequate to meet even high-case projected uranium demand through 2040. However, doing so will depend upon timely investments to bring resources into production; and without further resource additions, meeting high-case demand requirements to 2040 would consume about 87% of the total 2019 identified resource base recoverable at <$80/kg U.[15]

In addition to primary sources of uranium (mine production), secondary sources represent both a substantial source of current supply and a major resource in the future (recently secondary sources have accounted for roughly 25% of total supply). Secondary sources include:

- stocks of natural and enriched uranium (both civilian and military)
- nuclear fuel derived from the reprocessing of spent reactor fuels and military plutonium
- uranium from re-enrichment of depleted uranium tailings.

Due to the availability of secondary supplies, primary uranium production volumes have been significantly below (5–10% in recent years) world uranium requirements for some time.

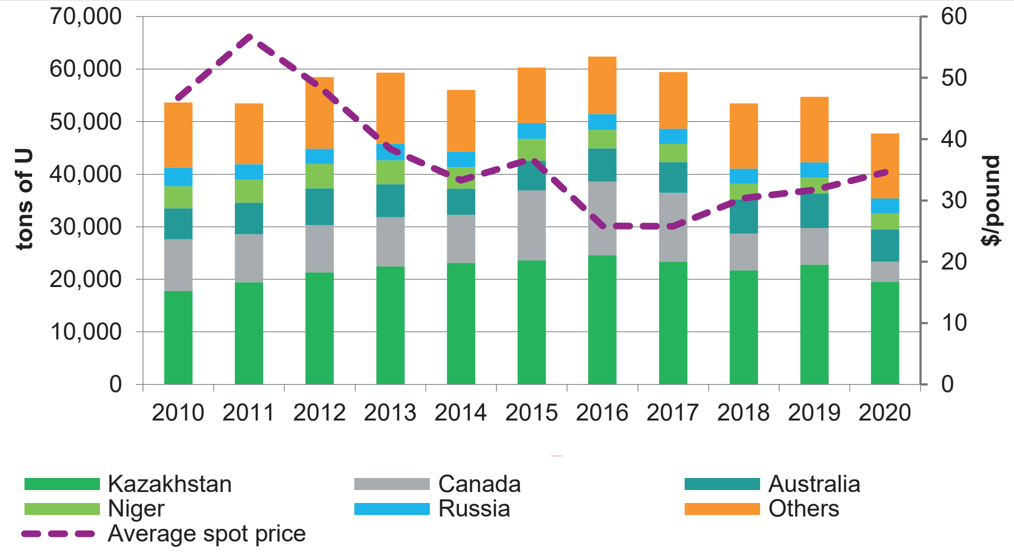
Following the Fukushima accident in 2011, a combination of stagnant or only slowly growing demand for uranium

13 The commitment to nuclear generation varies widely among countries. In several developed countries already possessing substantial generating capacity, the goal is to keep existing plants operating as long as this can be achieved safely, and upgrading existing generating capacity (e.g., United States, Canada, Czech Republic, Hungary, Mexico, the Netherlands, Slovak Republic), due to the demonstrated economic competitiveness of existing plants (low operating, maintenance, and fuel costs). And significant nuclear build-outs continue in China and India, where air pollution is a major problem and coal-fired generation still accounts for a major share of electricity generation. Other countries, including Belarus and Turkey, are embarking on generation for the first time. Conversely, some countries have decided for public safety and environmental reasons to phase out their existing fleets following the Fukushima Daiichi accident in Japan (Belgium, Germany). Finally, in Japan, where nuclear generation ceased in the immediate aftermath of the Fukushima Daiichi accident in 2011, safety reviews of 15 existing reactors have been completed and 9 have returned to service; the remaining 18 reactors are still in various states of the Nuclear Regulatory Agency's safety review process (https://www.world-nuclear-news.org/Articles/Japanese-industry-leaders-call-for-nuclear-restart).

14 The increase in fuel consumption is not expected to be linear with increased generation, due to fuel efficiency improvements associated with improved reactor designs.

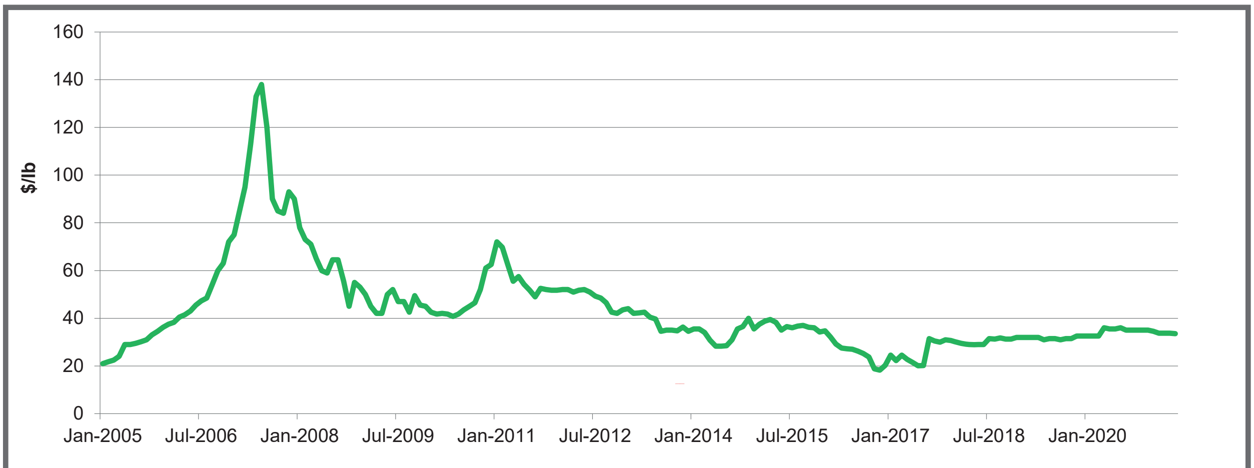
15 NEA and IAEA, *Uranium 2020,* pp. 13, 91–93.

Figure 7.5 Global uranium production by major producer vs. uranium price



Source: IHS Markit, World Nuclear Association, Uranium Miner © 2021 IHS Markit

Figure 7.6 Spot price of U_3O_8



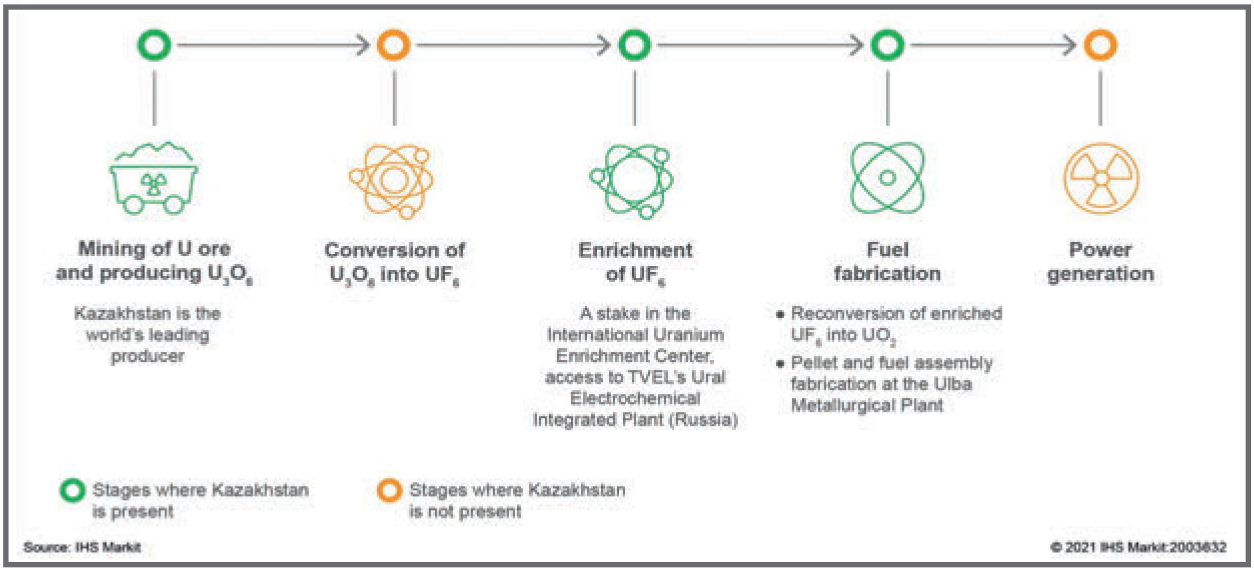
Source: IHS Markit, Uranium Miner, Cameco © 2021 IHS Markit

(with temporary reactor shutdowns or phase-outs in developed markets such as Japan and Germany being balanced with reactor build-ups in emerging markets such as mainland China and India) and rising uranium mine production has created a rather weak price environment for producers (see Figure 7.5 Global uranium production by major producer vs. uranium price). More specifically, early in this period Fukushima precipitated a pronounced decline in price (from $62.50/lb [$162.5/kg]) in March 2011 to a nadir of below $19/lb ($49/kg) in November 2016 (reaching levels not seen since early 2004), followed by weak and unsteady recovery (featuring a secondary bottom of $19.60/lb [$51/kg] in May 2017).[16]

The weakness was prolonged as new mine projects, started before the accident, began to come on stream, increasing supply (and driving excess inventories). Prices eventually began to find some support from voluntary curtailments in production in 2017–19 from major producers such as Kazakhstan and Canada, followed by temporary, involuntary curtailments necessitated by COVID quarantines in 2020, as traders bought material to cover near-term delivery commitments. Prices began a fitful, slow upward trajectory in 2018, rising from $21/lb ($55/kg) in April of that year, with month-end 2020 prices averaging almost $30/lb ($78/kg) for 2020, and remaining at that level in end-May 2021 (see Figure 7.6 Spot price of U_3O_8).

16 https://www.cameco.com/invest/markets/uranium-price

Figure 7.7 The "front end" of the nuclear fuel cycle



7.6 Uranium Transportation

The transportation of uranium concentrate in Kazakhstan is regulated and requires licenses from the Energy Ministry's Committee for Atomic and Energy Supervision and Control and from the Industry and Infrastructure Development Ministry's Transport Committee. Depending on the destination and cargo, the major modes used to transport standard uranium products are truck, rail, and sea, using sealed, twenty-foot equivalent unit (TEU) containers. Transportation of radioactive materials also involves the participation of security services under the Ministry of Internal Affairs.

In 2019, Kazatomprom spent 6.8 billion tenge ($17.9 million) in transportation and storage fees.[17] It transported U_3O_8 to licensed conversion facilities owned by companies Honeywell (US), Cameco (Canada), and Orano Cycle (France), first by rail from its operations in Kazakhstan, generally to the port of St. Petersburg in Russia, then by sea to various ports in the United States, Canada, and Europe.

When transporting materials to mainland China (uranium concentrate, pellets, fuel assemblies), Kazatomprom delivers cargoes to the Alashankou railway crossing on the Kazakhstan-China border. And when shipping to the Russian Federation (e.g., the Siberian Chemical Combine JSC for enrichment) it delivers cargoes by rail to the Tomsk-2 railway station in West Siberia (Russia). Kazatomprom generally delivers U_3O_8 to India by rail to the port of St. Petersburg, then by sea to the port of Mumbai.

The average cost of shipping ranges from $0.50 to $4.00/kg U_3O_8. Where practical, the company enters swap agreements in order to minimize delivery times, both when delivering to conversion facilities for Kazatomprom's subsequent use and when delivering to customers. The physical transportation of materials takes, on average, 100 days, whereas deliveries under swap agreements can take up to 25 days; in addition to saving time, the swaps reduce both transportation costs and the risks related to the transportation of uranium products.

7.7 Front End of the Nuclear Fuel Cycle

The nuclear fuel cycle has two phases. The "front end" consists of

- *mining* of uranium ore and production of uranium oxide (U_3O_8) concentrate
- *conversion* of U_3O_8 into uranium hexafluoride (UF_6)
- *enrichment* of UF_6 (i.e., the increase of the uranium-235 isotope concentration)
- *fuel fabrication,* which includes four separate steps:
    - reconversion into uranium oxide (UO_2)
    - production of ceramic fuel pellets
    - combination of pellets into fuel rods
    - assembly of the rods into a fuel assembly structure (see Figure 7.7 The "front end" of the nuclear fuel cycle).

17 This section includes material adapted from *Integrated Annual Report of Kazatomprom for 2019,* pp. 38–39, 345. On 30 June 2019 the tenge exchange rate was 380.1 tenge/USD.

As noted above, Kazakhstan currently is present in the front-end phase, specifically in the mining stage, as well in the fuel fabrication stage (namely, reconversion of enriched UF_6 into UO_2 and pellet and fuel assembly fabrication at the Ulba Metallurgical Plant [UMP]).

Following the use of fuel assemblies to generate electric power in nuclear power plants, the "back end" of the nuclear fuel is devoted to the reprocessing, storage, recycling, and disposal of spent nuclear fuel. As shall be discussed below, in the past Kazakhstan has participated (and continues to be involved) in the storage of Soviet-era nuclear waste, and has extant scientific expertise in commercial nuclear power generation (which ended in the country as recently as 1999), as well as in spent fuel storage and processing. This could be leveraged in the event that the country decides to construct a nuclear power plant to reduce greenhouse gas emissions from the electric power sector and otherwise meet future power demand.

The first phase in the front-end of the cycle (mining) was discussed above. Therefore, this section will cover important developments in Kazakhstan's experience with fuel conversion, enrichment, and fuel fabrication. As noted above, given the country's dominant position as a low-cost mine producer, its absence to date from certain phases of the fuel cycle should not be viewed as a sign of arrested development (it dominates in that portion of the front-end phase where most of the value is added – mine production).[18] Rather, its efforts to enter other phases of the cycle reflect a recognition by industry officials that diversification of products will afford greater flexibility in terms of sales options and reduced dependence on particular downstream processors.

7.7.1 Conversion

Uranium conversion is the processing of natural uranium concentrate (U_3O_8) into uranium hexafluoride (UF_6), which is the uranium feedstock for enrichment plants throughout the world. There are only a few conversion plants in the world, including major facilities in the U.S., Canada, France, Russia, and China. Although Kazakhstan presently does not participate in this segment of the front-end fuel cycle, conversion is typically the smallest component of the overall nuclear fuel cost (typically accounting for about 8% of the cost of a finished fuel assembly).[19]

However, Kazakhstan participates indirectly in the conversion segment through a JV with Canada's Cameco. As a part of an upstream asset deal in 2016, Cameco transferred its technology for the purification of uranium (a preliminary step toward conversion in which U_3O_8 is transformed into UO_3) to the joint venture on a royalty-free basis. The UO_3 produced in Kazakhstan was then sent to Cameco's conversion facility in Port Hope, Ontario for production of UF_6. As part of this deal, Kazatomprom also obtained a five-year option to license Cameco's conversion technology for the purpose of constructing and operating its own UF_6 conversion facility in East Kazakhstan Oblast at the site of the UMP. However, that project has now been postponed due to weak market conditions and the low margins obtained for conversion services.

In addition to Cameco's facility in Ontario, Kazatomprom ships U_3O_8 to converters located in the United States (Honeywell) and France (Orano), sometimes under swap arrangements (see the section on uranium transportation above).

7.7.2 Enrichment

Enrichment is the second largest cost component (after mine production) of the fuel used in conventional reactors, accounting for approximately 27% of the total. However, given its close association with the production of nuclear weapons material, enrichment technology is tightly restricted and occurs only in a few countries. And Kazakhstan, which has supported global nonproliferation efforts in the aftermath of the disintegration of the USSR, and whose only commercial operating reactor at Aktau closed in 1999, has not sought to develop its own enrichment capacity to date.[20] Four companies control the vast majority of the world's enrichment capacity: Rosatom (Russia), URENCO (Germany, Netherlands, and UK), Orano (France), and the China National Nuclear Corporation (CNNC). These companies operate enrichment plants based on gas centrifuge technology, which uses centrifugal force to separate the U235 and U238 isotopes in natural uranium.

18 For most nuclear reactors, upwards of 50% of the cost of fuel is contained in the natural uranium component (U_3O_8) of the end fuel product (i.e., the cost of mining).

19 The relative costs of the different components of the front end of the fuel cycle are from the World Nuclear Association, "Economics of Nuclear Power," March 2000, https://world-nuclear.org/information-library/economic-aspects/economics-of-nuclear-power.aspx.

20 In fact, it supports international efforts to limit the spread of enrichment by hosting an IAEA nuclear fuel bank that is designed to serve as an alternative source of low-enriched uranium (LEU, should supply not be available on the spot market) for nuclear power generation in countries that do not possess their own enrichment capacity (see below).

Kazakhstan participates in the enrichment segment (i.e., has access to enrichment facilities) through a cooperation agreement with Russia's state nuclear agency Rosatomprom. Since 2007, Kazatomprom has held a 10% share in the International Uranium Enrichment Center in Angarsk, Russia, which has a total enrichment capacity of 2 million separative work units (SWUs) per year (60 thousand of which are available for Kazatomprom). And, during the period 2013–20, Kazatomprom owned a 25% stake in enrichment operations at the Ural Electrochemical Integrated Plant in Sverdlovsk Oblast, Russia (as a result of its Uranium Enrichment Center JSC venture with Russia's TVEL), which has up to 5 million SWU of existing enrichment capacity. However, in March 2020, Kazatomprom sold the bulk of this position to a subsidiary of Rosatom, retaining only a single share in order to retain access to the services of the Ural plant on an as-needed basis.

7.7.3 Fuel fabrication and assembly

The final step in the front-end nuclear fuel cycle is the fabrication of fuel assemblies, which accounts for a significant share of the total nuclear fuel cost (~22%). Because fuel types (powder, pellets) can vary greatly depending on the type of reactor, fuel fabrication is a customized product, and is not considered a commodity-type market like the other three front-end nuclear fuel cycle sectors. Output from three major global vendors of fuel assemblies – Framatome (France), Global Nuclear Fuel (a joint venture between General Electric and Hitachi), and Westinghouse (United States) – is augmented by numerous domestic and international vendors, including Russia's TVEL, South Korea's KEPCO Nuclear Fuel, and Spain's ENUSA. Many utilities prefer to procure fuel from multiple suppliers, when possible.

Kazakhstan's UMP has for many years produced UO_2 powders certified for widespread use in reactors in the United States, Switzerland, Russia, and Japan. It also produces nuclear fuel pellets for Russian-designed RBMK reactors and French-designed AFA 3G reactors (including Framatome AFA 3G reactors in China).[21] After 2013, the export of pellets to Russia has diminished, as a result of the latter country's efforts to increase its own pellet production capacity. As a result, the UMP's fuel pellet exports to Russia in recent years have been minimal (10 tons in 2014, 0 tons in 2015, 24 tons in 2016), and deliveries have been redirected primarily to customers in China. Sales volumes of fuel pellets have since recovered strongly as a result of the acceleration of pellet purchases by China for its AFA reactors and establishment of a joint venture with the China General Nuclear Power Group (CGNCP) in 2015 (51% Kazatomprom, 49% CGNCP) to build a plant at UMP to produce fuel assemblies incorporating these pellets; 2019 pellet sales were 86 tons, up 2% from the 2018 level, but fell to 60.3 tons in 2020.[22]

CGNPC and Kazatomprom have now completed the construction of the nuclear fuel assemblies unit at UMP, based on Orano technologies, but it is not slated to start production until later in 2021. CGNPC has committed to purchase fuel assemblies in the amount of 200 tons of uranium metal equivalent (UME) per year for 20 years, with the first deliveries to begin in 2022.[23] This arrangement builds on past cooperation between CGNPC and Kazatomprom on technology transfer for the production and export of fuel pellets to CGNPC nuclear power plants beginning in 2012.

7.8 Power Generation

Public sentiment about nuclear power generation in Kazakhstan has tended to be mixed, reflecting a complicated history of radiation-related environmental damage and public health concerns stemming from Soviet nuclear weapons testing at a facility in the general vicinity of the city of Semipalatinsk (now Semey), in northeastern Kazakhstan. At least 460 nuclear explosions occurred at the Semey facility between 1948 and 1989, first above ground (1948–1964), and then underground (1964–1989) following the conclusion of the Nuclear Test Ban Treaty in 1963. Although the facility was closed in 1991, roughly one million people may have been exposed to radiation as a result of the tests, and the population of the region continues to experience an abnormally high incidence of immune system deficiencies and physical and mental defects. The primary environmental threat posed by the site today is a high level of residual radioactive contamination of soil and groundwater. In addition to the tests at Semey, as many as 40 nuclear detonations may have occurred at isolated testing grounds in western and southwestern Kazakhstan.[24] Public opposition crystallized late in the Soviet period (1989) in the establishment of the powerful Nevada Semipalatinsk anti-nuclear movement, at

21 During the Soviet period, UMP covered up to 80% of the USSR's nuclear power plants' needs in fuel pellets.

22 Kazatomprom National Atomic Company, *Integrated Annual Report of Kazatomprom for 2019,* p. 12; Kazatomprom National Atomic Company, *Integrated Annual Report of Kazatomprom for 2020,* p. 74. It should be noted that UMP is also an important producer of such rare metals as tantalum, beryllium, and niobium.

23 In late April 2021, Kazatomprom announced that it had agreed to sell a 49% share of its wholly owned subsidiary Ortalyk LLP (which owns and operates mines at the country's Central Mynkuduk and Zhalpak uranium deposits) to CGN Mining, a subsidiary of CGNPC. The sale (at $435 million) was contingent on the signing of the JV to construct the fuel assembly plant and CGNCP's guaranteed purchases of fuel assemblies from the plant and was finalized in July 2021 (see Table 7.2).

24 KAZENERGY, *The National Energy Report 2015,* p. 345.

a time when environmentalism offered a convenient and acceptable vehicle for Kazakh nationalism more broadly.[25]

Still, nuclear power affords one of the few reliable low-carbon alternatives to coal (alongside gas) as the baseload foundation for a more ambitious rollout of renewable electric power generation and a reduction of air pollution more broadly. As such, the idea of constructing a new nuclear reactor, of larger capacity than the older Aktau reactor (135 MW, Mangystau Oblast) that ceased operations in 1999, has periodically been discussed since its closure.

More specifically, in a State of the Union address in January 2014, First President Nursultan Nazarbayev instructed the government to develop a plan for building a nuclear power plant. The plan, compiled in May 2014 (and further amended in November 2016), sought to complete a feasibility study by 2018 on construction of two nuclear power stations in the city of Kurchatov (East Kazakhstan Oblast) and in the town of Ulken (Almaty Oblast) near Lake Balkhash. The location and main characteristics of the stations were chosen based on three previous studies: a 1997 feasibility study for a station in Ulken using Russia's VVER-640 PWR-type reactor; a 2006 feasibility study for a station in Aktau using Russia's VBER-300 PWR-type reactor; and a 2009 research study on an electricity balance forecast that required nuclear power generating capacities, and which recommended three locations (Ulken, Aktau, and Kurchatov). The Energy Ministry considered using a Russian reactor for the Kurchatov location, while for the Ulken location Generation 3 reactor designs by Westinghouse/Toshiba, AREVA/Mitsubishi, and Hitachi/GE were being considered.[26]

Most recently, in April 2019 Russian President Vladimir Putin offered Russia's direct assistance in the construction of a reactor, during a meeting with Kazakh President Kasim-Zhomart Tokayev.[27] However, following the meeting, a statement from Kazakhstan's Energy Ministry indicated that reactor technologies from companies of five countries, "including Russia's Rosatom," were under consideration.[28] But the ministry also said other, non-nuclear projects were being reviewed, such as more gas-fired plants, hydropower projects, and even coal-fired plants.

Apparently reflecting the sensitive nature of the proposal, as recently as in early April 2021 Kazakhstan's Energy Ministry pledged that any reactor constructed on Kazakh territory would be built only "after public hearings and consent from local executive bodies on the territory where construction . . . is possibly planned." And it is noteworthy that the draft of Kazakhstan's updated Nationally Determined Contribution (NDC) to the Paris Climate Agreement, issued in advance of COP26 in Glasgow in fall 2021 – which sets the goal of achieving carbon neutrality (net zero greenhouse gas emissions) by 2060 – stated that "No nuclear power plant will be constructed in Kazakhstan before 2030."[29] Although such a categorical statement ("before 2030") is not incongruent with the prolonged construction schedules typical of the industry (i.e., two reactors Rosatom plans to construct in Uzbekistan are not expected to be operational before 2028 and 2030, respectively), it is not consonant with the goals of the country's power-sector restructuring to accommodate its carbon neutrality pledge.

More specifically, the draft update states explicitly that the share of coal in generation will need to decline precipitously, from ~69% at present to 40% by 2030, accompanied by a quite accelerated build-out of renewable energy, which will rise to 24% of generation by 2030, instead of the 10% previously anticipated (see Chapter 2). If the renewable build-out materializes as planned, the role of natural gas will need to grow proportionally to ensure reliable baseload (and flexible) generation (the draft calls for an increase in gas generation from the present 20% to 25%). But as the draft explicitly acknowledges, this dependence on gas is a risk, given that commercial supplies of gas already are tight and can only grow meaningfully – under the present structure of upstream production incentives – through the curtailment of exports. A failure to develop the only other proven low-carbon technology to support baseload needs – nuclear – to close this potential gap could mean that the coal capacity reduction that is the basis for Kazakhstan's new NDC cannot proceed on the timetable necessary to meet its carbon reduction goals.

As NER 2021 entered its final stages of preparation, it appears that Kazakhstan's government has moved toward a more proactive position regarding domestic nuclear power generation. On 3 September 2021, President Tokayev stated: "I myself believe that the time has come to consider this issue in detail, since Kazakhstan needs a new nuclear power plant." He subsequently ordered officials in the government and the Samruk Kazyna National

25 Martha Brill Olcott, *Kazakhstan: Unfulfilled Promise,* Washington, DC: Carnegie Endowment for International Peace, 2002, pp. 90–91.

26 The PWR reactors (VVER and VBER), the most common in world use today, are pressurized water reactors that move water in two or more circuits, one to moderate neutrons and the others to boil water/move turbines to generate electricity. Generation 3 reactors employ the same basic design (are water-cooled), but have advanced safety features, simpler design, higher fuel burn-up, and longer operating life. For a more thorough discussion of reactor technologies, see KAZENERGY, *The National Energy Report 2017,* pp. 172–173.

27 https://www.rferl.org/a/kazakhstan-putin-offers-russian-nuclear-plant-help/29865177.html

28 For example, given the facility at UMP soon to be completed to deliver fuel assemblies to China's CGNPC, a design similar to the latter's reactors might warrant consideration.

29 "Obnovlennyy opredelyaemyy na natsional'nom urovne vklad (ONUV) respubliki Kazakhstan v dostizhenie temperaturnoy tseli Parizhskogo soglasheniya," proyekt, 16 February 2021, p. 5.

Wealth Fund to comprehensively study the possibility of constructing a nuclear power plant in the country.[30]

Short of an expensive commitment to a long-cycle construction project on one or more large (1000 MW or larger) reactors, smaller reactor designs (some of them modular) to facilitate rapid construction may provide an alternative. In recent years, there has been increasing interest in small modular reactors (SMRs), both in countries with established nuclear generation capacity (e.g. Argentina, Canada, the United States), and in heretofore "non-nuclear" countries in Europe, the Middle East, Africa, and Southeast Asia. SMRs, with capacities generally in the range of 30-300 MWe, could be suitable for areas with small electrical grids and for deployment in remote locations. SMRs offer smaller upfront investment costs and reduced financial risks compared to larger reactors typically being built today and may be deployed as alternatives to larger nuclear power plants in locations where such plants cannot be built, or to fossil-fired plants of similar sizes.

Developments in design and technology, technical feasibility, and economic competitiveness of SMRs are widely followed and well known, and a large number of SMR designs are under development (more than 70 designs in different stages).[31] Some projects have even reached the construction stage in Argentina (CAREM) and in China (HTR-PM), and Russia has connected the world's first floating nuclear power plant (KLT-40; 70 MW), the Akademik Lomonosov, to the grid and started commercial operation in May 2020. In the United States, the NuScale SMR design is in the final stage of design certification by the US Nuclear Regulatory Commission, and Oklo Power LLC is developing a 1.5 MW micro-reactor to supply energy at remote sites (Idaho).[32] NuScale's reactor is designed to be built underground, reducing security concerns and costs. Also in the United States, Terra-Power (a company founded by Bill Gates in 2008) is building a demonstration reactor in Wyoming (345 MW) that is cooled by liquid sodium and stores heat from the reaction as molten salt (similar to some utility-scale solar plants), which acts as a giant battery to store energy until it is needed to produce electricity. It is designed to ramp up and down more quickly than a water-cooled reactor and is to be sited at one of four locations in the state that are expected to be affected by the eventual closure of a local coal-fired power plant.[33]

7.9 Back-end Nuclear Fuel Cycle, Waste Management, and Research and Development

The back end of the nuclear fuel cycle involves the handling, storage, reprocessing, and disposal of spent nuclear fuel following power generation in a reactor. The processes involved are discussed in some length in *The National Energy Report 2017,* and – given that Kazakhstan currently has no commercial reactors and does not produce spent fuel other than the small quantities from its research reactors – readers are referred to that report for details beyond the superficial descriptions provided here.[34]

7.9.1 Waste management

Two of the three types of radioactive waste associated with uranium production and nuclear power generation are largely absent in Kazakhstan, except for limited volumes connected with research activities (see below). These include *intermediate-level waste* of elevated radioactivity (e.g., contaminated materials from reactors or reactor components) that are disposed by solidification in concrete and deep burial underground and *high-level radioactive waste* (e.g., spent nuclear reactor fuel) that contains fission products and requires cooling as well as additional protection during handling and transportation.[35]

Rather, the main form of radioactive waste currently associated with Kazakhstan's uranium sector is that associated with the front end of the nuclear fuel cycle, and specifically mining operations. Globally, uranium mining, depending on the method of extraction, can generate *low-level waste* containing small amounts of short-lived radioactivity, which may be present in the mine product itself (U_3O_8), the air (e.g., as suspended particles in dust), and on clothing, tools, and filters. Not dangerous to handle, it is usually buried in landfills. However, the in-situ leaching technology that accounts for all of Kazakhstan's current uranium mine output produces negligible volumes of waste even compared to conventional open-pit mining

30 https://caspiannews.com/news-detail/president-tokayev-says-kazakhstan-needs-nuclear-power-plant-2021-9-5-0/

31 See Nuclear Energy Agency and International Atomic Energy Agency, *Uranium 2020: Resources, Production, and Demand,* Paris: OECD Report No. 7551, p. 112.

32 NuScale claims that the capitalized construction cost per kW of its 12-module, 924 MWe plant design is well below that of a four-loop PWR ($2,850/kW versus $5,587/kW); https://www.nuscalepower.com/benefits/cost-competitive. (NuScale's small reactor is meant to be installed with multiple reactor units at a single site, in this case six SMRs at the US Energy Department's Idaho National Laboratory).

33 https://www.terrapower.com/natrium-demo-wyoming-coal-plant/; *The Economist,* 12 June 2021, p. 72; https://nuclearstreet.com/nuclear_power_industry_news/b/nuclear_power_news/archive/2021/06/09/will-wyoming-embrace-nuclear-power_3f00_-060901#.YMkZJ6hKiUm.

34 KAZENERGY, *The National Energy Report 2017,* p. 174.

35 The amount of high-level radioactive waste from a typical large nuclear reactor is estimated at 25–30 tons per year.

methods, as all materials except for uranium are returned underground. Nonetheless, some site remediation may be required as specified in Kazakhstan's Subsoil Code (2018) and newly promulgated Ecology Code (see below and Chapter 2), as the production waters from mining operations returned to the subsoil may be contaminated. For this purpose, a "liquidation fund" has been created, which is financed by annual contributions from subsoil users at a rate of at least 1% of the annual cost of exploration and production.

The U_3O_8 produced from mines is mildly radioactive, but strict health standards are required for workers handling uranium oxide concentrate. If it is ingested, it has a chemical toxicity similar to that of lead oxide (the body progressively eliminates most lead and uranium via urine). So in effect, the same precautions are taken as in a lead smelter, with use of respiratory protection in particular areas identified by air monitoring. Very long exposure times would be required (much longer than normal working conditions) to receive a harmful radiation dose from the handling of mine products.[36]

7.9.2 Research and development

Despite the absence of nuclear generation in the country at present, Kazakhstan has an impressive research and development capacity devoted to nuclear power generation, waste management, and radiation safety. The National Nuclear Center, as well as the affiliated Institute of Atomic Energy, Institute of Radiation Safety and Ecology, and Institute of Geophysical Research (Kurchatov branch) – all founded in Kurchatov in 1993 – build upon legacy scientific expertise dating from a Soviet-era program to develop a high-temperature nuclear rocket engine. The R&D complex at Kurchatov includes three research reactors (including the Tokamak thermonuclear power [fusion] reactor) and three experimental benches that test a wide range of reactor structural materials and components under different reactor technologies (e.g., water, sodium, and gas coolants) and operating conditions. These operations generate small quantities of high-level radioactive waste, and hence the Nuclear Center maintains a storage facility for ionizing radiation sources.[37] In addition, the Institute of Radiation Safety and Ecology, and the Institute of Geophysical Research are actively involved in environmental remediation activities (including the monitoring of radiation and geophysical conditions) at the Semipalatinsk nuclear test site.

In addition to the facilities at Kurchatov, the Institute of Nuclear Physics (INP) of the Republic of Kazakhstan (Almaty), established in 1957, has a VVR-K water-water research reactor, an isochronous cyclotron, electrostatic accelerator, industrial electron accelerator, and 22 scientific-research laboratories.[38] Employing over 700 people in its nuclear research institutions, INP is a leading scientific organization in the field of nuclear physics and solid state physics, radio-ecological research, and nuclear and radiation technologies.

In short, with its experience in operating a nuclear reactor in the past, extensive personnel base in its nuclear research institutions, and ongoing work in waste storage and environmental remediation, Kazakhstan has a strong human capital base to support nuclear power generation, should it decide to pursue this option in the future.

7.10 Notable Developments since 2017

In addition to the pending completion of the nuclear fuel assembly facility at UMP, important new developments involving the industry since *The National Energy Report 2017* include the following:[39]

- the adoption of the Subsoil Code, and later amendments to the Code pertaining to subsoil contracts in uranium mining
- the start of operations at the IAEA's international low-enriched uranium nuclear fuel bank at the UMP
- the reorganization of subsoil contracts between Kazatomprom and foreign partners at select mining joint ventures
- the signing of Kazakhstan's new Environmental (Ecology) Code into law on 2 January 2021, going into effect 1 July 2021.[40]

36 https://www.world-nuclear.org/information-library/safety-and-security/radiation-and-health/occupational-safety-in-uranium-mining.aspx#:~:text=Uranium%20ore%20and%20mine%20tailings,access%20needs%20to%20be%20restricted

37 The capacity of this facility is deemed to be inadequate for long-term operations, and the government plans to build additional capacity for waste processing and storage in the future. See KAZENERGY, *The National Energy Report 2017,* p. 174.

38 http://www.inp.kz/en_US/ and http://www.inp.kz/structure/science-tech-department/reactor/

39 Uranium and nuclear power were not addressed specifically in *The National Energy Report 2019.*

40 On 14 May 2020, Kazakhstan adopted a Law on "Amendments and additions to the legislative acts of the Republic of Kazakhstan on issues of civil liability in the field of atomic energy use." The Law amended provisions in the 1998 Law of the Republic of Kazakhstan "On radiation safety of the population" and the 2016 Law "On the use of atomic energy" and clarified civil liability of operators of nuclear installations for causing nuclear damage. Most importantly, the Law allowed the two key projects, the International Bank for Low-Enriched Uranium and the Production Plant for fuel assemblies at the UMP, to move forward.

7.10.1 New Subsoil Code and amendments

In July 2018, the Code on Subsoil and Subsoil Use entered into force in the Republic of Kazakhstan, and the CRIRSCO international system of reporting standards for mineral reserves was introduced.[41] It replaced the Law "On Subsoil and Subsoil Use" (24 June 2010), with the main objective of increasing the attractiveness of the mining sector for investment and expanding exploration activities. The 2018 Subsoil Code has, for the first time, introduced a rule under which licenses for exploration of solid subsoil resources can be granted to the first applicant (provided no one else has applied for the same deposit), while retaining the pre-existing procedure under which subsoil use rights are granted on the basis of a tender. The Subsoil Code also significantly simplified the application process for obtaining subsoil use rights. Under the Subsoil Code, subsoil use agreements and licenses may be granted to local or foreign legal entities or individuals. Transfers of subsoil use rights are only permitted after consent of the Competent Authority, and are prohibited (i) during the first year of an exploration contract; (ii) under contracts for geological assessment of known subsoil resources; and (iii) under contracts for gold mining.

The Subsoil Code provides for new obligations and a set of mandatory provisions to be established in the subsoil use agreement. In general, however, the content of subsoil use agreements under the Subsoil Code is practically the same as that under previous Subsoil Law.

The Subsoil Code also sets forth a limited list of grounds based on which the contract may be amended by way of executing a supplementary (amendment) agreement. Such amendments relate to information about the subsoil user, extension of exploration and/or production periods, transfer of use rights under the contract, or changes in the contract area. In case of changing (extending) the subsoil use agreement's term, the subsoil user shall enter into a new contract according to the terms and conditions of the model contract, if the original contract was entered into prior to the Subsoil Code's enactment and does not conform to the model contract. Changes and additions have been made to the Code's provisions on uranium mining, the most important of which were introduced in March 2021.

7.10.2 Low-Enriched Uranium Fuel Bank becomes operational

In late 2019, the long process of establishing an international fuel storage bank for low-enriched uranium (LEU) on Kazakh territory came to a successful end, as the IAEA's Low Enriched Uranium Bank (IAEA Fuel Bank), located at the UMP, received a second shipment of low-enriched uranium, reaching its designed storage capacity.[42] The project, now operational, supports international nuclear nonproliferation efforts by preventing the spread of uranium enrichment technologies, as it provides IAEA member states with access to the reserved volumes of low-enriched uranium used for fabricating nuclear fuel. The bank is capable of storing up to 90 tons of low-enriched uranium hexafluoride (UF_6) fuel, not an extraordinary volume for the plant, as volumes of fuel storage at the plant during the Soviet period had been significantly larger.

7.10.3 Reorganization of JV mining arrangements with foreign investors

In December 2017, Kazatomprom increased its stake in JV Inkai LLP from 40% to 60%. And in December 2018, the national company also increased its stake in JV Khorasan-U LLP (from 34% to 50%) and its effective stake in Kyzylkum LLP (from 30% to 50%), and an effective stake in LLP Baiken-U (from 5% to 52.5%).

7.10.4 New Ecology Code (2021) and best available technologies

The Republic of Kazakhstan's new Ecology Code, which took effect on 1 July 2021, specifies that all enterprises assigned to Category 1—the largest enterprises accounting for 80% of Kazakhstan's total atmospheric emissions (around 2,600 entities) —"will replace their old technologies with the best available technologies (BATs) by 2041, while the top 50 polluters within the group have to implement BAT by 2035."[43] More specifically, a Category I facility is one that has a significant and demonstrable environmental impact, and thus is subject to the most stringent oversight: a comprehensive environmental permit that requires it to meet specific technological standards for emissions, discharges, water quality, waste management, and electrical and/or thermal energy consumption. BATs are considered the best and most advanced activities and methods of operation to eliminate or minimize negative impacts on the environment (Eco Code, Chapter 9, Article 113.1).

41 CRIRSCO, the Committee for Mineral Reserves International Reporting Standards, is responsible for developing a set of international standard definitions for the reporting of mineral resources and mineral reserves.

42 Kazakhstan had concluded the agreement with the IAEA to construct the facility in August 2015. In accordance with the agreement, any country in case of urgent need and in order to avoid interruptions in deliveries can submit an official application to the IAEA for the supply of nuclear fuel. The organization redirects the application to the Fuel Bank. Costs associated with the establishment of the Fuel Bank were shared equally by Kazakhstan and IAEA, whereas the cost of acquiring and delivering LEU is borne by the IAEA (see KAZENERGY, *The National Energy Report 2017*, p. 168).

43 The Law identifies four main categories of polluters. Category 1 entities are those whose activities yield a significant harmful impact on the environment, primarily oil and gas companies, mining companies, and power plants. Category 2 enterprises have a "moderate" impact on the environment, Category 3 entities wield minor environmental damage (small businesses, car washes, service stations, etc.), while Category 4 businesses generate a minimal environmental impact, which are mainly small businesses.

No uranium producers are included in the top 50 polluters, because their environmental impacts are relatively limited.[44] However, the Code includes "mining of uranium and thorium ores, enrichment of uranium and thorium ores, production of nuclear fuel" in the broader Category 1 enterprises. Still, a strong argument can be made that the uranium producers' operations already incorporate technologies comparable to the best available globally:

- All of Kazakhstan's current production is based on ISL, considered the most economical and least environmentally disruptive mode of uranium mine production. Unlike in open pit and underground mines, the soil surface is barely disturbed, no tailings or waste rock are formed, radon emissions are minimized, and no toxic dust is created.[45]
- Nearly half (45%) of the country's mine output is derived from relatively recently established joint ventures between Kazatomprom and companies from France, Canada, Japan, Russia, and China, employing the latest technologies (see note 10 and Table 7.2).

However, ISL is not completely free of environmental impacts. There is the need to dispose of production waters (which contain the caustic leaching agents [such as sulfuric acid] and mine wastewater) following primary processing. In addition, there is a need to protect surrounding groundwater resources after mine decommissioning, and the injection of production water into ore-bearing horizons involves consumption of large amounts of energy, raising challenges in terms of both energy efficiency and GHG emissions. Therefore, key elements of Ecology Code compliance for ISL uranium producers include:

- **Production water management.** Typically, the production water (after being refortified with an oxidant and leaching agent) is returned to injection wells for reuse (i.e., reinjection into the orebody) and this recycling greatly reduces overall water and sulfuric acid consumption in the process. Any solution not reinjected into the orebody (e.g., a small flow is bled off to maintain a pressure gradient in the wellhead) must be treated as waste, as it contains various dissolved elements such as chlorides, sulfates, radium, arsenic, and iron that must be stored at approved disposal sites (e.g., disposal wells in a depleted portion of the orebody). BAT conceptually would involve recycling the production water as many times as possible, reducing its toxicity, while optimizing conditions of storage at disposal sites. In 2020, Kazatomprom implemented the R&D initiative "Development of Low-Acid Leaching Technology Using Cavitation-Jet Technologies in Combination with Special Chemicals," that is expected to reduce consumption of sulfuric acid for the leaching process by up to 20%. And in 2020, the company increased the volume of recycled/reused water in its operations by 334%.[46]
- **Groundwater protection.** One of the environmental challenges involving ISL is the need to avoid contamination of groundwater away from the orebody. The pressure gradient maintained at the wellhead helps accomplish this; water from the surrounding aquifer flows into the orebody, preventing the flow of mining solutions away from the mining area.[47] This limits groundwater contamination to the field itself. After ISL mining is completed, wells are sealed or capped, and the quality of the remaining groundwater in the field must be restored to a baseline standard determined before the start of the operation. The restoration of the neutral pH in the aquifers leached with chemicals is usually carried out by flushing the depleted underground with water until acceptable groundwater concentrations are attained. Conceptually, BAT here would involve restoring groundwater quality to a level approximating that prevailing before the onset of mining. Kazatomprom regularly monitors surface and groundwater at all current and former production sites to prevent discharges of pollutants into water bodies. In 2020, the company undertook additional research on the impact of ISL on groundwater and development of guidelines for contamination control of aquifers in uranium deposits and methods for interpreting aquifer monitoring data applicable to mining operations and deposit decommissioning. It also carried out in-depth environmental studies of the territories adjacent to its uranium mines and found no environmental impacts of production operations beyond the boundaries of the buffer zones (500 m radius) surrounding the mines.[48]
- **Energy production and consumption.** Due to the intense pumping of liquids during ISL, it is more energy intensive than traditional surface or underground mining technologies. The energy for pumping is often available only from large diesel generators, as uranium mining sites are often located at distant off-grid locations with no electricity transmission lines. BAT here would most likely involve efforts to improve the energy efficiency of operations as well as to explore the potential for onsite electricity generation from renewable sources of energy or the powering of pumps using biofuels. Kazatomprom follows the ISO 50001:18001 international standard for energy efficiency and implemented measures company-wide in 2020 to improve energy efficiency. More specifically,

44 Further, no uranium producers are included in Kazakhstan's emissions trading system, because the annual greenhouse gas emissions of each Kazatomprom subsidiary/affiliate do not exceed the threshold of 20,000 tons of CO_2-equivalent as established by the national laws for emissions reporting and inclusion in the system *(Integrated Annual Report of Kazatomprom for 2020,* p. 192).

45 See KAZENERGY, *The National Energy Report 2015,* p. 262.

46 *Integrated Annual Report of Kazatomprom for 2020,* pp. 119, 194.

47 Monitor wells are installed above, below, and around the target zones (i.e., portions of the orebody being exploited) to ensure that mining fluids are not migrating outside of the permitted mining area.

48 *Integrated Annual Report of Kazatomprom for 2020,* pp. 128, 139, 195, 198.

> it launched a new energy management system in line with ISO 50001 and conducts regular energy audits, yielding an estimated 145,000 GJ reduction in electricity consumption and a cost savings of 847 million tenge ($1.98 million) in 2020. The company also generated 3.5 MWh of solar PV power in 2020, used to power its operations, an 18.5% decline from 4.2 MWh in 2019 due to a reduced level of operations.[49] The company also is involved in a joint-venture, SKU-Z, which operates a sulfuric acid plant (SAP) to support Kazatomprom's mining operations while at the same time producing electric power and heat fueled by the combustion of sulfur. The electricity and heat are used in SAP operations, with small quantities sold to outside consumers. The installed capacity of the power plant is listed as 16 MW, and generates approximately 130 million kWh per year. [50]

Another way of assessing the technological level of Kazakhstan's uranium mine production is to compare it with that in the European Union, where the BAT approach has advanced most strongly. In the case of ISL, however, the experience of the European Union does not provide abundant guidance. Uranium mine output presently is minimal there, and ISL production is limited to a single site, the Stráz pod Ralskem production center in the Czech Republic, which produced only 33 tons in 2019.[51] However some clarity on European mining standards is provided in a recent European Commission report on nuclear energy.[52] In addition to general EU Directives regulating environmental impacts of mining on air and water quality and radiation safety, it indicates that uranium mining and milling activities must also conform to the specific EU Directives: Mining Waste Directive (2006/21/EC); Environmental Liability Directive (2004/35/CE) on prevention and remediation of environmental damage; and radioprotection provisions specified in the Euratom Basic Safety Standards (BSS).

But as a general rule the Commission notes:

> . . . the appropriateness of the internal governance of a civil company operating in a specific area of nuclear energy is proven by demonstrating that the company uses internationally recognized management systems to manage nuclear and industrial safety, radiation protection, technological and radioactive waste handling and environmental protection tasks during all phases of the activity concerned. (p. 76)

It continues by observing that:

> [t]he principles and practices of environmental[ly] friendly mining are being promoted by the International Council on Mining and Metals (ICMM). Mining companies that decided to operate as a "sustainable mine" must adhere to the ICMM principles of sustainable development. These ICMM principles were integrated into the following policy document of the Word Nuclear Association (WNA): *Sustaining Global Best Practices in Uranium Mining and Processing: Principles for Managing Radiation, Health and Safety, and Waste and the Environment* (p. 76; henceforth, the Principles).[53]

The Principles provide the foundation for responsible management of uranium mining and processing projects at all stages of planning and activities from exploration through development, construction, operation, and decommissioning. They also serve as the basis for detailed Codes of Practice that govern uranium mining and processing in specific national, regional, and site-specific contexts.[54]

Kazatomprom, as well as several of its joint venture partners (Orano, Uranium One, Cameco) are members of the World Nuclear Association and their operations are guided by the Principles. Further, in a chapter (Chapter 7) of Kazatomprom's 2020 annual report devoted to sustainable development and environmental protection, the company observed that it routinely monitors its compliance with the UN Global Compact and the Sustainable Development Goals (SDGs). In 2020, to reinforce the importance of this area, Kazatomprom approved its Corporate Sustainable Development Policy, which identified shortcomings and outlined specific measures needed to address them. It also began preparations in early 2020 for a gradual transition to a new model of production asset maintenance, repair, and operations management (MRO) based on the international quality standard, ISO 55000 *Asset management,* and leading business practices in maintenance, Reliability Centered Maintenance (RCM), Risk Based Inspection (RBI), and Total Productive Maintenance (TPM).[55] It also received TÜV's International ISO 14001 certification (environmental management systems) in 2020. [56]

49 *Integrated Annual Report of Kazatomprom for 2020, pp.* 107, 192, 273.

50 Ownership of SKU-Z, established in 2007, is Kazatomprom 49%, SAP-Japan Corporation 32%, and Uranium One Inc. 19%; see https://sap-u.kazatomprom.kz/ru/subcontent/company/o-nas-7 and https://sap-u.kazatomprom.kz/en/subcontent/production-electricity-turbo-generator-1

51 NEA and IAEA, *Uranium 2020,* p. 202.

52 Joint Research Centre, European Commission, *Technical Assessment of Nuclear Energy with Respect to the "Do No Significant Harm" Criteria of Regulation (EU) 2020/852 ("Taxonomy Regulation"),* 2021, pp. 78, 360.

53 https://www.world-nuclear.org/our-association/publications/position-statements/best-practice-in-uranium-mining-(1).aspx

54 The 11 Principles encompass sustainable development; health, safety, and environmental protection; compliance; social responsibility; hazardous materials management; quality management; accidents and emergencies; hazardous materials transport; training; storage of radioactive materials; and decommissioning and site closure.

55 Kazatomprom National Atomic Company, *Integrated Annual Report of Kazatomprom for 2020,* pp. 5, 33–34, 96, 102.

56 ISO 14001:2015 specifies the requirements for an environmental management system that an organization can use to enhance its environmental performance and sustainability of operations.

In light of the above, it appears that Kazatomprom, as the world's largest uranium mine producer, already has achieved substantial use of BAT in its operations, and is demonstrating a commitment to undertake continuing work toward this goal as envisioned in the new Ecology Code. Similarly, several of Kazatomprom's international JV partners have announced commitments to BAT in their uranium mining operations.[57] Thus, any Kazatomprom subsidiaries and joint ventures subject to environmental audits as Category 1 enterprises under the Ecology Code appear to be well positioned to receive environmental permits that would exempt them fines or other penalties specified in the Code.

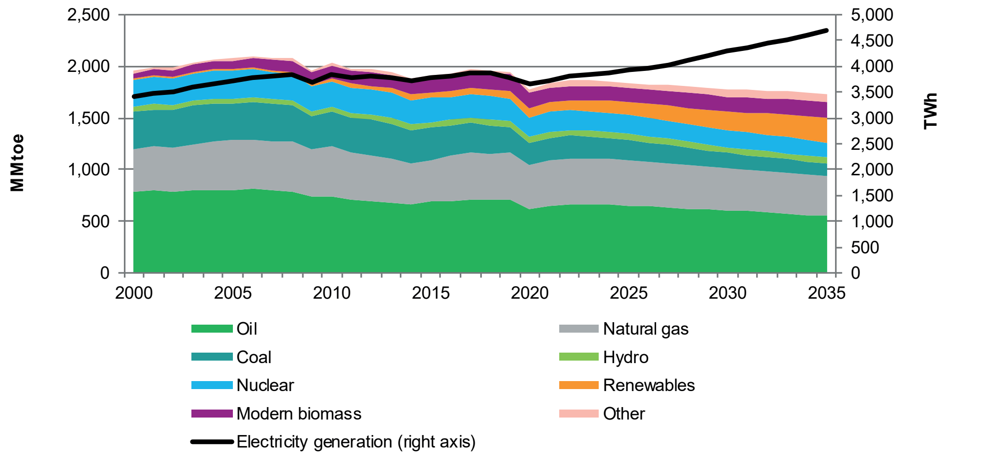
7.11 Recommendations

- Kazakhstan should continue to pursue its focus on uranium mining, as this is currently the most attractive segment of the nuclear fuel value chain (i.e., its global comparative advantage) given its large ore deposits suitable for ISL-based mining and its demonstrable progress in incorporating BAT in its operations.
- This notwithstanding, Kazakhstan should also continue its efforts to expand the uranium value chain in elements of the fuel cycle downstream from mining: reconversion and fuel pellet fabrication/fuel assembly. Downstream product diversification may not prove more lucrative than mining, but it does offer flexibility (in the form of increased sales options and reduced dependence on individual downstream processors) in the ultimate delivery of uranium to customers.
- Diversification also moves the country closer to being able to generate nuclear power domestically, although should Kazakhstan decide to pursue this option it must carefully weigh the role nuclear power would play in its overall energy balance.
    - Should it occupy a small niche, by providing reliable baseload electrical power as part of a targeted renewable power build-out (e.g., micro-reactors supporting wind and/or solar in specific projects)? Or replacing a small coal- or gas-fired power plant (via construction of an SMR of equivalent capacity)?
    - Or should it seek a larger scale of development, such as replacing a substantial amount of retired coal-fired generation in the industrialized northern and central regions of the country? In the latter case, one or more standard reactors on the order of 1000 MW capacity might be required.
- As noted in Chapter 2, many options are available to Kazakhstan in pursuing its Paris agreement commitment to reduce GHG emissions. Over the longer term, nuclear generation should not be ruled out as part of a comprehensive strategy to restructure Kazakhstan's electric power sector in order to meet its 2060 carbon neutrality pledge. This is especially the case in light of the need to reduce the role of coal—and limitations on the availability of commercial gas (see Chapter 4)—in baseline electric power generation. And uranium, like coal, is an abundant resource that can be sourced domestically.

57 For example, see https://www.orano.group/en/nuclear-expertise/from-exploration-to-recycling; https://www.cameco.com/about/sustainability/our-approach-to-esg-reporting/environment; https://uranium1.com/health-safety-environment/#health_safety.

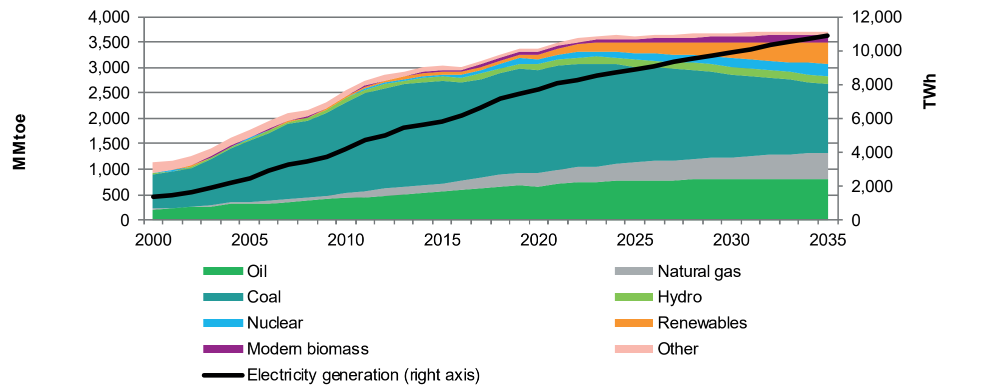
APPENDIX

Figure 1.1 European primary energy consumption by fuel in IHS Markit base case (Inflections) scenario to 2035



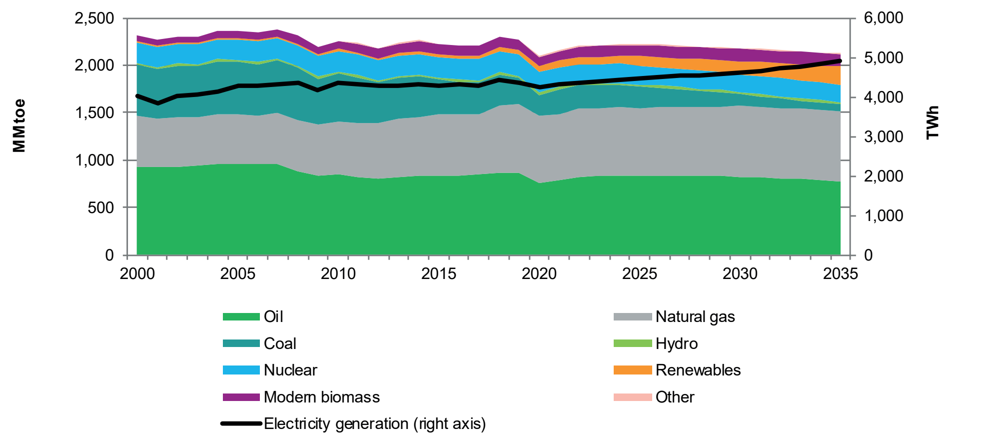
Notes: Renewables includes solar, wind, geothermal, and tide/wave/ocean energy. Other includes solid waste, traditional biomass (used in the domestic sectors; includes charcoal and wood), ambient heat, and net trade of electricity and heat.
Source: IHS Markit (Energy and Climate Scenarios)

Figure 1.2 China's primary energy consumption by fuel in IHS Markit base case (Inflections) scenario to 2035



Notes: Renewables includes solar, wind, geothermal, and tide/wave/ocean energy. Other includes solid waste, traditional biomass (used in the domestic sectors; includes charcoal and wood), ambient heat, and net trade of electricity and heat.
Source: IHS Markit (Energy and Climate Scenarios)

Figure 1.3 United States primary energy consumption by fuel in IHS Markit base case (Inflections) scenario to 2035



Notes: Renewables includes solar, wind, geothermal, and tide/wave/ocean energy. Other includes solid waste, traditional biomass (used in the domestic sectors; includes charcoal and wood), ambient heat, and net trade of electricity and heat.
Source: IHS Markit (Energy and Climate Scenarios)

Table 3.1 Crude oil and condensate balance for Kazakhstan: IHS Markit base-case outlook to 2035 (MMt)

	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	2025	2030	2035
Production	79.7	80.0	79.2	81.8	80.8	79.5	78.0	86.2	90.4	90.6	85.7	102.3	94.9	109.2
Total exports	67.5	69.6	68.1	72.2	69.7	64.8	63.4	69.6	70.2	70.3	68.5	83.3	75.6	88.8
Exports abroad	65.5	67.8	66.6	71.1	68.3	61.6	61.6	69.2	69.4	70.1	68.0	82.7	75.0	88.0
Exports to other republics	1.9	1.8	1.5	1.1	1.4	3.1	1.7	0.4	0.8	0.2	0.5	0.6	0.6	0.8
Total imports	4.9	7.1	6.1	7.2	0.5	0.1	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
From Russia*	4.9	7.1	6.1	7.2	7.1	7.0	7.0	10.1	10.0	10.0	10.0	10.0	10.0	10.0
From Other	0.0	0.0	0.0	0.0	0.5	0.1	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Net exports	62.6	62.5	62.0	65.1	69.3	64.7	63.4	69.5	70.2	70.2	68.5	83.3	75.6	88.8
Consumption (apparent)	17.1	17.5	17.2	16.7	11.6	14.7	14.7	16.7	20.2	20.3	17.1	19.0	19.3	20.4
Refinery throughput	13.7	13.7	14.2	14.3	14.9	14.5	14.5	14.9	16.4	17.0	15.8	17.5	17.7	18.7
Other consumption**	3.4	3.8	3.0	2.4	-3.3	0.3	0.2	1.8	3.8	3.3	1.3	1.5	1.6	1.7

Notes: Notes: *Russian oil swap volumes in 2014 (7 MMt and since 2017 at 10 MMt) are included in import and export flows for Kazakhstan for comparative purposes with flows in 2013.

**Balancing item; its composition is unknown, but it would include field and transportation losses (including losses in stabilization of condensate), changes in stocks, direct crude use, etc.

Source: IHS Markit, National trade statistics, Ministry of Energy RK

Table 3.2 Kazakhstan's crude oil exports by destination: IHS Markit base-case outlook to 2035 (MMt)

	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	2025	2030	2035
Total exports	69.3	69.2	65.6	72.2	63.1	63.4	64.0	69.9	72.5	72.4	68.7	83.2	77.2	77.8
Black Sea	48.8	51.2	46.8	48.3	45.0	45.7	49.7	57.5	61.5	63.3	59.5	70.3	69.4	66.4
CPC (Yuzhnaya Ozereyevka)	28.5	28.3	25.3	28.7	35.2	39.0	42.4	49.5	54.3	55.8	52.0	63.0	65.5	60.2
Other routes	20.3	22.9	21.5	19.6	9.9	6.7	7.3	8.0	7.2	7.5	7.5	7.3	3.9	6.2
Baltic Sea	7.4	4.3	6.6	9.9	9.3	9.4	10.5	8.9	8.8	8.1	8.3	8.1	2.5	5.2
Druzhba Pipeline (to Eastern Europe)	2.8	1.2	1.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
To Russia	1.2	1.2	0.7	1.3	1.4	2.8	0.8	0.6	0.5	0.0	0.0	0.0	0.0	0.0
Iran	1.2	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
East Asia	7.5	10.8	10.4	11.8	4.8	4.5	2.8	2.7	1.4	0.9	0.5	4.2	4.7	5.4
Kazakh crude to China (excluding Russian swap volumes)	7.5	10.8	10.4	11.8	4.8	4.5	2.8	2.7	1.4	0.9	0.5	4.2	4.7	5.4
Baku-Tbilisi-Ceyhan Pipeline	0.0	0.0	0.0	0.6	2.4	1.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
To Azerbaijan							0.1	0.1	0.1					
To Uzbekistan	0.5	0.5	0.1	0.3	0.1	0.0	0.1	0.2	0.2	0.1	0.5	0.6	0.6	0.8

Notes: Black sea routes include Novorossiysk (via Samara and from Makhachkala), Pivdenniy (via Transneft), Batumi/Kulevi, and rail exports via Russia. Baltic sea includes exports via Primorsk, Ust-Luga (BPS-2), Gdansk (via Transneft), and rail exports. Deliveries to Russia include shipments to refineries via Samara, as well as deliveries to the Orsk refinery and gas condensate to Orenburg.

Source: IHS Markit

Table 3.3 Kazakhstan's refined product balance: IHS Markit base-case outlook to 2035 (MMt)

	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	2025	2030	2035
Throughput	13.7	13.7	14.2	14.3	14.9	14.5	14.5	14.9	16.4	17.0	15.8	17.5	17.7	18.7
Output of products (reported)	12.8	13.4	13.7	13.8	14.5	13.5	12.9	13.0	13.4	14.0	11.5	15.6	16.3	17.4
Gasoline	2.9	2.8	2.9	2.7	3.0	2.9	3.0	3.1	4.0	4.5	4.5	5.1	5.2	5.6
Kerosene	0.5	0.4	0.4	0.4	0.4	0.3	0.3	0.3	0.4	0.6	0.5	0.7	1.0	1.0
Diesel fuel	4.4	4.6	4.1	5.1	5.0	4.6	4.7	4.4	4.6	5.0	4.7	6.1	7.1	7.7
Mazut	4.5	4.3	3.9	4.0	4.2	4.1	3.2	3.4	3.2	2.9	2.5	2.1	1.8	1.4
Lubricants	--	--	--	--	--	--	--	--	--	--	--	0.5	0.5	0.6
Other	1.4	1.6	2.9	2.0	2.2	2.6	3.4	3.8	4.2	4.0	3.6	3.0	2.1	2.4
Bitumen									0.6	0.7	1.0	1.0	1.0	1.0
Petroleum coke/other residual	0.4	0.5	0.5	0.6	0.9	0.9	0.9	1.3	1.5	1.6	1.6	1.6	1.5	1.4
Losses and fuel as % of throughput	6.5	2.4	3.8	3.2	3.1	6.4	11.1	12.8	18.3	17.6	27.3	11.0	8.0	7.0
Apparent Consumption														
Total (all refined products)	10.3	10.8	11.4	11.6	11.9	11.5	12.5	12.9	14.7	14.7	14.4	15.2	15.9	16.7
Gasoline	3.7	3.5	4.0	4.0	4.2	4.3	4.1	4.1	4.5	4.5	4.0			
Diesel fuel	3.2	4.1	3.9	5.5	5.3	4.6	5.1	4.7	4.8	5.2	5.2			
Mazut	1.4	0.7	-0.4	-0.7	0.2	0.1	-0.2	-0.4	0.3	0.3	1.0			
Other	2.0	2.4	3.9	2.7	2.1	2.5	3.6	4.5	5.1	4.7	4.3			
Net exports														
Total (all refined products)	3.3	3.0	2.8	2.7	3.0	3.0	2.0	2.0	1.7	2.3	1.4	2.3	1.8	2.0
Gasoline	-0.8	-0.8	-1.2	-1.3	-1.2	-1.4	-1.1	-1.1	-0.6	0.0	0.5			
Diesel fuel	1.2	0.6	0.2	-0.4	-0.3	0.0	-0.4	-0.3	-0.2	-0.2	-0.5			
Mazut	3.0	3.5	4.3	4.7	3.9	4.0	3.4	3.8	3.0	2.6	1.6			
Other	-0.1	-0.4	-0.5	-0.3	0.5	0.4	0.1	-0.4	-0.4	-0.1	-0.2			
Exports														
Total (all products)	5.1	4.4	4.8	5.3	5.1	4.9	3.9	4.0	3.4	2.8	2.3	2.8	2.3	2.5
Gasoline	0.1	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.1	0.5			
Diesel fuel	1.6	0.8	0.3	0.2	0.2	0.2	0.1	0.1	0.2	0.0	0.1			
Mazut	3.0	3.6	4.5	5.0	3.9	4.0	3.4	3.8	3.0	2.6	1.6			
Other	0.4	0.0	0.0	0.1	0.9	0.7	0.4	0.1	0.1	0.1	0.1			
Imports														
Total (all products)	1.8	1.5	2.1	2.5	2.1	1.9	1.9	2.0	1.7	0.5	0.9	0.5	0.5	0.5
Gasoline	0.9	0.8	1.2	1.3	1.2	1.4	1.1	1.1	0.6	0.0	0.0			
Diesel fuel	0.4	0.2	0.1	0.6	0.5	0.2	0.4	0.5	0.5	0.2	0.7			
Mazut	0.0	0.1	0.2	0.3	0.0	0.0	0.0	0.0	0.1	0.0	0.0			
Other	0.5	0.4	0.6	0.4	0.4	0.3	0.3	0.4	0.5	0.3	0.3			

Source: IHS Markit, Ministry of Energy RK, Bureau of National Statistics RK

Table 3.4 Product output by Kazakhstan's main refineries, 2012-20 (thousand metric tons)

	2012	2013	2014	2015	2016	2017	2018	2019	2020	Percent change 2019-20
Atyrau										
Crude throughput	4,423	4,430	4,920	4,868	4,761	4,724	5,268	5,388	5,016	-6.9
Motor gasoline	506	505	614	605	643	648	1,129	1,228	1,044	-15.0
Diesel fuel	1,218	1,222	1,344	1,207	1,391	1,375	1,456	1,516	1,478	-2.5
Jet kerosene	56	38	23	21	20	19	41	98	76	-22.3
Benzene	-	-	-	1	7	9	14	26	44	66.7
Heating oil	143	124	166	160	68	62	149	35	24	-32.0
Mazut	1,543	1,512	1,510	1,650	1,362	1,509	1,134	1,230	1,069	-13.1
Vacuum gas-oil	606	652	779	739	842	754	443	331	324	-2.0
Petroleum coke	75	95	137	111	121	120	133	123	128	3.8
LPG	14	20	28	29	36	39	166	127	127	0.0
Sulfur	1	1	2	3	3	2	4	4	5	23.5
Paraxylene	-	-	-	-	-	-	5	119	207	74.4
Pavlodar										
Crude throughput	5,037	5,010	4,926	4,810	4,590	4,747	5,340	5,290	5,004	-5.4
Motor gasoline	1,332	1,117	1,259	1,249	1,225	1,285	1,422	1,362	1,431	5.1
Diesel fuel	1,514	1,473	1,509	1,457	1,524	1,403	1,731	1,727	1,605	-7.1
Jet kerosene	100	133	125	11	-	-	72	192	113	-41.3
Mazut	810	763	668	822	560	691	708	731	538	-26.4
Vacuum gas-oil	123	400	192	123	29	97	66	126	-	-100.0
Petroleum coke	147	146	152	126	224	236	230	217	215	-0.9
LPG	244	215	239	263	244	257	311	279	291	4.0
Sulfur	24	23	25	30	28	27	47	48	45	-6.2
Bitumen	186	219	244	246	202	245	294	302	358	18.4
Heating oil						73	28	3	15	428.4
Shymkent										
Crude throughput	4,754	4,857	5,065	4,493	4,501	4,686	4,733	5,401	4,794	-11.2
Motor gasoline	1,046	1,038	1,126	988	1,032	1,027	1,332	1,908	1,958	2.6
Diesel fuel	1,336	1,376	1,346	1,192	1,203	1,209	1,243	1,518	1,411	-7.0
Jet kerosene	275	231	279	254	236	280	270	335	244	-27.2
Mazut	902	968	1,013	889	869	1,082	970	761	411	-46.0
Vacuum gas-oil	798	827	884	827	811	818	462	237		-100.0
Petroleum coke	146	148	142	113		-	41	114		-100.0
LPG	-	-	-	-	120	97	169	295	327	10.8
Sulfur	-	-	-	-	1	1	1	3	6	78.9

Source: Ministry of Energy RK, company reports, IHS Markit

Table 4.1 Kazakhstan's natural gas balance: IHS Markit base-case outlook to 2035 (Bcm/y)

	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	2025	2030	2035
Production (gross)	37.1	39.5	40.1	42.4	43.2	45.3	46.4	52.9	55.5	56.4	55.1	67.9	76.0	72.7
Production (commercial output)	24.6	25.2	25.3	25.5	25.6	28.4	30.3	34.7	38.0	37.6	34.8	35.8	36.1	34.9
Total imports*	4.0	4.1	4.5	5.2	4.0	4.9	5.8	5.1	5.7	8.8	4.3	6.1	6.5	7.4
Total exports*	14.5	16.0	12.8	13.1	11.6	13.3	12.8	16.8	19.1	19.4	16.7	15.2	14.5	11.8
Net exports	15.6	15.1	14.8	14.6	13.2	16.4	17.2	20.7	22.9	21.6	17.9	18.0	16.5	12.3
Apparent consumption (commercial gas)	16.7	17.8	16.8	17.4	17.3	20.7	22.4	22.9	24.7	26.0	26.0	26.7	28.1	30.5
Consumption (end-of-pipe deliveries)**	9.0	10.1	10.5	10.9	12.5	12.1	13.1	13.8	16.1	16.3	17.0	17.8	19.6	22.6

Notes: *Exports and imports reported from customs (trade) statistics differ from operational statistics reported by KazTransGas and the Ministry of Energy RK.

** Amount reported as consumption (end-of-pipe deliveries) by the Ministry of Energy RK.

Source: IHS Markit, National trade statistics, Ministry of Energy RK

Table 4.2 Kazakhstan's natural gas exports and imports by destination: IHS Markit base-case outlook to 2035 (Bcm/y)

	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	2025	2030	2035
Pipeline														
Karachaganak-Orenburg	9.2	9.3	8.0	8.2	8.4	9.6	9.6	9.6	10.3	9.9	9.9	9.5	9.5	9.2
Turkmenistan-Kazakhstan-China (CAGP+East Kazakhstan)	-	-	-	0.2	0.4	0.6	0.5	0.6	5.2	7.4	7.4	5.3	4.6	2.1
Total exports (customs data)	14.5	22.3	20.5	20.6	20.3	21.5	21.6	25.6	26.5	25.6	18.8			
Total exports (operational data)	14.5	16.0	12.8	13.1	11.6	13.3	12.8	16.8	19.1	19.4	16.7	15.2	14.5	11.8
FSU Countries	14.5	16.0	12.8	12.9	11.2	12.7	12.4	16.2	13.8	11.9	9.4	9.9	9.9	9.7
Non-FSU Countries	-	-	-	0.2	0.4	0.6	0.5	0.6	5.2	7.4	7.4	5.3	4.6	2.1
China*	-	-	-	0.2	0.4	0.6	0.5	0.6	5.2	7.4	7.4	5.3	4.6	2.1
Total import (customs data)	4.0	3.7	4.6	5.2	4.4	5.8	6.9	6.3	14.6	15.8	9.7			
Total import (sum)	4.0	4.1	4.5	5.2	4.0	4.9	5.8	5.1	5.7	8.8	4.3	6.1	6.5	7.4
Russia	1.6	1.6	1.3	1.7	1.2	1.7	2.9	3.0	3.2	5.1	3.4	3.5	4.0	4.0
Central Asia (Turkmenistan and Uzbekistan)	2.5	2.4	3.2	3.5	2.7	3.2	2.9	2.1	2.5	3.7	0.9	2.6	2.5	3.4
Net exports	10.4	12.0	8.3	8.0	7.6	8.5	7.0	11.8	13.4	10.6	12.4	9.1	8.0	4.4

Notes: Data for Kazakhstan's exports to Russia from 2011 are taken from Russia's reported receipts of Kazakh gas; total exports are taken from Kazakh national statistics, creating an export discrepancy.

*Kazakh volumes injected into the CAGP pipeline in 2017; main export flow to China through CAGP continues to be augmented with small volumes from East Kazakhstan Oblast.

Source: IHS Markit

Table 4.3 Natural gas consumption in Kazakhstan by oblast, 2012-20 (MMcm/y)

	2012	2013	2014	2015	2016	2017	2018	2019	2020
Aktobe	1,506	1,653	1,832	1,883	2,308	2,577	2,928	2,946	3,247
Almaty	1,337	1,356	1,644	1,552	1,659	1,862	2,051	2,010	2,318
Atyrau	1,332	1,482	1,571	1,525	1,778	1,606	2,091	2,321	2,362
East Kazakhstan				1	3	5	9	16	22
Kostanay	930	886	867	757	756	778	873	877	836
Kyzylorda	261	261	234	296	425	512	650	629	667
Mangystau	2,422	2,495	2,838	2,852	2,782	2,584	2,766	2,787	2,782
South Kazakhstan/Turkestan	1,081	1,021	1,230	1,100	1,192	1,247	1,869	2,099	2,225
West Kazakhstan	695	736	847	831	983	1,058	1,274	1,220	1,221
Zhambyl	944	1,048	1,395	1,303	1,176	1,618	1,576	1,413	1,366
Nur-Sultan city									4
Republic of Kazakhstan	**10,508**	**10,937**	**12,458**	**12,101**	**13,063**	**13,848**	**16,089**	**16,318**	**17,050**
Southern Kazakhstan (region)	3,624	3,685	4,503	4,251	4,452	5,239	6,146	6,152	6,576
Western Kazakhstan (region)	4,449	4,713	5,256	5,208	5,543	5,249	6,131	6,328	6,365
Eastern Kazakhstan (region)	-	-	-	1	3	5	9	16	22
Northwestern Kazakhstan (region)	2,436	2,539	2,699	2,641	3,064	3,355	3,802	3,822	4,082
North-central Kazakhstan (region)	-	-	-	-	-	-	-	-	4

Notes: Comprehensive oblast-level data not available for 2010-2011. Southern Kazakhstan includes Almaty Oblast and city, Kyzylorda Oblast, South Kazakhstan/Turkestan oblast and Shymkent city, and Zhambyl Oblast. Western Kazakhstan includes Atyrau, Mangystau, and West Kazakhstan oblasts. Eastern Kazakhstan includes East Kazakhstan Oblast. Northwestern Kazakhstan includes Aktobe and Kostanay oblasts. North-central Kazakhstan includes Nur-Sultan city.

Source: IHS Markit, Infotek, Ministry of Energy RK

Table 5.1 Kazakhstan's coal balance to 2020 (MMt)

	1995	2000	2005	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	Percent change, 2019–20
Coal production (hard+lignite)	83.2	74.9	86.6	106.6	111.4	115.7	114.6	109.3	102.6	98.6	107.9	114.1	110.7	109.2	-1.4
Coal consumption (apparent)	57.6	49.8	63	74.2	83.8	85.9	84	81.4	74.8	74.8	80.9	91.6	88.3	87.4	-0.9
Coal exports	26.1	25.7	24.1	32.6	27.8	30	30.8	28.1	28	24	27.1	23.4	23.1	22.4	-3.2
Outside the Former Soviet Union	1.1	0	1.3	0.5	1.6	1.7	3.8	3.4	4.1	2.7	4.5	2.2	1.7	0.3	-85.3
Former Soviet republics	24.4	25.7	22.8	32.1	26.2	28.3	27	24.7	23.9	21.3	22.7	21.2	21.4	22.1	3.3
Coal imports	0.5	0.7	0.4	0.3	0.2	0.2	0.2	0.2	0.2	0.2	0.1	0.8	0.7	0.6	-15.3
Outside the Former Soviet Union	-	-	-	-	0	0	0	0	0	0	-	0	0	-	-100
Former Soviet republics	0.5	0.7	0.4	0.3	0.2	0.2	0.2	0.2	0.2	0.2	0.1	0.8	0.7	0.6	-15.3

Source: IHS Markit, Bureau of National Statistics RK

Table 5.2 Kazakhstan's coal production and export: IHS Markit base-case outlook to 2035 (MMt)

	1990	1995	2000	2005	2010	2015	2020	2025	2030	2035
Production	131.6	83.2	74.8	86.6	106.6	102.5	109.2	103.9	98.3	88.7
Net Exports	41.5	11.8	25	23.7	32.4	27.8	21.7	20.3	19.1	17.2

Source: IHS Markit, Bureau of National Statistics RK