DEAR LADIES AND GENTLEMEN!

Over the past two years since publication of the KAZENERGY National Energy Report 2015, Kazakhstan’s economy has adjusted to the new reality. The end of the era of high energy prices has significantly changed the pace of the country’s economic development, as well as state policy priorities.

Despite the fact that the stabilization of oil prices has halted the decline of investment in oil production, the main challenge facing Kazakhstan’s economy in the foreseeable future will be the creation of new sectors with a competitive advantage for attracting investments into the country.

To that end, the government is working on the preparation of a new Subsoil Code, as well as amending the Tax Code, taking into account some of the recommendations provided in the NER 2015. These actions inspire confidence in the importance of the work on national reports performed by KAZENERGY Association, and reaffirm the role of such reports as reliable tools for promoting a constructive dialogue between the business community and government.

The new conditions of the global oil market opened up new opportunities. In a low oil price environment, some producers managed to significantly improve cost efficiency while maintaining and even increasing previous production levels. Utilizing this experience is extremely important for Kazakhstan’s oil and gas sector, which could benefit from the application of cost-optimization measures. Application of such cost optimization mechanisms, combined with the reliable transportation infrastructure that has developed since independence, will allow Kazakhstan to not only maintain, but also to enhance its role and position in global energy markets, and ultimately ensure stable revenue flows for the national budget.

In electric power sectors around the world, a new paradigm defined by the development of renewable energy sources has gained importance in recent years, and is expected to continue to grow over the near term. However, there are a number of limitations to the development of renewables in Kazakhstan: fully embracing such a renewables-centric paradigm requires state support. At the same time, introducing renewable resources into electric power generation represents only one of several tools that can be used to transition to “green” energy. Renewables should therefore be carefully introduced in combination with other policy measures, so as to ensure the reliable and affordable delivery of electric power to end consumers at a minimum social cost.

The unfettered development of renewables in Kazakhstan under current conditions, without necessary market mechanisms, will result in a significant increase in the cost of electricity and ultimately reduce the cost competitiveness of domestic producers. It is therefore extremely important for the state to establish a cogent vision for the country’s transition to “green” economy, select the best mechanisms through which to realize this vision, and determine the maximum limit of new renewable power capacity installations taking into account the current capacities of Kazakhstan’s power infrastructure.

This systemic approach, integrating renewables into the power sector, should also take into account the commitment to reduce greenhouse gas emissions by 15% undertaken by Kazakhstan in 2016 within the framework of the Paris Agreement, as well as feedback on greenhouse gas emissions regulation and legislation from the business community and independent experts.

Given such developments, KAZENERGY Association decided to prepare a third edition of the National Energy Report as part of the International Specialized Exhibition EXPO-2017 and the XI KAZENERGY Eurasian Forum. The 2017 Report was developed by world-renowned energy experts and the international consultancy, IHS Markit, who worked closely with the supportive members of the Association, while researching and writing the report.

I am grateful to the many experts from Kazakhstan who participated in preparing this Report. I am convinced that such a format of cooperation represents another significant contribution by the Association to improving the skills of domestic specialists, as interacting with foreign consultants allows them to develop their analytical skills in line with global standards.

This document, the 2017 Report, presents current and forecasted indicators on the fuel and energy sector, analysis of predominant trends for all main types of energy sources, as well as specific proposals by the Association to improve the current legislation in order to attract investment and implement advanced energy technologies in the country with the purpose of sustainable development.

I am confident that the rigor and independence with which the research for the Report was conducted ensures a balanced outcome that reflects the interests of the energy sector and economy as a whole. I hope that the Report will be a meaningful contribution to the future development of state energy policy.

Timur Kulibayev
Chairman
KAZENERGY Association
DEAR READERS!

On behalf of IHS Markit, we greatly appreciate the opportunity to be invited back to collaborate on the updated National Energy Report 2017 for Kazakhstan and to present an integrated outlook for its energy future. Hydrocarbons and other energy resources remain critical growth drivers in Kazakhstan’s economy and will be for some time to come, despite some diversification since independence and the traditional importance of the mining sector. The development of the oil and gas industry has served Kazakhstan very well, generating revenues that have been crucial since 1991 in solidifying its independence as a nation and delivering increasingly higher incomes and standards of living for its people. This development has also strengthened Kazakhstan’s relations with its neighbors and, together with rapidly increasing uranium production, established the country as a burgeoning force in the global energy industry and an important player in world markets and global affairs.

But the world has changed and the global energy situation continues to evolve. Kazakhstan faces strikingly different challenges than it did when the previous report was completed in 2015. For much of the period since independence, global commodity markets were dominated by the “commodity supercycle” of strong demand and high prices, driven by the emerging market nations and especially China. Kazakhstan, as a major natural resource producer, greatly benefited from the supercycle, although that period of rapidly growing demand for nearly all types of mineral resources has now ended. The oil market, too, has been turned upside down: it is now characterized by oversupply. Prices in international markets are now hovering at levels less than half of what they were three years ago and have been reluctant to show much buoyancy. In late 2016, Kazakhstan joined a historic agreement with OPEC and several key non-OPEC producers to reduce production and allow the market to re-balance, an agreement that was extended into 2018. Despite unprecedented compliance among the participants, the pact is challenged by the resurgence of US supply as a result of the emergence of shale oil.

These changes in the oil market are putting great fiscal pressure on the budgets of producer countries, like Kazakhstan. They are also changing the orientation of the international industry. Among international companies there is no longer the urgency to obtain access to resources as there was previously: now the goal is to remain profitable and cost-efficient in the new low-price environment through such strategies as reducing the length of investment cycles, focusing exploration in familiar basins and near existing infrastructure, and increasing use of automation and digitization technologies. Companies will continue to actively search for new opportunities, but they will be more selective, increasing the competition among resource-holding countries for available investment. As a result, we expect host countries will offer more flexible fiscal terms and local content requirements. There will also be increasing emphasis on timeliness and predictability in decision-making by countries in attracting international investment.

A second key change is that we are now in a post-Paris Climate Agreement world. The broad international support and general policy direction to reduce greenhouse gas emissions from the energy sector set in the Paris Climate Agreement of 2015 naturally has important implications for Kazakhstan not only as an energy producer and exporter, but also as an energy consumer. Kazakhstan’s unconditional commitment as part of the Agreement is to reduce its greenhouse gas emissions by 15% in 2030 compared to 1990, and by 20% contingent on availability of international funding.

The Report provides projections for how much of this reduction is possible by following policies and measures already in place, and outlines further strategies that could be employed to achieve full compliance.

Thirdly, the emergence of new technologies has the potential to dramatically alter the nature of energy production and use globally. One example is the accelerating build-out and falling costs of renewable energy, which registered record capacity additions in 2016. In transportation, electric vehicles appear to be poised to gain market, and this, coupled with new forms of mobility detailed in the Report, could have major implications both for greenhouse gas emissions and fuel demand.

These and other major changes provide the context for the work featured in this new Report. It presents a baseline outlook for Kazakhstan’s long-term energy future that is based on a careful analysis of both above-ground and below-ground factors. And although that future will be shaped by a vast array of drivers, developments, and conditions that we identify and explore in this update, it will likely be determined to an equal, if not greater, degree by Kazakhstan’s own policy responses and decisions.

Our hope is that this Report will contribute to an ongoing process of decision-making and policy formation in Kazakhstan that must respond to the changes outlined above. As before, the goal of the Report is to advance Kazakhstan’s economic progress and well-being in this dynamic new context, continuously building on the gains the country has achieved since 1991.

Dr. Daniel Yergin
Vice Chairman
IHS Markit
The National Energy Report 2017 (NER 2017) is developed as an integral part of the international exposition Expo 2017, hosted by Kazakhstan in Astana. The theme of Expo 2017 is "Future Energy," with the goal of finding innovative and practical energy solutions to pressing global social, economic, and environmental challenges.

From the same perspective, NER 2017 sets a course toward Kazakhstan’s energy future that is based both on emerging new technologies, with the potential to revolutionize the ways energy is produced and consumed, and on careful stewardship of the country’s abundant energy resources. Yet the energy future must also be sustainable.

The path to future energy outlined in NER 2017 is sustainable because it relies on domestic resources, will become increasingly "green" and efficient, allowing the country to fulfill its international environmental commitments, and it supports and enhances Kazakhstan’s economic growth and the well-being of its people.
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The National Energy Report 2017 was prepared for KAZENERGY by IHS Markit, but incorporates the work of many experts, both within Kazakhstan and abroad. These specialists represent a wide variety of organizations, including KAZENERGY members, state authorities of the Republic of Kazakhstan, research, development, design and engineering entities, as well as companies operating in the sector. The contributions of all these experts are gratefully acknowledged. We especially thank the Avangarde Group represented by its General Director, Ruslan Mukhamedov, as well as Oleg Arkipkin, who was actively involved in preparation of the Report. Their collaboration was invaluable in setting the overall direction and focus of the Report. Numerous specialists within and outside Kazakhstan also reviewed individual chapters of the Report corresponding to their individual areas of expertise. We are sincerely grateful for their suggestions and revisions. We especially thank Uzakbay Kasabalin, Deputy Chairman of the KAZENERGY Association, Bołat Akchulakov, General Director of the KAZENERGY Association, Ramazan Zhamphilov, Executive Director of the KAZENERGY Association, and Rustam Zhunusov, Deputy Chairman of the Board of the National Chamber of Entrepreneurs of Kazakhstan “Atameken”. This Report would not have been possible without their assistance and support.

Of key importance to production of the Report on schedule and in two languages was the work of the highly proficient translator, Maria Gavrilova. We also express gratitude to Ekaterina de Vere Walker for the translation of the chapter on electric power as well as to Nikolay Mirenkov and Andrew R. Bond for their keen editorial assistance.

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In closing, during the preparation of this report we have been truly fortunate to have met and worked with many wonderful and talented colleagues in Kazakhstan. We are particularly honored to present this report as part of the proceedings of the major international exposition EXPO 2017, hosted in Astana and devoted to issues of future energy. It has been a great honor for us to participate in the important work of charting the future development of Kazakhstan’s energy sector. Energy will remain a central element of the country’s economy for many years to come, helping to provide a solid foundation for the welfare of its people. On behalf of IHS Markit, the authors of this Report wish Kazakhstan the very brightest and most successful future.

In Appreciation,
Matthew Sagers, Senior Director (Matt.Sagers@ihsmarkit.com)
Paulina Mirenkova, Associate Director and Project Manager (Paulina.Mirenkova@ihsmarkit.com)
Christopher de Vere Walker, Director and Advisor (Christopher.deVereWalker@ihsmarkit.com)
Andrew R. Bond, Senior Associate (abond@bellpub.com)
Dina Sholk, Senior Analyst (Dina.Sholk@ihsmarkit.com)
Daniel Berkove, Senior Associate (Daniel.Berkove@ihsmarkit.com)
Ekaterina de Vere Walker, Senior Associate, and Director, SEEPX (katya@seepx.com)

Association KAZENERGY expresses sincere gratitude of the following companies, rendered the support in development and publication of the National Energy Report 2017:

Association of Oil Service Companies
Kazakhstan Petroleum Geologists Society (KONG)
D.O. Gancharov
Global Gas Group LLP
Zh. Dzhanabergenov
Settlements and Financial Center for Renewable Energy Support LLP
B.A. Smagulov, A.A. Kabytov, D.E. Baigunakova
Electric Power and Energy Saving Development Institute JSC
R.G. Lidal, V.K. Tyugai, G.I. Omiedchenko
Chokin Kazakh Research Institute of Power Engineering JSC
Amaty University of Power Engineering and Telecommunications
Information-Analytical Center of Oil and Gas JSC
KarMunGas Production and Drilling Technology Research Institute LLP
Azbika Information Center
Samruk-Kazyna – United Green LLP
European Bank for Reconstruction and Development
Zhasyl Damu JSC
KAZENERGY Association
Association of Mining and Metallurgical Enterprises (ACMP)
Association of Renewable Energy
IHS Markit

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In Appreciation,
Matthew Sagers, Senior Director (Matt.Sagers@ihsmarkit.com)
Paulina Mirenkova, Associate Director and Project Manager (Paulina.Mirenkova@ihsmarkit.com)
Christopher de Vere Walker, Director and Advisor (Christopher.deVereWalker@ihsmarkit.com)
Andrew R. Bond, Senior Associate (abond@bellpub.com)
Dina Sholk, Senior Analyst (Dina.Sholk@ihsmarkit.com)
Daniel Berkove, Senior Associate (Daniel.Berkove@ihsmarkit.com)
Ekaterina de Vere Walker, Senior Associate, and Director, SEEPX (katya@seepx.com)
1. INTRODUCTION

1.1 NATIONAL ENERGY REPORT 2017
1.2 A CHANGING INTERNATIONAL ENVIRONMENT
1.3 CHALLENGES FOR KAZAKHSTAN
1. INTRODUCTION

On the global stage, Kazakhstan is particularly prominent as an energy producer. Its proven reserves of oil, coal, and uranium all rank among the top dozen or so countries in the world, and natural gas in the top 20. Further, Kazakhstan leads the world in production of uranium, and annually ranks among the top 10 producing countries for coal and top 20 for oil. Over the past two decades, it has nearly quadrupled its oil output and is emerging as a new global oil-producing “heavyweight”; most of the incremental oil production growth within the Commonwealth of Independent States (CIS) over the next two decades is expected to come from Kazakhstan.

The passage above, from The National Energy Report 2015 (NER 2015), provides clear evidence of Kazakhstan’s international stature as an energy producer. That report also highlights the importance of energy to Kazakhstan’s national economy, when it notes (based on 2014 data):

- Energy production and trade, and 50% of state budget revenues. It has also been the primary destination of foreign direct investment (FDI) within Kazakhstan.

The energy sector, especially oil, is of paramount importance for the country’s economy, accounting for about 22% of the country’s GDP; two-thirds of total export earnings, and 50% of state budget revenues. It has also been the primary destination of foreign direct investment (FDI) within Kazakhstan.

The numbers cited above have declined slightly since 2014, reflecting the downturn in world oil prices, but the energy sector still accounts for about 20.4% of total GDP (2016) and about 60% of total export earnings. Thus the imperative for wise and careful stewardship over the country’s diverse and abundant energy resources is as compelling today as at any time in the country’s history.

1.1. NATIONAL ENERGY REPORT 2017

The National Energy Report 2017 (NER 2017) builds on the comprehensive analysis in NER 2015 (which covered all sectors of Kazakhstan’s energy industry), but through a more selective focus on four key dimensions, which feature prominently in the organization of this report.

First, the chapters on oil, refined products, gas, coal, uranium, electric power, and greenhouse gas (GHG) emissions each provide a concise update of the main statistical indicators and developments in these areas since the publication of NER 2015. Wherever possible, analysis of data for 2015 and 2016 are accompanied by coverage of trends and developments up through mid-2017.

Second, NER 2017 provides an updated assessment of the Outlook for each energy sector, evaluating the most recent energy industry targets and forecasts contained in official state documents (e.g., Concepts, Strategies) and Energy Ministry plans in light of current conditions. In many cases this evaluation includes comparison with proprietary IHS Markit forecasts and scenarios. When IHS Markit forecasts differ from state and industry projections—such as in the case of crude oil production—NER 2017 provides general explanations for the divergence in expected outcomes.

A key section in most chapters—Infrastructure and Technologies—represents a third major focus of NER 2017. Here the goal is to review the state of development of promising new sector-relevant technologies globally and their potential impact on energy markets. This also assesses their suitability for implementation in Kazakhstan, taking into account the development goals and targets for the country’s fuel and energy complex.

A fourth and final focus in each sector-themed chapter—Regulation—is on the legislative and regulatory environment surrounding energy production and consumption in Kazakhstan. Here NER 2017 reviews current legislation in each major energy industry, identifies key problems and major themes, and suggests changes in legislation and regulation that could potentially improve market function, energy security, and investment attractiveness.

1.2. A CHANGING INTERNATIONAL ENVIRONMENT

In addition to its specific focus on the four dimensions described above, NER 2017 stands out by virtue of a new perspective that reflects major developments in the international energy environment since the publication of NER 2015. These include:

- The agreement reached at the 21st Conference of the United Nations Framework Convention on Climate Change (so-called “Paris Agreement”) in November 2015, whereby nearly all of the world’s nations agreed to reduce (GHG) emissions according to self-defined goals, known as intended nationally determined contributions (INDCs). The agreement went into force a year later with the status of international law (having achieved a record number of ratifications in so short a time), and now commits countries (including Kazakhstan) to make concerted efforts to reduce emissions through such measures as energy efficiency improvements, modification of the energy mix in their economies (away from coal and toward natural gas and renewable energy), and carbon pricing (either through carbon taxation or emissions trading).

- A resetting of the world crude oil balance (reflecting oversupply in the medium term coupled with moderate demand growth) at a new price level only roughly half (~$50/bbl) that of early 2014. A combination of lower services costs, efficiency improvements, and voluntary production cuts (among OPEC and selected other major producers such as Russia and Kazakhstan) have allowed major oil producers to remain profitable despite the lower price environment. However, their adjustments—in the form of reducing cycle length, focusing exploration in familiar basins and near existing infrastructure, and relying on automation and digitization technologies to enhance productivity and reduce cost—have shifted the terms of trade in their favor vis-à-vis national governments in negotiations involving new energy investments. In this highly competitive environment, Kazakhstan and other countries must redouble efforts to enhance their investment attractiveness.

- Accelerating build-out of renewable energy capacity. There were record additions of renewable energy capacity globally in 2016 (150 GW), reflecting strong policy support for solar photovoltaics and onshore wind, design improvements, scale economies, and falling capital costs, especially for solar. Renewable energy accounted for more than half of total global generation capacity added, and will be the fastest-growing source of new energy supply for global power generation to 2040. If the necessary

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3 Kazakhstan’s oil and gas industry contribution to GDP in 2016 was 18.2%
policy support is maintained, solar and wind power could capture 50% or more of total net power capacity added in 2016–40. Their share of total energy supply will still remain small, however, because of the initial base, but growing over time. Climate change mitigation is a powerful driver for renewables, but in many countries, reducing air pollution and diversifying energy supplies to improve energy security play an equally strong role.

• Role of natural gas as a “bridge” fuel in question. Renewables’ rapid growth has come in part at the expense of new thermal-fired capacity. Although gas has definite advantages in terms of flexibility, reliability, and—in certain markets—cost over other types of thermal generation, new gas investments are now lagging behind investments in renewables. This calls into question the role gas will play in bridging the transition to renewable energy by displacing coal in the power generation. One factor that could conceivably disrupt or attenuate this role is more rapid than expected development of grid battery storage technology. Will the economics of renewables improve so rapidly that it could dramatically transform the global energy transition away from gas? If this transition happens quickly, the current global oversupply situation and low price environment for gas could be exacerbated.

• The “next big thing” in low-carbon energy? The accelerated build-out of wind and solar power has benefited from a largely unexpected convergence of favorable policy, economic conditions, and technologi- cal advances. Could some other low-carbon energy technology be poised for a similar “breakthrough”—i.e., much more rapidly than anticipated—as govern- ment position themselves as alternative fuels. As such, these could be “stranded” resources beyond what can be utilized in the domestic economy. Energy export trade trends could be developed primarily according to a commercial logic, whereas use of energy such as gas, coal, and to an extent refined products in the domestic economy tend to be guided by a quasi-com- mercial logic in which social interests also play a role. For example, substantial quantities of coal used to generate heat energy at combined heat-and-power plants are consumed at a net economic loss (subsi- dized by revenues from electric power generation). Somewhat similarly, the build-out of natural gas-fired power generation capacity in southern Kazakhstan, which would support the country’s efforts to reduce its carbon footprint as well as assist in the disposal of associated gas from oil production, has been limited in part by high import prices, high transportation and processing costs of domestic associated gas as well as concerns that electricity rate hikes to consum- ers needed to finance the build-out and the costs of gas processing would violate a social commitment to low-cost power. NER 2017 observes that a less than fully commercial approach by the state towards any energy source generates opportunity costs in the form of diminished companies’ revenues that would otherwise be devoted to capital investments in up- grading existing capacities and installing new ones. Mechanisms have proven to be efficient in allocating costs of such investment through the process of price formation.

• Integrated approach to power sector devel- opment calls for a new concept for the sector’s development to 2035 with a view to 2050. Kaz- akhstani energy policies have a long tradition of transforming a generally concurrent approach to the sector, this reasoning applies equally to major planned expansions in the country’s “mega” projects and to enhanced recovery operations at smaller, more remote projects. Changes in hydrocarbon resource sizes and government policies discussed in this report should facilitate future investments by further increasing Kazakhstan’s com- petitiveness as an attractive investment destination.

1 The emissions are calculated by IHS Markit for energy consumption only (about 80–85% of total GHG emissions economy-wide in recent years), thus allowing for consistent historical comparison.

2 It should be noted, however, that Kazakhstan’s planning outlook in many key areas extends only scarcely more than a decade (to 2030), so there is a growing need for a longer term perspective for many sectors of the fuel and energy complex, especially for electric power.
2. GENERAL INVESTMENT CLIMATE IN KAZAKHSTAN

2.1 KEY POINTS

2.2 GLOBAL INVESTMENT TRENDS

2.3 OVERVIEW OF KEY INVESTMENT TRENDS IN THE FUEL AND ENERGY COMPLEX OF KAZAKHSTAN

2.4 KAZAKHSTAN’S FUEL AND ENERGY COMPLEX INVESTMENT ATTRACTIVENESS UPDATE

2.5 OVERVIEW OF KEY LEGISLATION AND REGULATORY CHANGES IN KAZAKHSTAN RELATED TO INVESTMENT POLICY

2.6 RECOMMENDATIONS ON DEVELOPMENT GOALS AND REGULATORY SYSTEM
2. GENERAL INVESTMENT CLIMATE IN KAZAKHSTAN

2.1. KEY POINTS

• The stabilization of world oil prices around $50 per barrel since the second half of 2016 has launched a new upstream investment cycle globally. This new cycle, a response to supply growth deceleration resulting from dramatic cuts in capital investment since 2014, has been strengthened by commitments of OPEC and key non-OPEC oil producers to collective slashing output by almost 1.8 million barrels per day (MMb/d) during the first half of 2017 (now extended to March 2018). Annual exploration and production (E&P) spending will rise for the first time since 2014.
• Companies participating in the new investment cycle perceive the opportunity to remain profitable at a much lower price than that prevailing over much of the previous decade. Reflecting an emphasis on reducing oil and gas E&P costs, the focus of new investment thus far has been on projects in which production can respond quickly to price signals (i.e., shorter cycles) and in areas where geology, operating conditions, and host-country environment are known to be favorable, and where infrastructure either already exists or is close at hand.
• IHS Markit forecasts that the growth in demand for hydrocarbons in the world market will reach 115 million barrels per day by 2040, but at the same time a lower level of price equilibrium for crude oil is expected (about $80 per barrel), instead of about $100 per barrel according to the National Energy Report 2015) due to a significant cost reduction of a large oil production segment. Due to the decline in the price equilibrium to $80 per barrel in the long term, the forecast of Kazakhstan’s average annual GDP growth rate over the forecast period to 2040 was reduced by 1 percentage point (from 3.4% to 2.4%).
• Another key investment trend globally involved record additions of renewable energy capacity in electric power in 2016 (150 GW), more than for any other form of energy. This is more than half of the total generating capacity added, and reflects falling capital costs and strong policy support for solar photovoltaics and onshore wind. The trend is expected to continue into 2017 and beyond. Although new renewable capacity in electric power is projected to be added more rapidly than other sources on an average annual percentage basis, by 2040 renewable sources of energy will still account for only 5% of total global primary energy consumption, with the aggregate share of coal, oil, and gas still accounting for over three-fourths. In Kazakhstan, as much as 2 GW of renewable energy capacity (wind, solar) could be installed by 2020 (amounting to 3% of total capacity), a tenfold increase from the 2016 level.
• In Kazakhstan, in response to negative developments in the global oil and gas industry after Q2-2014 (the low oil price environment as well as the stasis in the investment cycle for big upstream projects), gross inflows of foreign direct investment (FDI) contracted by nearly half, falling to $14.8 billion in 2015. The stabilization of oil prices in 2016, however, helped reverse the trend: gross FDI inflows in 2016 increased by 39% to $20.6 billion.
• Kazakhstan’s overall score according to IHS Markit’s proprietary Petroleum Economics and Policy Solutions Country Ratings and Rankings Module (PEPS)—which measures the country’s attractiveness as a destination for FDI in upstream oil and gas development—decreased slightly from 4.6 in Q4-2014 to 4.4 in Q1-2017. The decline was mainly driven by a modest increase in upstream success (negligible addition of reserves per new field wildcat well) as well as a deterioration in macroeconomic factors (the country’s primary fiscal balance deteriorated while real per capita GDP growth fell significantly).
• In contrast, Kazakhstan recently has ascended rapidly in the annual country rankings on the World Bank Group’s “Ease of Doing Business Index” (EDB), a widely used ranking of countries according to the degree to which a country’s regulatory environment is conducive to the operation of a business. Kazakhstan ranked 35th of 190 countries for 2017; of special relevance to its attractiveness to outside investors, Kazakhstan scores particularly high on the “protecting minority investors” component, ranking third among all countries for 2017. However, it continues to be hindered on general measures of overall investment attractiveness by the relatively low labor skills of the workforce, unpredictable and variable tax laws, and fluctuation of policy (reflecting pressure on the tenge in the low oil price environment, clarity and predictability of currency control laws), and limited access to financing.

2.2. GLOBAL INVESTMENT TRENDS

Global investment in nonrenewable energy in 2017 is only now beginning to recover after more than two years of retrenchment in response to depressed prices for oil, natural gas, coal, and uranium. Investment outfalls in 2016 were particularly pronounced in oil, where robust supply growth and weakening demand growth had created a surplus of ~1.5 MMb/d on the world market. The ensuing global oil price decline that began in mid-2014 (when prices were above $100 per barrel) reached a bottom in February 2016, with Brent prices rebounding off lows (below $28 per barrel) to levels of above $50 per barrel by early June 2016—a level that has held more or less stable since then. As time as supply and demand appear to be moving slowly toward a new equilibrium (see Figure 2.1; Figure 2.2; and Figure 2.3). One factor leading toward that new equilibrium has been the supply growth deceleration resulting from dramatic cuts in capital investment in the industry.

Spending in exploration and production in the global oil and gas industry (upstream E&P capex) is estimated to have declined from $706 billion in 2014 to $495 billion in 2015 and $355 billion in 2016 (see Figure 2.4) according to the International Energy Agency (IEA), upstream E&P capex of ~$500 billion annually is necessary to keep global supply stable over the long term. Cutbacks were especially pronounced in parts of the world where the industry is highly sensitive to price signals, such as North American shale production and offshore North Sea. North American E&P capex plummeted from $328 billion in 2014 to $98 billion in 2016. US production, reflecting a declining rig count among shale producers, fell from 9.6 MMb/d in June 2015 to 8.5 MMb/d by mid-August 2016. Other major producers registering output declines in 2016 included Kazakhstan, China, Mexico, Colombia, Venezuela, Nigeria, and Canada.

![Figure 2.1. Dated Brent (FOB North Sea) price outlook to 2020 (base case)](image-url)
Over 250,000 jobs in the industry worldwide were estimated to have been lost between mid-2014 and 2016. Although skepticism remains regarding whether the cartel’s members will honor these commitments going forward, in April 2017 the IEA issued data indicating 99% compliance with the OPEC reduction target for Q1 2017. Efforts to preserve capital varied across the industry, but included such strategies as selling assets, cutting dividends, and reducing exploration budgets and staff. Producers also postponed or abandoned exploration and field development in higher marginal cost environments, shut down less productive rigs, became takeover targets, or filed for bankruptcy protection (as have over 120 North American oil and gas producers since the start of 2015) (see Figure 2.5).

It should be noted, however, that not all of the E&P spending reductions reflected negative conditions for the producers. Their payments to oil and gas services providers also declined markedly during the downturn. The IHS Energy Upstream Operating Costs Index recorded a 5% decline in 2016. The index is currently 18% below its peak of second quarter 2014 (see Figure 2.6).

However, the stabilization of oil prices around $50 per barrel since the second half of 2016 appears to have launched a new global upstream investment cycle, strengthened by the commitments of OPEC and key non-OPEC oil producers (in November and December 2016, respectively) to collectively slash output by almost 1.8 MMbd during the first half of 2017 to support prices. On 25 May 2017 the agreement was extended nine months, to March 2018. The new wave of upstream spending is evident in the

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1 Over 250,000 jobs in the industry worldwide were estimated to have been lost between mid-2014 and 2016.

2 Although skepticism remains regarding whether the cartel’s members will honor these commitments going forward, in April 2017 the IEA issued data indicating 99% compliance with the OPEC reduction target for Q1 2017.
rapid revival of North American shale drilling activity as well as in deals recently concluded by multinational oil companies to develop new fields in Iran and in the Gulf of Mexico. Further evidence of resumption in investment activity is the rising trend in the monthly global oil and gas rig count since December 2014, then at or near the beginning of the drilling nosedive that lasted into mid-2016. The resurgence in upstream spending also is reflected in decisions to ramp up field expansions at two of Kazakhstan’s three major “mega” projects described in Chapter 3. The CG1 plan at Kashagan appears to be a promising way of boosting phase 1 production by an additional 80,000 b/d, to 450,000 b/d, in advance of a decision on phase 2. The FID on TC0’s Future Growth Project at Tengiz sets the stage for the addition of 12 MMt/y (260,000 b/d) of field production, with first oil from the expansion expected in 2022. The number of final investment decisions (FIDs) world wide on major projects is expected to rise in 2017, and IHS Markit specialists foresee E&P capex rising from $365 billion. That anticipated 2017 expenditures are only slightly more than half those in 2014 suggests not only a more cautious approach over the near term but likely also a fundamentally different strategy in an environment of $50 oil. It will take some time for activity to recover to 2014 levels as upstream E&P capex in 2021 is expected to remain 19% below 2014 levels in nominal terms. Companies participating in the new investment cycle expect to achieve profitability at a much lower price than that prevailing over much of the previous decade, with consequences for projects based on higher-cost reserves. In part this reflects long-term calculations of increasing competition from renewable sources of energy, the prospect of reaching “peak demand” at some point in the future, or even the necessity of leaving some reserves “in the ground” should the political impetus toward reducing carbon emissions be strengthened. These long-term concerns, as well as the uncertainty of price movements over the near term, place emphasis on economics and cost reductions in current operations than on reserve replenishment. Although only general trends in the new investment cycle are emerging, at least three can be identified that deserve greater scrutiny: length of wells or higher proppant intensity. Producers are also finding various ways to increase production efficiencies by economizing on rig rates, high-grading, improved well performance, and scalebacks in project design. Deepwater project costs have fallen by more than 20% since 2014, with 5 billion barrels of oil and gas equivalent globally now developable at breakeven prices of $50 per barrel of oil equivalent (boe), assuming a 15% internal rate of return (offshore) conditions.

Second, the geography of recent investment thus far favors areas near or adjacent to productive fields, where some combination of geology, operating conditions, and host-country environment are known to be generally favorable, and where infrastructure either already exists or is close at hand. A good example is BP’s plan to invest $9 billion to install a second platform at its Mad Dog field in American waters in the Gulf of Mexico. Further evidence of resumption in upstream drilling activity is the rapid revival of North American shale drilling activity. Although there has been a rapid rebound in unconventional oil and gas production in North America in response to ris-

9 This compares with 15 billion bbloe of land-based tight oil resources in undrilled wells.

The key assumptions underlying the revised price forecast are lower E&P cost inflation, as well as reduced marginal costs of E&P through efficiency gains derived from technological advances. More specifically, global liquids demand is now projected to reach roughly 108 MMb/d by 2025, and grow to 115 MMb/d by 2040. In combination with this slower demand growth, the E&P cost curve has now been recalibrated at a lower level. The marginal demand barrel is now expected to require a Brent price of only ~$80 to cover full-cycle costs (falling from ~$90–100/bbl in the previous forecast) (see Figure 2.8). In this more competitive environment, only a few offshore E&P capex projects have reached the $80/bbl level only in the mid-2020s, after which the price remains relatively stable in constant 2016 dollar terms out to the end of the forecast period (see Figure 2.7).
A major consequence for Kazakhstan of an outlook for a mean Brent price that is “lower for longer” is that our forecast for the country’s GDP growth has been moderated. More specifically, the lower long-term oil price expectation (and lower global prices for other key export commodities) knocks a full percentage point off Kazakhstan’s projected annual GDP growth over the forecast period: 2.4% versus 3.4% (see Figure 2.9). Figure 2.9. Kazakhstan’s GDP growth rate has been reduced.

2.2.2. Electric power and the role of renewable energy

Another key development in overall global energy investment trends is the dramatic growth in renewable energy capacity. There were record additions of renewable energy capacity globally in 2016 (150 GW, 87% of which were wind and solar), more than for any other form of energy, reflecting strong policy support for solar photovoltaics and onshore wind and falling capital costs, especially for solar (see Figure 2.10). Renewable capacity accounted for more than half of total generation capacity added, and the trend is expected to continue in 2017. While climate change mitigation is a powerful driver for renewables, it is not the only one. In many countries, cutting deadly air pollution in urban areas and diversifying energy supplies to improve energy security play an equally strong role in growing low-carbon energy sources, especially in emerging Asia. This growth has come in part at the cost of new natural gas-fired capacity. Although gas has considerable advantages in terms of flexibility, reliability, and—in certain markets—cost, new gas investments are lagging behind investments in renewables. In the United States in 2016, for example, solar and wind made up 63% of new capacity additions while gas additions were 29% of the total.}

In many countries of the world, the accelerated development of renewable energy has been accompanied by a shift in financing mechanisms, away from more costly (fixed) feed-in tariffs (FITs) and in the direction of capacity auctions/tenders, which are believed to afford a more cost-effective way of supporting renewable energy development (as detailed in NER 2015). This trend is particularly noticeable in Asia. For instance, India issued tenders of more than 7 GW of solar and wind capacity in 2016 under national- and state-level schemes. Meanwhile, the Chinese central government lowered onshore wind and utility-scale solar FITs (by 5–15% starting in 2018 for wind and by 13–19% starting in 2017 for utility-scale photovoltaics [PV]) and has begun trials of competitive auctions for utility-scale solar PV. In late 2016 Japan announced plans to cut FITs annually over a three-year period and plans to switch to an auction-based procurement system in 2017, and in Australia the launch of several large-scale tenders (focusing on PV and storage) was part of a program to restore confidence in overall market potential. In the Middle East, Jordan and Dubai have increased their solar targets, while tenders proceeded. And Saudi Arabia confirmed its commitment to a revised 2030 renewable target by announcing new tenders.
Despite the rapid pace of the renewable energy build-out, it is important to keep in mind that traditional hydrocarbon sources will continue to support the bulk of global energy consumption for many years to come, at least out to the end of our projection period. By 2040, renewable sources of energy will account for only 5% of total global primary energy consumption, with the aggregate share of coal, oil, and gas still accounting for over three-fourths (see Figure 2.11). However, the picture will vary widely in different parts of the world, with some regions (e.g., Europe) relying on renewable energy to play a much greater role, whereas in others natural gas (US, Kazakhstan) or natural gas and nuclear power (China) are expected to account for most incremental energy consumption (see Figure 2.12, Figure 2.13, 2.14., 2.15).

Focusing more narrowly on future global electricity generation, the expanding role of renewables is more evident. By 2040 wind and solar generation are expected to account for 8% and 6%, respectively, of total generation, as their costs become increasingly competitive with traditional sources of electric power (see Figure 2.16 and Figure 2.17). Even here, however, it is important to note that: (a) the economics of renewables is much more complicated than simple comparisons of the levelized cost of electricity (LCOE) would suggest; (b) renewable capacity additions still require policy support; and (c) intermittent renewable power technologies alone will not reliably provide all the capacity and energy demanded by consumers.

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2.3. OVERVIEW OF KEY INVESTMENT TRENDS IN THE FUEL AND ENERGY COMPLEX OF KAZAKHSTAN

Foreign investment contributes greatly to economic development in emerging economies such as Kazakhstan. Even though it generally accounts for a relatively small share of gross investments, it is a key means of obtaining technologies, capital, management skills, and access to export markets. Kazakhstan’s success in attracting substantial inflows of foreign investment in the years since independence has accelerated the country’s national development and the overall transition to a market economy, especially in the energy sector. Initial-ly, during the Soviet period, the only available form for investment by foreign nationals were joint ventures, but Kazakhstan has established a variety of other vehicles, including wholly owned foreign subsidiaries and equity investment in domestic firms. For Kazakhstan’s energy sector, the importance of foreign direct investment (FDI) is that it allows the country to utilize its enormous resource potential by carrying out projects that otherwise simply could not have been realized, either because of their scale or their technical challenges. Specifically, such operationally and technologically challenging projects as Kashagan, Karachaganak, or Tengiz all required engineering and managerial capabilities available only outside of Kazakhstan, found largely in the leading international oil companies (IOCs). In turn, the expenditures on these projects in-country have driven expansion and change in many other supporting sectors across the economy.

Total gross inflows of foreign direct investment (FDI) in Kazakhstan’s economy has increased from $1.3 billion in 1993 to a peak of $29 billion in 2012 before decreasing slightly to $24 billion in 2013-14. The total stock (cumulative amount) of direct foreign investment for the entire economy since 1993 had reached $241.9 billion by the end of 2014. However, in response to negative developments in the global oil and gas industry after Q2-2014, gross FDI inflows into Kazakhstan’s economy contracted by nearly half, falling to $14.8 billion in 2015 (see Figure 2.18). The low oil price environment and the downturn in the investment cycle hit foreign investment flows into two sectors particularly hard in 2015: investments into oil and gas production declined by $4.5 billion to $2.8 billion, while investments into exploration fell by $0.2 billion. This decrease explains half of the overall gross FDI decline. Other sectors of the economy that experienced lower FDI inflows include manufacturing (primarily the metallurgical sector with a 1.2 billion decline) and trade (a decline of $1.3 billion). The stabilization of oil prices in 2016 reversed the trend: gross FDI inflows increased by $5.8 billion to $20.6 billion, driven by FDI into oil and gas production ($2.9 billion increase) and other sectors (manufacturing and trade; a $2.8 billion increase).

In terms of individual investor countries, the Netherlands retained its lead-investor position. It was responsible for roughly two-thirds ($7.7 billion) of overall FDI inflows in 2016, compared to 29% ($6.8 billion) in 2014 (see Figure 2.19). This is explained by the fact that operators of major projects like Kashagan and Karachaganak are companies registered in the Netherlands.

FDI is a widely used indicator for assessing the inflow of foreign investment into the national economy. According to the generally accepted methodology of the International Monetary Fund, FDI refers to the investment of a company that is a resident of one country into a company that is a resident of another country with the aim of acquiring a stake (and earning a profit) for a long period. For the threshold value that separates direct investments from portfolio investments, a share of 10% is accepted. The statistical data used in the preparation of this chapter of the Report collected and published by the National Bank of the Republic of Kazakhstan reflect the acquisition by foreign investors of more than 10% of voting shares, their share in reinvested (undistributed) profits, and the gross increase in the debt burden of such enterprises.
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 sharply in current dollar terms (by roughly 43%) during 2014–16, a decline enhanced by the depreciation of the tenge against the dollar in 2015 and 2016 (see Figure 2.20). However, fixed capital investment in (constant) local currency terms rose by 25% relative to 2014, to 6 trillion tenge in 2015 and 2016 (see Figure 2.21). About two-thirds of this increase was driven by three sectors within the broader "industry" category: oil and gas extraction, mining and exploration services, and petroleum refining. The share of fixed investment in the oil and gas sector rose from 18.4% of the total economy in 2013 to 23.4% in 2016.

The ratio of net FDI inflows to GDP (a variable used by the World Bank to compare world economies) for Kazakhstan increased from 3.2% in 2014 to 3.6% in 2015, after averaging 5.7% during the period between 2010 and 2013 (prior to the world oil price collapse in 2014). For other hydrocarbon producing countries of the region, Azerbaijan's FDI inflows as a share of GDP picked up as well, increasing from 5.9% to 7.6% during the same period, which reflects the continuing implementation of key upstream projects, including Shah Deniz Stage 2. The FDI to GDP ratio in Turkmenistan and Uzbekistan increased by 2.3 and 0.6 percentage points, respectively, to 11.9% and 1.6%, driven by multiple upstream and refining projects involving foreign investors. At the same time, the ratio in Russia decreased from 1.1% in 2014 to 0.5% in 2015 largely due to imposed international sanctions. These FDI dynamics demonstrate that investor interest in the region continues, albeit at a moderated pace, especially with regard to specific major projects. Such dynamics also speak to the existing competition for FDI between countries.

### 2.4. KAZAKHSTAN’S FUEL AND ENERGY COMPLEX INVESTMENT ATTRACTIVENESS UPDATE

#### 2.4.1. IHS Markit PEPS country ratings and rankings module

The assessment of Kazakhstan’s investment attractiveness dynamics in 2015 and 2016 is based on the IHS Markit PEPS (Petroleum Economics and Policy Solutions) Country Ratings and Rankings Module (CRSM) that ranks various countries by overall exploration and production attractiveness. The module uses over 50 variables under three key categories—Recent E&P Activity, Fiscal Attractiveness, and Petroleum Sector Risk—weighted at 20%, 50%, and 30% (respectively)—to produce overall country scores. The scores are updated on a quarterly basis (see Figure 2.22).

The Fiscal Attractiveness category considers eight fiscal factors, each modeled under a country’s fiscal regime for three groups of hypothetical oil fields—marginal, economic, or upside. These groups are formed by considering economics (on a gross project basis—i.e., before government involvement) for six hypothetical fields with a preselected size of reserves first under three development cost scenarios, and then under three market price scenarios.

The Recent E&P Activity category provides an assessment of the country’s upstream potential. It includes four groups of factors: country’s production of oil and gas, remaining reserves of oil and gas, upstream activity, and upstream success (the two latter factors...
are assessed over the last five years). The upstream activity group includes such factors as the number of new field wildcats (NFW) drilled, new licenses awarded, and the number of active companies. Upstream success is evaluated using four factors: reserves added for oil and gas, success rate of NFW, and reserves added per NFW. The Petroleum Sector Risk category’s objective is to help assess whether the expected rewards from oil and gas projects will be commensurate with the associated above-ground risks. Five groups—Politics, Economics, Hydrocarbon Sector Entry, Hydrocarbon Sector Operations, and Hydrocarbon Sector-Shocks—contain 21 risk factors, most of which are based on qualitative judgements.

Kazakhstan’s overall PEPS score decreased from 4.6 in Q4-2014 to 4.4 in Q1-2017. Kazakhstan’s overall ranking is generally low, in the bottom quartile, and its relative standing is declining over time. Among other oil-producing countries, a decrease in the overall score during the same period is observed for the United States (by 0.4 to 7.0), Norway (by 0.3 to 6.1), Canada (by 0.2 to 7.0), and Angola (by 0.2 to 4.9), while countries that increased their overall score include the UK (by 1.0 to 7.6), Russia (by 0.2 to 4.4), and China (by 0.1 to 6.3).

• Among the three key categories utilized to compile the PEPS, Recent E&P Activity declined most steeply for Kazakhstan, falling from 4.2 in Q4-2014 to 3.6 in Q1-2017. The decline was mainly driven by a decrease in the Upstream Success group of factors, as the addition of reserves per NFW during this period was negligible.

• Fiscal Attractiveness category’s score remained at 4.1 during the same period, as the higher export duty (as the result of replacing a flat rate with a new formula tying the duty to the oil price on the global market in 2016) lowered the tax base, thus softening the overall financial impact.

2.4.2. General indicators of investment attractiveness

In addition to the insights provided by IHS Markit’s E&P rankings Fiscal Attractiveness and Petroleum Sector Risk modules, it is instructive to briefly review how Kazakhstan’s overall business environment has been evaluated according to two widely used comparative international indicators.

The World Bank Group’s “Ease of Doing Business Index” is the best-known such comparative indicator, compiled annually since 2001. The Index ranks countries according to the degree to which a country’s environment is conducive to the operation of a business.9 The rankings are adjusted each year to reflect, among other things, reforms or changes initiated that have made it either easier or more difficult to conduct business.10 As the figures in Table 2.1 indicate, in recent years Kazakhstan has ascended rapidly in the EDB rankings as the overall business environment has been evaluated according to the two widely used comparative international indicators.

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Kazakhstan overall ranking 15 30 77 41 35

No. of countries 189 189 189 189 190

4. The Index averages a country’s percentile rankings on 10 component indicators to derive a composite score, which is then used to assign a final “Ease of Doing Business” (EDB) ranking. The 10 indicators measure the ease of starting a business; dealing with construction permits; getting electricity; registering property; obtaining credit; protecting minority investors; paying taxes; trading across borders; enforcing contracts; and resolving insolvency (see http://www.doingbusiness.org/rankings).

5. The rankings are annual and the coverage period ends on 1 June of the preceding year; for example, the 2017 index covers the period beginning 2 June 2015 and ending on 1 June 2016.
A second indicator briefly mentioned here is the World Economic Forum’s Global Competitiveness Report. Although it is not explicitly a measure of investment attractiveness, it can be viewed as a proxy of sorts, inasmuch as the components it uses to define competitiveness—the set of institutions, factors and conditions that determine the level of productivity of an economy—should also manifest more or less directly in returns on investment.

As evident from Table 2.2, the World Bank hierarchy is similar to the OECD. The United States, United Kingdom, Norway, Canada, and Malaysia all fall within the top 25 slots in the ranking, whereas Kazakhstan, Russia, and China occupy intermediate positions (Kazakhstan ranks 46). Nonetheless, Kazakhstan is committed to improve in terms of its overall ranking on absence of corruption (71st) and open government (73rd).

The Global Competitiveness Report also provides the results of a 2016 executive opinion survey indicating the five most problematic factors for doing business in Kazakhstan: tax rates, corruption, access to financing, tax regulations, and inflation (not unexpected given the pressure on the tenge in the low oil price environment), tax rates, corruption, access to financing, and tax regulations. Insight into two of these factors (corruption and the regulatory environment) is provided by a separate Rule of Law Index (ROLI) compiled by the World Justice Project. On the 2016 ROLI rankings, Kazakhstan ranked 77th among 126 countries, up from 75th in 2015. The index is designed to measure a nation’s adherence to the rule of law from the perspective of how ordinary people experience it.

Of particular relevance to investment attractiveness, Kazakhstan ranked noticeably higher on order and security (49th) and regulatory enforcement (57th) and near the bottom on access of corruption (71st), and open government (73rd).

2.5. OVERVIEW OF KEY LEGISLATION AND REGULATORY CHANGES IN KAZAKHSTAN RELATED TO INVESTMENT POLICY

As reflected in its rise in the EDB ranking, Kazakhstan has continued to take steps toward improving the investment climate and promoting investments, both domestically and from abroad. In a major administrative change, in August 2014 the Ministry of Industry and New Technologies, and the Ministry of Transport and Communications were combined into a new Ministry for Investments and Development. One of the key goals of the new ministry is to improve the investment climate by stimulating the investments into new manufacturing and production projects that use modern technologies. Specifically, the Investment Ministry’s strategic plan of actions to 2021 sets goals to improve the investment climate that are tied to Kazakhstan’s position in the World Economic Forum’s Global Competitiveness Report rankings discussed above. Specifically, the Ministry aims at creating an enabling environment in areas the GCR identified where Kazakhstan appears to be lagging, including local supplier quality and quantity, state of cluster statistics; and the environment.

In recognition of Kazakhstan’s progress, in April 2017 the country became the first in Central Asia to join OECD’s Investment Committee (as an associate member). The Committee’s mandate is to interpret and implement the Declaration and Decisions on International Investment and Multinational Enterprises from 1976, and to comply with the Codes of Liberalization of Capital Movements and Current Invisible Operations. In addition, the local government, and the actual financing of programs. Subsoil users are therefore required by law (Law on Subsoil and Subsoil use) to submit information in support of the EITI implementation, and these reports are made publically available online, on the integrated information system—"Unified system of subsoil use management of the Republic of Kazakhstan."
separate pieces of legislation, including the Law on Investments. Compared to the Law on Investments, the Code: (a) granted the Investment Ministry the authority to solicit the Foreign Ministry to issue a special Investor type of visa for foreign professionals; (b) increased the period an investor could apply for investment preferences from one year to two years; and (c) expanded tax preferences to include exemption from paying VAT on imports. While these laws are positive developments, authorities must work to ensure universal, uniform understanding, interpretation and application of laws.

Currently, the government is developing a national investments attraction and sustainability strategy until 2022 an initiative designed to promote economic diversification by attracting investments to sectors beyond natural resources based on the recommendations of the World Bank. Specifically, the strategy’s goals are to attract foreign investments that will improve operational efficiency, to promote investments in already existing investment projects, to carry out privatization, and to promote public-private partnerships. The implementation of this strategy is the responsibility of the Kazakhstan Investment Agency—an arm of the Investment and Development Ministry, which is mandated to attract investments to Kazakhstan. Kazakhstan is authorized to provide support to investment projects through the Kazakhstan Investment Agency, representing Kazakhstan’s government.

2.6. RECOMMENDATIONS ON DEVELOPMENT GOALS AND REGULATORY SYSTEM

Kazakhstan has made substantial progress in increasing its attractiveness as a destination for investment. As in all other countries, there is room for further progress. The analyses summarized in this chapter support the following recommendations.

- First, pertaining directly to the oil and gas industry, a decline in investment attractiveness between Q4-2014 and Q1-2017 recorded by the IHS Markit PEPS Country Ratings and Rankings Module (in the category of Recent E&P Activity) suggests continuing challenges within a group of factors defined as “Upstream Success”: reserves added for oil and gas for success rate of NFW, as well as reserves added per NFW. The addition to reserves per NFW during this period, for example, was negligible. These upstream challenges are included among those highlighted by the Kazakhstan Upstream Oil and Gas Technology Roadmap prepared in 2013 (Shell Roadmap), summarized in the following chapter (see Section 3.3.3).

- The Shell Roadmap identifies the reduction of drilling and well costs in challenging geological environments through new well-drilling technologies and equipment as one of the three main directions that would yield the greatest immediate benefits to the industry and its investors. The overall PEPS investment attractiveness score also fell as Petroleum Sector Risk increased due to macroeconomic factors, as the country’s primary fiscal balance deteriorated while real per capita GDP fell, and the broader economy more generally, is increased spending on domestic workforce training. A relatively low level of labor skills is a weakness identified in firms-level business indicators of economic performance, and is especially relevant in situations where foreign investments must comply with local content regulations. The goal should be to increase the number of workers available with minimum requirements of training, and also to gradually increase the overall level of training. Cooperative training programs involving foreign investors and Kazakhstan’s educational institutions should be explored as means of developing highly specialized and technical skills.

- Kazakhstan’s focus on establishing a legislative foundation and creation of a regulatory environment supporting investment is commendable and appears to be achieving tangible results (e.g., the country’s recent performance as measured by the World Bank’s Ease of Doing Business indicators). However, the build-up has not been accompanied by an expansion of the bureaucracy overseeing investment projects. The consolidation of government investment services offered to foreign investors received one “window,” or a single dedicated channel (Investors Services Center), and the creation of the position of Investment Ombudsman appear to be positive steps aimed at minimizing and resolving the red tape encountered by investors. However, the existence of numerous other offices supporting investment (Investors Council, Council on Improving the Investment Climate, Investment Command Center) appears to be a multiplicity of authorities that could be confusing for foreign investors. Often different bureaucracies have conflicting mandates and overlapping authorities, multiple government approvals for operations adds to the time and administrative efforts required to conduct business. Attention should be focused on a careful delineation of authority among these bodies, the elimination of duplicative responsibilities, and perhaps a certain degree of consolidation.

- Kazakhstan is currently drafting a new Tax Code. Recommendation for the new tax code would be to remove multiple steps in tax processes, such as the introduction of the “single window” base, representing Kazakhstan’s government.

- In reforming the Subsoil Code, Kazakhstan should refer to the proposed recommendations in the 2015 NER.

- Kazakhstan should continue to realize its plan to improve the administration process by instituting an e-invoicing initiative. Reducing banking fees and promoting the use of cash registers and electronic payment methods would help to promote transparency and improve efficiency of the financial administration of doing business in Kazakhstan.

- The application of a local content policy has been an extremely important practice that can, and should, be applied to all future foreign investment projects in Kazakhstan. But a local content policy should be designed to cultivate the long-term growth of domestic capacities, rather than to generate immediate activity. In January 2016, the government introduced new rules for calculating the “local content percentage” of companies contracted by oil companies developing a project. The new definition stipulates that any company with less than 95% of Kazakhstan employees by headcount as zero local content, regardless of other criteria. Whereas previous rules recognized various approaches to defining local content, such as percentage of payroll, hours worked, and value of product produced, the current rule focuses exclusively on short-term job creation. Therefore, Kazakhstan should reform its local content laws to provide additional flexibility and recognize the indirect benefits, such as skills training and technology and know-how transfers, that foreign investment and personnel bring to the country.

- Similarly, greater restrictions on work permits for foreign workers only complicate the ability, and sometimes willingness, of foreign companies to do business in Kazakhstan.

22 In this context, it is relevant to note that the East Asian “economic miracle” is largely attributed, among other things, to that region’s sustained levels of investment in human capital over a long period. In other words, there is an “education miracle behind the economic miracle”; see Kandhyala B.G. Tilak, Building Human Capital in East Asia: What Others Can Learn, Washington, DC: International Bank for Reconstruction and Development, 2005.
3. CRUDE OIL AND GAS CONDENSATE PRODUCTION

3.1 KEY POINTS
3.2 UPSTREAM OIL AND GAS CONDENSATE EXTRACTION UPDATE
3.3 UPSTREAM EXPLORATION AND TECHNOLOGIES
3.4 LEGISLATIVE BASE AND REGULATION OF KAZAKHSTAN’S UPSTREAM SECTOR
3. CRUDE OIL AND GAS CONDENSATE PRODUCTION

3.1. KEY POINTS

- In 2016, oil output from Kazakhstan declined for third year in a row: -1.2% in 2014, -1.6% in 2015, and -1.9% in 2016, to 78 MMt (1.66 MMb/d); these declines were concentrated at mature fields, mainly in Aktobe and Kyzylorda oblasts. But since late 2016, declines were concentrated at mature fields, mainly

- Although Kazakhstan’s 2017 output may be deliberately constrained somewhat by its pledge to support oil prices by reducing oil output (see below), ongoing developments at two of its three “mega” projects provide a foundation for solid future output growth: the CC01 debottlenecking at Kashagan will provide an additional 80,000 b/d to the existing designed plateau of about 17 MMb/d (~370,000 b/d) for phase 1, and the decision to proceed with the Future Growth Project at Tengiz sets the stage for the addition of 12 MMb/d (260,000 b/d) of field production in the early 2020s.

- Kazakhstan agreed in late 2016 to participate in the plan by OPEC and other major oil producers to hold back output to support oil prices during the first half of 2017, pledging a symbolic output reduction of 20,000 b/d. This plan was later extended by additional nine months, to March 2018.

- Due to lower expected investment in the current lower global oil price environment, IHS Markit has adjusted (to the downside) its base case scenarios for Kazakhstan’s oil production and exports out to 2040. Nonetheless, Kazakhstan is expected to increase production longer term, and will remain the second largest oil producer and exporter within the CIS region.

- Growth in Kazakhstan’s crude exports via the CPC pipeline over the past two years occurred as exporters redirected significant volumes from other (more expensive) routes to fill expanded CPC capacity. CPC handled 68% of total Kazakh crude exports in 2016, up from 63% in 2015. Like many other Kazakh producers, Kashagan oil is now also reaching export markets via the Russian pipeline system as well as CPC.

- The reversal of the Atyrau-Kenkiyak oil pipeline section, which has been planned but delayed for several years, is expected to occur in 2017–18. Once the Kenkiyak-Atyrau pipeline section is reversed, increased Kazakhstan-China export flows can be achieved, but this oil will have to be attracted from western Kazakhstan. To flow east, the netback for crude from western Kazakhstan (realized sales price after transportation) needs to be the same or higher as from westward exports. Also, questions remain about the availability of the reserve base to increase oil flows in this direction.

- A key challenge is the lack of growth in the reserve base: recent years have seen a significant decline in the exploration activity and success rates, in the Precaspian Basin and across Kazakhstan in general, by KazMunayGaz (KMG) and international oil companies. Key factors contributing to the decline in exploration activity and success rates have been cutbacks in exploration spending generally in the low oil price environment as well as the declining relative attractiveness of Kazakhstan internationally for upstream investors.

3.2. UPSTREAM OIL AND GAS CONDENSATE EXTRACTION UPDATE

3.2.1. Liquids reserve base

As of 1 January 2016, the State Commission on Reserves (GKS) listed Kazakhstan’s petroleum liquids (oil and gas condensate) reserve base (state balance) at 5.3 billion metric tons.1 Of this, 4.85 billion tons are crude oil reserves, while the rest (445 million metric tons [MMt]) is gas condensate (see Table 3.1). The official state balance lists oil and gas condensate reserves for 332 fields, including 271 oil fields and 61 gas condensate fields. The state reserves balance has increased slightly (by 2.1%) since 1 January 2014, with reserves in the A+B+C1 category increasing by about 1.9%, while those in category C2 increased by 2.6%. A significant part of the increase in reserves is likely the result of recalculation of reserves at existing fields; there have been few new discoveries and those that were made tended to be small fields.

Table 3.1. Kazakhstan’s proven oil and condensate reserves in 2016 (MMt)

<table>
<thead>
<tr>
<th></th>
<th>A+B+C1</th>
<th>C2</th>
<th>A+B+C1+C2</th>
</tr>
</thead>
<tbody>
<tr>
<td>Crude Oil</td>
<td>3 158 812</td>
<td>1 688 728</td>
<td>4 847 540</td>
</tr>
<tr>
<td>Condensate</td>
<td>159 153</td>
<td>86 396</td>
<td>445 549</td>
</tr>
<tr>
<td>Total</td>
<td>3 317 965</td>
<td>1 775 124</td>
<td>5 293 089</td>
</tr>
</tbody>
</table>

Source: State Commission on Reserves (GKS)

3.2.2. Key recent oil and gas condensate production trends

Over the past three years, Kazakhstan’s oil production has exhibited a declining trend, although the re-start of production at Kashagan is reversing this in 2017 (see Figure 3.1). National crude and condensate output has declined each year since 2014: it fell 1.2% to 80.8 MMt (1.7 MMb/d) in 2014; a further 1.6% to 79.5 MMt (1.67 MMb/d) in 2015; and in 2016 output fell to 78 MMt (1.66 MMb/d), down another 1.9% year-on-year (see Table 3.2). The declines were concentrated in Kyzylorda Oblast (Turgay Basin) and Aktobe Oblast, owing to an ongoing secular decline at mature fields in these two areas. Over the period 2014–16, aggregate oil and condensate output fell by an average annual rate of 8.3% in Kyzylorda Oblast and by 12% in Aktobe Oblast.

1 This is reported according to the domestic definition (in categories A+B+C1+C2). Kazakhstan’s remaining proven + probable “2P” reserves (roughly the international equivalent of the domestic definition of A+B+C1) is 3.16 billion tons (or about 23 billion barrels); IHS Markit estimates a slightly larger amount of 2P reserves for the country in 2016, at 43 billion barrels. BP estimates Kazakhstan’s 2P reserves at about 30 billion barrels.
Amidst the three mega-projects, the Karachaganak Petroleum Operating (KPO) consortium in West Kazakhstan Oblast recorded a stable production rate of around 11.6 MMT (265MMb/d) during 2016, during which its production performance improved. This was carried out resulting in a lower production compared to 2015 of about 3.1%. In contrast, the TengizCheVRol (TC) consortium in Tengiz field in production in 2015 by 1.8% and another 1.5% in 2016, to reach 27.6 MMT. TCD accounted for about 36% of total Kazakh oil output in 2016. The re-start of Kashagan production was a major achievement in 2016. Total output for the field was about 1.8 MMT in the final three months of the year (an average of 81,000 b/d), but production is continuing to gradually ramp up in 2017. Taking a closer look at the top oil producers in Kazakhstan, the following dynamics emerge:

- **TCO (Tengiz)**
  - Output growth reached an all-time high of 27.6 MMT (600,000 b/d), up 1.5% year-on-year. Field production dynamics will remain largely tied in the near term to the specifics of TCO maintenance schedules and turn-arounds. For example, over a month was set aside for maintenance of sour gas plant and sour gas injection (SGP/SGI) facilities, beginning in August 2016 (45 days for SGP and 35 days for SGI).
  - IHS Markit expects Tengiz output to remain relatively flat for the next few years, with 2017 average expected production the first investment decision (FID) for the Future Growth Project (FGP)– wellhead pressure management project (WMPM)– sets the stage for the addition of 12 MMt/y (260,000 b/d) of field production, with first oil from the expansion expected by the consortium in 2022. The $36.8 billion expansion program includes $27.1 billion expenditure on facilities and $3.5 billion on wells. It is noteworthy that over 50% of the detailed engineering work related to the expansion had already been completed before the FID—far beyond the usual amount undertaken before project sanction. Key elements of the FGP-WMPM project, which is expected to generate around 20,000 jobs at the peak of construction, include the following planned new facilities:
    - 106 production and 15 gas injection wells
    - A hydrocarbon gathering system and plant to reinject sour natural gas
    - Five gas turbine generators (GE Frame 9 units, each with capacity of 130 MW).

- **KPO (Karachaganak)**
  - KPO production is expected to be maintained at plateau in the near to medium term. Plateau extension projects (KPO)– sets the stage for the addition of 12 MMt/y (260,000 b/d) of crude from KMG’s share of oil production from the TCO project over a period of four years, in exchange for a $3 billion prepayment made in tranches by Vitol with financing from commercial banks (six internal banks from the deal). In another similar arrangement, the volume of Kashagan oil that KMG will supply to Vitol under terms of an August 2016 prepayment contract (KPO)– wellhead pressure management project (WMPM)– sets the stage for the addition of 12 MMt/y (260,000 b/d) of field production, with first oil from the expansion expected by the consortium in 2022. The $36.8 billion expansion program includes $27.1 billion expenditure on facilities and $3.5 billion on wells. It is noteworthy that over 50% of the detailed engineering work related to the expansion had already been completed before the FID—far beyond the usual amount undertaken before project sanction. Key elements of the FGP-WMPM project, which is expected to generate around 20,000 jobs at the peak of construction, include the following planned new facilities:
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National company (NC) KMG owns stakes in almost all significant oil and gas assets in Kazakhstan. The company also acts in the interests of the state, which has prerogative to own and operate strategic assets (c. 12% of national oil production) in the country. The total share of NC KMG (based upon equity ownership) in NC KMG’s oil production amounted to about 29% in 2016.

Output by KMG EP, the exploration and production arm of NC KMG, remained flat in 2016 at 12.3 MMT, but declined by 2% in 2016 to 12.2 MMT. Its 100% owned subsidiaries, UzenMunayGaz and EmbaMunayGaz, together produce a 2.2% combined uptick in production in 2016, to 8.4MMt (an average of 147,000 b/d) of crude.

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KazMunayGaz (KMG)

"Smart field," also known as "digital field," technology involves equipping critical field infrastructure, such as valves and pumps, with sensors that measure and transmit important data on temperature, pressure, and other parameters, allowing for quick optimization of well operation.

Kazakhstan (NCOC)

The restart of Kashagan in late September 2016 marked a historical milestone in Kazakhstan’s oil and gas industry.

1% Production restarted almost exactly three years after the October 2013 gas pipeline leaks that forced a shutdown of the field during the field’s initial start-up, following the completion of a pipeline replacement program. The field reached commercial levels of production (75,000 b/d) on October 2014. In 2015, production amounted to 0.96 MMT in the final three months of the year (an average of 81,000 b/d). In the first half of 2017, production amounted to 3.54 MMT (an average of 151,000 b/d, with output in June reaching 192,000 b/d). Production will grow further after reinjection begins—scheduled for the latter part of 2017, and is scheduled to reach the designed plateau level of 365-370,000 b/d perhaps by the end of the year. Kashagan’s production in 2018 is expected to be flat with Kazakhstan’s symbolic commitment with OPEC to cut 20,000 b/d of production.
3.2.3. National oil and gas condensate production outlook

Despite the considerable distress that the Kazakhstan’s upstream sector has been under due to the global oil price decline, overall prospects for the industry are far from gloomy. Kazakhstan still has significant existing reserves and upstream potential, but policy needs to be recalibrated to more effectively encourage exploration and to incentivize producers to invest and expand their operations in Kazakhstan, especially smaller and medium-sized ones. Nonetheless, Kashagan is expected to be the primary driver of production growth in the medium term.

In IHS Markit’s base case scenario, Kazakhstan’s crude oil production is projected to increase from 78 MMR (1.66 MMb/d) in 2016 to 93.7 MMR (1.97 MMb/d) in 2020 and then 148.3 MMR (3.13 MMb/d) in 2040; this represents an average annual rate of growth of 2.7% over the 2016–40 outlook period (see Figure 3.2). In the high case, national output reaches 179.2 MMR (3.79 MMb/d) in 2040. In the low case, however, output decreases in the later years of the outlook. Output reaches a maximum of 94.7 MMR (2.0 MMb/d) in 2030 and then declines slowly, falling to 88 MMR (1.86 MMb/d) in 2040. IHS Markit’s outlook for Kazakhstan’s crude oil production in the low case does not include development of Kashagan phase 2, but phase 2 is assumed in the base and high cases. The rationale for assuming the eventual realization of Kashagan phase 2 has been in line with previously estimated capex, where expected additions in output from phase 2 (raising aggregate output to ~1 MMB/d) would require much lower capex per barrel compared to phase 1’s original target of 450,000 b/d, later reduced to 350,000-370,000 b/d. Given Kashagan’s importance to both the government and the consortium, an accommodation of future developments (such as an extension of the project’s contract) and implementation of phase 2 seems reasonably likely. The CC01 expansion project approved in November 2016 will bring productive capacity to the original 450,000 b/d of output. This project appears to reflect an evolving perspective on future development at Kashagan, even within phase 1, that seeks incremental productivity improvements at existing operations, similar in philosophy to “brownfield” investment projects.

Figure 3.2. Outlook for Kazakhstan’s oil production by scenario

![Graph showing oil production outlook for Kazakhstan](image)

The IHS Markit base case tries to approximate a so-called PSO outlook: the actual results have an equal likelihood of being higher or lower than the basecase projections. The high-case figures approximate a P90 outlook: the actual results have a 90% probability that they will be lower than the outlook numbers. Similarly, the low case is intended to approximate a P10 outlook: the actual results have only a 10% probability that they will be lower than the outlook numbers. These probabilities are intended only as rough guides in interpreting the production projections.

The rationale for assuming the eventual realization of Kashagan phase 2 has been in line with previously estimated capex, where expected additions in output from phase 2 (raising aggregate output to ~1 MMB/d) would require much lower capex per barrel compared to phase 1’s original target of 450,000 b/d, later reduced to 350,000-370,000 b/d. Given Kashagan’s importance to both the government and the consortium, an accommodation of future developments (such as an extension of the project’s contract) and implementation of phase 2 seems reasonably likely. The CC01 expansion project approved in November 2016 will bring productive capacity to the original 450,000 b/d of output. This project appears to reflect an evolving perspective on future development at Kashagan, even within phase 1, that seeks incremental productivity improvements at existing operations, similar in philosophy to “brownfield” investment projects.

Although the overall IHS Markit forecast is built up from developments in eight main categories of producers, either major projects by themselves or grouped together by location, crude quality, or type of operation. These components are described in more detail in NER 2015.

Besides the three mega projects, a host of smaller projects also figure in Kazakhstan’s oil development going forward, albeit less prominently. Importantly, the IHS Markit outlook assumes the proliferation of new, smaller projects over the forecast period, and also a relatively slow (instead of more rapid) decline in Kazakhstan’s older, existing fields as a result of the growing application of new technology and practices. Recently revised official outlooks from the Ministry of Energy for Kazakh oil production are generally less optimistic, reflecting the changed circumstances in global oil markets over the past several years. The latest Ministry outlook envisions national output rising by almost 4% in 2017, to 81 MMR (1.74 MMb/d), but foresees national output reaching a maximum of only 113 MMR (2.43 MMb/d) in 2030 and 91.5 MMR (1.83 MMb/d) in 2040. The key difference between the outlooks is the view on older fields: generally IHS Markit envisions a far more attenuated decline with the introduction of new technology that has proven successful in older fields. Not surprisingly, Kazakhstan’s overall oil production profile will continue to be largely driven by developments at the three “mega” projects: Tengiz, Karachaganak, and Kashagan (see Figure 3.3). Kashagan is the main factor returning Kazakhstan to a production and export growth trajectory from 2017, although after 2020 the key boost to growth will come from the launch of the Tengiz expansion project. The major uncertainties underlying IHS Markit projections are whether Kashagan’s phase 2 will go ahead, and whether a project to maintain liquids production at Karachaganak will come to fruition. Realizing the long-term potential of these major projects is in the interests of both the operators and the government of Kazakhstan, but doing so requires the introduction of prudent policies that stimulate further investment and allow for efficient operations. Importantly, the contracts for the three “mega” projects expire in 2033, 2037, and 2041, respectively, and contract extensions to provide sufficient payback periods or other contract adjustments may be examples of such prudent policy.
IHS Markit envisions that Kazakhstan could very well join the ranks of the top ten oil exporters by 2030, up from its current position in the top twenty. This forecast rests on a series of assumptions, including Kashagan phase 2 development and the application of new technology at brownfields. (Figure 3.6. and Figure 3.7). Thus, Kazakhstan’s future success as an oil exporter largely rests on its ability to create a competitive and attractive investment climate at home.

The “other offshore” category includes three types of offshore projects: (1) already-discovered fields within the North Caspian Operating Company license area (e.g., Kalmkas-More, Aktote, Kairan); movement on development of at least one of these other offshore fields has gotten under way, but obviously the timing and pace of development will be heavily influenced by larger Kashagan issues such as an extension of the production-sharing agreement; (2) joint 50:50 offshore projects between Russia and Kazakhstan (e.g., Tsentralnoye, Kurmangazy); and (3) other projects involving prospective offshore blocks, usually being pursued as JVs between KMG and international investors (e.g., Nursultan, Abay, Satpayev, Isatay).
Greater flexibility needed in cross-project operations to allow for facility sharing

Given the “lower for longer” outlook for global oil prices, and the intense competition for upstream investment globally, cost-cutting and efficient project execution now lie at the center of oil and gas companies’ strategies. Companies are moving in a variety of ways to reduce costs, including project redesign, opting for simpler and less expensive concepts, improvement of operational practices, such as optimizing well design and reducing the number of days to drill a well, and focusing more on the high-value end of their overall project portfolios. Cost-cutting is particularly important for new or “greenfield” projects, as these tend to have greater uncertainty and higher risks in execution.

Project redesign that allows for joint development and use of critical infrastructure across projects is an important mechanism to reduce costs, especially for smaller greenfield projects in a difficult operating environment, which would apply to the Kalamkas-More and Khazin offshore fields. The two license blocks are held respectively by the North Caspian Operating Company (NCOC) and Caspi Merseryt Operating Company (CMOC). Both of these projects also happen to be Production Sharing Agreements (PSAs).12

The cost-reductions achieved by co-development and joint use of infrastructure, such as pipelines, processing and storage facilities, could allow the development of these fields, both of which contain light, sweet crude, to become commercially viable, whereas under current economic conditions their separate development renders them uneconomic. However, Kazakhstan’s existing Subsoil Code does not allow for the joint-development of licensed assets and creation of common infrastructure. The challenge is exacerbated by the “ring fences” that define the scope of activities of both PSAs. But it appears that their PSA contracts do not contain terms that per se would prohibit outright the creation of such arrangements. There is considerable precedent for shared use of infrastructure between projects internationally. Shared use of infrastructure was a key enabling factor that allowed for the development of Qatar Petroleum’s (QP) LNG projects. QP’s subsidiary companies, Rasgas and Qatargas, entered into separate JVs with different IOCs that covered upstream production as well as liquefaction capacity. While the liquefaction plants are separate and operated by the individual JVs, storage, marine facilities, utilities, and offshore areas are shared by multiple JVs. Similarly, at the now-idle Egypt LNG (ELNG) facility, the ELNG consortium owns common facilities, while each liquefaction train is owned by a different holding company.

Beyond allowing shared use of infrastructure, governments are amending PSA terms to allow for commercialization of new, particularly high-risk projects. In 2011, the government of the Republic of Equatorial Guinea amended its contract with Ophir that incorporated previously unlicensed areas into Block R. This modification paved the way for Ophir to pursue further investment, as Block R is now slated to be feedgas for Fortuna FLNG, the first train of which is announced to come online in 2020. Thus, recognizing the complexity and expenses involved in offshore projects in the Caspian Sea, in order to improve investment attractiveness and spur hydrocarbon development, the government of Kazakhstan should follow the examples of other governments to modify their legal and tax regimes terms in order to secure rise of investment for exploration activity and get additional investment through joint development.

Key points of importance to policymakers concerning the oil production outlook for Kazakhstan include:

• The three mega projects will supply the bulk of Kazakhstan’s future oil production, so policy decisions should support activities that prolong stable (or rising) production at these projects.
• Kazakhstan should not disregard the potential of its mature fields. International experience shows that mature fields can be worked over much longer periods under smart policy regimes that support the introduction of appropriate technologies.
• Kazakhstan should invest in exploration to support replacement of reserves and future production.
• Any significant future development of offshore assets beyond Kashagan will be driven largely by investment conditions – simply, how does Kazakhstan compare with the investment climate in other parts of the world? The government of Kazakhstan should adopt appropriate policies that enable development of these fields.

3.2.4. Oil exports and transportation

Oil exports

Kazakhstan has always exported the bulk of its crude production (80% in 2016). Its total crude exports have increased from 20.3 MMt (425,000 b/d) in 1992 to 62.3 MMt (1.25 Mb/d) in 2016, a more than threefold increase (see Figure 3.8). In 2016, 61.5 MMt of the 62.3MMt exported reached international (non-CIS) markets. Historically, most of Kazakhstan’s crude has exited via Russia, and last year over 94% of Kazakhstan’s international crude exports still transited Russia by pipeline or rail (see Figure 3.9). This relationship remains very important to both Kazakhstan and Russia. Most of Kazakhstan’s pipeline exports via Russia move either through the CPC or via the Abyrua-Samara system operated by KTO and the Russian pipeline system operated by Transneft.13

Kazakhstan has embraced a “multi-vectoral strategy” for its oil exports, utilizing multiple routes going north, south, east, and west (See Figure 3.9).

The key export routes for Kazakhstan’s crude oil (and condensate) in 2016 are shown in Figure 3.10.
Kazakhstan–China Pipeline (KCP)
Shipsments of Kazakhstan crude to China via the KCP pipeline (i.e., the 963 km Atasu-Alashankou section) fell in 2015, to 4.4 MMt; in 2016, the decline in Kazakhstan exports to China accelerated, with volumes down 37.5% to 2.8 MMt. As in 2014, the bulk of KCP throughput in 2015–16 was considered Russian crude, delivered via a swap arrangement with Rosneft that began in January 2014: Russian crude delivered to the Kazakh border, recorded as “deliveries to Kazakhstan” before 2014 and supplied to the Caspian Pipeline Consortium (CPC)
Growth in Kazakhstan’s crude exports via the CPC pipeline over the past two years exceeded the total growth of export of oil out of the country, as exporters redirected significant volumes from other routes to fill expanding CPC capacity. CPC handled 68% of total Kazakh crude exports (up from 63%) in 2016. Altogether, Kazakh exports via CPC jumped 9% in 2016, to 42.4 MMt/y (891,000 b/d) from 39 MMt in 2015. 2017 exports are expected to reach ~55 MMt (see text box: CPC expansion).

CPC Expansion
Almost as soon as the CPC pipeline launched operations in 2001, discussions about its expansion also began. In December 2008 CPC shareholders agreed to expand the pipeline from the existing nameplate capacity at that time of 28 MMt/y (560,000 b/d) to 67 MMt/y (1.3 MMb/d) (although it could be expanded further to 76 MMt per year with drag-reducing agents, DRA). Construction on the expansion program began in July 2011, but it has proceeded more slowly than expected. Completion of the three-phase expansion project is now expected by the end of 2017.

The initial phase of the expansion focused on the overhaul of the existing CPC facilities, including rehabilitation of five existing pumping stations and re-placement of approximately 88 km of pipeline within Kazakhstan, as well as construction of the existing loading buoy at the Black Sea terminal of Yuriyeva Ozernevevka and three additional storage tanks with 100,000 cubic meters capacity each (from an initial four tanks). The second phase involved construction of five new pumping stations, and the third consisted of building five more new pumping stations and construction of three additional storage tanks of 100,000 cubic meters each (storage capacity at the tank farm at Yuriyeva Ozernevevka is to be expanded to 400,000 cubic meters to 1,000,000 cubic meters). The total cost of the expansion project is estimated at $5.4 billion.

Atyrau-Samara
Throughout the Atyrau-Samara pipeline rose in 2015 (up 1.9%, to 15.6 MMt [330,000 b/d]), owing in large part to increased crude compensation deliveries to Russia, but throughput declined in 2016 to 15.0 MMt (300,000 b/d). The Kazakh oil entering Atyrau-Samara and other Transneft pipelines remains destined for international markets access via Russia’s Baltic Ust-Luga export terminal or Novorossiysk.” In 2016 KTO began transporting Kashagan crude via the Atyrau-Samara oil pipeline section to Ust-Luga in October 2016. The initial shipments of Kashagan oil were transported via the Transneft system and mixed into Russian Urals Blend. However, from the start of 2017 Kashagan oil is transported in batches that preserve the quality of the crude. The crude is then added in the stream of low-sulfur Siberian Light crude to Novorossiysk.

It should be noted that Uzen-Atyrau-Samara pipeline is a “hot” trunk oil pipeline where the oil is heated along the entire length of the pipeline due to a significant amount of highly viscous (heavy) oil coming from the Mangistau Oblast. It is expected that after the flow through Kyzyl-Kenkiyak pipeline is reversed, the lighter oil that currently flows to Atyrau from Aktoke Oblast will be exported to China, and the quality of oil in the Uzen-Atyrau-Samara pipeline could deteriorate if a similar amount of similar crude is not injected from Atyrau-based production. Too much of a shift in composition to heavy crude could require the installation of additional oil heating facilities and some reconstruction of the existing pipeline. Also, a sizable variation in crude quality delivered to Samara would need to be settled with Russia.

Omzak-Pavlodar-Shymkent-Uzbekistan
On 23 March 2017, the Governments of Kazakhstan and Uzbekistan signed an agreement to use the existing Omzak-Pavlodar-Shymkent pipeline for exporting Russian and Kazakh oil to Uzbekistan. As a part of the agreement was signed by KMG and Uzbekneftegaz. The pipeline’s existing extension from Shymkent to Bukhara is currently in disrepair, and oil is planned to be transported from Shymkent to Uzbekistan by rail. According to Kazakhstan’s Minister of Energy, initial exports will be around 1 MMt (20,000 b/d) per year, with possible increases in volumes.}\n
\[18\] For more information on price dynamics at Alashankou, see NER 2015, chapter 7.2.
\[19\] State regulation does not apply to the oil export and transit tariffs.
\[20\] Shareholders in the BTC Pipeline Company are BP (30.1%), SOCAR (25%), Chevron (8.9%), Statoil (8.7%), TP (6.3%), Eni (5%), Total (5%), ITOCHU (3.4%), ConocoPhillips (2.5%), INPEX (2.5%), and DNV-GL Videsh Limited (2.36%).
\[21\] KCTS was initially conceived in 2007. The project would include construction of a pipeline from Eskeni in western Kazakhstan, the landing point for Kashagan volumes, to a new port at Kuryk on the Caspian coast. By 2012–13 the pipeline had not been completed, and in August 2014, KMG announced that KCTS would be delayed until 2018–19 as there was no need for an additional 25 MMt per year (500,000 b/d) of export capacity given the delay in the second phase of the Kashagan project.

\[22\] The pipeline’s connection at Samara allows Kazakh exports to reach any of the western export points served by the Transneft pipeline system. Over the years, Kazakh crude has been exported via marine terminals on the Black Sea, but especially Novorossiysk, via the Druzhba pipeline to Eastern Europe, and via marine terminals on the Baltic Sea.

\[23\] For more information on price dynamics at Alashankou, see NER 2015, chapter 7.2.

**Figure 3.10. Distribution of Kazakhstan’s crude oil exports by route, 2016**

- CPC
- Atyrau-Samara
- Aktobe-Manychakab
- China (excluding Russian transit)
- Kazakhstan (Russia, Black Sea, BTC)
- Atyrau to Azerbaijan, Georgia
- Russia (to Dnerberg)
3.2.5. Regulation of pipeline transportation tariffs

Amendments introduced to Kazakhstan’s Law “On Natural Monopolies and Regulated Markets” in May 2015 excluded services for oil transportation for transit through Kazakhstan and for export from Kazakhstan from the regulatory sphere of natural monopolies, meaning that these tariffs are determined by KTO independently. The oil transportation tariff for domestic shipments is still regulated by the Committee for Regulation of Natural Monopolies and Protection of Competition (KREMIZK). Export volumes to which the export tariff applies provide the bulk of KTO’s revenues. The decision to let KTO determine its tariffs comes amid strong competition from CPC for export volumes. In response, KTO is working to improve efficiency, competitiveness, and quality of its service. In 2016, KTO transported 43.8 MMt of crude (including 7 MMt of Russian transit crude); the company transports around 47% of Kazakh crude (excluding Russian transit volumes).

For the domestic market, tariffs are calculated on a “cost-plus basis,” where the tariff covers the costs of operating the pipelines and a small profit margin to ensure sufficient revenues for business functions. The regulator (KREMIZK) sets tariff ceilings. The methodology for calculating the domestic crude tariff via trunk pipelines is also approved by KREMIZK, with the current methodology approved in 2014. Tariffs are calculated for the transit of 1 ton of oil per 1000 km. The most recent ceiling levels for domestic tariffs were approved in 2015 for the period of 2015–19. This general approach to tariff-setting has generally provided a fairly stable and transparent structure for many years.

Tariffs for oil pipelines operated by joint-ventures (such as Atasu-Alashankou, Kenkiyak-Atyrau) have their own individual tariffs that are regulated by KREMIZK, although the Ministry of Energy also participates in special circumstances, as with the transit tariff for Russian crude going to China. The tariff for CPC is determined by a separate mechanism, set internally by the consortium as a part of its overall operating agreement. To attract more oil transit volumes from Russia to China, a unit tariff was established in September 2012, covering the entire route from the Russian border to the Chinese crossing point, which included crude traveling through KTO pipelines and the 3V pipeline section. Although initially established in tenge per ton (1,499.15 tenge per ton), it was changed to be paid in dollars in November 2014 (retractively applying to shipments back to January 2014), effectively raising the tariff for Russian shippers because of the devaluation of the tenge. The latest tariff on the route was approved by the Ministry of Energy on 1 March 2017 for the period 2017–18 at $11.36 per metric ton, raising the tariff for Russian crude going to China. The tariff for Russian crude going to China is determined by a separate mechanism, set internally by the consortium as a part of its overall operating agreement.

Out to 2040, Kazakhstan’s crude exports are expected to grow, driven by rising crude output and only modest domestic oil consumption growth. The IHS Markit base case scenario projects Kazakhstan’s crude exports to expand to 112 MMt (2.2 MMb/d) by 2030 and reach 129 MMt (2.6 MMb/d) by 2040 (see Figure 3.11). Exports via the CPC, Kazakhstan-China, and BTC pipelines are expected to increase the most, while exports via Russia’s Transneft system are expected to increase more slowly.

3.2.6. Oil export outlook

Out to 2040, Kazakhstan’s crude exports are expected to grow, driven by rising crude output and only modest domestic oil consumption growth. The IHS Markit base case scenario projects Kazakhstan’s crude exports to expand to 112 MMt (2.2 MMb/d) by 2030 and reach 129 MMt (2.6 MMb/d) by 2040 (see Figure 3.11). Exports via the CPC, Kazakhstan-China, and BTC pipelines are expected to increase the most, while exports via Russia’s Transneft system are expected to increase more slowly.

3.2.7. Global oil market developments and trends

A key strategic consideration for Kazakhstan with respect to longer term oil exports is the changing geography of global oil demand, particularly in regional markets that it has either historically supplied (Europe) or in which it is establishing a strong position (China). In Europe, the traditional market for Kazakhstan’s crude oil, receiving 78% of its non-CIS crude oil exports in recent years, long-term oil demand is expected to slowly decline (see Figure 3.12). Due to a combination of factors—slower economic growth, decarbonization and energy efficiency policies, technological advancements in the transportation sector, social change, and economic restructuring—oil product demand growth has become almost negligible in recent years. European refined product demand is expected to gradually contract longer term, at an annual rate of around 0.4% through 2040, with product imports also declining (see Figure 3.13). Long-haul product imports, from Russia, the Middle East, and North America, among others, have been playing an increasingly important role in satisfying European product demand, but this is expected to ebb and give way to a growing share from indigenous refining. Prior to 2014, European refining activity was on a downward decline, as product imports increased. Since 2014, however, refining activity has rebounded: total crude and condensate runs reached 12.6 MMb/d (625 MMT) in 2016, compared to 11.95 MMb/d (595 MMT) in 2014. Longer term, IHS Markit expects demand for crude oil, and indigenous crude oil production, in Europe to slowly decline (see Figure 3.12). With falling European crude production, and a slower drop in crude demand (-0.6% per year on average to 2040), the European market is expected to remain relatively open to Kazakhstan’s crude exports over the forecast period, for at least some incremental volumes.
China, along with India and the United States, is considered one of the key pillars of demand growth for liquids worldwide, and it will accordingly remain an important crude export market for Kazakhstan. As China’s economy matures, oil demand growth will slow of course. Growth in the transportation sector will ultimately decelerate due to the penetration of alternative fuels and vehicle powertrains, while demand in petrochemical production will likely remain resilient. As a result, in China, crude demand is projected to continue to increase: on average by 0.75% per year out to 2020, while its own indigenous production is expected to decline by about 1.2% per year on average. Therefore, China’s crude oil imports will rise substantially over the forecast period (by 1.1% per year) (see Figure 3.14). At present, Kazakhstan is not exporting large volumes of its crude to China (only 2.8 MMb/d in 2016). However, longer term, exports to China are expected to rise substantially. IHS Markit expects crude deliveries through the Kazakhstan-China pipeline to reach 15 MMb/d (301,000 b/d) by 2020, and more than double to 34 MMb/d (683,000 b/d) by 2040 (see Figure 3.11).

3.3. UPSTREAM EXPLORATION AND TECHNOLOGIES

3.3.1. Exploration Activity in Decline

One of the key challenges facing Kazakhstan’s oil industry is the lack of growth in the reserve base, particularly new discoveries. Recent years have seen a significant decline in the exploration activity/success rates both in the Precaspian Basin and across Kazakhstan in general, and both by KMG and by international companies. There have not been many recent discoveries despite the country’s apparent large potential. Not only did exploration spending and drilling reach a low point in 2016 (see below), but so did exploration results: the annual addition to oil reserves dropped to only 22% of annual production last year (i.e., about 17 MMb). Another indicator of this lack of success in discovering new fields is that the number of oil producers has stagnated as fewer and fewer new entrants are being attracted to Kazakhstan: listed oil producers numbered 90 in 2016 compared to 89 in 2015 and 87 in 2014. In contrast, the listed number of producers was only 45 in 2005 and 81 in 2010. More specifically, in the “post-Kashagan” era—i.e., since the Kashagan consortium completed its extremely successful offshore exploration program in 2003—exploration results in Kazakhstan have been quite modest. The few significant discoveries made during the period include Truva North (oil: 500 MMb [68.5 MM]), Ansaagan (gas: 17.5 Bcm), Rokhazhakey (gas: 17 Bcm), and Rovnoye (oil: 112 MMb [41 MM] and gas: 80 Bcm). Continued offshore Caspian exploration has yielded many unsuccessful wells (e.g., Kurmangazy, Tyub-Karagan, Atash), while a few discoveries made (Zhambyl, Pearls Group, and Block N) have uncertain commerciality in the present economic environment.

Even so, all of these discoveries have been made by foreign investors, while the national oil company's own exploration program has not produced the desired results. KMG has managed to add only a few additional discoveries in the Precaspian Basin to the state balance, while its ambition to drill deeper, targeting pre-salt plays, has not yet borne any fruit. Several deep wells have turned out to be dry (e.g., in the Zharkamys East and Karatob-Sanyakmys blocks), some have never been completed due to technical problems (e.g., the Devonian play at Unikhatu), and some blocks were relinquished even before a well was drilled (9-R and Temir). There are several reasons for this lack of success. The geological reasons include the well-known difficulty of exploring the Precaspian, the country’s most prospective basin: deep reservoirs under a thick salt layer, overpressure, unpredictable reservoir quality of the pre-salt carbonate plays, and the presence of sour gas. Exploring this basin requires relatively sophisticated drilling technologies, is costly, and involves high risk. However, more important to the decline in exploration activity/success rates has been such problems as underinvestment in exploration more generally, with relatively low levels of external investment due to a combination of above-ground factors, including relatively unfavorable legislation. In the legislative and commercial arenas they include:

The Project Eurasia initiative seeks to partly address these challenges, including great depth, reservoir quality risk, overpressure, and presence of sour gas, all of which complicate development and increase costs. The Project Eurasia initiative was officially launched to address the issue of the Precaspian’s remaining potential. The initiative was approved by Kazakhstan’s government and was officially launched

3.3.1.1. Hydrocarbon Prospectivity in the Precaspian Basin: Project Eurasia

The Precaspian Basin remains the country’s main prospective area for conventional petroleum resources. According to Kazakh estimates, the basin holds around 80% of the country’s undiscovered resources with the basin’s pre-salt section holding the most promise. It is believed that its pre-salt carbonate platforms play still holds significant potential for large to medium-sized discoveries. However, the presalt exploration has significant operational challenges, including great depth, reservoir quality risk, overpressure, and presence of sour gas, all of which complicate development and increase costs. The Project Eurasia initiative was officially launched to address the issue of the Precaspian’s remaining potential. The initiative was approved by Kazakhstan’s government and was officially launched

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11 A significant decline in the exploration activity/success rates in Kazakhstan was identified as one of the primary shortcomings in the IHS Markit’s proprietary PEPS investment attractiveness index discussed in Chapter 2 (“upstream activity” and “upstream success” variables). A recent example is the buyback by KMG EP of a 49% share of the 167.9 km² Kazovskiy Severnyiy block in July 2017 from Hungary’s MOL for a nominal $1. The shares in the block, which is located northwest of Uralsk near the Russian border, had been acquired by MOL from KMG EP in 2012. However, with no commercial discovery, MOL decided to sell the asset. But when no buyers emerged, KMG EP took it back.

12 For example, the availability of a suitable rig to drill in super-shallow waters forced the LUKOIL-Repsol consortium to relinquish the Zhambyl block before even completing a well. The first Kazakhstan-built jack-up rig was operational only in 2017. There is also the Caspian Explorer semi-submersible rig.
by the Kazakh and Russian presidents in October 2014. The project seeks to identify the Precaspian Basin’s deep potential in the Kazakh and Russian sectors by drilling an exploration well up to 15 km deep. The project is expected to run through 2020 at an estimated cost of $500 million. It will be implemented by a consortium of Kazakhstan and international companies, which is in the process of negotiation for being formed. The start of the project was originally scheduled for 2016. The Energy Ministry held the first round table meeting about legal and contractual aspects of the Eurasia consortium project with Eni, Rosneft, CNPC, SOCAR, and NEOS GeoSolutions in February 2017, with a memorandum of understanding being signed in June 2017. The project would comprise three stages, the first being collection and processing of existing data. A second stage should acquire a series of regional seismic lines. Stage three would drill a new deep reference/stratigraphic test well. The president of the Association of Petroleum Geologists of Kazakhstan, Dr. B. Kuandykov, who also serves as the project coordinator, estimates the basin’s deep potential to be around 40 billion tons of oil equivalent in up to 20 fields.

3.3.2 Kazakhstara’s oil services and drilling trends

Service activities in Kazakhstan have grown steadily to address increasingly challenging local technical issues. In particular, drilling is a key segment of the services industry—along with associated construction and equipment. Drilling is an input into upstream production, and while it is important to reflect on the relative level of effort (the amount of inputs into the process), this does not always translate directly into actual results. Kazakhstan’s service sector is relatively small, but is growing steadily both financially and physically. Since 2000, fixed investment into Kazakhstan’s petroleum extraction (a rough proxy for upstream expenditures for services) reached a high (so far) of $8.6 billion in 2010, but fell to $5.3 billion in 2016 (see Figure 3.15).23 Compared to Russia, Kazakhstan’s market for upstream services is much smaller: investment in Russia’s upstream oil sector amounted to about $28.1 billion in 2016. Similarly, Russia’s oil-related drilling, at 25.6 million meters in 2016, was nearly 23 times as much as in Kazakhstan, with only 1.1 million meters.

Total drilling activity in Kazakhstan recovered rapidly after the 2009 recession, reaching about 2.5 million meters in 2014, which is more than double the 2009 result (1.2 million meters), but drilling has contracted sharply since in 2015–16 (see Figure 3.16). Exploratory drilling has contracted the most, falling to only about 16% of total drilling activity. Consequently, Kazakhstan’s operating well count initially grew somewhat after 2010, but has remained fairly steady at about 21,500 wells in the last few years (see Figure 3.17).

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23 Fixed capital investment by a firm is defined as 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.
One approach for evaluating the level of exploration spending in Kazakhstan is to look at the ratio of exploration spending to production of the so-called Global Integrateds—a group of international majors that includes BP, Chevron, ExxonMobil, Shell, and Total—as well as Eni and Statoil—since 2000. The key trends are:

- Total combined exploration expenditures of these majors between 2000 and 2013 globally increased at an average annual rate of 11.9%, rising from $6.8 billion to a peak of $29.4 billion (in nominal dollars) (see Figure 3.18). Total expenditures then plummeted, reflecting the weak oil price environment and the general cutback worldwide in upstream spending, falling to just $11.8 billion for exploration in 2016. In 2016, annual exploration spending by the individual companies varied between $0.7 billion (for Eni) and $3.6 billion (for Royal Dutch Shell).
- But at the same time, aggregate production of hydrocarbons globally for these companies as a group, our size scalar, varied between 18.3 million barrels of oil equivalent (MMboe/d) and 20.2 MMboe/d, averaging 19.2 MMboe/d over this period (see Figure 3.19).

Therefore, scaling the companies’ exploration spending by the amount of hydrocarbon production, the spend of these companies on exploration globally increased from $1,024 per thousand boe (Mboe) produced in 2000 to a peak of $4,282 per Mboe in 2013 (and a low point of $860 per Mboe in 2003), but then declined to $1,640 per Mboe in 2016 (see Figure 3.20). The average over the period was $2,161 per Mboe. In comparison, in 2016 KMG EP spent about 5 billion tenge ($15 million at the average annual exchange rate) on exploration in its core assets, which had a production last year of about 64.4 MMboe, so the ratio for the company is about $233 per Mboe, a level substantially lower than that of most international companies. There are two ways to look at Kazakhstan’s exploration needs as a whole. One is to apply the 2016 international ratio, of $1,640 per Mboe, to Kazakhstan’s hydrocarbon production of 745.9 MMboe, which means that the country would need to be spending about $1.2 billion per year on hydrocarbon exploration to be spending on par with the large international E&P companies. The second way is to apply the average ratio for the period, of $2,161 per Mboe, which means that Kazakhstan would need to spend about $1.6 billion per year on hydrocarbon exploration to match the effort of international companies. Both calculations arrive at very similar results.

3.3.3. Upstream technologies: general digitalization, smart wells, horizontal drilling, multi-stage hydraulic fracturing

Because oil and gas production is among the most capital and technical intensive of all industries, technological innovation is critical to supporting the discovery of economically viable new reserves and improving the efficiency of resource extraction. For example at older existing fields, international experience indicates that decline can be stemmed (and in some cases even reversed!) by a combination of improved, fairly simple production methods and innovative exploration techniques, with striking results. Additionally, effective use of 3D or even 4D seismic surveys can significantly expand the reserve base to which the more advanced production methods can be applied. Major new technologies involved in the exploration, development, and production of oil and gas deposits include general digitalization, smart wells, horizontal drilling, multi-stage hydraulic fracturing, seismic, basic reservoir modeling, and careful placement of new wells to boost oil production and limit water extraction.

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\[\text{Kazakhstan’s mature fields currently appear to be producing at rates below their ultimate potential. The average recovery rate is below 25%, whereas geological experts estimate that recovery rates could reach 30–40% after some basic modifications.}\]
These same techniques have also been success-
fully applied to achieve performance maximiza-
tion at new greenfield acreages as well.

IHS Markit’s Upstream Costs and Technology Ser-
vice researches technology developments by E&P
organizations worldwide to understand chang-
ing technology priorities as well as to gain early
insights into broader industry strategy develop-
ments. E&P organizations include: commercial
and state oil producers; oilfield services (OFS)
 firms; engineering, procurement, and construction
(EPC) firms; universities; as well as independent
research organizations. IHS Markit conducted
the first inventory in 2012–13 by surveying 45 E&P or-
ganizations. This approach has some limitations,
including a bias towards organizations that are
more publication-prone; lack of coverage of sectors
supplemental to E&P such as IT or automation and
control technologies; and lack of direct correlation
with budget or staff allocations by E&P organiza-
tions. However, the size and diversity of the survey
helps to overcome these limitations to accurately
reflect industry focus areas and trends.

IHS Markit has structured the results of its analysis
in the form of an IHS Markit E&P Technology Clas-
sification Schema that details technology develop-
ment under five major focus areas (see Table 3.3).
The change in upstream technology development
focus areas between the surveys conducted in
2012–13 and in 2014–15 reflects the upstream in-
dustry’s shift from growth to retrenchment in re-
response to the oil price downturn, as E&P organiza-
tions moved away from long-term capital-intensive
projects with uncertain outcomes to focus on tech-
nologies that rapidly deliver cost-effective short-
term value and scale.

Specifically, in the low oil price environment com-
panies reduced their emphasis on all aspects of
well construction and intervention technologies
(e.g., drilling, completion, reservoir stimulation).
Drastic cuts in exploration activity likely contrib-
uted to the reduced focus on seismic acquisition
technology, while investment continues to grow in
seismic processing and interpretation technologies
that can be applied to legacy seismic surveys in a
cost-effective manner.

As companies emphasize efficiency to help manage
capital and operating costs, as well as to protect-
base production levels, they have promoted digi-
tal and automation technologies, including oilfield
mobility and connectivity technologies, robots and
drones, and the installation of automated sensors
and data-collection that allow for real-time data
analytics and potentially, artificial intelligence (see
also Chapter 2.2 on global investment trends). An-
other emphasis is on short-term, incremental fa-
cilities technology development, including electri-
fication and dual-fuel engines to increase energy
efficiency, advanced materials and miniaturization
to reduce facility weight, and smart coatings and
flow assurance to reduce maintenance.

The industry appears to be prioritizing increas-
ing recovery from existing reservoirs, so recovery
technologies such as IOR/EOR (e.g., waterflood-

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### Table 3.3. IHS Markit technology classification scheme

<table>
<thead>
<tr>
<th>Focus Area</th>
<th>Technologies</th>
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<tbody>
<tr>
<td>1. Seismic Processing &amp; Imaging</td>
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<tr>
<td>2. Well Construction &amp; Intervention</td>
<td></td>
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<tr>
<td>3. Facilities &amp; Subsea</td>
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<tr>
<td>4. Recovery</td>
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<tr>
<td>5. Digital</td>
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1.1 Seismic Acquisition Technologies & Methods (wireline, 3D, 4D)
1.2 Seismic Processing & Interpretation (improved seismic imaging)
1.3 Micro-seismic
1.4 Non-Seismic Remote Sensing Methods (LiDAR, thermal imaging, etc.)
1.5 Time-lapse Methods (seismic and non-seismic)
1.6 Wireline Telemetry & Tools (e.g., resistivity, NMR)
1.7 Rock property & Rock Correlation Tools (non-wireline)
1.8 Basin & Play Insight Tools

2.1 Bit Technology (drilling)
2.2 Drilling & Workover Fluids (e.g., drilling mud, welldrilling fluids)
2.3 Completion Technologies (compositional, multi-physics, intelligent completions)
2.4 Coiled Tubing (drilling, intervention, well clean up, stimulation)
2.5 Drilling & Workover Fluids (e.g., drilling mud, welldrilling fluids)
2.6 Reservoir Stimulation (hydraulic fracturing, chemical treatments, hyper-completions)

3.1 Subsea Processing (gas, gas condensate, reservoir fluids)
3.2 Subsea Power (generation, battery technology)
3.3 Extreme Environment Equipment (temperature, corrosive fluids, etc.)
3.4 Processing Technology (heavy oil upgrading, etc.)
3.5 Flow Assurance
3.6 Water Handling
3.7 Gas Monitization Methods (pigging, CNG, etc.)
3.8 Carbon Capture Storage and Use (CCUS)
3.9 Spill Response (dispersants, micro-plastics)
3.10 Maintenance & Inspection

4.1 Artificial Lift (Subsea boosting, pump technologies, gas lift, compression, etc.)
4.2 Water Flooding
4.3 Gas and Miscible Chemical Flooding Methods
4.4 Miscible Flooding Methods (gas, gas cycling, polymer, solvent, nitrogen, CO2, surfactant, etc.)
4.5 Thermal Methods (steam flooding, cyclic steam, TALF, combustion, SAGD, and its derivatives)
4.6 In-situ & Wellbore Processing & Upgrading (microfluidic methods, downhole separation, etc.)
4.7 Tracers (chemical tracers, radiology, etc.)
4.8 Methane Hydrate Production Mechanisms

5.1 Digital Oil Field of the Future (reservoir management optimization, production optimization, surface facilities optimization, etc.)
5.2 Integrated Characterization & Simulation (reservoir, process, etc.)
5.3 Big Data & Analytics (pilotization of drilling, workover, subsea, etc.)
5.4 Standard Application & Data Platforms
5.5 Sensors (fiber, PT, etc.)
In order to help Kazakhstan focus its research and development (R&D) efforts and to contribute to the government’s innovation agenda, Shell in collaboration with more than 300 representatives across the entire oil and gas industry (including both operators and R&D personnel), undertook the Kazakhstan Upstream Oil and Gas Technology Roadmap project between 2010 and 2013. The project’s goal was to provide a coherent picture of the most urgent challenges facing Kazakhstan’s upstream oil and gas in order to assign priorities for high-level decision making. Through the workshops, interviews, and expert panels, the project identified, screened, and ranked major technology challenges and proposed solutions. The project’s first phase resulted in the formulation of 15 prime challenges in five technology target areas, as well as 50 main solutions, all presented in May 2011. These five target areas are described below:

**The reservoir characterization area** includes the challenges of: (1.1) seismic data acquisition; (1.2) reservoir description—geology, rock, and fluid interpretation; (1.3) well logging and in-well monitoring; (1.4) core analysis and data interpretation; and (1.5) fluid property analysis.

Kazakhstan was found to have moderate overall capability in this target area, with strong geological knowledge, good subsurface modeling capabilities, and developing capabilities in core and fluid analysis. In contrast, there is little R&D focus on seismic data acquisition and some lack of awareness of issues surrounding the handling of high-H,S streams.

**Field equipment** encompasses the challenges of: (2.1) corrosion plus equipment and materials for sour service; (2.2) operating in the offshore ice and during cold weather; and (2.3) management of sulfur. Here the Roadmap survey determined that Kazakhstan is reasonably well situated. There are good capabilities in sulfur management and ice operations, and high quality field engineering design services. However, work on equipment and materials for sour service was found to be lacking in focus in the upstream area.

**Fluid flow and processing** comprises the challenges of: (3.1) flow assurance and sand control; and (3.2) water management. The assessment exercise highlighted technical weaknesses in this area in the upstream but noted much stronger flow assurance and water treatment capabilities downstream.

**Wells and field management** consists of the challenges of: (4.1) drilling and well costs; and (4.2) field management: optimized recovery including IOR/EOR (improved oil recovery/enhanced oil recovery). The roadmap assessment found capabilities in this area to be patchy. Institutions/laboratories were found to be generally weak, but some excelled in particular areas (e.g., drilling-fluid testing, use of waterflooding and EOR techniques to optimize recovery, dynamic modeling).

**HSE and operations** incorporates the challenges of: (5.1) emergency response and disaster recovery; (5.2) operational HSE (health, safety, environment) risk reduction under sour production conditions; and (5.3) environmental impact. The roadmap assessment found that little work was being done in the area of emergency response and disaster recovery or in operational risk reduction in sour conditions. In contrast, several institutions/laboratories were undertaking good work on environmental impact and are in a position to offer competitive impact assessment services.

During the second phase of the Roadmap Project, the detailed analysis of the first stage results was complemented by a technology readiness study that assessed the feasibility of the solutions’ implementation in Kazakhstan. In addition, experts assessed Kazakhstan’s research and development capabilities by visiting universities and research companies.

During the third phase, a workshop in June 2012 resulted in development of an outlook for the industry taking into account findings from the first two phases. Also, experts identified enablers (examples of best practices) by reviewing policy measures taken in Norway, Brazil, China, and Malaysia.

The fourth phase resulted in shaping the roadmap and formulating compelling recommendations for decision-makers in Kazakhstan with the help of consultants from the University of Cambridge. At this stage, all the challenges were ranked by technology experts in accordance with their potential, if addressed, to provide the maximum financial benefit (i.e., reduce costs and increase production), as well as to reduce risk and promote safety. Specifically, improved and enhanced oil recovery (challenge 4.2), equipment and materials for sour service (2.1), drilling and well costs (4.1), and water management (3.2) were judged to be the most pressing challenges, each yielding potential savings in excess of $5 billion. These were followed by ice/cold weather operations (2.2), health and safety risk reduction in sour conditions (5.2), and management of sulfur (2.3) each yielding potential savings in the $3–$4 billion range. The total value of successfully responding to all 15 challenges would be in the tens of billions of dollars. But what is also evident from the Roadmap’s analyses of specific measures designed to address these challenges is that their implementation will be proportionately expensive.

Then the experts identified over 230 solutions, which were consequently bundled into a group of 75 solutions. These were ranked based on the cost and time required for implementation, opportunities to promote local content and local research and development, and the personnel qualifications required. Specifically, in terms of local content, the project identified that the most realistic opportunities are in the areas of steel and concrete structural design and fabrication, the provision of upstream chemicals, and well sand-screen manufacturing. In addition, the manufacture of corrosion-resistant alloys, the provision of special core analysis services, jack-up rigs for cold climates, ice-scouring design, as well as sulfur storage, transport, and products were identified as areas with further opportunities.

Finally, solutions were categorized depending on how these could be obtained under three scenarios: simply transferred to Kazakhstan, transferred to Kazakhstan but requiring significant adaptation, and would need to be invented.

Kazakhstan’s upstream industry participants highlighted several specific technologies, the implementation of which would seem to be readily achievable in a relatively short period of time. The correct...
application of these technologies could solve issues that are considered to be “low hanging fruit”. These include:

Data automation and digitization solutions. Installation of sensors on valves and pumps, and well-log digitization allow for the real-time collection of information on temperature, pressure, and flow analysis. Interpreted data, collected from smart-field technologies, can assist subsoil users to preemptively anticipate and avoid operational complications, improve HSE conditions, eliminate non-productive time, and identify potential new areas for drilling. Data automation and digitization solutions can also assist in reservoir visualization, monitoring, and analysis; well performance monitoring and evaluation; artificial lift optimization; wildfire management; well log data; seismic modeling; and asset integrity management systems. More accurate data will lead to more effective operations and more efficient use of critical resources, such as water. Though, it is important to add that any move to digitize data must be complemented with personnel training so that the data is accurately interpreted.

Pipe leak detection systems. Leaks in oil pipelines both at the surface and downhole are a major issue for Kazakhstan’s oil sector. Installing leak detection systems (so-called “internal” detection methods, also known as computational pipeline monitoring systems) would reduce losses and improve operational efficiency. Such systems use fast-scan sensors to monitor pressure, flow, and temperature, and identify tell-tale indicators of leaks. Another promising approach is the use of fiber optic cable sensors in oil and gas pipelines.

The installation of distributed temperature and pressure sensors over completion intervals could help monitor inflows, and passive gauge data could assist in determining optimal flow rates, and identifying mechanical problems.

Corrosion management systems. Such systems are identified as particularly relevant at such major fields as Tengiz and Kashagan due to these fields’ extreme weather, high pressure, and elevated levels of hydrogen sulfide and carbon dioxide. New and developing anti-corrosion technologies are now available that are less expensive than corrosion-resistant alloys currently utilized, and could be applied in Kazakhstan. For example, Mesocoat, a subsidiary of US-based Abakan, Inc. that focuses on subsurface engineering solutions, has designed a CermaClad high-speed technology that uses a high intensity light source to fuse anti-corrosion materials to large swaths of steel. Application of this innovation to the pipe-cladding manufacturing process could potentially provide a solution to the problem of providing more affordable, corrosion-resistant pipes in Kazakhstan.

For offshore operations, remote assistance technologies, such as Hitachi’s ASSIST, allow workers to remotely intervene with a rig or in the field to transmit information to a central office via live video streaming, and vice versa. Such a technology could prove useful in situations in which rapid decision-making is essential, should unusual circumstances arise. These remote communications systems would be particularly important in shared facilities, if co-development of offshore assets proceeds. Moreover, communications interoperability platforms, such as those operated by Motorola Solutions, could be very helpful for KMG to better coordinate messaging, information flow and instructions between headquarters in Astana and field leadership, as well as in training workers and contractors in the field.

Passive monitoring of producing oil fields is not conceptually a new technology, but is a relatively new and emerging analytical practice in E&P, specifically reservoir management. The driving concept behind the technology is that a reservoir is not static, and oil recovery, over time, affects the host rocks. Understanding of reservoir potential can thus be enhanced in real time by passively monitoring the host rock using a variety of technologies that do not activate a seismic source, but rather use already in-place sensors (geophones) to track subsurface changes. Passive seismic monitoring is often used to track, evaluate, and mitigate earthquake risk, reservoir deformation, and fluid leakage, as well as to optimize operations at an existing project. While passive seismic monitoring is not widely practiced as part of standard reservoir management, its use could proliferate in the future as the methodology is refined and the data retrieved from such operations support additional applications. Over the long term in Kazakhstan, such technology and analytical methods, when accurately applied in the appropriate context, could potentially discover new reserves in already producing assets and better manage existing reserves.

Regardless of the type of equipment, technology is only a tool, and it is the correct application of the tool that renders it effective. Policymakers and energy executives in Kazakhstan must keep in mind that importing technology goes hand in hand with the correct application of the technology. Recognizing the acute global competition for investments in the oil and gas sector, the government of Kazakhstan has initiated a legislative review of both the Tax and Subsoil Use codes (see below). This review provides an opportunity to create a healthy environment for investment and effective resource development and to set up a more attractive long-term, stable investment framework. We encourage the government of Kazakhstan to take bold steps in this direction in the interests of long-term development of the national oil and gas industry.

### 3.4.1. Subsoil Regulation

In addition to low exploration rates, another challenge of the Kazakhstan’s oil sector is finding the right combination of subsoil and tax regulation to ensure continued success of the industry. The National Energy Report 2015 detailed the development and current situation in the subsoil and tax codes as they relate to the oil and gas industry, highlighting achievements and downsides of Kazakhstan’s current tax and subsoil codes.

Financial aspects of the oil and gas industry are primarily governed by the Tax Code, which establishes the rules of subsurface use taxation, and the Subsoil Use Law, which contains the basic legal framework for granting, using, and assigning or terminating rights to a subsurface user as well as for subsoil transactions.11 Recognizing the importance of investment in the oil and gas sector, the government of Kazakhstan has initiated a legislative review of both the Tax and Subsoil Use codes (see below). This review provides an opportunity to create a healthy environment for investment and effective resource development and to set up a more attractive long-term, stable investment framework. We encourage the government of Kazakhstan to take bold steps in this direction in the interests of long-term development of the national oil and gas industry.

11 That is, Law No. 293-IV of the Republic of Kazakhstan on Subsurface and Subsurface Use, dated 24 June 2010; and Law No. 2385 of the Republic of Kazakhstan on Petroleum (of 28 June 1995), which had been in force previously, was superseded.

### 3.4.1.1. Tax Code

Kazakhstan’s Tax Code (introduced in January 2009) employs multiple tax instruments as opposed to only one or two; it also specifies levies on both sales and profits. This combination has the potential to provide a greater balance of interests between producers and the government over the life of a project. The introduction of Kazakhstan’s Tax Code was a major step toward establishing a clearer framework for taxation of the energy sector, leading to greater certainty and transparency in Kazakhstan’s taxation structure, although the timing was unfortunate, as it was introduced during the great global recession and financial crisis, when global oil prices fell from highs of about $130 per barrel in mid-2008 to only about $40 per barrel in early 2009.

Kazakhstan has generally been cautious to substantially amend the Tax Code. Nonetheless, there are a number of problematic components in Kazakhstan’s existing tax regime, and tax reform must occur in order to reinforce the changes made in the proposed Subsoil Code. Chief among them are the relatively high total tax take compared to international experience, and the especially high upfront take by the government. This means that the tax burden is not proportional to the risks born by the investor, particularly at different stages of the project cycle. Also the Tax Code does not fully encourage the adoption of new technologies to arrest declines at mature fields. Finally, the current Tax Code lacks a stable long-term contractual framework for large, high-risk projects with long gestation periods for investment, such as for offshore blocks.

Kazakhstan’s oil sector policy has moved in a positive direction overall in the wake of the recent world oil price collapse beginning in 2014, with one important consequence so far being reform of the crude export duty regime. Kazakhstan introduced a new crude export duty formula, effective 1 March 2016, based on a sliding-scale tax structure, with duty rates on crude oil exports linked to the average price of Urals and Brent blends during a monthly monitoring period—resulting in an initial export tax rate under the new fiscal system of $40 per ton. The export duty is imposed when crude oil prices are above $25/bbl, with duty rates rising faster when the price is above $105/bbl. In practice, the new formula did not lead to any immediate change in duty rates on crude oil— as the government’s crude oil export duty was already $90/ton; after it lowered the rate from $60/ton on 1 January 2016. The export tax policy shift is nevertheless a welcome change for oil companies operating in Kazakhstan. Previously, the government had taken an ad hoc approach to making adjustments to the tariff level. The new formula makes government oil export tax policy more transparent and predictable. A significant increase in investments is one of the key indicators of future oil production levels. Given that investment decisions are largely based on economics and profitability, government policy has
a direct impact on the development of the sector. Until now, Kazakhstan’s approach to recognizing and rewarding initiatives on investments in marginal or mature fields has been somewhat lacking. Still, the Tax Code allows the government to administratively lower the Mineral Resources Extraction Tax (MRET) for selected high-cost or “hard-to-recover” fields or projects on a case-by-case basis. Initially, applications for relief were accepted only from companies wherein, and was demonstrated unprofitable. A special commission exists to review each individual application. For example, the Karazhanbas field (in Mangistau Oblast) was reclassified as a low-profitable, high water-cut, marginal, and worked-out field. Under a resolution of the Government of the Republic of Kazakhstan (18 June 2014), the MRET for the field was set at only 0.5%.26

In another resolution, approved as of March 2016, UzenMunayGaz again submitted a request for the inclusion of its Uzen and Karamandybas fields (in Mangistau Oblast) in the category of unprofitable or low-profitability fields that are eligible for MRET relief. In September, the government granted tax breaks for both fields, reducing the MRET from the 2015 rate of 13% to 9% for all of 2016, on the condition that the fields turn out to be unprofitable.27

The new Subsoil Law (discussed below) proposes to establish norms that would automatically qualify a field as unprofitable without having to go through the existing bureaucratic procedure. These norms would be a part of a coordinated framework involving both the Subsoil and the new Tax Code. The purpose of these proposals will result in an initial revenue loss for the budget, but would ultimately stimulate subsoil users to marginal or mature and hard-to-work fields around in increase or maintain production, thereby broadening the oil production tax base. To incentivize production at mature fields, norms that create a threshold for profitability might need to be modified further, to ensure a certain level of profitability for the investor. In line with President Nazarbayev’s State of the Nation address in January 2017, the government has been developing a new draft of the Tax Code. The initiative involves introducing a Tax on Financial Results for technologically complex projects, while streamlining taxation for exploration and production contracts:

- For offshore projects and deepwater projects with wells over 6 km depth, the draft envisages moving from the current revenue-based taxation to a tax on financial results (profits), as well as the abolition of “special payments,” including the commercial discovery bonus and compensation for historical costs.
- For deepwater projects with well depths between 2 km and 4 km, the draft seeks to retain the current taxation scheme, but add concessions for marginally profitable fields.
- For existing exploration contracts, the draft plans to abolish requirements related to personnel training and R&D.
- For new exploration contracts, the draft’s concept is to blur the line between the corporative income tax and excess profit tax by allowing enterprises to count exploration contract expenditures as company spending rather than as individual subsidiary expenditures. Producers will be able to allocate 25% of total exploration costs annually to such expenditures.
- For new production contracts, the draft retains the current taxation regime, but adds field concessions for marginally profitable fields.
- Concessions for marginally profitable fields include lower MRET rates for fields that are depleted or with high water content or high viscosity oil. Such fields automatically qualify for the lower tax rate, without having to go through a complicated administrative process.

3.4.1.2. Subsoil Code

The key law that sets the basic framework for regulation of Kazakhstan’s upstream sector is the Law on Subsoil (2010), which replaced the Law on Oil (1995) and the previous Subsoil Law (1996). The Law on Subsoil specifies the rights and responsibilities of state entities involved in upstream operations, defines specific rules and rules for granting these rights, details the rights and responsibilities of subsoil users, sets terms for exploration and production activity (including for offshore), and establishes the regulatory foundation for environmental protection.

The key drawbacks of the existing Subsoil Law include a large number of bylaws (currently, over 60), its frequent amendments (since the Law’s adoption in 2010, it was changed 48 times), as well as a large number of applicable regulations from other legal domains, all of which complicate industry regulation. Still, following the aforementioned President’s address on January 2017, a concerted effort to develop new subsoil legislation was accelerated. A new Subsoil Code is scheduled to be adopted by both houses of parliaments by the end of 2017. It is important to note that the new legislation will be a code and not a law. In Kazakhstan, the legal system, codes have a status superior to ordinary laws and therefore supersede them when contradictions arise. Codes, by their nature, provide more detailed regulation and require fewer broad rules, which should lead to a more effective and efficient legal framework. Amending a code is more complicated than amending a law; therefore subsoil legislation in the form of a code should ensure greater efficiency.

The ongoing drafting of a Subsoil Code provides Kazakhstan’s lawmakers with an opportunity to address the challenges to the upstream sector posed by individual investment, insufficient geological exploration and development, and declining production from legacy fields. The July 2017 draft Code seeks to achieve several goals; chief among them:

- Improve the investment attractiveness of Kazakhstan’s oil and gas sector in a low oil price environment.
- Create conditions for the sustainable development of the oil and gas industry, recognizing its contribution to employment, social stability, and economic activity in the country.
- Maintain a sufficient degree of state regulation and control in order to ensure the rational use of mineral resources, preserving environmental and human safety.
- Ensure predictable and fair rule of law.

The draft Code contains several major proposed changes that seek to improve upstream regulations, including some recommendations made in theNER 2015:

- The Code provides for a contract for exploration and production, with clear conditions for the end of the exploration period and the transition to the production period. The draft Code also specifies terms for the issuance of a production contract at previously discovered fields. Under the new Code, investors have the automatic right to develop when exploration results are positive. This is not the case with the current Subsoil Law. This change eliminates a major disincentive to actually carry out exploration, and should incentivize continuing upstream field development following successful exploration.
- During the exploration phase, the new Code will not require investors to make expenditures for specific purposes or to spend on local R&D and personnel training.
- The draft Code allows for open access of investors to geological information, except for cases that fall under the law on protection of state secrets.
- The Code envisages offering subsoil rights for hydrocarbons based on auctions. It also clarifies a set of criteria a potential subsoil user needs to satisfy, including some operational experience. The Code mandates auctions in case of an application for a given block from an interested investor and provides guidance for simplification of the auction process.
- Following a recommendation in the 2015 NER, the code explicitly outlines “in plain language” procedural and administrative obligations of subsoil holders, and provides a list of administrative procedures required for companies participating in auctions.
- The draft Code stipulates a model subsoil contract. The Code streamlines the way project documents are developed and approved; more specifically, technical documents are not required before a contract is signed, but can be developed, audited, and approved afterwards.
- The Code presents a “one window” approach for state experts to review reserves data at the time of project documentation for production. While there are a number of administrative procedures with stringent deadlines, the Code presents these steps clearly, in plain language.
- The draft Code establishes a new legal mechanism for geological exploration using private funds. This provision specifically establishes a legal framework for the implementation of the “Eurasia” project, specifying the parameters for international and state cooperation in subsoil development.
- Contracts are to be signed within 20 working days of announcing the block which should occur on the same day of the auction), without having to pass through other legal and/or economic reviews by authorities. The current Subsoil Law requires contracts to pass through both types of reviews, which could respectively extend the process by 30 days each.
- The draft Code eliminates the requirement of presenting a detailed work program (an amendment to the contract detailing related obligations) from an investor, as it duplicates the required project documentation. Instead the contract would only indicate the minimum amount of work (accepted by the winner of the competition). Production volumes are indicated only in the project documentation, not in the contract.
- The Code envisages gradual transition (with an interim period required for thorough preparation of state authorities, the expert community, and companies in the sector) to the SPE-PRM international resource classification system for hydrocarbons (Step 74).28
- The status of the national oil and gas company, particularly with respect to managing strategic operations, and for the purposes of consulting with the World Petroleum Congress (WPC) and the American Association of Petroleum Geologists (AAPG). The current edition was adopted in 2011.

26 The MRET in Kazakhstan uses ad valorem rates that escalate based upon the annual production volume of the subsurface user, varying between 5% and 16% of sales revenues.

27 In 2015 UzenmunayGaz (OMG) also applied but did not receive a temporary preferential rate for the mineral extraction tax for the Uzen and Karamandybas fields.

28 The SPE-PRM Petroleum Resources Management System was developed in 1997 by the Society of Petroleum Engineers (SPE) jointly with the World Petroleum Congress (WPC) and the American Association of Petroleum Geologists (AAPG). The current edition was adopted in 2011.
fields, is preserved.

• The factors are also enhanced and clarified parameters of state regulation over issues of financial deductions (to a special escrow type account) for the liquidation of subsoil use consequences at the end of the contract period (in order to minimize the risks and costs for the state).

• Base case project documentation for hydrocarbon field development is subject to expert review by state authorities to ensure effective, rational, and environmentally responsible use of subsoil resources.

• The draft Code establishes penalties for violation of project documentation (up to the termination of the contract). The Code eliminates existing gaps in state control over the performance of contractual obligations. However, certain provisions that have raised concerns among investors in the past, and introduces others that appear to be problematic:

  • As in the current Subsoil Law, the Code requires investors to pay a signing bonus, and the size of this bonus is the principal factor the state considers when awarding subsoil rights through an auction. Given the auction format, the signing bonus is effectively the “price” of the new asset. Bonuses as guiding criteria have the advantage of being an easily understood and comparable indicator of the quality of the bid for the upstream use rights; they also ensure some up-front revenue for the government and may incentivize companies to explore and develop contract areas more rapidly. But generally, sizable up-front bonuses are usually only suitable in highly prospective areas where there is strong competition among investors for petroleum rights and the geology is relatively well known.

  Although competitive processes for granting subsoil use rights (tenders and auctions) are widely used for hydrocarbon exploration and production globally, the 보내는 사람 이라는 바탕을 중심으로 한 기준의 다른 요소들의 중요성을 보여준다. 다른 요소들의 중요성을 보여주는 요소들은 다음과 같다.

  • The Code continues to heavily regulate the procurement activities of subsoil users (of equipment, services, etc.) in oil and gas projects (although it also tries to streamline these requirements to minimize corruption-related risks). Although the new Code does not require investors to make expenditures for social purposes or to spend on local R&D and personnel training during the exploration stage, these requirements are retained during the extraction phase, along with local content requirements.

  • Article 29 in the revised draft references labor and migration laws, and specifies that no more than 50% of management in a firm should consist of foreign workers, and foreign workers should comprise no more than 50% of the total workforce, during both the exploration and production stages.

  • The draft Code in its current iteration also limits the duration of exploration and extraction activities. For exploration the limit is six years, except for exploration of complex projects requiring wells with a depth greater than 6 km and having high hydrogen sulfide content or an excessively high reservoir pressure (for which the exploration term can be extended only once (for three years, or six years for projects with deep wells) for assessment purposes and once (for three years) for test production. For extraction, the Code establishes a maximum period of 25 years for ordinary or 45 years for major and unique projects. After expiration of these periods, the government has the right to attach supplementary conditions for contract extension, in addition to those specified in the original contracts. Such conditions could entail new requirements for the investor, such as creation of new facilities, optimization of existing capacity, or marketing of production solely to domestic consumers.

The draft Subsoil Code has made a number of improvements to the existing regulation of the subsoil sector, including incorporating the recommendations of the 2015 NER, and significantly simplifying auction procedures and detailing various operational requirements. The draft Code also strengthens state oversight over operational activities in the sector. Although this aspect of legislation is understandable, it tends to echo an overall tendency of overregulation and control by the state in the economy and creates additional hurdles to new investments. In particular, proposals related to contract extension projects of national significance could substantially increase the regulatory burdens at the three “mega” projects, and ultimately threaten incremental spending.

3.4.2. Review of program documents in the upstream sector

Under Kazakhstan’s constitution, the President sets the strategic direction of domestic and foreign policy, while the government incorporates it accordingly into its economic, social, and other policies. Kazakhstan’s strategic policy documents related to the upstream sector set a common goal—to further exploration and development of the country’s abundant subsoil resources. These constraints may limit the major foreign investors in developing large and complex projects.

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President include:

**Concept of development of the fuel and energy complex of the Republic of Kazakhstan to 2030**

The Concept of development of the fuel and energy complex (FEC) to 2030, developed in June 2014, is a key document setting strategic goals for the upstream sector, including the intensification of exploration activity by attracting investment, as well as developing resources that are not financially and/or technically viable under the current tax regime through the creation of fiscal stimuli, that would allow companies to apply resource recovery technologies. In addition, the concept calls for changes in existing sector policies. Specific measures include: informing investors about upcoming changes in subsoil and tax regulations to 2030; studying the harmonization of fiscal terms with Russia under the framework of the Eurasian Economic Union (EAEU); setting export duties for oil and products to incentivize domestic oil refining; developing fiscal stimuli to promote investments in exploration (including through ring-fencing, securing priority rights for the development of resources in the event an investor succeeds in exploration, releasing investors in exploration projects from social spending obligations), incorporating regulations to promote national development of upstream projects, renewing building and construction standards, and including yearly production and technology plans for an upstream project’s development into the terms of the subsoil license tender.

**Concept of the development of the geological industry of the Republic of Kazakhstan to 2030**

The Geology Sector Development concept from August 2012 identified several problems facing Kazakhstan’s geological industry, including: the lack of skilled local specialists; a lack of activity by local research, scientific, and industry players; the inefficient organization of the exploration sector; and a lack of access to geological information. While the concept’s realization was expected to result from mineral resource development programs to be developed by the government every five years, only one such program (for the period 2010–2014) has yet to be compiled.

**Strategic plans of the Ministry of Energy of the Republic of Kazakhstan**

Strategic plans formulated by the Ministry of Energy of the Republic of Kazakhstan set specific goals for each energy subsector. The strategic documents set projections of oil and gas production over time and are periodically adjusted in light of changing conditions. The most recent Strategic Plan to 2021 (issued in December 2016) outlines the following objectives for the oil industry:

- Production of crude oil to reach 86 MMt (including Kashagan) in 2018 and 87 MMt in 2021. The longer term forecast is now being revised to reflect the expectations of a “lower for longer” price forecast. The long-term forecast from April 2014 had envisioned crude output reaching 118 MMt in 2030 (see Table 3.4).
- The document envisions that the depletion of oil and gas reserves after 2050 could leave Kazakhstan with an average annual liquid production of only around 55 MMt. To avoid such an outcome, the FEC concept calls for the active development of geological exploration through the attraction of investments and possible future development of subsurface resources not financially attractive under current tax conditions. It envisions that the share of FDI in the oil sector will exceed 30% by 2020, and will continue at this level to 2030.
- FEC 2030 forecasts Kazakhstan’s crude oil exports to Europe will increase very slowly, at a rate of 0.8% per year. However, it projects that demand for Kazakh crude in Asia Pacific markets, including China and India, will grow more briskly, by 2.1% annually to 2030. The 2030 strategy stipulates that in this context it is important to create a unified Kazakhstan-China pipeline sourced by crude production from Caspian fields.16

### 3.4.3. Recommendations on development goals and regulatory system

Hydrocarbon policy reform does not mean that Kazakhstan’s authorities need to unnecessarily compromise legitimate national security, budgetary, and other concerns, but it does imply a general rebalancing of state and oil industry interests. The goal of reform should be to stimulate growth in the industry, which should help “lift all boats”—both state revenues and companies’ returns on their invest-

### Table 3.4. Government projections for oil and gas production (various years)

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### Notes

15 In September 2014 the government developed a draft Concept of effective management of natural resources. Although the draft was offered for Nazarbayev’s consideration, it has never been signed. In relation to the upstream sector, the concept set such goals as more extensive resource exploration, increasing production and exports of natural resources (in response to high global demand), attracting foreign investments provided these bring in modern technologies and/or develop local manufacturing, and ensuring that production does not endanger the environment.

16 Another strategic goal outlined in FEC 2030 is refinery modernization.
Kazakhstan therefore should follow through with its plans to revalue its reserves reporting system to change its pricing methodology. Such a revaluation was delayed for a reasonable pace over several years) to the widely used international classification of hydrocarbon reservoir systems SPE-PRMS. There is little (if any) evidence that Kazakhstan is adhering to the existing, legacy system inherited from Soviet times. Such a change would eliminate the need for companies (and the government) to maintain two sets of books, and the inherent incompatibility between the two systems.

**Improved investment attractiveness and tax stability**

Improving attractiveness to investors, both domestic and foreign, and offering tax stability are two key factors that can help reverse the decline in upstream exploration and mature field production. This can be done by:
- Letting the companies have more control and the government less in key economic aspects and operational decisions on project development
- Because using of hefty (signing/discovery) bonuses acts as a major disincentive to exploration activity and spending, Kazakhstan should consider focusing the auction awards on technical and financial capabilities and offerings of the applicant and eliminate or at least reduce the emphasis on the size of the signing bonus; positive movement on this front is that the government is reassessing the discovery bonus
- Reduce high levels/multiple forms of government tax take (e.g., export duty and export rent tax)
- Ensure tax stabilization in the new Tax Code to help reduce uncertainty

Over the longer term, supportive fiscal measures could include reducing the importance of export taxes in favor of direct upstream taxes that more closely reflect the cost conditions faced by individual producers. This may raise the price of oil on the world market and reduce the incentives of some international companies with large reserves to invest in Kazakhstan. One of these might be compensation of oil companies’ associated gas processing costs (along the lines indicated in existing legislation). In addition, Kazakhstan is currently studying the feasibility of offering integrated emissions permits (IEPs) instead of the current rather complex regime of individual emissions permits, which require complicated monitions, penalties, and exceptions. Although widely used internationally, and authorized in Article 79 of Kazakhstan’s Environmental Code, IEPs have not yet been implemented in Kazakhstan. An IEP is a single document that certifies the right to emit an agreed-upon amount of greenhouse gas. It is a far simpler mechanism than the traditional allowance system.

**Improvement in the operating environment**

As a result of measures reported in this chapter, Kazakhstan has taken steps to improve the operating environment. Kazakhstan therefore should follow through with its plans to revalue its reserves reporting system to change its pricing methodology. Such a revaluation was delayed for a reasonable pace over several years) to the widely used international classification of hydrocarbon reservoir systems SPE-PRMS. There is little (if any) evidence that Kazakhstan is adhering to the existing, legacy system inherited from Soviet times. Such a change would eliminate the need for companies (and the government) to maintain two sets of books, and the inherent incompatibility between the two systems.

Kazakhstan’s legislation needs to reflect the industry’s importance to the economy, as well as the increasingly competitive global upstream environment in which outside investors have grown accustomed to widely followed international practices concerning the issuance of licenses, the classification of reserves, and other administrative measures. Such practices include:
- **Simplification of access to subsoil use contracts** (Step 75 in the 100 concrete steps program)
- **Increased transparency/availability of geological data**
- **Improved incentives for companies with licenses/contracts for taking on exploration risk; implement combined exploration/production licenses/contracts**
- **Provide durable guarantees of contract predictability**
- **Adoption of the international reserves classification system that reflects economics as well as geology (Step 74 in the 100 steps program)**
- **Reduction of administrative barriers, unnecessary procedures, and unreasonable deadlines. More specifically, to revolve the interest of international companies in its exploration sector, Kazakhstan should apply internationally recognized best practices used by leading hydrocarbon-producing countries, including having a designated “Competent Body” responsible for tendering. Another key measure is to establish a separate specialized entity that focuses on and maintains geological information. Some of these recommended measures and practices are already embodied in the new draft Subsoil Code.**

A next step, following successful exploration, would be for Kazakhstan to adopt standard international practices in reserve classification. Kazakhstan’s legacy classification system calculates reserves from what is possible to extract under the best possible conditions. The international approach is different, as it looks at what is economically feasible to recover. The conceptual framework is reflected in the Subsoil Code, where partial development of a deposit is not permitted if the rest of the reserve may be impaired, even if it is not economic to produce. Such a position does not consider the potential for future technological advances that can make marginal, “impaired” deposits recoverable.
4. KAZAKHSTAN’S OIL REFINING SECTOR

4.1 KEY POINTS

4.2 Refined Products: Supply and Demand

4.3 Infrastructure and Technologies: Key Challenges, Ideas, and Solutions
4. KAZAKHSTAN’S OIL REFINING SECTOR

4.1. KEY POINTS

- Kazakhstan has three main oil refineries as well as a number of mini-plants; total primary distillation capacity for the three main plants is currently listed as 15.35 million metric tons (MMt) per year (307,000 barrels per day [b/d]). Although these plants have some conver- sion capacity, the Kazakh refining system is relatively unsophisticated, so the output structure remains heavily skewed towards mazut (residual fuel oil), which no longer matches the country’s refined prod- uct needs.

- In aggregate, Kazakhstan’s refineries cur- rently cover only about 85% of domestic product consumption, with imports covering about 15%.1 This is because Kazakhstan exports a large proportion of its own output (mostly heavy products such as mazut), while it must import light products (motor fuels), mostly from Russia, to meet domestic demand.

- A major refinery modernization program is underway, which when completed will significantly alter the product slate towards light products (motor fuels). Demand has shifted decisively towards light products—gasoline, diesel fuel, and jet kero- sene—with the modernization of its economy since independence. The resulting mismatch between pro- duction and consumption has led to an increasing dependence upon imported products, especially of high-octane gasoline and jet kerosene. However, re- finery modernization, when completed, should help correct the mismatch and significantly reduce the need for imports of light products. In Kazakhstan, we project that aggregate refinery throughput will expand to about 17 MMt per year by 2030, an amount sufficient to cover gasoline and diesel consumption, following refinery modernization. A sizable increase in the output of gasoline and diesel is expected from the existing refineries, while the production of mazut is expected to contract. Because of the expectation of relatively modest growth in aggregate consump- tion of light products, the construction of another major refinery in Kazakhstan would result in significi- cant excess capacity for domestic needs; there also are only fairly limited possibilities for refined product exports given the country’s inland location.

- The government has moved towards liberalizing its refined product market, as it has lifted retail price regulation for gasoline and diesel fuel; prices remain regulated for A-80 gasoline and LPGs, but these are expected to be deregulated as well in 2017–18. But the refineries remain insulated from market forces; they do not operate as market actors, buying crude and selling refined products: instead, they receive a tolling fee for the crude that they process that is determined by the national oil company KazMunayGaz (KMG). The refining sector remains highly administered.

- The refineries are slated to be privatized. The refineries were listed in the planned privatization of a number of state-owned assets before 2020. But the status of this program remains uncertain.

4.2. REFINED PRODUCTS: SUPPLY AND DEMAND

4.2.1. Structure of the refined products sector

Kazakhstan has three main refineries (Atyrau, Pavlodar, and Shymkent), a specialized bitumen plant, and over 30 mini-refineries.2 Crude distillation capacity for the three main plants is currently listed as 15.35 MMt per year (307,000 barrels per day [b/d]). Two of the large refineries—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.3 The bitu- men plant is also owned on a parity basis, but by KMG and China’s China International Trust and Investment Corporation (CITIC).

Kazakhstan’s refineries operate commercially based on a processing scheme, so they remain insulated from market forces. Before a January 2017 deregula- tion, these processing tariffs were set by the regulator, KMG/2.2. Starting from 2017, the processing tariffs for Atyrau and Pavlodar refineries are set by KMG’s Board of Directors, while the tariff for the Shymkent refinery is set by the Board of Directors of the managing company, PetroKazakhstan. The sizable increase in the process- ing tariff in 2017 is due to inclusion of an investment component to compensate for refinery modernization. Dozens of large and small tolling (give-and-take) pro- jects work with the refineries: they purchase oil from subsided users, transport it to the refineries, get it pro- cessed, and then sell the resulting products. KMG EP is the largest crude oil supplier to Kazakhstan’s refineries (2.9 MMt in 2016). In accordance with the agreement between KMG and KMG EP signed during KMG EP’s IPO in September 2006 (and valid through 2015), KMG EP was obligated to supply certain amounts of crude oil to KMG’s refining and marketing subsidiary (KMG RM). In April 2016, the commercial relationship between KMG EP and KMG RM changed. Previously crude oil for refin- 1According to the Ministry of Energy of RK there are 32 small refineries, each with less than 800,000 tons/yr of processing capacity. Collectively, these 32 plants have 6.5 MMt of capacity, but reportedly processed only about 450,000 tons of feedstocks in 2016. Apparently, these small plants contribute little in terms of domestic supply of finished products. Apparently the only plane with any level of processing capacity is Aksay-based Kondorset, which recently commissioned a vacuum distillation unit, part of a $170 million in- vestment plan to upgrade the plant. It launched the project in December 2016 and anticipates by April 2018 that the introduction of amendments into the Law on Regulation of Petroleum Products Sales largely shut down these small plants because of a ban on selling semi-processed products, but an order issued by the Ministry of Energy in April 2017 reduced the number of these plants, allowing the small refineries to resume operations.

2KMG owns 99.5% of the shares of the Atyrau refinery, 100% of Pavlodar refinery, and 49.8% of Shymkent.

3 Most recently, this happened in October 2015, when the tariffs were approved at 20,501 tenge ($74) per ton for Atyrau, 14,895 tenge ($42) per ton for Pavlodar, and 11,453 tenge ($42) per ton for Shymkent.

4 As a result of KMG RM’s disbandment in 2017, the functions of the agent under the agency agreement with KMG EP are likely to be transferred to KazMunayGaz Omindor or to the relevant administrative department within KMG.

5 This is calculated as crude (and condensate) production minus exports plus imports. This includes field losses as well as any changes in stocks. See Table 3.2, of the 15.8 MMt of apparent crude oil consumption in Kazakhstan in 2016, 14.9 MMt were sup- plied to the refineries, and the remaining 0.8 MMt constituted field losses, changes in stocks and own use.

6 However, the Pavlodar refinery (petrochemical plant) processes West Siberian crude supplied through the Omsk-Pavlodar-She- ymkent pipeline from the Russian Federation. However, since it is supplied via a swap arrangement, from a commercial point of view, the crude delivered to the Pavlodar refinery is effectively purchased from Kazakhstan suppliers. A small amount of the crude delivered to Pavlodar is purchased from Russia and sold within Kazakhstan through the Interpipe and Omsk-Pavlodar-She- ymkent pipeline system (from Samara via Tiumen-Omsk-Novosibirsk pipeline), but the bulk of the delivery is simply compensated to the Russian supplier (Rosneft) by making the same amount of crude as delivered to the Kazakh-Russia border available at the Kazakhstan-China border. According to KMG EP’s annual report, the company supplied 22% of the crude volume delivered to Pavlodar refinery in 2016.

KMG subsidiaries (including KMG EP) are the main suppliers of crude oil feedstock to the Kazakh refinerr- ies.7 However, the main production assets of these subsidiaries are mature fields now in decline: over the past decade production at KMG’s 100%-owned entities declined by about 12%, amounting to about 8.4 MMt
in 2016.8 Over the longer term, production at these as-
sets is expected to continue its secular decline, gener-
ating concern over the availability of crude supplies to
meet the country’s oil demand in the 2020s. The main
crude production centers outside these legacy fields
are the three “mega” projects operated by TCO, KPO,
and NCOC. The key sources of growth in Kazakhstan’s
oil production are, in fact, these international projec-
tions. Given the declining output trajectory of the key
pro-
ducers supplying the domestic market, Kazakhstan’s re-
neries may need to attract some crude from these
other producers longer term. These producers would be
interested in supplying the domestic market only if
offered a price commensurate with the export options
available for this crude. In other words, the domestic
price would have to be at export parity (i.e., quoted
international prices minus marine freight, pipeline and
other transport costs, and applicable export taxes). 
Currently, however, the effective price at which crude
is supplied to domestic refineries is much lower than
export options, and the gap has even widened since
what in the last two years even though international
oil prices declined (see Table 4.1). Domestic crude oil
prices were about 40% of the average Urals (Mediter-
anean) prices for exports by producers in 2013–14,
but dropped to about 33% in 2015 and 25–29% in 2016.
When transit fees and export duties are added to
the equation, average realized prices for producers
on their domestic sales dropped from about 50% of
international prices minus marine freight, pipeline and
other transport costs, and applicable export taxes). But
demand for domestic refined products remained high in
Kazakhstan. In contrast, the country’s synthetic crude
production (the aggregate of all entities in which it holds a stake, weighted by KMG’s ownership share in each) is much higher, and has been rising: the calculated amount was 22.1 MMt in 2016, representing 28.3% of Kazakhstan’s total national
production last year.

At the same time, the Ministry of Energy, vested with
regulatory responsibility in the oil and gas sector, de-
termines the quantities of crude oil that subsoil users
run (see Table 4.3). The aggregate output of refined products in Kazakhstan declined to 12.9 MMt in 2016, even though crude throughput remained about the same as in 2015
at 14.5 MMt (see Table 4.2). The three major refiner-
ies have quite different product slates, reflecting their
different refining configurations and the type of crude
that they run (see Table 4.3). The aggregate output
slate of the country, however, has improved slightly in
recent years, even though much of the refinery modern-
ization program remains to be realized. The share
of light and middle distillates compared to throughput
increased somewhat: the share of gasoline rose from
20.9% in 2014 to 22.8% in 2016, and the share of
diesel went from 34.9% to 36.3%; the share of mazut
dropped from about 29.0% to 24.8% (see Table 4.2). The
depth of refining (conversion ratio) for all three of
the major refineries has been rising; Atyrau’s improved by
6.04% in 2016, reaching 65.2%; for the other two,
the improvement was only 1-4%, with Pavlodar’s depth
increasing to 76.6%, and Shymkent’s to 75.4%.11

Table 4.1. Comparison of domestic crude prices versus export
crudes and export prices netbacks in Kazakhstan, 2012–16

<table>
<thead>
<tr>
<th></th>
<th></th>
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<th></th>
<th></th>
<th></th>
</tr>
</thead>
<tbody>
<tr>
<td>Light products</td>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td>Export price (USD/bbl)</td>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td>Export netback (USD/bbl)</td>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td>Effective realized domestic price for producers on crude sales in the domestic market (excluding excise and VAT)</td>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td>Domestic price as percentage of international price</td>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td>Domestic price as percentage of export netback value</td>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
</tr>
</tbody>
</table>

Source: The Author

8 This indicator, defined as the share of “premium products” (essentially light products and lubes) in the output mix, was 74.2% for
Russian refining overall in 2015 and improved to 79.1% in 2016 versus 71% in 2000–02; but this is still short of the 85–90%
levels in advanced Western countries such as the US and Germany.

4.2.3. Refining operations and output

Reported aggregate output of refined products in
Kazakhstan declined to 12.9 MMt in 2016, even though
crude throughput remained about the same as in 2015
at 14.5 MMt (see Table 4.2). The three major refineries
have quite different product slates, reflecting their
different refining configurations and the type of crude
that they run (see Table 4.3). The aggregate output
slate of the country, however, has improved slightly in
recent years, even though much of the refinery modern-
ization program remains to be realized. The share
of light and middle distillates compared to throughput
increased somewhat: the share of gasoline rose from
20.9% in 2014 to 22.8% in 2016, and the share of
diesel went from 34.9% to 36.3%; the share of mazut
dropped from about 29.0% to 24.8% (see Table 4.2). The
depth of refining (conversion ratio) for all three of
the major refineries has been rising; Atyrau’s improved by
6.04% in 2016, reaching 65.2%; for the other two,
the improvement was only 1-4%, with Pavlodar’s depth
increasing to 76.6%, and Shymkent’s to 75.4%.11

Table 4.2. Kazakhstan’s refined product balance, 2010–16

| Year | Gasoline | Kerosene | Diesel fuel | Mazut | Fluid 
liquids | Total (all refined products) |
<table>
<thead>
<tr>
<th></th>
<th></th>
<th></th>
<th></th>
<th></th>
<th></th>
<th></th>
</tr>
</thead>
<tbody>
<tr>
<td>2010</td>
<td>3,164</td>
<td>3,097</td>
<td>2,327</td>
<td>1,645</td>
<td>1,523</td>
<td>11,244</td>
</tr>
<tr>
<td>2011</td>
<td>3,052</td>
<td>2,954</td>
<td>2,245</td>
<td>1,545</td>
<td>1,456</td>
<td>10,202</td>
</tr>
<tr>
<td>2012</td>
<td>3,016</td>
<td>2,930</td>
<td>2,306</td>
<td>1,581</td>
<td>1,504</td>
<td>10,343</td>
</tr>
<tr>
<td>2013</td>
<td>2,880</td>
<td>2,810</td>
<td>2,455</td>
<td>1,628</td>
<td>1,566</td>
<td>10,305</td>
</tr>
<tr>
<td>2014</td>
<td>2,811</td>
<td>2,742</td>
<td>2,585</td>
<td>1,652</td>
<td>1,611</td>
<td>10,253</td>
</tr>
<tr>
<td>2015</td>
<td>2,743</td>
<td>2,674</td>
<td>2,694</td>
<td>1,690</td>
<td>1,662</td>
<td>10,293</td>
</tr>
<tr>
<td>2016</td>
<td>2,675</td>
<td>2,606</td>
<td>2,754</td>
<td>1,720</td>
<td>1,714</td>
<td>10,169</td>
</tr>
</tbody>
</table>

Source: The Author

11 This indicator, defined as the share of “premium products” (essentially light products and lubes) in the output mix, was 74.2% for
Russian refining overall in 2015 and improved to 79.1% in 2016 versus 71% in 2000–02; but this is still short of the 85–90%
levels in advanced Western countries such as the US and Germany.
### Table 4.3. Product output by Kazakhstan’s major refineries

<table>
<thead>
<tr>
<th>Year</th>
<th>2012</th>
<th>2013</th>
<th>2014</th>
<th>2015</th>
<th>2016</th>
<th>2017</th>
</tr>
</thead>
<tbody>
<tr>
<td>Crude throughput</td>
<td>4,423</td>
<td>4,340</td>
<td>4,320</td>
<td>4,660</td>
<td>4,761</td>
<td>4,650</td>
</tr>
<tr>
<td>Motor gasoline</td>
<td>505</td>
<td>505</td>
<td>614</td>
<td>605</td>
<td>643</td>
<td>771</td>
</tr>
<tr>
<td>Diesel fuel</td>
<td>1,218</td>
<td>1,222</td>
<td>1,394</td>
<td>1,207</td>
<td>1,391</td>
<td>1,351</td>
</tr>
<tr>
<td>Jet kerosene</td>
<td>57</td>
<td>38</td>
<td>23</td>
<td>21</td>
<td>20</td>
<td>22</td>
</tr>
<tr>
<td>Bitumen</td>
<td>-</td>
<td>-</td>
<td>-</td>
<td>1</td>
<td>7</td>
<td>8</td>
</tr>
<tr>
<td>Heating oil</td>
<td>143</td>
<td>124</td>
<td>166</td>
<td>160</td>
<td>168</td>
<td>181</td>
</tr>
<tr>
<td>Mazut</td>
<td>1,543</td>
<td>1,512</td>
<td>1,510</td>
<td>1,603</td>
<td>1,362</td>
<td>1,274</td>
</tr>
<tr>
<td>Vacuum gas-oil</td>
<td>616</td>
<td>652</td>
<td>779</td>
<td>739</td>
<td>842</td>
<td>518</td>
</tr>
<tr>
<td>Petroleum coke</td>
<td>75</td>
<td>95</td>
<td>137</td>
<td>111</td>
<td>123</td>
<td>146</td>
</tr>
<tr>
<td>LPG</td>
<td>14</td>
<td>20</td>
<td>28</td>
<td>29</td>
<td>36</td>
<td>34</td>
</tr>
<tr>
<td>Sulfur</td>
<td>1</td>
<td>1</td>
<td>2</td>
<td>3</td>
<td>3</td>
<td>3</td>
</tr>
</tbody>
</table>

### Table 4.4. Outlook for Kazakhstan’s refined product balance

<table>
<thead>
<tr>
<th>Product</th>
<th>2010</th>
<th>2015</th>
<th>2020</th>
<th>2025</th>
<th>2030</th>
<th>2030-20</th>
</tr>
</thead>
<tbody>
<tr>
<td>Production</td>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td>Throughput</td>
<td>13.7</td>
<td>14.5</td>
<td>16.0</td>
<td>16.3</td>
<td>17.0</td>
<td>1.1</td>
</tr>
<tr>
<td>Output of products (exported)</td>
<td>12.8</td>
<td>13.5</td>
<td>15.2</td>
<td>15.6</td>
<td>16.5</td>
<td>1.3</td>
</tr>
<tr>
<td>Gasoline</td>
<td>2.9</td>
<td>2.9</td>
<td>4.0</td>
<td>4.4</td>
<td>4.8</td>
<td>3.3</td>
</tr>
<tr>
<td>Kerosene</td>
<td>0.5</td>
<td>0.3</td>
<td>0.5</td>
<td>0.7</td>
<td>0.9</td>
<td>7.7</td>
</tr>
<tr>
<td>Diesel fuel</td>
<td>4.4</td>
<td>4.6</td>
<td>6.2</td>
<td>5.6</td>
<td>7.3</td>
<td>3.2</td>
</tr>
<tr>
<td>Mazut</td>
<td>4.3</td>
<td>4.1</td>
<td>2.9</td>
<td>2.4</td>
<td>1.7</td>
<td>-3.2</td>
</tr>
<tr>
<td>Other (includes LPGs, VGO, etc.)</td>
<td>1.4</td>
<td>2.6</td>
<td>2.5</td>
<td>2.2</td>
<td>2.1</td>
<td>-1.1</td>
</tr>
<tr>
<td>Total refined products (excluding asphalt)</td>
<td>20.4</td>
<td>20.8</td>
<td>22.5</td>
<td>22.1</td>
<td>23.8</td>
<td>2.6</td>
</tr>
<tr>
<td>Apparent consumption</td>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td>Total (all refined products)</td>
<td>10.3</td>
<td>12.5</td>
<td>13.0</td>
<td>13.5</td>
<td>14.3</td>
<td>1.4</td>
</tr>
<tr>
<td>Gasoline</td>
<td>3.7</td>
<td>4.3</td>
<td>4.2</td>
<td>4.4</td>
<td>4.5</td>
<td>0.4</td>
</tr>
<tr>
<td>Diesel fuel</td>
<td>3.2</td>
<td>3.6</td>
<td>5.6</td>
<td>5.0</td>
<td>6.5</td>
<td>2.3</td>
</tr>
<tr>
<td>Mazut</td>
<td>1.4</td>
<td>-0.6</td>
<td>1.1</td>
<td>1.1</td>
<td>1.0</td>
<td>-0.1</td>
</tr>
<tr>
<td>Other</td>
<td>2.0</td>
<td>2.2</td>
<td>2.4</td>
<td>2.0</td>
<td>2.0</td>
<td>-0.2</td>
</tr>
<tr>
<td>Net exports</td>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td>Total (all refined products)</td>
<td>3.3</td>
<td>3.0</td>
<td>3.0</td>
<td>2.8</td>
<td>2.9</td>
<td></td>
</tr>
<tr>
<td>Gasoline</td>
<td>-0.8</td>
<td>-1.4</td>
<td>-0.3</td>
<td>0.0</td>
<td>0.3</td>
<td></td>
</tr>
<tr>
<td>Diesel fuel</td>
<td>1.2</td>
<td>0.0</td>
<td>0.6</td>
<td>0.8</td>
<td>0.8</td>
<td></td>
</tr>
<tr>
<td>Mazut and other “shokhwe toplik”</td>
<td>3.0</td>
<td>4.7</td>
<td>1.8</td>
<td>1.4</td>
<td>0.7</td>
<td></td>
</tr>
<tr>
<td>Other</td>
<td>-0.1</td>
<td>-0.3</td>
<td>0.9</td>
<td>0.8</td>
<td>1.2</td>
<td></td>
</tr>
</tbody>
</table>

Note: Ministry projection for 2017.

Source: Ministry of Energy of RK.

### 4.2.5. Exports and imports of refined products

Kazakhstan exports low value-added (heavy) products while importing premium products, a function of its outdated refined product slate, which the current modernization program is meant to address. Overall, product exports (as reported by customs statistics) declined from 5.1 MMMT in 2014 to 3.9 MMMT in 2016—the lowest level observed since 2008. Fuel oil (together with VGO and other heavy products) remains the major refined product export, as its share in the overall products’ exports amounted to 92% in 2016, compared to 94% in 2014. Kazakhstan does not export light products outside the Customs Union, in connection with the current ban under an agreement with the Russian Federation. Overall product imports dipped to 1.8 MMMT in 2016. Imports of gasoline decreased to 1.1 MMMT in 2016. High-octane automotive gasoline continued to be the major import product.

### 4.2.6. Refined product consumption outlook

According IHS Energy’s base case forecast, gasoline and diesel demand are set to grow only modestly through 2030, lifting up aggregate oil product demand. Apparent gasoline consumption will grow from 4.1 MMMT in 2016 to 4.5 MMMT in 2030, and diesel consumption will increase from 5.1 MMMT (2016) to 6.5 MMMT in 2030. Aggregate apparent product demand is expected to reach about 14.1 MMMT in 2030 (see Table 4.4). Actual mazut consumption will continue to decline, albeit slowly, as mazut is important to Kazakhstan’s electric power sector, mining, and heavy industries; demand by these industries is forecast to hold relatively steady at about 1.0 MMMT in 2030.

### 4.2.4. Domestic refined products consumption

Kazakhstan’s apparent consumption of refined products increased to 12.9 MMMT in 2016 compared to 12.0 MMMT in 2015. The increase was led by diesel and "other" (see Table 4.2). Apparent consumption of motor gasoline was less buoyant, actually declining slightly. Actual reported consumption of all refined products in Kazakhstan (excluding LPGs) was 9.8 MMMT in 2015. This was comprised of 62% diesel (used mainly in the transport sector for road and rail transport, as well as in agriculture), 14.9% motor gasoline, 13.4% mazut, 4.3% kerosene, and 4.0% bitumen.

13 Another tool widely used by the Kazakhstan authorities in order to influence the domestic market and pricing is periodic introduction of administrative bans on exports of certain refined products. Such bans mostly apply to light and middle distillates. Initially designed to help meet demand in agriculture during peak periods (sowing in spring and harvesting in autumn), these bans were applied year after year. The most recent was introduced by the Order of the Minister of Energy of the Republic of Kazakhstan from June 26, 2015 No. 437 “On the introduction of a temporary ban on the export of oil products” for a period of six months. Only small volumes of diesel fuel are allowed to be exported in the off-periods of low demand.

14 According to 2015 data, mazut consumption by power plants and large boiler houses amounted to 443,000 metric tons.

15 These projections are based on IHS Markit base-case macroeconomic assumptions that envision average annual GDP growth in Kazakhstan to 2030 at 2.6%, with a general assumption of gradually slowing growth over time, reflecting the larger economic base.

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Given this demand picture, refinery throughput is expected to expand to only about 17 MMt in 2030 (see Table 4.4). This amount of crude runs is more than sufficient to meet domestic demand for gasoline with the changed product slate following refinery modernization. The IHS Markit outlook assumes that enough crude oil is processed by the domestic refineries to balance gasoline demand without resorting to imports, although the country would still export and import some oil products because demand for the overall product slate is never perfectly balanced by refinery production. Given limited projected growth in domestic products demand, the construction of another major refinery would lead to aggregate overproduction and low national refining capacity utilization.

Also, given Kazakhstan’s inland location, possibilities for refined product exports are quite limited.

4.3. INFRASTRUCTURE AND TECHNOLOGIES: KEY CHALLENGES, IDEAS AND SOLUTIONS

4.3.1. Kazakhstan’s refinery modernization program

Kazakhstan’s $6 billion refinery modernization program was officially approved in 2010 with three key objectives: to improve the refining slate by increasing production of light products (high-octane gasoline and diesel) and eliminating the need for Russian light product imports; to improve fuel quality to comply with the principles and rules of technical regulation within the framework of the Eurasian Economic Union; and to increase the refineries’ throughput capacity. The modernization program is expected to be completed at the Pavlodar and Atyrau refineries by the end of 2017, and at Shymkent by the end of 2018 (see Table 4.5).

Table 4.5. Installed processing capacity at Kazakhstan’s main refineries (thousand metric tons per year)

<table>
<thead>
<tr>
<th>Type of capacity</th>
<th>Almetyevsk</th>
<th>Pavlodar</th>
<th>Shymkent</th>
<th>Sum for Three Main Refineries</th>
</tr>
</thead>
<tbody>
<tr>
<td>Crude distillation capacity (MMt)</td>
<td>5.0</td>
<td>5.6</td>
<td>5.1</td>
<td>5.25</td>
</tr>
<tr>
<td>Vacuum distillation</td>
<td>3.00</td>
<td>3.00</td>
<td>4.00</td>
<td>4.00</td>
</tr>
<tr>
<td>Catalytic cracking ( FCC )</td>
<td>-</td>
<td>2.39</td>
<td>2.00</td>
<td>2.00</td>
</tr>
<tr>
<td>VGO cracking</td>
<td>-</td>
<td>1.50</td>
<td>1.50</td>
<td>1.00</td>
</tr>
<tr>
<td>Catalytic reforming (CCR)</td>
<td>-</td>
<td>-</td>
<td>-</td>
<td>-</td>
</tr>
<tr>
<td>Hydro-treating</td>
<td>-</td>
<td>-</td>
<td>-</td>
<td>-</td>
</tr>
<tr>
<td>Isoalkylation-C5/C6</td>
<td>-</td>
<td>-</td>
<td>-</td>
<td>-</td>
</tr>
<tr>
<td>Bitumen production</td>
<td>-</td>
<td>-</td>
<td>-</td>
<td>-</td>
</tr>
<tr>
<td>Sulfur production</td>
<td>-</td>
<td>-</td>
<td>-</td>
<td>-</td>
</tr>
<tr>
<td>Hydrogenation (methanol)</td>
<td>-</td>
<td>-</td>
<td>-</td>
<td>-</td>
</tr>
<tr>
<td>Naphtha splitter</td>
<td>-</td>
<td>-</td>
<td>-</td>
<td>-</td>
</tr>
<tr>
<td>Aromatics production</td>
<td>-</td>
<td>-</td>
<td>-</td>
<td>-</td>
</tr>
<tr>
<td>Oxygenates/MTBE</td>
<td>-</td>
<td>-</td>
<td>-</td>
<td>-</td>
</tr>
</tbody>
</table>

Source: KNB

Following modernization, the three main refineries will be capable of fully satisfying Kazakhstan’s domestic demand through at least 2025. According to Deputy Energy Minister Aset Magauyev, modernization will increase gasoline yield to 32% (from 20%) per ton of crude oil, and 29% for diesel, while jet kerosene will grow from 2% to 5%. Total production of gasoline and diesel fuel could exceed 10 MMt/y, perhaps providing some surplus for export. However, until the modernization program is completed, Kazakhstan will continue relying on imports of light products from Russia.

Modernization might address some of the fuel use and losses at the refineries, such as from deteriorated steam pipeline thermal insulation as well as optimization of furnace and boiler operation. However, it can be expected that implementation of deeper conversion technologies and increased refinery capacity as a result of modernization may lead to higher fuel consumption (own use). Collectively, the three main refineries and the bitumen plant incurred losses and fuel use of 7.3% of crude runs in 2016, varying from 11.2% for Pavlodar to 1.8% for the bitumen plant (6.2% at Almetyevsk and 5.3% for Shymkent). These figures do not seem excessive in international perspective. Average refining losses and own consumption as well as fuel use in Russia as a whole were 6.3% in 2015, but these vary from only about 2–4% for simple hydrocracking refineries up to 6–8% for full conversion refineries; the presence of associated petrochemical facilities naturally increases losses and fuel use. In Europe, high conversion plants with catalytic cracking and hydrocracking have fuel use and losses in the range of 7.5–8.5%, while simply hydrocracking refineries are in the range of 4.5–4.7%.

The potential for energy efficiency improvements at the three refineries is quite high (up to 10%). However, the implementation of energy-saving measures faces the problem of missing incentives by the refineries, as the cost of oil and refined products used in the process of efficiency improvements will be incentivized if they affect the refineries’ revenue, for example, if the refineries buy feedstock (crude oil) and sell the refined products, i.e., function as independent market companies. In such a situation, refinery efficiency improvements become a strategic task in increasing profitability.

Pavlodar refinery

Built in 1978 to process West Siberian crude, the Pavlodar refinery is the most technologically sophisticated of Kazakhstan’s refineries. Its conversion ratio is 76.6%, with a Nelson complexity index calculated by IHS Markit at 7.4. In 2016, the share of gasoline and diesel in the total output of refined products was 68%, while the share of mazut (fuel oil) was 14% (see Table 4.3). Pavlodar’s refinery modernization got underway in 2011 and is expected to be completed by the end of 2017, with production of K4 and K5 fuels beginning in 2018 (see the text box: Kazakhstan’s tightening fuel standards). Prior to 2015, Pavlodar’s modernization envisioned an increase in annual throughput capacity from the current 5.1 MMt to 7.9 MMt, reconfiguring the plant to refine domestic (Kazakhstan’s) crude, as well as improving the quality of product output (to produce K4 and K5 fuels). However, in 2015 the modernization project was scaled back, and now is aimed only at improving the quality of products, not expanding distillation capacity or reconfiguring the refinery for a different type of crude. Total capex for Pavlodar’s modernization is $831 million, of which $409 million in financing was provided by a short-term loan from KMG and a long-term loan from the state-owned Development Bank of Kazakhstan.

Kazakhstan’s tightening fuel standards

Kazakhstan has been moving toward tighter fuel specifications to improve air quality, adopting similar standards to the European Union (EU) progressively in several steps. Kazakhstan’s fuel specifications are now determined via its Eurasian Economic Union agreements. Following the conclusion of the Agreement on Unified Principles and Rules of Technical Regulation between Russia, Belarus and Kazakhstan, the Customs Union Commission introduced Technical Standards for automotive fuels in October 2011. However, these agreements provide a more relaxed timeline for refining and for losses is borne by the crude suppliers, not the refineries themselves. Under the agreement, the fuel oil (mazut) and the refinery gas consumed at the refineries do not really have any value (cost) for the refineries. Therefore, there is no incentive to ensure savings and reduce energy losses. Loss reductions and efficiency improvements will be incentivized if they affect the refineries’ revenue, for example, if the refineries buy feedstock (crude oil) and sell the refined products, i.e., function as independent market companies. In such a situation, refinery efficiency improvements become a strategic task in increasing profitability.

Kazakhstan’s tightening fuel standards

Kazakhstan, given its delayed refinery modernization program, with the transition to more stringent specifications in Kazakhstan lagging well behind Russia and Belarus. The specifications correspond to Russia’s “class” benchmarks, which are similar to the Euro standards (the difference being that the Russian and Kazakh class benchmarks allow for lower octane fuels) (see Table 4.6). K-4 and K-5 gasoline have regulated octave levels while the octane levels in Euro-4 and Euro-5 gasoline are not.
The introduction of a moratorium on small and medium business inspections from February 2014 limited state control functions; the moratorium was aimed at improving business conditions. But because of the need to monitor fuel quality throughout Kazakhstan, the filling stations were required to meet the Euro-4 standard as of 1 January 2013.63 It should be noted that the introduction of refined product quality standards as such has not fully solved the problem of the quality of the fuel sold to consumers. Quite often, quality checks of the fuel sold at filling stations revealed noncompliance with the established standards. This was mainly due to fuel falsification by the filling station owners, including mixing fuels of inferior quality and using additives to increase octane levels.

Parlodar’s existing units will be upgraded and new piping and instrumentation installed; in addition, a new isomerization unit (570,000 tons/year), and a naphtha splitter (1,961,000 tons/year), and a sulfur production unit. The work was carried out by Sinopec Engineering and KazStroyServis and was financed by the Development Bank of Kazakhstan and China’s ExIm Bank. The aromatics production complex (APC) Project Phase 1. The licensor’s commitments (guarantees) with regard to the CCR were met.

The licensor companies’ – UOP (USA) and Axens (France) – refining technologies are used for project execution. The licensor’s commitments (guarantees) with regard to the CCR were met. The licensor companies’ – UOP (USA) and Axens (France) – refining technologies are used for project execution.

The KGPN project, launched in 2011, is being implemented by China’s Sinopec Engineering, Japan’s Marubeni, and Kazakhstan’s KazStroyServis. The project drew external financing from Development Bank of Kazakhstan, China’s ExIm Bank, and Japan’s JBIC. KGPN involves the construction of 12 new process units, allowing the production of K-4 and K-5 quality fuels.

KGPN units use technologies by France’s Axens. The catalytic cracker (2.4 MMt/y capacity) uses company’s R2R proprietary technology, while the LPG desulfurization unit uses Sulforx technology. Axens’ Alkyfining technology is used for upgrading the LPG cuts, while oligomerization technology is used for converting olefinic fractions into gasoline. It is capable of handling a variety of heavy feedstocks, including atmospheric residue, heavy gasoil, vacuum gasoil, and heavy gasoil, converting them into lighter, high-value products such as LPGs, light gasoil, and gasoline. The KGPN project is on track to be completed by 2017, with production of K-4 and K-5 diesel fuel commencing in 2018. The plan is for the refinery to produce 1.745 MMt of gasoline, 1.64 MMt of diesel, and 0.244 MMt of jet kerosene after modernization is completed.

Shymkent refinery

In 2016, the share of gasoline, diesel, and jet kerosene in the total output of refined products at the Shymkent refinery (PKOP) was 58%, while the share of fuel oil was 32% (see Table 4.3). A key goal in Shymkent’s modernization is debottlenecking, so that the plant can go back to its original designed capacity of 6 MMt/y as well as to improve fuel quality and increase production of light products. The modernization project, with an outlay of $1.85 billion, is financed and executed by the plant’s joint owners, KMG and CNPC, with the main contractor being China Petroleum Engineering & Construction Corporation (CPECC). Once completed, the Shymkent refinery’s installed crude distillation capacity will reach 6 MMt/y, and its net profit score will increase by 8.2%, while producing K4 and K5 quality motor fuels. The refinery is expected to become operational at its full post-modernization capacity in Q-4, 2018, after the completion of the catalytic cracking complex.

The Shymkent refinery modernization includes two stages. The first stage is aimed at improving product quality and producing K4 and K5 type fuels and involves the installation of an isomerization unit, diesel hydro-treater, and a sulfur production unit. The second stage involves increasing throughput capacity and installing a catalytic cracking unit, gasoline hydrotreater, sulfur production unit, LPG demercaptanization unit, and a hydrocracker. The licensor companies – UOP (USA) and Axens (France) – refining technologies are used for project
4.3.2. Deregulation of the refined products market

In general, the downstream sector in Kazakhstan remains highly administered, overlain with strong demand planning. The existing system of downstream market regulation in Kazakhstan reflects the sector’s struggle to meet light product demand, involving direct control and regulation in different segments by a variety of state bodies, including the Ministry of Energy, the Ministry of Finance (which is responsible for refined products trade control), the Ministry for Investments and Development (which is responsible for technical standards and safety), and the Ministry of Agriculture (which regulates refined products supply for the agricultural sector).

Currently, the state regulates:

- Schedules of crude supplies by oil producers to refineries
- Annual volumes and monthly schedules of refining
- Annual volumes and monthly schedules of supplies by producers of refined products with retail prices regulated by the state to the regions of Kazakhstan
- Retail prices for certain refined products
- Procedure of access to refining facilities by oil producers

The state approves:

- Refinery maintenance schedule
- Refining companies’ investment programs
- Imports and exports are also tightly controlled. In accordance with the Agreement between the Government of the Russian Federation and the Government of the Republic of Kazakhstan from December 9, 2010 on trade and economic cooperation in the field of oil and oil products supplies to the Republic of Kazakhstan, the import volumes are set by the state while the wholesale exports of light and middle distillates outside the customs territory of the Customs Union are prohibited from January 1, 2014.

However, it should be noted that Kazakhstan has made further progress towards market liberalization. First, the number of products for which prices are regulated was reduced: in December 2014 the list of regulated products consisted of gasoline grades A-80, A-92, A-93 as well as diesel and LPGs, while in September 2015 gasolines A-92 and A-93 were excluded, and in July 2016 diesel was also excluded. This leaves retail price regulation applying only to gasoline A-80 and LPGs.

Deregulation of retail price caps for gasoline grades A-92, A-93, and diesel fuel allowed prices to rise slightly. Specifically, average retail prices for gasoline A-92 and A-93 increased from 108 tenge ($0.36) per liter in September 2015 to 124 tenge ($0.39) in October; while average retail prices for diesel increased from 99 tenge ($0.30) per liter in July 2016 to 113 tenge ($0.34) in August 2016, and reached 131 tenge ($0.39) per liter in October 2016 (Figure 4.1). However, the worries of the market participants with regard to potential initiation of an investigation by the regulatory authority (KREMiZK) and the consequences thereof is limiting any significant increase in deregulated fuel prices. Secondly, state regulation of refinery processing tariffs was abolished. In particular, Step 53 of the program “One Hundred Steps” put forward by President Nazarbayev in 2015 changed the concept of the work of the antimonopoly service in order to ensure compliance with OECD standards. In January 2017, KREMiZK’s Register of Dominant (Monopoly) Players (for which price regulation is applied), which in cluded the country’s three main refineries, was officially abolished. Therefore, refinery processing tariffs were freed from direct state regulation and are now set by company management (see above).

The government will continue to administratively influence the prices for certain types of refined products, especially until refinery modernization is completed. After modernization, retail prices (A-80 and LPG) are expected to be deregulated and the restrictions on refined products export and import are expected to be lifted. The prices for refined products in the domestic market will be moving towards parity with prices for Russian products (taking into account the differences in taxes) within the single economic space. To compensate for significant investments in modernization, refinery processing rates have been increased and are expected to grow even more. As of 1 April 2016, the processing tariffs were confirmed by KMG’s Board of Directors at 20,501 tenge/ton ($59.9/ton) for crude to Atyrau, and 14,895 tenge/ton ($43.5/ton) for Pavlodar. From April 2017, the processing fees were raised to 24,512 tenge ($61.7) per ton at Atyrau and 16,417 tenge ($52.6) per ton at Pavlodar. These processing tariffs, which essentially are the refineries’ operating margin (at $11.2/bbl and $7.2/bbl), are quite high compared to the margins prevailing in the global market, including Russia (see the text box: Global Refining Margins). In the next few years, the processing rates at Kazakhstan refineries are expected to be raised to 115/ton ($15.8/bbl). The necessity of a tariff increase for loan repayment is evident from both the refining operation point of view and the state refining sector strategy point of view. However, such a high level of processing tariffs will have a negative impact longer term. First and foremost, high refinery tariffs mean that price liberalization or even a significant increase in crude oil prices in the domestic market becomes difficult, as refined product prices are effectively capped by parity with Russian (imported) products, so higher crude acquisition costs cannot be simply passed through to refined product prices (see Figure 4.2). Therefore, careful attention should be paid not only to the financial liabilities of the refineries, but also to the interests of the producers supplying crude to the refineries.

The potential for growth in crude oil prices is much greater than in refined product prices through market integration with Russia. It will become increasingly difficult for Kazakhstan’s refineries to obtain crude without lowering processing tariffs.

**Figure 4.2. Refined product prices in Kazakhstan and Russia**

- **A-80 (Kazakhstan)**
- **A-80 (Russia)**
- **A-92 (Kazakhstan)**
- **A-92 (Russia)**
- **Diesel (Kazakhstan)**
- **Diesel (Russia)**

Notes: For Russian, light wholesale prices are for Urals region converted to Tenge at average monthly exchange rate by Kazakhstan Central Bank. For Kazakhstan, light wholesale prices are country’s average.

Sources: (35 Market), Statistical Committee of RK © 2017 35 Market
Refining margins in Northwest Europe have fallen from $5/bbl in 2015 to less than $2/bbl in 2016. In Russia, the tax maneuver eliminated the substantial subsidy the refining sector received on exports of heavy refining products, and refining margins fell from nearly $8/bbl in 2014 to less than $2/bbl in 2016. The average refining margin in Northwest Europe is now around $1.4/bbl, and is expected to remain low—between $1.00 and $1.50/bbl over the next few years. In Northwest Europe, the average full-cost FCC refining margin is expected to be $1.80/bbl and $1.67/bbl in 2017 and 2018, respectively, while hydrocracking margins will likely be $2.20/bbl and $2.17/bbl over the same period. In the near term, global refining margins will remain flat as inventories remain high. Over the medium term (2019–2025), refining margins are expected to rebound slightly due to the impact of the change in IMO bunker fuel specifications. The product differential between light products and heavy sulfur fuel oil (HSFO) will grow as HSFO will need to be priced at thermal parity to coal and heavy products. Margins for some secondary processes, notably coking and hydrocracking, will increase more rapidly than FCC margins, as these technologies are critical for converting high-sulfur fuel oil into lighter streams. In contrast, sour cracking conversion and heavy sour simple conversion will be under enormous duress and at risk for shut-in around 2020, as their net margins will barely breakeven. After 2025, over the long term, refining margins remain fairly flat, if not enter a period of terminal decline, as transportation efficiency gains and greater consumption of alternative fuels will dampen products demand growth.

Refining margins around the world have plummeted since 2015 due to global crude oversupply, low crude prices, and high levels of installed refining capacity (see Figure 4.3). Shrinking margins can force less competitive refiners (typically small, unsophisticated plants) to shut down altogether. Between 2009 and 2016, global refinery rationalization led to the closure of almost 8 Mbd (400 MMb/d) of refining capacity.

In the near term, global refining margins will remain flat as inventories remain high. Over the same period, refining margins in Kazakstan will remain attractive to refiners: $169 for gasoline, $169 or $113 for diesel (depending on the specific fuel type), and $113 for fuel oil. The export duty for diesel and fuel oil was subsequently reduced to $60 per ton in March 2015. In March 2015 Kazakhstan did the duty rate on oil products to the international price of crude oil, but this arrangement was short-lived as in May 2015 the formula was revoked. The government introduced a formula again in February 2016, but it has not yet been implemented and the export duty remains simply a fixed amount per ton. Historically, export duties in Kazakhstan on refined products were much lower than in Russia, but this has changed with the latest elements of Russia’s phased tax maneuver and lower global oil prices (Russian duties are set as percentages of export prices for crude oil); although Russian export duties on heavy products remain higher than they are in Kazakhstan, they are now much less than in Kazakhstan on light products (see text box: Russian export duties on refined products.)

4.3.3. Refined product taxes

In addition to VAT that applies to all goods and services sold in Kazakhstan, two other types of taxes affect refined products: export duties and excise taxes. Kazakhstans levies export duties on many types of goods, particularly crude oil, but export duties also apply to refined products that might be exported, such as fuel oil. Since 2014 the government has set the export duty for all products as a fixed dollar amount per ton: $169 for gasoline, $169 or $113 for diesel (depending on the specific fuel type), and $113 for fuel oil. The export duty for diesel and fuel oil was subsequently reduced to $60 per ton in March 2015. In March 2015 Kazakhstan did the duty rate on oil products to the international price of crude oil, but this arrangement was short-lived as in May 2015 the formula was revoked. The government introduced a formula again in February 2016, but it has not yet been implemented and the export duty remains simply a fixed amount per ton. Historically, export duties in Kazakhstan on refined products were much lower than in Russia, but this has changed with the latest elements of Russia’s phased tax maneuver and lower global oil prices (Russian duties are set as percentages of export prices for crude oil); although Russian export duties on heavy products remain higher than they are in Kazakhstan, they are now much less than in Kazakhstan on light products (see text box: Russian export duties on refined products.)

Russian export duties on refined products

One of the major drivers of Russian tax reform in recent years has been reducing economic incentives for export-oriented “opportunistic” refining that either destroys or adds little aggregate value; it emerged because of the much lower export duties imposed on refined product exports than on crude oil since 2004. This type of refining activity usually employs simple crude refining capacity (primary distillation atmospheric units) and produces semi-finished products, such as straight-run gasoline, basic middle distillates and, most importantly, large quantities of heavy fuel oil, for which there is little demand in Russia. The main purpose of such export-oriented refining is to take advantage of the generous subsidy for the export of refined products, especially fuel oil, provided by the Russian state in the form of relatively high export taxes on crude relative to refined product exports. But the subsidy facilitating export-oriented refining has become increasingly unsustainable for the Russian government in recent years for a variety of reasons, one of them being the need for more revenue, and is also at odds with policymakers’ longer-term goal of Russian refinery modernization. The first key turning point of recent years in the Russian government’s approach to taxation of crude and refined product export streams was the so-called “60-66” tax reform introduced in October 2011, which represented a critical initial step in reducing preferential export tax terms for lower-quality products. The “60-66” regime, which came into effect in late 2011 and lasted until 2014, reduced the marginal crude export tax rate from 65% to 60% of the ullage price and unified most refined product export duties at the rate of 66% of the crude export tax (the gasoline export duty was set higher, at 90%, in an effort to curb domestic gasoline shortages). The 66% rate represented a slight decrease in the tax burden for the higher-quality export streams to which it applied but was at the same time a substantial export tax increase in the case of fuel oil. Exports of fuel oil nevertheless remained profitable under the new tax regime; just less profitable than before. Overall, this reform left Russian refiners with a refined product export tax subsidy of about $17 per barrel (at an average global crude oil price of $100 per barrel), and facilitated an additional increase in primary refining to support higher exports of diesel and fuel oil. With the latest round of the tax maneuver, particularly the equalization of the export duty on fuel oil with crude oil, the privileged export tax regime for most heavy refined products was eliminated, to both stimulate a lightening of the Russian refinery slate and reduce the massive state subsidy to the Russian refining sector. State support for the refining sector is set to continue under terms of the maneuver, but at greatly reduced levels and mainly for lighter product streams; e.g., in the form of reduced gasoline and diesel export tax rates relative to the crude export duty rate. In January 2017, the export tax rates for oil and oil products were changed as follows:• A 30% marginal rate for crude oil (down from 42% in 2016);• Rates for refined products (as a percentage of the crude oil duty rate) became 30% for gasoline and 55% for naphtha (down from 61% in 2016); 30% for medium distillates (down from 40% in 2016); and 100% for heavy products (up from 82% in 2016). Therefore, currently (as of August 2017), the regular export tax on crude oil changed to $74.4 per ton, while the export tax on most light and refined products changed to $32.3 per ton, while for heavy products this became $74.4 per ton, the export duty for straight-run gasoline (naphtha) became $40.9 per ton, while for automobile gasoline it changed to $22.3 per ton, while the export tax on LPGs (propane, butane) remained at zero.

Figure 4.3. Refining margins in Northwest Europe

Global refining margins

Refining margins around the world have plummeted since 2015 due to global crude oversupply, low crude prices, and high levels of installed refining capacity (see Figure 4.3). Shrinking margins can force less competitive refiners (typically small, unsophisticated plants) to shut down altogether. Between 2009 and 2016, global refinery rationalization led to the closure of almost 8 Mbd (400 MMb/d) of refining capacity.

In the near term, global refining margins will remain flat as inventories remain high. Over the medium term (2019–2025), refining margins are expected to rebound slightly due to the impact of the change in IMO bunker fuel specifications. The product differential between light products and heavy sulfur fuel oil (HSFO) will grow as HSFO will need to be priced at thermal parity to coal and heavy products. Margins for some secondary processes, notably coking and hydrocracking, will increase more rapidly than FCC margins, as these technologies are critical for converting high-sulfur fuel oil into lighter streams. In contrast, sour cracking conversion and heavy sour simple conversion will be under enormous duress and at risk for shut-in around 2020, as their net margins will barely breakeven. After 2025, over the long term, refining margins remain fairly flat, if not enter a period of terminal decline, as transportation efficiency gains and greater consumption of alternative fuels will dampen products demand growth.
Another urgent issue for Kazakhstan is excise tax harmonization with Russia because of the importance of imported gasoline in Kazakhstan’s consumption. To a certain extent, this applies to VAT as well, where different rates are applied. Fiscal harmonization is always a major issue in regional integration schemes, such as the Eurasian Economic Union (EAEU). Differences in excise duties among countries can have a major impact on the competitiveness of their refined products within the unified economic space, and are also major sources of government revenues. For example, within the European Union, an agreement on harmonization of excise duties for petroleum products was only reached in June 1991. Because of the contentiousness of the issue, several previous attempts to harmonize at specific levels and then within specified bands failed. The agreement reached sets minimum rates above which member states are free to set their own taxes (see text box: Harmonizing Excise Taxes on Refined Products).

Harmonizing excise taxes on refined products

Fuels subject to excise tax in Kazakhstan include motor gasoline (excluding aviation gasoline), diesel fuel, and crude oil/gas condensate; other refined products are not excisable. Currently, crude oil and gas condensate have zero excise tax. Excise taxes were established in the 2009 Tax Code, but since 2015 the tax rates are set separately by the government. For some time after being established in the Tax Code in January 2009, excise tax rates remained at 5,000 tenge per ton on gasoline and 600 tenge per ton on diesel fuel. These are the total rates that apply to retail prices. Refiners (or wholesale participants) paid excise taxes at a rate of 4,500 tenge per ton for gasoline and 540 tenge per ton for diesel on all their domestic sales. Retail sellers were responsible for the remaining excise (500 tenge per ton for their gasoline sales and 60 tenge per ton for their diesel sales). If refiners (or wholesalers) engage in direct sales to consumers, then they pay the entire excise amount.

In November 2015, the excise tax on gasoline was raised to 11,000 tenge per ton (10,500 tenge at the wholesale level and 500 tenge at the retail level) while the excise tax on diesel remained unchanged at 600 tenge per ton (540 tenge wholesale and 60 tenge retail) (see Table 4.7). However, starting from October 2016, excise taxes on diesel were made seasonal: between November and March the rate is reduced to 600 tenge per ton (540 tenge wholesale and 60 tenge retail), while between April and October the rate of 9,360 tenge per ton (9,300 tenge wholesale and 60 tenge retail) is applied. In March 2017 the government expanded the period of reduced diesel excise taxes to last from November to May.

Since 2011, Russia has employed a differentiated approach to excise taxes, aimed at stimulating conversion to higher grades with lower excise and punishing lower grades of product with higher excise. Kazakhstan’s excise tax rates remain much lower than Russia’s. Through 2014, gasoline excise was little more than 10% of the Russian level, and for diesel it was only 1–2% (see Table 4.7). These ratios jumped to 24% for gasoline and 6% for diesel in 2015 (driven by a decrease in Russia’s diesel excise tax in 2015). By 2017 the ratio had fallen back to 15% for gasoline (as excise tax in Russia went up), but sharply increased to 25% for diesel following the seasonal raise of the tax in Kazakhstan.

4.3.4. Privatization

In January 2016, the Ministry of National Economy published a list of more than 360 state- and municipally-owned companies targeted for eventual privatization in the 2016–20 program. The ambitious program, part of the government’s anticrisis plan, aims to privatize 5% of all municipal enterprises in the country and 15% of all state enterprises, reducing the overall role of the state in the economy. The role of the refiners in this program remains ambiguous.

4.3.5. Key recommendations

• As the state is gradually loosening its administrative control over the downstream sector, Kazakhstan needs to continue to move forward in market liberalization. The country needs to commit to further relaxation of existing administrative measures, including full price liberalization for all refined products (A-80 and LPG), lifting controls on exports and imports, and abolishment of planning of refining volumes and oil supplies to refiners as well as scheduling refined products supply to the domestic market.
• In particular, domestic crude prices need to be allowed to rise to export netback parity. In time, this will provide sufficient incentive for crude producers to supply domestic refiners.
• Given limited projected growth in domestic products demand, the construction of another major refinery within the period to 2030 would lead to aggregate oversupply and low national refining capacity utilization; possibilities for refined product exports are quite limited.
• For a number of reasons, including the planned privatization program and stimulating greater energy efficiency at the refineries, it is recommended to make the refineries merchant operators, buying crude and selling refined products rather than remaining on a tolling scheme.
• The mechanism of subsidizing agricultural producers at the expense of other refined products market participants, when refined products (mainly diesel fuel) are supplied at special low prices during the sowing and harvesting campaigns, should be abolished; agricultural enterprises should pay regular market prices for their fuel supplies.
• As shown by the historical example of the EU, regional integration is most effective when member states liberalize domestic policies and cross-border arrangements. Therefore, as a member of the EAEU, in the long term, Kazakhstan should introduce market mechanisms and refrain from establishing restrictive administrative mechanisms with regard to refined products production, distribution, and trade. In a liberalized market, any company should be able to sell refined products in any part of the country.
• Longer term rates of export duties and excise taxes should be aligned with those in Russia as a part of the single economic space.
• Although there is a desire for a revision of railway tariffs with elimination of cross-subsidies for other goods traffic at the expense of oil products, this item need not be highest on the actionable priority list. The gain for oil participants is much less than the sizable business impact from higher rail tariffs on other commodities such as coal.17
• Develop a mechanism for the member states of the Eurasian Economic Union, especially Kazakhstan and Russia because of the long shared border and the high volume of product trade, to harmonize their excise tax rates for refined products.

17 See section 6.2.7 on “Coal transportation” in this report’s Chapter 6 on coal.
### Table 4.7. Refined product excise taxes in Kazakhstan and Russia

<table>
<thead>
<tr>
<th></th>
<th>January 2012</th>
<th>January 2013</th>
</tr>
</thead>
<tbody>
<tr>
<td><strong>Russia</strong></td>
<td></td>
<td></td>
</tr>
<tr>
<td><strong>Straight-run gasoline (market)</strong></td>
<td></td>
<td></td>
</tr>
<tr>
<td></td>
<td>(rubles/ton)</td>
<td>(dollars/ton)</td>
</tr>
<tr>
<td>Class 3</td>
<td>7 824</td>
<td>250,4</td>
</tr>
<tr>
<td>Class 4</td>
<td>6 822</td>
<td>218,4</td>
</tr>
<tr>
<td></td>
<td>5 143</td>
<td>164,6</td>
</tr>
<tr>
<td><strong>High-octane gasoline</strong></td>
<td></td>
<td></td>
</tr>
<tr>
<td>Class 3</td>
<td>4 098</td>
<td>121,2</td>
</tr>
<tr>
<td>Class 4</td>
<td>3 814</td>
<td>122,1</td>
</tr>
<tr>
<td></td>
<td>3 562</td>
<td>114,0</td>
</tr>
<tr>
<td></td>
<td>3 562</td>
<td>114,0</td>
</tr>
<tr>
<td><strong>Heating oil</strong></td>
<td>--</td>
<td>--</td>
</tr>
<tr>
<td><strong>Aviation kerosene</strong></td>
<td>--</td>
<td>--</td>
</tr>
</tbody>
</table>

**Note:** Excise tax differentiated in Russia by classes beginning in 2011.

<table>
<thead>
<tr>
<th></th>
<th></th>
<th></th>
<th></th>
<th></th>
</tr>
</thead>
<tbody>
<tr>
<td></td>
<td>(rubles/ton)</td>
<td>(dollars/ton)</td>
<td>Exchange rate (per dollar)</td>
<td>(rubles/ton)</td>
</tr>
<tr>
<td><strong>Russia</strong></td>
<td></td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td><strong>Straight-run gasoline (market)</strong></td>
<td></td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td></td>
<td>(rubles/ton)</td>
<td>(dollars/ton)</td>
<td>Exchange rate (per dollar)</td>
<td>(rubles/ton)</td>
</tr>
<tr>
<td>Class 3</td>
<td>11 252</td>
<td>333,1</td>
<td>33,76</td>
<td>11 200</td>
</tr>
<tr>
<td>Class 4</td>
<td>11 110</td>
<td>328,9</td>
<td>32,76</td>
<td>10 500</td>
</tr>
<tr>
<td></td>
<td>10 725</td>
<td>317,5</td>
<td>31,20</td>
<td>10 500</td>
</tr>
<tr>
<td></td>
<td>9 916</td>
<td>293,5</td>
<td>28,55</td>
<td>10 500</td>
</tr>
<tr>
<td></td>
<td>6 450</td>
<td>190,9</td>
<td>184,9</td>
<td>7 330</td>
</tr>
<tr>
<td></td>
<td>6 446</td>
<td>190,8</td>
<td></td>
<td>4 350</td>
</tr>
<tr>
<td></td>
<td>6 446</td>
<td>190,8</td>
<td></td>
<td>4 350</td>
</tr>
<tr>
<td></td>
<td>5 437</td>
<td>160,7</td>
<td></td>
<td>3 450</td>
</tr>
<tr>
<td></td>
<td>4 787</td>
<td>141,1</td>
<td></td>
<td>3 450</td>
</tr>
<tr>
<td></td>
<td>6 446</td>
<td>190,8</td>
<td></td>
<td>3 000</td>
</tr>
<tr>
<td></td>
<td>--</td>
<td>--</td>
<td></td>
<td>2 300</td>
</tr>
</tbody>
</table>

**Note:** Changes in excise taxes went into effect in December 2013 and April 2017. Diesel excise tax in April 2017 became seasonal; 3,360 tonne/ton is applicable between June and October, while a rate of 860 tonne/ton is applicable between November and May.

**Source:** VIE Yearbook
5. NATURAL GAS

5.1 KEY POINTS
5.2 NATURAL GAS SECTOR UPDATE
5.3 INFRASTRUCTURE AND TECHNOLOGIES: KEY CHALLENGES, IDEAS, AND SOLUTIONS
5.4 REGULATION OF KAZAKHSTAN’S GAS SECTOR
5. NATURAL GAS

5.1. KEY POINTS

Kazakhstan has sizable reserves of natural gas, but the bulk of this is high-sulfur associated gas, which is expensive to process and whose output is essentially tied to liquids production. Consequently, development and use of this gas remains problematic, complicated by low producer prices, limited ability of consumers to pay for higher priced gas, the need to transport it long distances within Kazakhstan to many markets, and limited (to date) export opportunities. A relatively high share of natural gas extraction (36% of gross output in 2016) continues to be reinjected to support recovery of oil. But the share of gas in primary energy consumption has been rising; currently natural gas is viewed as a key “bridge fuel” in power generation between baseload coal and intermittent renewable energy sources, addressing the growing need for additional flexible capacity while producing less greenhouse gas emissions than coal. For natural gas to decisively increase its role in the national economy, prices for natural gas in Kazakhstan will need to increase, both at the upstream level and at the end-consumer. This will incentivize upstream suppliers to make more gas available and will cover the additional costs of transporting gas to more distant consumers. However, some form of state support for gas may be necessary (similar to the mechanisms supporting renewable energy), given the challenges for gas to be competitive, especially in power generation because of Kazakhstan’s very low-cost domestic coal. Another important aspect of gas pricing policy is the need to harmonize Kazakhstan’s end-user prices with those in Russia as part of the general movement towards creating a single economic space within the Eurasian Economic Union. To expand domestic gas consumption, promote “greener” energy, and boost the economy’s international competitiveness, the government of Kazakhstan placed responsibility for development of the domestic gas market with a “national operator” by creating a single-buyer model in the Law on Gas and Gas Supply in 2012. Since then, KazzTransGas (KTG), the specialized gas subsidiary of national oil company KazMunayGas (KMG), essentially functioned in this role, as it included various subsidiaries within its structure that operated the centralized trunk pipeline infrastructure and distribution systems, bought and sold gas domestically, and carried out gas exports and imports. Under the Law on Gas and Gas Supply the national operator has a pre-emptive right to purchase processed associated gas from producers. But with the decision to phase out KTG as a centralized holding (see below), the role of national operator presumably will shift to either KMG itself or directly to KTG’s specialized gas subsidiaries.

Natural gas to grow

For gas to grow its role, gas prices need to increase and its price needs to be more competitive, especially in power generation. Development of the industry. Currently, producer prices for gas are quite low, which helps keep prices down for end-consumers, although not necessarily in the areas that rely on imported gas (the north and especially the south of the country), where gas tends to be more expensive. Additional indigenous supply will require more processing, which increases its cost, and to make gas more widely available, it will need to be transported over long distances, which also adds to costs. What is clear is that the prices for natural gas will be under upward pressure to stimulate additional supply.

5.2. NATURAL GAS SECTOR UPDATE

Although the production of natural gas (both associated and nonassociated) has been increasing in Kazakhstan over the past several years, interest and concerns about gas availability and use remain high. KTG, the state-owned entity broadly responsible for the domestic gas market (see below), has been hard at work gasifying more places, linking the country’s gas-producing and gas-consuming regions, and creating the technical preconditions for the launch of large-scale exports to China. In particular, natural gas is now viewed as a bridge fuel in power generation between baseload coal and intermittent renewable energy sources, addressing the growing need for additional flexible capacity while producing less greenhouse gas emissions than coal. The key questions that frequently arise is whether Kazakhstan has enough gas to support both growing domestic consumption and its export commitments.

As mentioned above, Kazakhstan has plentiful reserves of gas, but the bulk of this gas is high-sulfur associated gas, which is expensive to process and remains tied to liquids production. Pricing policy is going to play an important role in the future development of the industry. Currently, producer prices for gas are quite low, which helps keep prices down for end-consumers, although not necessarily in the areas that rely on imported gas (the north and especially the south of the country), where gas tends to be more expensive. Additional indigenous supply will require more processing, which increases its cost, and to make gas more widely available, it will need to be transported over long distances, which also adds to costs. What is clear is that the prices for natural gas will be under upward pressure to stimulate additional supply.

5.2.1. Overall vision and organizational structure

President Nursultan Nazarbayev initiated a process of widespread, corporate transformation across national wealth fund Samruk Kazyna’s 13 subsidiary companies in an October 2014 speech, in which he emphasized the imperative to increase the fund’s value and to advance Kazakhstan’s overall economic well-being. The most important of these subsidiaries, national oil company KMG, incorporates KTG within its structure. For KMG, a key transformation goal is to improve operational performance, efficiency, and monetary value. To help achieve these goals, in November 2016, KMG Chairman Sauat Mynbayev announced that KTG would be abolished as an administrative management company, while KTG’s key subsidiaries, such as KTG Airnak and Intergas Central Asia, would function as direct subordinate companies of KMG.

Law on Gas and Gas Supply

Since passage of the Law on Gas and Gas Supply in January 2012, Kazakhstan’s domestic gas market has been increasingly moved into the hands of state-owned KTG, as the “national operator” for the country’s single-buyer model. KTG operates most of the country’s single-buyer model. KTG operates most of

for Karachaganak development is being discussed, targeting a scaled-back project. A decision is still expected to be announced by the end of 2017, with the launch planned for 2022. In July 2016 the TCO consortium operating the Tengiz project approved the FID for the TCO Future Growth Project (FGP)—Wellhead Pressure Management Project (WPMP). Although the prime driver for the decision to expand operations was to increase oil production (beginning in 2022), gross gas extraction is also poised to increase, although most of the increment is planned to be reinjected.

• Production outlook. IHS Markit projects that gross output will reach about 48 bcm per year in 2020, 72 bcm in 2030, and 77 bcm in 2040 in the base case, while volumes of commercial gas are expected to increase to about 27 bcm per year in 2020, 35 bcm in 2030, and 47 bcm in 2040. The key factor in determining Kazakhstan’s overall gas production outlook is the country’s overall oil production outlook, as this is the principal driver for gas production.

• Processing and transportation. With the launch of processing capacity for Kashagan gas (Bolashak), Kazakhstan now has four major gas processing plants, with a combined capacity of 23.8 bcm/y. In aggregate, together with the availability of Russian capacity at Orenburg, this amount appears adequate to handle the bulk of Kazakhstan’s expected volumes of commercial gas for the next decade or so. One of the major developments in Kazakhstan’s gas transportation sector was the 2015 completion of the remaining segment (Beyneu-Bozoy) of the Beyneu-Bozoy-Shymkent (BBS) pipeline, which allows gas produced in the western part of Kazakhstan to reach the country’s southern area and paves the way for eventual large-scale gas exports to China.

5.2.2. Production outlook

In aggregate, total expected volumes of commercial gas for the next three years is expected to increase to about 27 bcm per year in 2020, 35 bcm in 2030, and 47 bcm in 2040. The key factor in determining Kazakhstan’s overall gas production outlook is the country’s overall oil production outlook, as this is the principal driver for gas production.

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An example of this is KTG’s offtake contract with Tethys Petroleum for its (shallow, dry) gas production in Aktobe Oblast. In December 2014, a new gas sales contract with KTG was announced, which increased the purchase price of gas by 42% to $75 per thousand cubic meters (Mcm), which was more than double the national average producer price for gas at the time.

Historically, only 9 oblasts received piped gas, but this became 10 in 2015 with the launch of deliveries in East Kazakhstan Oblast. KTG has displaced the private gas trading companies that previously operated in various parts of Kazakhstan, buying gas from producers and selling it to consumers.

Despite the ambitious goals for gas in Kazakhstan, and especially its envisioned role in sustainable energy, the general inadequacy of much of state gas policy, particularly gas pricing policy, is indicated by KTG’s generally precarious financial position resulting from its diverse roles and responsibilities at the center of the sector. Large financial losses were incurred by KTG in 2014–15, although the company returned to profitability in 2016. KTG’s consolidated financial results for 2013–16 show the impact on the company’s gross revenues of the general decline in oil and gas prices, which failed to be compensated for in other parts of the value chain (see Figure 5.1, Table 5.1). Consolidated This reflects the fact that the bulk of gas production in Kazakhstan occurs as a distress was also tenge devaluation and what it did to financing expenses, as much of the company’s outstanding loans were dollar-denominated.

KazTransGas consolidated financials include the following subsidiaries:

Table 5.1. Consolidated financial summary for KazTransGas

<table>
<thead>
<tr>
<th>Subsidiary</th>
<th>2016</th>
<th>2015</th>
<th>2016 Business line</th>
</tr>
</thead>
<tbody>
<tr>
<td>Intergas Central Asia</td>
<td>100%</td>
<td>100%</td>
<td>100% trans pipeline transportation</td>
</tr>
<tr>
<td>KTG Aktau</td>
<td>100%</td>
<td>100%</td>
<td>100% Gas sales and distribution</td>
</tr>
<tr>
<td>KTG Tolli (Kazakhstan)</td>
<td>100%</td>
<td>100%</td>
<td>100% Gas sales and distribution</td>
</tr>
<tr>
<td>KTG Omsk</td>
<td>100%</td>
<td>100%</td>
<td>100% Transportation</td>
</tr>
<tr>
<td>Astana Gas KOG</td>
<td>100%</td>
<td>100%</td>
<td>100% Construction of Trans gas pipeline to Astana (West-North Center)</td>
</tr>
<tr>
<td>KTG Karaganda Operating</td>
<td>100%</td>
<td>100%</td>
<td>100% Unboned exploration</td>
</tr>
<tr>
<td>Intergaz Finance BV (Netherlands)</td>
<td>100%</td>
<td>100%</td>
<td>100% Inter of turboconvert</td>
</tr>
<tr>
<td>KazTransGas Bishkek (Kyrgyzstan)</td>
<td>100%</td>
<td>100%</td>
<td>100% Rejoin reform/transition/modernization of Shakhent-kishine:center gas pipeline</td>
</tr>
<tr>
<td>KTG Aktobe</td>
<td>–</td>
<td>–</td>
<td>–</td>
</tr>
<tr>
<td>Ada Gas Pipeline</td>
<td>50%</td>
<td>50%</td>
<td>50% Construction and operation of Kazakhstan-China gas pipeline system</td>
</tr>
<tr>
<td>Beyneu-Buynazar Pipeline</td>
<td>50%</td>
<td>50%</td>
<td>50% Construction and operation of the Beyneu-Buynazar pipeline</td>
</tr>
<tr>
<td>AvtoGas</td>
<td>50%</td>
<td>50%</td>
<td>50% Construction, operation, and maintenance of gas filling stations</td>
</tr>
</tbody>
</table>

KTG has not exercised effective control over the Georgian subsidiary since a Georgian court ruling in 2009.

5.2.2. Natural gas reserves

Kazakhstan’s State Commission on Reserves (GKS) listed the country’s gas reserve base (state balance) as of 1 January 2016 at 4.01 trillion cubic meters (Tcm). This is roughly the same figure as has been reported for the past several years.1 Of this, 2.27 Tcm is “solution” gas (held in solution with liquid hydrocarbons in the reservoir) and 1.74 Tcm is “free” gas.2 Most (3.72 Tcm) of the country’s reserves are concentrated in the North Caspian Basin, and approximately 98% of the country’s gas reserves are

1 This is reported according to the domestic definition (in categories A+B+C1+C2) and appears to roughly correspond to the international equivalent of proven + probable (“2P”) reserves. IHS Markit estimates Kazakhstan’s remaining 2P gas reserves at 134 trillion cubic feet (3.8 Tcm).

2 By international definitions for just “proven” (“1P”) reserves, Kazakhstan is considered to possess 1.0 Tcm as of the end of 2016, or 0.5% of the global total (BP Statistical Review of World Energy, June 2017). By this measure Kazakhstan ranks fifth among CIS countries (after Russia, Turkmenistan, Uzbekistan, and Azerbaijan) and 26th in the world.
located in western Kazakhstan (Mangistau, Atyrau, West Kazakhstan, and Aktau oblasts). About 85% is found in just a few large fields (e.g., Tengiz, Karachaganak, Zhanazhol, Imamovskoye), mostly in deep subsalt deposits (up to 5 kilometers), multi-component composition, and high sulfur content, all of which greatly complicate development and production. The official state balance for 2015 identifies reserves in 228 fields, of which 68 were reportedly in production.

5.2.3. Historical gas production trends

In 2016, for the third year in a row, Kazakhstan’s gross gas production (including reinjected volumes) diverged from liquids production trends, even though nearly half of Kazakhstan’s gas is produced with oil at oilfields as associated gas (see Figure 5.2). In 2016, gross gas production increased 2.4%, to 46.4 Bcm, in contrast to a 1.9% decline in oil (including condensate) output. So far in 2017 gas production is growing robustly, increasing by 15.4% in the first half. Commercial production (gross output minus re-injection) in Kazakhstan has also been on the rise. In 2016, “commercial” output (defined by the state statistical agency to also include field use) reached 26.8 Bcm, with 11.4 Bcm being reinjected to sustain liquids production (see Table 5.2).

Table 5.2. Kazakhstan’s gas supply and demand balance (billion cubic meters)

<table>
<thead>
<tr>
<th>Total extraction</th>
<th>45,2</th>
<th>46,4</th>
<th>48,2</th>
</tr>
</thead>
<tbody>
<tr>
<td>Use of raw gas at the field for internal needs</td>
<td>20,5</td>
<td>19,6</td>
<td>21,2</td>
</tr>
<tr>
<td>Own needs (including on-site electricity generation)</td>
<td>8,3</td>
<td>8,2</td>
<td>7,8</td>
</tr>
<tr>
<td>Re-injection into reservoir</td>
<td>12,3</td>
<td>11,4</td>
<td>13,4</td>
</tr>
<tr>
<td>Commercial gas available for distribution</td>
<td>24,8</td>
<td>28,8</td>
<td>26,9</td>
</tr>
<tr>
<td>Internal consumption (non-SNGPs)</td>
<td>12,1</td>
<td>13,1</td>
<td>13,2</td>
</tr>
<tr>
<td>Gas exports**</td>
<td>12,7</td>
<td>13,7</td>
<td>13,7</td>
</tr>
</tbody>
</table>

* Including swears
** Estimated for 2017.

Gross production includes total volumes extracted from the reservoir, so it also includes all non-methane components, including hydrogen sulfide, carbon dioxide, nitrogen, etc. It also includes reinjected volumes. In standard international statistical practice, reported production does not include reinjected volumes, but only “commercial” output available for project use and distribution to consumers.

Karakachaganak

Kazakhstan’s gas output comes mainly from the Karachaganak and Tengiz projects, which together account for over 75% of Kazakhstan’s total production (see Figure 5.3). The Karachaganak field (in West Kazakhstan Oblast) is the largest producer (see Figure 5.4). Gross production by the Karachaganak Petroleum Operating (KPO) consortium, however, has been basically flat over the last four years. It increased from...
17.5 Bcm in 2013 to 18.2 in 2014–15 and declined to 17.7 Bcm in 2016. About half of the gross output has been reinjected, although reinjected volumes have declined slightly: for example, in 2013 the share of reinjected gas was 53%, but by 2016 it had declined to 46%. The field’s commercial output has been flat at about 9.6 Bcm over 2015–16. Nearly all of Karachaganak’s raw (high-sulfur) gas output is sent across the border to Russia for processing. Gas extraction is planned to rise to 7 Bcm in 2020 and 16 Bcm in 2030, but 9 Bcm available for actual consumption. Gross gas output for Tengiz is expected to remain at current levels until about 2022, when the next phase of expansion (the FGP-WPMP) at the field is completed. While this will raise gross gas extraction, much of the increment is planned to be reinjected, so little additional commercial gas is expected to be produced.

Production by other gas producers

Aggregate output growth by other gas producers was the main driver of Kazakhstan’s gas production growth in 2015–16. Aggregate production by other producers increased by 16.8% year-on-year in 2015 to about 12.2 Bcm, and 11.8% year-on-year to 13.6 Bcm in 2016 (see Figure 5.4). The largest among these is CNPC-Aktobemunaygaz, the third-largest gas producer in Kazakhstan. Its production expansion became possible with the completion of a third train at the Zhanaozhol gas processing plant, raising the plant’s total processing capacity to 7 Bcm/y.

5.2.4. Gas production outlook

Gas production in the country is expected to remain close to 2016 levels for the decade ahead. It is unlikely that material upstream developments will be pursued aimed at producing natural gas alone. This is largely because the domestic gas market does not provide strong incentives for such development given relatively low gas prices in the domestic market. The Ministry of Energy is currently revising its long-term gas output forecast, previously outlined in the Gas Industry Concept to 2030 in three scenarios: optimistic, realistic, and pessimistic. An updated mid-term forecast to 2021 has already been released (see Table 5.3). Importantly, the mid-term gas output forecast has been adjusted downward, essentially aligning with the low (pessimistic) outlook laid out two years ago in the Gas Industry Concept; it is now expected to reach about 47.5 Bcm in 2020 rather than 62 Bcm envisioned in the Concept’s “realistic” scenario (medium case) (see Table 5.3). Commercial gas volumes are now expected to be about 28.4 Bcm in 2020 in this most recent update. IHS Markit’s own outlook envision that both gross gas production and commercial gas production will be slightly higher than in the Gas Industry Concept longer term. We project that gross output will reach about 50 Bcm per year in 2020, but 72 Bcm in 2030 and 77 Bcm in 2040 in our base case, while volumes of commercial gas are expected to increase to about 27 Bcm in 2020, 35 Bcm in 2030, and 47 Bcm in 2040 (see Table 5.4). and Figure 5.5). The main factor explaining the difference is that IHS Markit envisions a higher level of oil production than the Ministry, which results in more associated gas (see Chapter 3). The three mega-projects will continue to dominate Kazakhstan’s gas production, and much of the future increase in output is expected to come primarily from Kashagan (the North Caspian Operating Company or NCOC) (see Figure 5.6). However, more than 50% of Kashagan’s gross gas extraction is planned to be reinjected. An onshore gas processing plant with 6.2 Bcm/y capacity was built to process Kashagan’s raw gas, which contains significant amounts of sulfur (about 18% H2S and 4–5% CO2). In August 2013, NCOC and KTG signed a long-term purchase agreement whereby KTG would buy 2.5–3.0 Bcm of Phase 1 processed dry gas annually through 2041 (the current expiration of the PSA).

Figure 5.5. Kazakhstan in expected to remain a net gas exporter

<table>
<thead>
<tr>
<th>Year</th>
<th>Commercial gas production</th>
<th>Gas produced</th>
</tr>
</thead>
<tbody>
<tr>
<td>2015</td>
<td>27.1</td>
<td>45.3</td>
</tr>
<tr>
<td>2016</td>
<td>26.0</td>
<td>49.0</td>
</tr>
<tr>
<td>2017</td>
<td>26.5</td>
<td>49.4</td>
</tr>
<tr>
<td>2018</td>
<td>27.1</td>
<td>50.3</td>
</tr>
<tr>
<td>2019</td>
<td>27.9</td>
<td>46.8</td>
</tr>
<tr>
<td>2020</td>
<td>28.4</td>
<td>47.5</td>
</tr>
<tr>
<td>2021</td>
<td>29.6</td>
<td>49.4</td>
</tr>
</tbody>
</table>

Source: Ministry of Energy, Kazakhstan in expected to remain a net gas exporter.

1 KPO shareholders are Eni 29.25%, Shell 29.25%, Chevron 18%, LUKOIL 13.5%, and KMG 10%.
2 Historically, about 8.0–8.5 Bcm annually went to Orenburg, and under the previous contract was slated eventually to rise to 16 Bcm. However, the new contract reduces annual deliveries to no more than 9 Bcm.
3 KPO’s ownership structure changed with Shell’s takeover of BG (one of KPO’s original stakeholders), announced on 8 April 2015 in a cash-and-shares offer valued at £47 billion ($73.9 billion), and completed in February 2016; Shell now holds the entirety of BG’s original 29.25% share.
4 The Karachaganak consortium and the government have studied possibilities for building a 5 Bcm per year gas processing plant under a long-term agreement with KazRosGas, a joint venture between KMG and Russia’s Gazprom, signed in 2007. In June 2015, KPO and KazRosGas extended that deal through 2038, securing an outlet for the bulk of KPO’s current gas production for the remaining period of the field’s PSA.
5 The planned next phase for Karachaganak development remains under discussion, but the scope is being scaled back considerably. In June 2017 it was reported that costs have been reduced to $4.5 billion. In September 2016, Kazakhstan’s Energy Ministry, KMG, KTG, and Shell (a new stakeholder in the KPO consortium after its acquisition of BG) signed a memorandum of cooperation in gas processing and petrochemicals market research.
6 Energy Minister Bournabayev indicated that on-site processing of Karachaganak gas will be considered again.
7 TengizChevron (TCO)’s gross gas output has been rising over the past three years to reach an all-time high of 15.1 Bcm in 2016. About 52% (or 7.8 Bcm) of gross output was reinjected in 2016, leaving 7.2 Bcm available for actual consumption. Gross gas output for Tengiz is expected to remain at current levels until about 2022, when the next phase of expansion (the FGP-WPMP) at the field is completed.
8 While this will raise gross gas extraction, much of the increment is planned to be reinjected, so little additional commercial gas is expected to be produced.
9 About 8.0–8.5 Bcm annually went to Orenburg, and under the previous contract was slated eventually to rise to 16 Bcm. However, the new contract reduces annual deliveries to no more than 9 Bcm.
10 Construction cost for the plant was estimated at $3.7 billion, so in 2014 the plans were put indefinitely on hold. In July 2016 the TCO consortium approved the final investment decision (FID) for the TCO Future Growth Project (FGP-WPMP), which sets the stage for the addition of 12 MMt/y (260,000 b/d) of field production. The project’s costs are estimated at $36.8 billion. TCO plans to drill around 100 wells for the project.
11 About 52% (or 7.8 Bcm) of gross output was reinjected in 2016, leaving 7.2 Bcm available for actual consumption. Gross gas output for Tengiz is expected to remain at current levels until about 2022, when the next phase of expansion (the FGP-WPMP) at the field is completed. While this will raise gross gas extraction, much of the increment is planned to be reinjected, so little additional commercial gas is expected to be produced.
12 The Ministry’s definition of commercial gas volumes is the amount available for distribution to consumers after taking out upstream and midstream usage.
Mangistau Oblast), Tengiz (7.9 Bcm/y capacity in Atyrau Oblast; owned by KMG (2.9 Bcm/y capacity in a gas processing plant. The four main plants are the old chaganak’s gas across the border at Russia’s Orenburg booster station is unusual because the pipelines operating at different pressures: 55 kilogram-force (kgf)/cm

To further increase flexibility in supplies, KTG built a small bypass line between the Orenburg-Taishenkent-Bishkek-Almaty pipeline and Line C of the Central Asia Gas Pipeline system (CAGP). This booster station provides increased energy security, as it establishes an alternative route for uninterrupted gas supply to Almaty that bypasses the territory of Kyrgyzstan. The booster station is unusual because the pipelines operate at different pressures: 55 kilogram-force (kgf)/cm² for the older pipeline and 100 kgf/cm² for new lines (including both high and low pressure).

National gas transmission system

The national trunk gas transmission system reached 15,265 km in 2015–16 (see Table 5.5). Together with the main underground storage facilities, these are owned and operated by KTG’s specialized subsidiary Intergas Central Asia. The trunk transmission system carried 96.2 Bcm in 2016, the bulk of which was actually transit gas (see below).

One of the major recent developments in gas transportation was the 2015 completion of the BBS pipeline.15 This pipeline allows gas produced in the western parts of Kazakhstan to reach not only the southern regions, but it also paves way for the start of large-scale gas exports to China. Gas flows via BBS to southern parts of Kazakhstan to reach not only the southern regions, but it also paves way for the start of large-scale gas exports to China. Gas flows via BBS to southern

Over the past several years Kazakhstan has expanded its national gas transmission system and local pipeline distribution networks to increase the overall level of gasification in the country and to create a unified national pipeline transportation network. This has been a long-held ambition of the government in order to improve energy security as well as to make the economy more “green.” Improving and developing the country’s gas infrastructure was the primary responsibility of KTG. In 2015, KTG reported that it operated a system of 39,300 km of gas pipelines (including both high and low pressure).

6.1.4.7. Gas processing

Table 5.5. Trunk gas pipelines in Kazakhstan

<table>
<thead>
<tr>
<th>Year</th>
<th>Length (km)</th>
<th>Shipments (Bcm)</th>
<th>Average shipment length (km)</th>
<th>Turnover (billion tenge)</th>
<th>Average length of haul (km)</th>
</tr>
</thead>
<tbody>
<tr>
<td>2016</td>
<td>15,265</td>
<td>96.2</td>
<td>327</td>
<td>29.2</td>
<td>326</td>
</tr>
<tr>
<td>2015</td>
<td>15,205</td>
<td>131.7</td>
<td>114.0</td>
<td>31.0</td>
<td>380</td>
</tr>
<tr>
<td>2014</td>
<td>15,129</td>
<td>115.7</td>
<td>118.4</td>
<td>30.8</td>
<td>390</td>
</tr>
<tr>
<td>2013</td>
<td>15,028</td>
<td>115.3</td>
<td>118.8</td>
<td>30.6</td>
<td>398</td>
</tr>
<tr>
<td>2012</td>
<td>15,028</td>
<td>115.6</td>
<td>118.6</td>
<td>30.5</td>
<td>399</td>
</tr>
<tr>
<td>2011</td>
<td>15,028</td>
<td>115.3</td>
<td>118.4</td>
<td>30.8</td>
<td>380</td>
</tr>
<tr>
<td>2010</td>
<td>15,028</td>
<td>115.7</td>
<td>114.0</td>
<td>31.0</td>
<td>326</td>
</tr>
</tbody>
</table>

Source: Ministry of Energy; Statistical Committee of RK; IHS Markit (Eurasian Gas Export Outlook)

5.2.6. Gas transportation

5.2.5. Gas processing

The bulk of Kazakhstan’s gas output requires processing. There are four major gas processing plants (GPDs) in Kazakhstan, a number of smaller plants, and also an important arrangement for the processing of Kachaganak’s gas across the border at Russia’s Orenburg gas processing plant. The four main plants are the old Kazakh plant owned by KMG (2.9 Bcm/y capacity in Mangistau Oblast), Tengiz (7.9 Bcm/y capacity in Atyrau Oblast), Zhanazhol (7 Bcm/y capacity in Aktobe Oblast), and Bolashak (6 Bcm/y capacity in Atyrau Oblast). With the addition of Khashak (Bolashak) processing capacity, these four plants now have the capacity to process 23.8 Bcm/y. In aggregate, together with the availability of Russian capacity at Orenburg, this amount appears adequate to handle the bulk of Kazakhstan’s expected volumes of commercial gas for the next decade or so.

15The portion of the pipeline between Bozy and Shymkent (1,166 km) was completed in September 2013, with the Beyneu-Bozy segment completed in 2015.
the long distances involved. The distance gas would have to travel between Orenburg (after processing) and Shymkent would be 2,704 km (503 km between Orenburg and Aleksandrov-Gay, 726 km between Aleksandrov-Gay and Beynow, and 1,475 km on BBS), of which around 2,580 km would be on Kazakh territory. Currently, tariffs for domestic shipments on most trunk pipelines are set by the regulator at post-stamp-type tariffs that do not reflect distance. For example, the tariff that went into effect in January 2017 was 2,231 tenge/Mcm (~$6.7/Mcm). Given the average length of gas shipments in Kazakhstan (577 km in 2016—see Table 5.5), the average tariff rate for domestic shipments would be about $1.16/Mcm/100 km, which is somewhat higher than average rates in other large systems in countries such as Russia, US, Britain, or France.

Given these improvements, Kazakhstan’s gas pipeline infrastructure is now technically capable of delivering gas from fields in northwest Kazakhstan to southern areas such as Shymkent and Almaty, with settlements were gasified in 2016 in West Kazakhstan, Zhambyl, Mangistau, Aktobe, and Kyzylorda oblasts alone. KTG plans to bring gas to eight more settlements in 2017, including Taldykurgan. KTG has expended considerable effort in South Kazakhstan Oblast:

- In 2017, the Ministry of Energy allocated 500 million tenge to build local gas pipelines to link up to the BBS trunk line.
- In 2015, KTG completed the modernization of the gas distribution system in Shymkent, an undertaking launched in 2009. The project increased the capacity of the gas system from 85 Mcm/hour to 258 Mcm/hour.
- Other efforts to modernize gas networks in South Kazakhstan Oblast included the replacement of dilapidated gas pipelines with new polyethylene ones, replacing old gas distribution points with new ones, optimization of gas distribution networks based on updated hydraulic calculations, introduction of automated systems measuring gas flow to Orenburg, which may be recorded once as raw gas when it leaves Kazakhstan and then included again from its southern border. According to operational data reported by Kazakhstan’s Energy Ministry (DBK), the DBK opened a credit line for KTG Aimak JSC to build gas supply infrastructure in Kyzylorda for 24.7 billion tenge, which covered around 30% of the project costs. KTG also plans to spend over 7 billion tenge (~$20 million) for gas infrastructure in Kostanay Oblast. Furthermore, the EBRD will provide €294 million loan to KTG to finance the modernization and overhaul of the underground gas storage facility at Bozy (€424 million euro), and for the modernization and upgrade of the existing gas distribution infrastructure and construction of new domestic gas supply pipelines in Mangistau and Aktobe regions (~652 million tenge).

### Table 5.6. Length of gas distribution pipelines in Kazakhstan (kilometers)

<table>
<thead>
<tr>
<th></th>
<th></th>
<th></th>
<th></th>
<th></th>
<th></th>
<th></th>
<th></th>
<th></th>
<th></th>
<th></th>
</tr>
</thead>
<tbody>
<tr>
<td>Total for Kazakhstan</td>
<td>13,562</td>
<td>14,869</td>
<td>16,280</td>
<td>17,779</td>
<td>20,248</td>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td>Astana city</td>
<td>1,447</td>
<td>1,438</td>
<td>1,411</td>
<td>1,386</td>
<td>1,386</td>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td>Aktau city</td>
<td>1,727</td>
<td>1,715</td>
<td>1,699</td>
<td>1,675</td>
<td>1,675</td>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td>Almaty city</td>
<td>2,094</td>
<td>2,097</td>
<td>2,087</td>
<td>2,075</td>
<td>2,075</td>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td>Zhambyl</td>
<td>540</td>
<td>540</td>
<td>540</td>
<td>540</td>
<td>540</td>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td>Mangistau</td>
<td>1,100</td>
<td>1,098</td>
<td>1,093</td>
<td>1,090</td>
<td>1,090</td>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td>Aktobe city</td>
<td>1,346</td>
<td>1,346</td>
<td>1,346</td>
<td>1,346</td>
<td>1,346</td>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td>Mangistau</td>
<td>1,346</td>
<td>1,346</td>
<td>1,346</td>
<td>1,346</td>
<td>1,346</td>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td>South Kazakhstan</td>
<td>1,353</td>
<td>1,353</td>
<td>1,353</td>
<td>1,353</td>
<td>1,353</td>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td>North Kazakhstan</td>
<td>1,117</td>
<td>1,117</td>
<td>1,117</td>
<td>1,117</td>
<td>1,117</td>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td>East Kazakhstan</td>
<td>1,117</td>
<td>1,117</td>
<td>1,117</td>
<td>1,117</td>
<td>1,117</td>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
</tr>
</tbody>
</table>

**Source:** Kazexp.org; Centre Kazakhstan, Energy, and Economy.

Kazakhstan’s primary energy consumption outlook

![Figure 5.7. Kazakhstan’s primary energy consumption outlook](image)

17 A major issue in the calculation of apparent consumption is the volume of exports. National customs statistics report exports as exceeding 20 Bcm in 2011–16, an amount nearly as large as total commercial volumes available (see Table 5.4). Nearly all of Kazakhstan’s gas exports go north, to Russia, but Russia reports that it receives only 10.2 Bcm from Kazakhstan at its southern border. According to operational data reported by Kazakhstan’s Energy Ministry (DBK), some of the exports were classified as “apparent” gas consumption. This is a result of the volume of exports as exceeding 20 Bcm in 2011–16, an amount nearly as large as total commercial volumes available. In 2015, the volume of gas shipped north were 20.2 Bcm. The reason for these sizable discrepancies in reported export stems from the statistical treatment of Kazakh gas flowing to Orenburg, which may be recorded once as raw gas when it leaves Kazakhstan and then included again when it reenters Russia after being processed under the existing swap arrangements with Gazprom.
5.2.8. Domestic gas supply

While much of domestic consumption is met with its own indigenous production, Kazakhstan also imports some gas from Uzbekistan and Russia, in the south and south of the country, respectively. In 2016, Kazakhstan reported its total imports as 6.9 Bcm, which would represent about 30% of total apparent consumption. Russia’s Gazprom Export reported that it delivered 2.9 Bcm to Kazakhstan last year. Gazprom’s Annual Report for 2016 says that it supplied a total of 4.7 Bcm to Kazakhstan in 2016, of which 1.9 Bcm was Uzbek gas delivered to southern Kazakhstan. Kazakhstan’s national customs statistics report that it imported 3.9 Bcm from Russia, 1.7 Bcm from Uzbekistan, and 1.3 Bcm from Turkmenistan. The answer lies in either moving more gas to Kazakhstan or to increase imports, and one of the considerations for this is the price of gas. Because Russia is long on gas, there should be no particular problem in continuing imports from the north. However, in the south, Uzbekistan’s gas balance is becoming increasingly tight (due to rising domestic consumption), so in the south the main supplier is likely to become Turkmenistan rather than Uzbekistan. Turkmenistan is also long on gas and should be interested in making it available to Kazakhstan on regular commercial terms. According to the Ministry of Energy’s long-term forecast as specified in the country’s official gasification program (currently under revision), the amount of commercial (end-of-pipe) gas available to consumers by 2030 is about 21 Bcm (see Table 5.3). About 18.1 Bcm of the available commercial gas in 2030 is projected to be consumed domestically, under the “realistic” scenario, while the remainder is expected to be exported. In 2040, the sectoral breakdown of consumption is expected to be as follows: industrial enterprises are projected to consume about 5.7 Bcm, electric power plants about 7.2 Bcm, and residential-commercial users 5.2 Bcm. Geographically, 35% of consumption in 2030 is forecast for western Kazakhstan, 42% in southern and eastern Kazakhstan, and 23% in northern Kazakhstan.

5.2.9. Domestic gas consumption outlook

Longer term, the role of gas in the national economy is expected to grow and to become more prominent in the overall energy balance. This growth is expected to occur on a number of fronts, including growing industrial consumption, conversion of some coal-fired combined heat-and-power plants (TETs) to gas, and construction of new gas-fired generation capacity; this will require expansion of both the trunk pipeline system as well as local distribution networks. IHS Markit expects the share of gas in national primary energy consumption to increase to about 26% by 2020, 30% by 2030, and 38% by 2040 (see Figure 5.7). Gas consumption (end-of-pipe deliveries) is projected to increase at an average annual rate of 2.9% between 2016 and 2040, to reach nearly 21 Bcm in 2030 and 27 Bcm in 2040 (see Figure 5.8) in Kazakhstan.

Table 5.7. Consumption of Natural Gas Delivered by Pipeline (million cubic meters)

<table>
<thead>
<tr>
<th>Year</th>
<th>Eastern Kazakhstan</th>
<th>Southern Kazakhstan</th>
<th>Other Kazakhstan</th>
<th>Western Kazakhstan</th>
</tr>
</thead>
<tbody>
<tr>
<td>2004</td>
<td>0.0</td>
<td>0.0</td>
<td>0.0</td>
<td>0.0</td>
</tr>
<tr>
<td>2007</td>
<td>2.872</td>
<td>3.099</td>
<td>0.684</td>
<td>0.729</td>
</tr>
<tr>
<td>2008</td>
<td>3.023</td>
<td>3.684</td>
<td>0.751</td>
<td>0.795</td>
</tr>
<tr>
<td>2009</td>
<td>3.625</td>
<td>4.034</td>
<td>0.795</td>
<td>0.849</td>
</tr>
<tr>
<td>2010</td>
<td>3.023</td>
<td>4.034</td>
<td>0.795</td>
<td>0.849</td>
</tr>
<tr>
<td>2011</td>
<td>3.625</td>
<td>4.034</td>
<td>0.795</td>
<td>0.849</td>
</tr>
</tbody>
</table>

Source: Oil and Gas Kazakhstan, No. 1, 2010, p. 222; (data for 2012-2013 from Kengis).

Notes: Tabled statistics include data from the national gas distribution system as well as processing losses as well as midstream uses (pipelines and any changes in stocks) (see Figure 5.5). The key question for domestic consumption involves solving the disparity between growing demand in areas such as southern Kazakhstan and the location of domestic gas production, mainly in western Kazakhstan. The answer lies in either moving more gas long distances between sources of production and consumption or to increase imports, and one of the considerations for this is the price of gas. Because Russia is long on gas, there should be no particular problem in continuing imports from the north. However, in the south, Uzbekistan’s gas balance is becoming increasingly tight (due to rising domestic consumption), so in the south the main supplier is likely to become Turkmenistan rather than Uzbekistan. Turkmenistan is also long on gas and should be interested in making it available to Kazakhstan on regular commercial terms.

5.3.1. Gasification program

Among the more ambitious goals of the drive to increase the share of gas in the country’s future energy consumption is the gasification of the Astana region. A number of plans have been proposed in recent years. In 2012, President Nazarbayev called for the construction of an 895 km pipeline connecting Karyta (in Russia’s Chelyabinsk Oblast) with Astana. The pipeline, which originally would source Russian
NATIONAL ENERGY REPORT

This is the minimum amount needed to cover capital costs, operating costs, and 12% VAT based upon average expected throughput volumes over 20 years.

The cost of constructing the Kartaly-Astana pipeline, estimated in 2014 at $1.3 billion, likely would also be lower after a new gas processing plant would be completed there. By late 2014, however, the unfavorable external economic environment made the combined cost of constructing the pipeline and processing plant prohibitive and the project was postponed.21 At roughly the same time, consideration was given to supplying the city with LNG produced from coal-bed methane (CBM) at a large liquefaction plant (or plants), and delivered to the city by truck or rail. Support for these plans appears to have waned recently as well, as CBM resource development projects have lagged, and small-scale LNG imports from Russia (Yekaterinburg) have commenced to supply selected users in Astana (see section 5.3.3 below on coal-bed methane development). Another alternative now in development is phase 1 of the SaryArka pipeline (1,076 km), which would source western Kazakhstan natural gas from the existing BBS pipeline and deliver it to Astana, with the additional benefit of supplying the industrial cities of Zhezkazgan and Karaganda en route (see Figure 5.9).22 Because the total transport distance (including along roughly half the length of BBS) is quite long, SaryArka could potentially deliver gas from western Kazakhstan (Atyrau-Mangistau oblasts) to Astana at a cost of ~$147/Mcm (assuming procurement cost of gas from producers at ~$52/Mcm) (see Figure 5.10). The shorter, previously proposed Kartaly-Astana pipeline could potentially deliver gas to Astana from Russia at a cost of ~$147/Mcm, assuming Russian gas can be procured at an average import price of ~$50/Mmcf.23 SaryArka’s lower projected capital costs appear to provide a major advantage, partly because no gas processing plant would need to be constructed and partly as a result of the lower overall cost environment following the tenge devaluation in 2015. Total capex for phase 1 of SaryArka is expected to be $756 million versus $1.3 billion estimated in 2014 for Kartaly-Astana (see Table 5.8). The indicative cost recovery tariff for SaryArka phase 1 would be $47/Mcm compared to $81/Mcm for Kartaly-Astana.24

Kazakhstan’s “operational” exports of natural gas in 2016 amounted to 12.7 Bcm ( invoiced exports are much higher, 21.6 Bcm in 2016—see above). Kazakhstan exported 12.3 Bcm northward, essentially to Russia (of which Karachaganak gas was 9.6 Bcm), and 0.5 Bcm went east to China. Kazakhstan currently exports small volumes of natural gas to China from the small and remote Sarybulak field in eastern Kazakhstan to a small gas liquefaction plant in western China. These small-scale exports to China commenced in 2013. Kazakhstan’s gas exports to Russia are expected to remain important as part of the established relationship with the Orenburg gas processing plant (expected to continue), although the overall volumes are projected to decline slightly longer term. Exports to China (via CAGP) are projected to start relatively soon (probably by 2019–20), but volumes will remain small both because of a relatively low availability of commercial gas volumes in Kazakhstan and because of China’s diversified supply portfolio and current market oversupply.25 In June 2017, KMG and China’s CNPC signed a deal to supply up to 5 Bcm of Kazakhstan gas to China over the next two years. This is a reaffirmation of the intergovernmental agreement between Kazakhstan and China, initially signed in 2007 to deliver up to 10 Bcm/y to China. However, this much gas is unlikely to be available for export in the period to 2030. In our base case, total exports shrink to about 7 Bcm in 2025, but rise thereafter, reaching about 15 Bcm in 2040. Russia remains the major destination, with Chinese exports reaching a maximum of 6 Bcm in 2040 (see Figure 5.11). Longer term IHS Markit expects Kazakhstan to remain a net gas exporter, although for some regions continued imports will remain economically beneficial due to logistics and costs; in particular, it will make sense to continue to import gas from Uzbek-

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21 The cost of the gas processing plant at the time was estimated at $3.7 billion, and the pipeline itself at $1.3 billion.
22 SaryArka phase 2 would extend northward another 450 km from Astana to Kokshetau and Petropavlovsk.
23 The cost of constructing the Kartaly-Astana pipeline, estimated in 2014 at $1.3 billion, likely would also be lower now after tenge devaluation.
24 This is the minimum amount needed to cover capital costs, operating costs, and 12% VAT based upon average expected throughput volumes over 20 years.
25 In 2016, with the installation of the Bozoy and Karaozek compressor stations, gas exports to China from Kazakhstan became technically possible.
stan and (increasingly) Turkmenistan in the south of the country (despite the availability of BBS) and Russian gas in the north to Kostanay Oblast.26

Figure 5.11. Outlook for Kazakhstan’s gas exports (base case)

Besides the question of gas availability to fill the BBS pipeline, the tariff for BBS was set by the regulator at 18.071 tenge/Mcm, or the equivalent of about $52.4/Mcm. This is relatively expansive compared with the general trunk pipeline tariff of $6.7/Mcm, although it is only about 43% of the estimated tariff needed to actually recover costs (see Table 5.8). Even so, current prices for industry in southern Kazakhstan are about $75/Mcm, so KTG loses money on gas volumes delivered to southern Kazakhstan via BBS: acquisition costs in western Kazakhstan are only about $22/Mcm, but when added to the BBS tariff already brings cost up to about $75/Mcm, without including VAT, distribution costs, etc. In comparison, in 2016, the average import price for Uzbek gas was about $65/Mcm, although the import price for Turkmen gas was considerably higher, at over $150/Mcm.

Table 5.9. Kazakhstan’s gas transit (billion cubic meters)

<table>
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</tr>
</thead>
<tbody>
<tr>
<td>Shipment via CAGP to China</td>
<td>7.9</td>
<td>7.0</td>
<td>6.9</td>
<td>6.7</td>
<td>8.7</td>
<td>8.3</td>
<td>7.4</td>
</tr>
<tr>
<td>from Turkmenistan</td>
<td>3.0</td>
<td>3.5</td>
<td>2.3</td>
<td>2.8</td>
<td>3.8</td>
<td>3.4</td>
<td>3.1</td>
</tr>
<tr>
<td>from Uzbekistan</td>
<td>4.0</td>
<td>4.0</td>
<td>4.5</td>
<td>4.8</td>
<td>5.7</td>
<td>6.3</td>
<td>6.2</td>
</tr>
<tr>
<td>Shipment to Russia from Central Asia</td>
<td>22.2</td>
<td>15.9</td>
<td>19.2</td>
<td>16.6</td>
<td>14.6</td>
<td>6.6</td>
<td>6.2</td>
</tr>
<tr>
<td>from Turkmenistan</td>
<td>10.7</td>
<td>9.5</td>
<td>10.9</td>
<td>10.8</td>
<td>13.0</td>
<td>3.1</td>
<td>0.0</td>
</tr>
<tr>
<td>from Uzbekistan</td>
<td>11.4</td>
<td>6.4</td>
<td>8.3</td>
<td>3.7</td>
<td>3.5</td>
<td>6.2</td>
<td>6.2</td>
</tr>
<tr>
<td>Residual (Russian gas)</td>
<td>50.8</td>
<td>45.6</td>
<td>33.6</td>
<td>20.7</td>
<td>43.3</td>
<td>44.3</td>
<td>31.3</td>
</tr>
</tbody>
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5.2.12. Gas pricing in Kazakhstan

Kazakhstan’s gas procurement prices for producers are governed by the rules set out in the 2012 Law on Gas and Gas Supply, which prescribes that they should include the cost of producing and processing gas as well as the transportation costs to the point where the “national operator” (still apparently KTG) takes title, and a profit margin no higher than 10%. However, there has been some concern that it will be hard to ensure that these costs are in fact covered by the offered purchase price, since the state-owned buyer holds a much stronger bargaining position. At the end of 2016, the average gas price received by Kazakhstan’s producers was only $22 per Mmc, which requires minimal processing, current prices may still yield a positive return. However, for higher cost producers, particularly those that need to gather and process their associated gas, the current price does not really cover costs.

At the consumer level, gas prices are regulated by the State Committee for Regulating Natural Monopolies and Competition Protection (KREMIZK). KREMIZK’s concern is to keep prices affordable for consumers, and it views the current level of producer prices as being too high to effectively achieve this objective. KREMIZK also regulates tariffs for domestic gas transport and storage. Kazakhstan’s consumer gas prices vary within the country and are affected by several important factors. The first is the acquisition cost of natural gas. In oblasts that depend on imported gas, end-user prices reflect higher acquisition costs, while in oblasts with domestic gas supply end-user prices are lower. Prices of imported gas have risen steadily over the past decade. The average price for imported gas was about $55 per Mmc in 2008, while in 2013 it increased to about $95/Mmc before falling to $69/Mmc in 2016. The second factor is the transportation component, or the distance gas must travel to reach consumers, as this affects KTG’s costs, and finally an investment component that reflects what is being spent on gasification in each region. There is also some differentiation between industrial and household gas prices. Generally, industry prices are higher, although in the import-dependent regions the difference is less significant (see Figure 5.13).

Figure 5.12. Average producer price for natural gas in Kazakhstan (in December each year)
Over the longer term, end-user natural gas prices are planned to be harmonized with those in the Russian Federation as part of a general movement towards the open economic space within the Eurasian Economic Union. This concept was reinforced with the 2011 ratification of the agreement “On the Rules for Granting Access to the Services of the Natural Monopolies in the Gas Transportation Sector and on the Pricing and Tariff Policies in the Countries Participating in the Common Economic Space,” which is supposed to lead to price harmonization.

Given that gas production, trade, and the size of the domestic market in Russia is much larger than in any other EAEU members, it stands to reason that domestic prices in Kazakhstan will converge with the domestic prices in Russia rather than vice-versa. The process of forming the EAEU’s unified gas market is proceeding along a path agreed upon by the member states (see text box).

As Kazakhstan continues toward end-user gas price harmonization, the key question for policymakers is which Russian pricing zone should Kazakhstan’s domestic prices be harmonized (especially in western Kazakhstan)?22 Russian industrial consumers in the gas-producing area of the Yamal-Nenets Okrug in West Siberia paid $42.8/Mcm in late 2016, compared with an industrial price of $75.1/Mcm in Saratov Oblast, a gas-consuming province in European Russia that neighbors Kazakhstan to the northwest—a difference of about 75%. Such regional disparities around the mean price within Russia are expected to continue going forward. In the gas-producing areas in western Kazakhstan, domestic prices paid by industrial consumers were roughly equivalent to the prices paid by industrial consumers in the gas-producing Russian price zones: for example, prices in Atyrau Oblast at the end of 2015 were $30.2/Mcm, compared with $37.7/Mcm in Yamal-Nenets (see Figure 5.14); however, at the end of 2016 this had dropped to $24.6/Mcm in Atyrau versus $42.6/Mcm in Yamal-Nenets Okrug.

Kazakhstan should harmonize its prices with the lower industrial prices found in gas-producing zones in West Siberia and not with the higher prices in consuming regions in European Russia. This would allow industry in western Kazakhstan to remain competitive within the broader economic space of the EAEU and will make for an easier adjustment for consumers. In this scenario, gas prices in western Kazakhstan would follow essentially the same trajectory as the Yamal-Nenets Okrug in Russia, with prices moving upward basically at the rate of domestic (Russian) inflation after closing the gap back up in 2017–20 (see Figure 5.14).

Achieving a unified gas market within the Eurasian Economic Union

The Eurasian Economic Union (EAEU) – the next stage of economic integration after the Customs Union (2010) between the three founding members Russia, Kazakhstan, and Belarus - began operating on 1 January 2015, with Armenia joining on 2 January and Kyrgyzstan formally joining in August 2015. The Union seeks to create a common market and ensure free movement of labor, capital, goods, and services within its borders. The process of forming the EAEU’s unified gas market is proceeding upon an agreed path formulated in the Concepts for the EAEU Gas Market (completed in 2016), to be followed by development of programs for each national market by 1 January 2018 (specifying explicit actions to be taken by EAEU countries).23 Finally, international legal agreements among the countries are to be concluded by 1 January 2024 and put in force by 1 January 2025.24

The approved EAEU gas market Concept sets a three-stage integration path (see Decision No. 7 of the Supreme Eurasian Economic Council dated 31 May 2016). The first stage, which is to be implemented by the year of 2020, envisages:

- harmonizing the legislation of the Member States with regard to the EAEU common gas market regulation;
- ensuring availability (accessibility) and complete disclosure of information on available (free) capacities in the gas transportation systems located in the territories of the Member States
- unifying gas-related standards and regulations of the Member States as well as engineering/technical standards, regulations, codes and specifications governing operation of the gas transportation systems located in the territories of the Member States
- creating an information exchange system providing information on domestic gas consumption as well as gas transportation and supply pricing in the territories of the Member States, including wholesale gas prices and tariffs for gas supply through gas transportation systems;25
- developing and approving common rules of access to the gas transportation systems located in the territories of the Member States;
- establishing the procedure for gas exchange trading in the EAEU common gas market approved by the competent authorities of the Member States;26

22 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.

23 Approval of the Concept on Gas Markets by the EAEU Supreme Eurasian Economic Council occurred on 31 May 2016, while the EAEU’s Intergovernmental Council approved the draft of the oil and oil products market Concept on 20 May 2016.

24 Each country will determine its own transportation tariff.

25 The right of equal access to the EAEU gas pipeline infrastructure means that companies from one EAEU country have the same right to access pipeline infrastructure in another EAEU country as do other country’s gas producers who are not owners of the pipeline infrastructure; this implies that Gazprom still might have priority access to its own pipelines in Russia, for example.
5.2.13. LPG: production, consumption, transportation, and global trends

Production of liquefied petroleum gases (LPGs; propane and butane) in Kazakhstan increased from 2.5 MMt in 2014 to 2.7 MMt in 2016. The change is mainly due to a 194,000 ton increase in output by the Zhanazhol gas processing plant (owned by CNPC-Ak Tobemunaygaz). Accordingly, the share of Zhanazhol’s output in total LPG production increased from 10% in 2014 to 17% in 2016 (see Figure 5.15). While most of the produced LPG continues to be exported, export volumes are decreasing: exports amounted to 2.1 MMt in 2016 compared to 2.3 MMt in 2014. In terms of destination countries, Turkey remained the leading buyer of LPG from Kazakhstan, purchasing 0.5 MMt in 2016 (compared to 0.6 MMt in 2014), followed by Poland (0.4 MMt in 2016) and Tajikistan (0.3 MMt). Higher LPG production, coupled with lower exports, indicates that the apparent consumption of LPG in Kazakhstan grew substantially, from about 270,000 tons in 2014 to 620,000 tons in 2016. Wholesale prices in the domestic market and domestic delivery volumes remain under state regulation (Law on Gas and Gas Supply) and are set on a quarterly basis. In September 2014, authority over LPG market regulation was transferred to the Energy Ministry, including the authority to set a wholesale price ceiling and to develop a monthly domestic supply schedule. Amendments made in February 2015 to the formula that sets the wholesale price ceiling changed the discount coefficient: instead of comparing per capita income in Kazakhstan with that in Russia, the coefficient now reflects the level of gasification in

34 Meeting domestic consumption in each Member State has priority over exports.

33 The Consulting Committee is a working group developing proposals and recommendations on strategic issues in relation to gas transportation and supply between the Member States, under Article 9 of the Treaty of the EAEU.

32 Amendments made in February 2015 to the formula that sets the wholesale price ceiling changed the discount coefficient: instead of comparing per capita income in Kazakhstan with that in Russia, the coefficient now reflects the level of gasification in

5% of the current quarter. As the result, wholesale price ceilings increased from 11,000 tenge (~$33) per ton in Q2-2016 to 23,000 tenge (~$67) in the following quarter, to 28,000 tenge (~$86) in 1Q-2017 (see Figure 5.16). This administrative approach to the LPG market has led to periodic regional deficits as well as surpluses, as real demand has significantly deviated from the schedules compiled by the Ministry of Energy of RK. Market liberalization would address these recurring problems.

According to the Statistics Committee, there were 3,683 LPG-consuming vehicles (including buses, vans, and trucks) in Kazakhstan by Q2-2017, or 0.9% of the registered light vehicle fleet of 3.85 million. Meanwhile, the number of mixed use vehicles (presumably mainly LPGs) doubled from 67,761 vehicles in 2015 to 133,786 vehicles at the beginning of 2017, or 3.5% of the total fleet. Regionally, Mangystau Oblast has the highest share of mixed vehicles (40%), followed by Aktobe at 14%. For LPG-only vehicles, around 18% were registered in Almaty City, 9% in Almaty Oblast, and 11% in Aktoobe Oblast. Kazakhstan’s LPG retail market is dominated by specialized retail players. Some major ones include Bey
Global LPG trends

The world’s total LPG supply expanded by 17 MMt to 295 MMt between 2014 and 2016, as global propane output increased by 8 MMt to 159 MMt, while production of butane grew by 8 MMt to 136 MMt (see Figure 5.17). This increase has been driven largely by growing hydrocarbon output from unconventional plays (shale gas and tight oil developments) in North America. Specifically, since 2013, North American LPG production grew by 15 MMt, reaching 85 MMt in 2016. Global demand growth in concentrated mainly in China and India; demand in Europe, North America, and the Middle East actually declined marginally. The massive increase in US LPG production has impacted trade patterns. US propane exports, most of which went to China, increased from 13 MMt in 2014 to 295 MMt in 2016 (23% of the world’s total propane exports) to over 18 MMt in 2016 (28%). China’s growing domestic demand has driven import demand up to 13 MMt in 2016 from 5 MMt in 2014, surpassing imports to all of Latin America (10 MMt in 2016). In Europe, propane imports from the US displaced propane originating in the Middle East and Africa, while imports from the CIS grew incrementally from 3.5 MMt to 4.1 MMt. Growth in butane demand came primarily from the Far East and India, and was met mainly by exports from the Middle East.

Going forward, IHS Markit projects that global LPG production will grow from 295 MMt in 2016 to 360 MMt in 2025. Almost 40% of this increase is expected to come from unconventional plays in North America, and one quarter from the Middle East. Absorbing this increase will be a challenge, but 40% of the demand growth during this period will be in the Far East region (primarily China), and another 18% from India. In terms of sectors, 60% of the projected increase in demand is expected to come from the residential/commercial sector, and 30% from the petrochemical sector. China will remain the major propane importer, with its share of total world imports growing from 19% in 2016 (13 MMt) to 29% in 2025 (22 MMt), while India, Latin America, and the Southeast Asian countries will also increase propane imports. The sizable growth in expected output, as noted previously in the National Energy Report 2015, is likely to put downward pressure on prices for LPG—which traditionally has been priced as a specialty refined product rather than as a gas-based fuel—in particular regions. These traditional pricing arrangements have been coming under increased pressure, particularly in North America, and it is not inconceivable that a similar situation could unfold in Europe, as intensifying competition between US and Middle East exports leads to weakening LPG prices.24

A move towards gas-based, rather than niche (reﬁned product) pricing of LPG in Europe would have important consequences for Kazakhstan. Kazakhstan is a relatively small supplier and therefore a price taker. Kazakhstan presently absorbs only a limited amount of the LPG it produces, exporting roughly three-fourths of its total output. It thus seems prudent for policymakers to undertake contingency planning focused on additional measures to increase LPG consumption domestically where possible: further expanding its use in the transport sector, extending its availability to residential/commercial consumers in areas where piped gas is unavailable, and developing a petrochemical industry in sectors that utilize LPG as a feedstock.25 Policymakers should implement fiscal incentives to fueling station owners to install necessary infrastructure to purchase, store, and sell LPGs. Kazakhstan should also consider offering tax credits to consumers who either refurbish their cars, to handle cleaner fuel, or purchase new cars with engines capable of handling LPGs (see Recommendations).

5.24. Sulfur utilization update

Kazakhstan’s sulfur production has continued to grow in recent years, reaching 2.54 MMt in 2016. TCO continued to be the largest sulfur producer, with an output of 2.33 MMt in 2016, compared to 2-MMt in 2014–15. The Future Growth Project (FGP) is not expected to cause sulfur output to increase significantly, as the associated gas will be reinjected to maintain reservoir pressure for oil production. At Kachagan, sulfur production is expected to reach about 1.1 MMt/y with phase 10 of output. Recent upgrades at the Shymkent and Atyrau refineries have also increased the country’s sulfur production capacity (see Chapter 4). A 4,000 tons/y sulfur production unit in Shymkent was commissioned in December 2015. The unit produced 534 tons of sulfur in 2016, and is expected to produce 481 tons in 2017.

5.3. INFRASTRUCTURE AND TECHNOLOGIES: KEY CHALLENGES, IDEAS AND SOLUTIONS

Natural gas is widely considered to be an important fuel bridging the transition from high-carbon-emitting coal to renewables. Natural gas is viewed as taking on the important role of providing flexible power while displacing coal in power generation. However, the role of gas as a bridge fuel globally has come into some question as a result of the recent rapid build-out of renewable power worldwide. A hotly debated topic is now the price of future electricity from renewables. Can the costs of renewables continue to come down, ultimately to levels below those of coal or natural gas? Proponents of renewables say yes, whereas sceptics are undecided or negative. It is important, however, when considering this question to add the broader costs of renewables into the equation (beyond generation costs, there are costs associated with back-up generation and connection to the grid). One factor that could conceivably disrupt or attenuate the seemingly indispensable role allotted to natural gas as a bridge fuel is more rapid than expected development of grid battery storage technology. Views vary greatly on the likelihood and timing of such disruption. IHS Markit does not expect battery storage to have a significant impact on the industry until after 2050. But this is the technology that everyone is now watching. Even if the transition to renewable energy is more rapid than currently anticipated (and advances in battery storage capacity proceed apace), natural gas will still have a role to play. Natural gas is considered to be a perfect back-up fuel for the intermittent renewables, ready to promptly enter the grid when needed. The proliferation of renewables is often predicated on ensuring that sufficient backup generation capacity exists (e.g., during dark, cloudy, and windless periods), and if new capacity is needed, natural gas often is the most obvious choice.

5.3.1. Gas in petrochemical applications

Ambitious plans to establish a major gas-based petrochemical industry at two sites in western Kazakhstan (Tengiz and Karabatan) have suffered a major setback in the current difficult economic environment. The big blow was the announcement by LG Chem, South Korea’s largest chemicals company, to pull out of a planned project to build a $4.2 billion ethylene-polyethylene facility at Karabatan, near Atyrau.26 This announcement was made at the end of 2015, citing rising costs and falling oil prices, despite the fact that Karabatanis located within the boundaries of a National Industrial Petrochemical Technopark (special economic zone) set up by presidential decree in 2007 that would enjoy significant tax benefits and other privileges. The planned complex was to produce olefins (ethy-
are proceeding in other low-cost feedstock locations though it must be recognized that major investments of demand and pricing for petrochemicals, associated utilities, whereas the steam cracker, but-
tene-1 unit, and the polypropylene and polyethylene production units would be located at the Karabatan site. A 200 km pipeline was planned to transport ethane extracted in the GSU to Karabatan, while rail transport was to be used for the extracted propane (see Figure 5.18).

The withdrawal of LG Chem has effectively stopped progress on phase 1 for now, but UCC announced that it still plans to proceed with the other part of the complex. UCC announced in August 2016 that it was still planning to complete the polypropylene production line, a unit for producing technical gases (evidently using the Solway process), and a gas turbine power plant with a generating capacity of 310 MW. Importantly, UCC did launch a new polymer products

5.3.2. Use of natural gas in transportation and other potential uses for natural gas

Global trends in use of natural gas in transportation

The use of cleaner alternative transportation fuels, including natural gas, has been promoted by many governments, as concerns of pollution and human impact on the environment became more prominent in public discourse. Use of natural gas in transportation also answers a key strategic policy goal for the future, including transportation, liquefaction (if necessary), and end-markets (building heat, process, industrial, and small-scale LNG). Although with the narrowing price gap between the fuels in the past few years with much lower oil prices, the rate of penetration of gas vehicles has slowed. In addition to liquefied petroleum gases (LPGs; i.e., propane and butane), which are used widely in automobiles in Kazakhstan and elsewhere, there are two forms in which natural gas (methane) has been used in motor vehicles globally: compressed natural gas (CNG) and liquefied natural gas (LNG). Unlike oil and oil products, which can be easily transported and stored for essentially unlimited periods of time, and used in a variety of machines, the properties of natural gas require special vehicles, storage, and supply-chains. Promoting greater CNG/LNG use in Kazakhstan will therefore require significant investments by private and public authorities throughout the value chain, including transportation, liquefaction (if using associated gas from domestic fields), transportation, regasification, and end-markets (building demand by encouraging vehicle switching). Globally, the following trends have emerged with respect to fostering greater LNG/CNG use in transportation:

- **CNG/LNG use is challenged in light-duty vehicles (passenger cars), due to fuel density and on-board storage issues, as the fuel tank occupies much of the useful space and the vehicle still would not be able to travel more than 100–200 km without refueling.**

- **The switch to CNG/LNG can be more easily made for medium- and heavy-duty vehicles (trucks and buses):**

- **CNG, for example, is widely used in urban/commercial fleets that have a short range and return to the same base each day, such as garbage trucks and city buses. These types of vehicles have a predictable and relative short routes that makes both of the key challenges for CNG use in transportation—storage/ fueling infrastructure and travel distance—more manageable. Additionally, these larger fleets tend to be managed by a company that is able to take advantage of economies of scale when fueling and operating the vehicle fleet.

- **LNG, on the other hand, has found its widest use in long-haul trucking. This is because an LNG tank holds more fuel than a CNG tank, as the natural gas is held in a denser, liquefied form.**

IHS Markit projects that globally the use of natural gas in road transportation will grow at an average rate of 5.9% annually between 2016 and 2040 (albeit from a small base), reaching 202 MMtoe in 2025, 116 MMtoe in 2030, and 184 MMtoe in 2040. The share of natural gas in road transportation will remain relatively small, however: only 7.2% in 2040, with the majority share still held by gasoline at 49% and diesel at 41%.10
LNG in trucking and small-scale LNG: China and global trends

China has been leading the global shift to LNG in trucking, due to a large price differential between diesel and natural gas historically, demand for flexible gas supplies (especially during peak times of usage or by residential users currently outside gas grid coverage), as well as the need to establish an entirely new supply infrastructure in any case, instead of trying to adapt a large existing one. However, the rate of penetration is slowing, following gas price reforms (beginning in 2013) that raised gas prices while diesel prices have declined. Earlier, consumers were highly motivated to either retrofit their diesel-fired trucks or buy new factory-built models to run on LNG because the payback time for such investment was under 12 months. But as the price gap began to narrow, the payback period of the higher investment rose, lessening the overall appetite for switching from diesel to LNG. Although payback periods in key regions in China are still favorable, the concerns over future price reform and its implication for the truck fleet operators’ bottom line began to slow the growth of LNG transport in China. Also, on the gas supply side, Chinese LNG consumption has yet to match the expectations of domestic growth and have been constrained to record levels of LNG contract volumes. With the global gas market expected to be in oversupply through 2023, China will be importing LNG at extremely competitive prices, which will be competing with domestic small-scale LNG delivered to consumers in coastal provinces; large-scale LNG imports grew by almost 38% in 2016.

Nonetheless, tightening the fuel and emissions standards in China have helped retain the relative competitiveness of natural gas versus diesel in trucking.

Another factor helping sustain gas competitiveness in this sector is that the Chinese government raised oil taxes during the low oil price environment of late 2014 through mid-2016, so the diesel price for end-consumers did not fully reflect the decrease in global oil prices. The increase of LNG-fired trucks in China is impressive: from essentially zero LNG-fueled vehicles in 2008; there were ~260,000 LNG trucks on the road in 2016. By the end of 2016, there were about 2,700 LNG fueling stations in China, supported by a sizable small-scale inland liquefaction capacity (i.e., in addition to the large coastal import facilities) of 26.9 MMt.

Despite the continued positive developments in trucking, recent changes in market fundamentals have adversely impacted China’s small liquefaction business more generally. China’s gas market has quickly turned from supply constrained to oversupplied, reducing the need for gas outside of the traditional pipeline system. Declining prices of competing fuels—such as diesel and LPG—and other gas supply sources (e.g., coal) also reduce the cost competitiveness of domestically produced LNG. In 2016, only 2.9 MMt of small liquefaction capacity was added in China, representing only 12% annual growth, dropping from 25% in 2015 (and compared with 49% average annual growth in 2010–14). A further 15–16 MMt is currently under construction, and 10.1 MMt is in the planning phase, although some may face delays. As such, the sector’s capital oversupply situation, utilization of this capacity has been somewhat low, falling from around 56% in 2014 to 38% in 2016. Since 2014, gas production from small LNG plants in China has remained relatively stagnant, accounting for 6.4% of total gas supply in 2016. If before 2008 most of China’s small LNG supply came from “stranded gas” in small fields, at present an increasing number of new LNG plants are using unconventional gas as feedstocks. Several plants are using CBM, taking advantage of CBM volumes that have struggled to find pipeline access to the market. The first liquefaction facility to use shale gas as a feedstock came online in early 2015 and a second is now under construction. A few plants also use coxing gas as feedstock.

The importance of state policy in shaping gas use in China’s transportation sector is not an anomaly. Government subsidies and policies have been a prime reason for the adoption of CNG and LNG as a transport fuel worldwide. In China, policy support for natural gas in transport recently was further strengthened in the National Development and Reform Commission’s 13th Five-Year Plan for Natural Gas Development. For the first time, the 13th FYP specifically mentions supporting policies for natural gas vehicles and vessels and sets targets to increase the total natural gas vehicle fleet (of all types) to more than 10 million by 2020 and the total number of vehicle refueling stations (CNG and LNG) to more than 12,000 by end-2020 (up from 6,500 at the end of 2015).

Although nowhere else has the scale of conversion matched that of China, other countries have seen some shift to natural gas in transportation as well. In the United States, lack of fueling infrastructure is inhibiting sales of LNG trucks, despite the wide price differential in fuels, although limited LNG infrastructure is now in place as a launching pad for further development. LNG is facing a major new challenge in the US from CNG “long-range solutions,” whereas LNG can be used in long-haul trucking. Some developers see greater potential in CNG and are thus expanding the number of LNG fueling stations along major trucking routes; but use of LNG in municipal public transport is already fairly widespread in the US, where legislation requires all state-funded organizations to purchase gas-powered vehicles when renewing their fleet. In the US passenger car market, however, consumers looking to save on fuel costs are more likely to opt for hybrid or battery electric vehicles than those powered by natural gas, at least over the near term. Natural gas vehicles are both more costly up front (by roughly $8,000) than conventional vehicles and have a narrower (by up to 40%) driving range. Further, only about 1% of conventional fueling stations for light-duty vehicles are equipped for natural gas. However, in US commercial transport, the prospects for adoption of natural gas will continue to be favorable even in the current low oil price environment. Although commercial fleet owners face initial expenses that can match the cost of LNG fueling stations, the higher price and reliability of the diesel engine, lower and less volatile natural gas pricing will likely lead to a gradual erosion of diesel demand growth.

In Europe the focus has been not so much on vehicle transportation but on the bunker market (ships), mainly in Northwest Europe, while the LNG trucking market is still in its infancy. CNG is slightly more widely used in Europe, although the situation differs by country. For example, Italy has over a thousand CNG stations, while in the UK there are less than 20. EU countries offer selective tax breaks for gas-powered transportation. For example, in Italy, alternative-fueled vehicles (including natural gas) have a three-year tax exemption and all newly built fuel filling stations must be equipped with a compressed gas filling unit. Meanwhile, France prohibits the use of diesel fuel for municipal public transport and waste collection.

In 2013, the European Commission unveiled a package of measures to encourage the use of alternative clean fuels in Europe, including proposals for common standards governing the design, use, and distribution of such fuels. The measures include potentially binding targets for countries to construct a minimum level of infrastructure for clean vehicle fuels such as electricity, hydrogen, and natural gas. A core component of the clean fuel strategy is the use of LNG and CNG in transport. The Commission proposes that LNG refueling stations be installed every 400 km along the roads of the Trans-European Core Network by 2020. For CNG-powered vehicles, the Commission aims to ensure that refueling points are available Europe-wide with maximum distances of 150 km by 2020.

In Russia, natural gas has been used for transportation since the 1980s, mostly as CNG, although its use dropped sharply in the 1990s. In recent years, interest in CNG and LNG has revived, especially from Gazprom, as the company is looking at various ways to monetize its gas by expanding domestic gas consumption. Gazprom has launched a special-purpose company Gazprom Gazomotornoye Topivo and plans to step up CNG infrastructure investments. This initiative has found strong political support as well, with the government promulgating plans for expansion of CNG for urban fleets.43

43 In the United States, a long-haul tractor trailer typically logs between 75,000 and 175,000 miles per year over a typical service lifetime of three to five years.

44 In 2014, KTG and Gazprom Gazomotornoye Topivo signed a memorandum of understanding on cooperation and advancement of natural gas use in transportation, including creation of a unified technical policy between the two countries and increasing personnel training in this area.
Potential Use of Natural Gas in Transportation in Kazakhstan

Use of natural gas as a motor fuel in Kazakhstan could help achieve a number of important policy goals. First, together with Kazakhstan’s refinery modernization program (see Chapter 4), natural gas use may help alleviate a shortage of refined products for transportation.14 Second, it would help utilize local resources, increasing energy independence and supporting the local economy. Third, it could potentially help monetize stranded gas resources that are not connected to the main gas pipelines. Finally, it would mitigate the environmental impacts of vehicle fuel consumption on urban air quality, and with gas being less carbon-intensive than oil products this could also help the country meet its CO₂ emissions reduction targets. Formulation of a general policy that links these four policy goals in order to promote their coordinated development calls for a CNG/LNG use to progress beyond the “niche” stage. IHS Markit calculates that by 2020 at least 0.5 Bcm/y of natural gas will be used as transportation fuel in Kazakhstan (see below).

The Concept of gas industry development to 2030 envisions the share of natural gas in motor fuel consumption by public and utility transport to reach at least 30% in Almaty and Astana and at least 10% in cities by 2020, growing to 50% in Almaty and Astana and at least to 30% in the oblast centers by 2030. A network of CNG fuelling stations is planned in the framework of the Kazakh section of the planned Europe-China transit corridor.

Kazakhstan has already begun to use natural gas as motor fuel in transport, although activity remains quite limited at present. By the end of 2015, there were 5 CNG stations in Kazakhstan. Almaty Oblast had the highest number of stations, KTC has a CNG Network Development Plan to 2022, with specialized subsidiaries—KTC Onomedi and Avtoiuz-like—responsible for the construction, operation, and maintenance of CNG filling stations and related infrastructure. Astana’s first CNG fueling station opened in 2017, fueling shuttles that carry visitors to the EXPO-2017 exhibition as well as vehicles used in general city transport. The planned gasification of Astana, beginning with small-scale LNG, is already underway, Gazprom Export and Global Gas Group signed a contract in December 2016 for the delivery of 320,000 tons of LNG, Gazprom projects a gradual ramp-up in LNG deliveries to Kazakhstan, totaling 5,000 tons in 2017 and reaching 320,000 tons (the equivalent of ~0.5 Bcm of dry gas) in 2021. To meet these supply obligations, Gazprom plans to carry out a design study for a 35,000 ton liquefaction facility in Yuzhnouralsk and to build a facility in Chelyabinsk than the existing one in Yekaterinburg.

In Kazakhstan, the gas-oil price gap may enable the expansion of LNG-fueled transportation, although much depends on the cost of the sourced natural gas. A significant price gap still exists between the fuels, as prices for oil products have been deregulated while natural gas prices are still regulated. In April 2017, the average retail diesel price was the equivalent of $10.4 per MMBtu, while the average price paid by households was only $1.5 per MMBtu. For an industrial consumer, such as a small liquefaction plant, the acquisition price it would pay for gas would be higher than for households, but still was only $1.8 per MMBtu in April 2017. This was significantly lower than the diesel equivalent (see Figure 5.19). However, growing diesel consumption in Kazakhstan, especially in transportation, represents an opportunity for LNG sales to substitute for some of the diesel consumption in trucks. Kazakhstan’s diesel demand has been growing and is already the largest component of Kazakhstan’s product demand balance, with trucks accounting for the largest share of diesel consumption (~30%). Extractive enterprises in the mining sector could potentially benefit from switching their quarry equipment from diesel fuel to LNG. Another option for future LNG use is rail transport.

By IHS Markit estimates, even a liquefaction plant based on more expensive imported Russian gas (as is the case with Yekaterinburg small-scale LNG) would seem to have strong economic prospects, at least when the output can be sold as a refined product. The addition of announced capex and estimated opex for building a new facility to the industrial acquisition costs for gas still results in total costs of $6.0 per MMBtu, which includes considerable room to compete with diesel fuel in the local market (see Figure 5.20). But these costs reflect the LNG supplier costs only, which include the cost of feedstock gas and cost of conversion into LNG. Promoting LNG use in Kazakhstan must be analyzed at a systemic level that would account for the costs incurred downstream, including the expenses to retrofit an LNG truck or fleet, modify fueling stations, adjust supply chains, and install regasification terminals.

The relatively high cost of delivered LNG from Yekaterinburg, reflecting technology and transportation distances, mean that at least some end-consumers are able and willing to pay higher prices for the cleaner, albeit pricier, fuel. Niche buyers willing to incur such expenses could include industrial and commercial users for the production of high-value-added chemicals or glass products or services, for peak-shaving needs, and even selected residential consumers. However, even if the end-consumers are willing to pay gas prices high enough to cover additional operational costs (e.g., remote locations where the competing fuel for heating is refined products, such as gasoil or fuel oil), the net price consumer to LNG would be LPG. LPG is the general fuel used in situations where piped gas supplies are unavailable. The limited consumption of LPG and gasoline in Kazakhstan, particularly in remote rural regions, renders the use of small-scale LNG for general gasification of households and small industries balanced.

LNG prices continue to be regulated by KREMiZK, and in recent years have been consistently lower than other forms of fuel, including natural gas (see Figure 5.19). As a result, the number of vehicles running on LPGs or a mix of gasoline and LPG has been growing. In such a price environment LNG in transport and residential use will likely continue facing considerable competition from LPG. There are a number of practical issues that need to be taken into consideration with use of LNG in transportation and in liquid form. First, LNG has a shelf-life, while holding tanks at refilling stations can maintain cryogenic temperatures necessary to store LNG indefinitely, trucks can only hold the LNG for five to seven days before complete boil-off occurs. Thus, once delivered, LNG must be used immediately. Second, vehicle storage tanks for LNG are significantly heavier than those for diesel, which puts additional stress on paved roads. The Transportation Committee under the Ministry of Development would need to improve the quality of road-building materials such as concrete and asphalt, and upgrade roads

14 Kazakhstan’s demand for gasoline and kerosene has been growing since the 2000s, and has been met by increasing imports, mostly from Russia.

15 The company, a subsidiary of Gazprom, transports and distributes gas in Russia’s Sverdlovsk, Chelyabinsk, Kurgan, and Orenburg regions.


17 The industrial acquisition price is what an LNG plant would pay for its source gas to make LNG fuel for transportation. Then it would sell this product at a fueling station. LNG would compete mostly with diesel, comparisons to the diesel retail price are the most relevant.

18 This cost does not include transportation of LNG to a different consumption point; delivery to a customer ex-plant is assumed.
so they are capable of handling heavier vehicles on a regular basis. Meanwhile, LNG trucking companies and fueling station operators must carefully organize delivery routes in order to prevent boil-off without jeopardizing a breakdown in supply. Some measures can be taken to encourage LNG use. For instance, LNG storage and filling stations do not need to be颜se of the country.

48 See “National plan on quota distribution on GHG emissions 2016-2020” and additional changes introduced on 7 May 2012, No. 586 “Confirming the plan of distribution of quotas for GHG emissions.”

49 In early March 2017, Saryarka announced that preliminary exploration at Sherubay-Nurinsky and Taldykuduk provided the basis for an inferred methane resource estimate of about 150 Bcm in the Karaganda coal basin.

5.3 CoalBed Methane

Global experience has shown that successful, commer-
cial CBM development is relatively expensive, involves long lead times, and requires a variety of economic, structural, and legal preconditions. The economic-
ics of CBM recovery are influenced by depth, perme-
ability, seam thickness, as well as water disposal/ processing costs, proximity to gas processing facilities and current or anticipated gas prices.

In China, which is estimated to contain over 59 tri-
lion cubic meters (Tcm) in reserves, coal mine meth-
ane (CBM) recovery began in the early 1990s primarily to enhance coal mine safety and to diversify energy supply. Gas production from CBM only began in the mid-2000s. By 2015, total CBM commercial production was 0.8 Bcm (approximately above-ground CBM), far below the government targets of 16 Bcm above-ground at 100% utilization rate and 14 Bcm at 60% utilization rate.

In 1999, the Profit Act of 1980 created the fiscal terms for unconventional resources, includ-
ing generous tax concessions, which allowed for the development of CBM in the Powder River Basin. Simi-
larly, in China, companies engaged in domestic CBM production are exempt from paying a resource tax on above-ground extraction, and receive a subsidy of 0.3 renminbi (RMB) per cubic meter (cm) ($1.20/MMB-
tu) during the 13th Five Year plan period (2016–20).

In coal-rich Shaanxi province, the regional govern-
ment granted an additional 1 RMB per cubic meter ($0.50/MMBtu) subsidy to CBM producers to spur de-
velopment. Despite such tax concessions, high costs and limited pipeline access have largely curtailed the growth of CBM production. In China, for example, the Shik Market estima-
tion of the potential for CBM production is still among the highest for gas supply in China: In 2016 CBM costs were ranging between $10 and $15/MMBtu ($0.35–
0.52/cm), much higher than the regulated cuyate in Shaanxi and Inner Mongolia at $5.35/MMBtu ($0.18/
/cm), and Shanxi at $7.62/MMBtu ($0.26/cm). Al-
though wholesale prices of unconventional gas are not reg-
ulated, prices do serve as an im-
portant benchmark, especially now that the domestic gas market is largely oversupplied.

In Kazakhstan, the economics of CBM recovery have been favorable but the government has exercised considerable due diligence in exploring the long-term feasibility of utilizing this potentially abun-
dant resource. An Instruction from the President of Kazakhstan in January 2010 paved the way for state support of CBM production and initiated related legal and administrative changes. In 2013 Saryarka assigned KTG the task of leading the development of CBM resources, and in March 2014 the government approved a roadmap for implementation of the KTG plans to undertake CBM project development.

Several legislative changes were enacted, aimed at promoting CBM production. Amendments to the Entre-
preneurial Code in April 2016 implied that investment projects related to CBM production would be eligible to receive investment preferences from the state (al-
though the government has yet to include CBM pro-
duction in the list of prioritized activities that receive such preferences). The Subsoil Law was amended to include the definition of coal bed methane. In Sep-
tember 2016 Ministry of Energy of RKh approved a plan for the development of CBM exploration in Karakalpakstan. To promote research supporting CBM produc-
tion, Karaganda State Technical University opened a dedicated research laboratory in November 2016 with financing from Kazakhstan’s National Fund.

Much of the recent interest in the development of CBM has been tied to plans for the gasification of Astana. At the time of the publication of The National Energy Report 2015 a number of options (in addition to the suspended Kertaly-Astana natural gas pipeline project) for the gasification of the Astana region were being studied. A major focus of attention at that time was on the CBM resources associated with coal deposits in nearby Karaganda Oblast. In April 2015, KTG and the Saryarka Social-Economic Entrepreneurial Corporation (SEC Saryarka) launched a feasibility study to determine the potential for CBM production in the Karaganda Basin to supply the gas needs of that region as well as that of Astana. The goal was to determine whether CBM resources in suitable proximity to potential consum-
ers were of sufficiently high methane content for LNG production or other applications. One variant of the concept envisioned the construction of a local liquefac-
tion plant that would convert CBM into LNG for trans-
portation by either rail or truck to Astana and other cities in the region. Exploration activity at the Sherubay-Nurinsky block, the license for which belongs to SEC Saryarka, involved KTG drilling five experimental production wells (where hydrofracking was carried out), and three explo-
tion wells during 2015 and 2016; three more wells are planned to be drilled in 2017. The analysis of core samples suggested methane content of 10–12 cubic meters per ton of coal. Baker Hughes in association with Kazakh Institute of Oil and Gas is undertaking a feasibility study of the project, with the goal of developing full-scale development.

If the study is deemed successful, KTG plans to implement the project with China’s Xinjiang Guanghui Petroleum Company. The Taldykuduk-Gaz Group Venture between SEC Saryarka and Gas Production Company carried out further exploration at Taldykuduk acreage, drilling two exploration wells in 2015 and two experimental pro-
duction wells in 2016.46 In February 2017 SEC Saryarka also announced tenders seeking investors to partici-
pate in exploration of two allotments—Tenteisky and Karazhan-Shakharsky—the licenses for which the Government of Kazakhstan received in April 2014 and December 2015, respectively. To finance exploration activities, SEC Saryarka applied for 5.8 billion tenge ($18 million) of state budget financing. Not surprisingly, piped gas remains the most like-
siely source of supply for Astana rather than CBM. In March 2017, Minister of Energy Kanat Bozbayev announced that KTG had completed a feasibility study for the construction of a natural gas pipeline (an ex-
tension from the BBS pipeline) to supply Astana. How-
ever, because the pipeline extension will also supply the large pipeline centers of Windfall and Karaganda before reaching Astana (and then Kokshetau), it ap-
ppears to have significant implications for plans to de-
velop long-term CBM supply in the region. Rather than being a primary source of gas for industry and gasification facilities, the CBM would be used mainly for the municipal-domestic sector in the capital region, CBM, because of its lower heating value than natural gas, and higher costs appears destined for more limited ap-
lications. These include use as a fuel in small boilers and in small-scale electrical generation at the sites of coal production (e.g., much of the generated gas is used as a power source in oil production), with the added benefit of reducing the explosion risk in underground mines.

This reassessment, involving a more limited role for CBM, appears to reflect the recognition that CBM re-
coveries is technologically difficult. Large-scale CBM re-
covery (as in the pilot projects discussed above) would probably require bringing in an experienced foreign partner, along with its technology and workforce. CBM recovery is also a relatively dirty process, as the dewatering of coal seams to reduce pressure for gas extraction generates significant volumes of saline wa-
ter that must be processed or otherwise disposed. The dewatering of non-saline aquifers could affect fresh-
water resources. Given that water scarcity is already an expanding issue and generic resource objectives with respect to water usage specified in the policy, “On the Transition to a Green Economy,” CBM development in Karaganda would likely be counter-
productive to Kazakhstan’s sustainable development goals.

Even with limited data on the permeability of coal ba-
sins in Karaganda, the challenges of water treatment, high development costs, and limited pipeline access combine to make CBM recovery in Karaganda a costly, protracted, and perhaps environmentally unsustainable endeavor. While CBM is now included in Kazakhstan’s Subsoil Code, Kazakhstan still lacks proper regulation with respect to taxes for unconventional resources and water disposal procedures for such operations. A CBM simpler solution to gasification of the region would be structural reform of the natural gas sector through in-
creasing end-consumer gas prices and reforming the Subsoil and Tax codes in a manner consistent with the recommendations presented in this report.

5.4. REGULATION OF KAZAKHSTAN’S GAS SECTOR

5.4.1. Review of Kazakhstan’s relevant legislation and national and international goals and targets in the gas sector

The key goals for the gas industry as outlined in the various gas industry development concepts (reviewed below) include:

• Expanding the base for natural gas production
• Modernization and expansion of gas processing capacities; full use of all components of natural gas associated gas
• Increasing the output of pipeline-quality dry gas and also gas as feedstock into petrochemicals
• Development of gas transportation infrastruc-
ture: pipelines, compressor stations, new ways of transporting gas (LNG), as well as technologies for using gas as a transportation fuel
• Gasification of the capital Astana and general increased gasification of the country
• Increasing the investment attractiveness of the gas industry
• Increasing domestic demand for natural gas, in-
cluding new categories of consumers
• Resource savings through reducing losses in all sectors of the gas industry

46 Initially the West-North-Center gas trunk pipeline was viewed as the potential answer to this goal; however, currently the SarykAryka pipeline to Astana via Kyzylorda Oblast is considered the leading option.

48 For details, see The National Energy Report 2015, section 8.7.
Flaring—the burning of natural gas in an open flame at production sites—has long been part of the process of hydrogenation extraction in the global petroleum industry. Thousands of gas flares at oil production sites worldwide burned about 149 Bcm of natural gas in 2016.10 In some instances flaring is an important safety measure during drilling operations and at natural gas facilities; flaring safely disposes of gas during equipment failures, power outages, and other emergencies or disruptions in drilling or processing operations. But the gas might otherwise pose hazards to workers or nearby residents. However, the continual and routine flaring of natural gas deemed to be unmarketable because of lack of gathering infrastructure, distance from pipelines and markets, low prices, or other factors, wastes a potentially valuable resource and produces GHG and other emissions that can negatively affect human health and the environment.11

Producers in Kazakhstan have been adjusting to changes in gas flaring legislation since 2005, when Kazakhstan prohibited gas flaring for all subsoil contracts signed after 1 December 2004. Since then, regional and local agencies have increased monitoring and fines for gas flaring. The Subsoil Law passed in 2010 goes one step further by prohibiting commercial development of a field without a plan for utilization/use of associated gas (for example through transportation to stimulate wider use of natural gas in the economy, the interests of consumers and producers. But in order to stimulate wider use of natural gas in the economy, a number of changes to current legislation need to occur:

- The most important change involves gas prices. To have more dry gas available to domestic consumers, prices for producers need to be higher. But there also needs to be a market for the gas at these higher prices. If consumers are used to paying higher prices and the government wants to encourage higher gas consumption, then some type of support policies (subsidy) will have to be developed. Higher gas prices also can help encourage energy efficiency and energy savings in the economy.

- Coal’s current low cost of production and delivery offers very stiff competition to higher cost gas. Given that the coal industry is also extremely important to the economy, making drastic changes that would hurt the coal industry and at the same time dramatically raise coal prices could damage the broader economy. But introduction of a carbon price could improve the competitiveness of natural gas. It is advisable to ensure that no provisions are included in the forthcoming Subsoil Code impede exploration and development of gas fields by providing an acceptable return to investors for undertaking risk while ensuring their ability to market any produced gas.

Another issue is effectively disposing of small volumes of stranded gas in remote fields where oil is the main product. Higher prices would make recovery of such gas more attractive. But regulation also can play a role: if strict flaring or utilization requirements are enforced, these small producers might effectively shut in their production completely. The goal of reducing fuel and energy cost could be served by deviating from the policy in such a way that it incentivizes conservation/ utilization/associated gas (for example through higher domestic gas prices) rather than simply punishes the lack of an effective outlet.

5.4.2. Flaring of associated gas: a case for regulatory reform

The general plan for Gas Infrastructure Development in the Republic of Kazakhstan in 2015–2030 (adopted in late 2014) codifies Kazakhstan’s long-held plans to increase domestic gas demand as an environmentally clean fuel, mainly using domestic natural gas resources. The 2010 Subsoil and Subsoil Use Law regulates the use of natural resources and is the primary tool for influencing the expansion of the resource base for natural gas production. This Law also provides specifications related to utilization of associated gas. It is advisable to ensure that no provisions are included in the forthcoming Subsoil Code impede exploration and development of natural gas fields by providing an acceptable return to investors for undertaking risk while ensuring their ability to market any produced gas. Strategic plans formulated by the Ministry of Energy offer more frequent (usually annual) updates on natural gas energy balance and forecasts for phased development of the gas transportation system and to increase domestic gas demand as an alternative to imports. The lat- est Strategic Plan was issued in 2016 with an outlook to 2021. Its specific goals include targets for residential gasification, associated gas utilization, gross and commercial gas production, and labor productivity. Other important legislation that governs development and regulation of Kazakhstan’s gas industry includes:

- The Law on Natural Monopolies and Regulated Markets (1996) defines the legal basis for state regulation of national monopolies (i.e., network industries such as gas and power, railroads, etc.)
- The Law on Energy Saving and Energy Efficiency Improvement (January 2012) sets the strategic direction of state policy related to energy efficiency, spells out the authority of various state entities, and identifies requirements for achieving efficiency improvements.

Legislation on Kazakhstan’s gas industry clearly states that a balance needs to be found between the interests of consumers and producers. But in order to stimulate wider use of natural gas in the economy, a number of changes to current legislation need to occur:

- The most important change involves gas prices. To have more dry gas available to domestic consumers, prices for producers need to be higher. But there also needs to be a market for the gas at these higher prices. If consumers are used to paying higher prices and the government wants to encourage higher gas consumption, then some type of support policies (subsidy) will have to be developed. Higher gas prices also can help encourage energy efficiency and energy savings in the economy.

- Coal’s current low cost of production and delivery offers very stiff competition to higher cost gas. Given that the coal industry is also extremely important to the economy, making drastic changes that would hurt the coal industry and at the same time dramatically raise coal prices could damage the broader economy. But introduction of 10 This is the estimate of the World Bank using the US National Oceanic and Atmospheric Administration’s (NOAA) infrared satellite technology to measure gas flares as part of the Global Gas Flaring Project (GGFP). According to these estimates, considerably (less than 5% of the global total). 11 Complete combustion of pure natural gas (methane or CH4) produces only CO2 and water. However, combustion in air and incinerators is seldom 100% complete. Unprocessed natural gas usually contains a mixture of hydrocarbons and other substances, which can form a variety of chemical compounds during combustion. These include the greenhouse gases carbon monoxide (CO) and nitrogen oxides (NOx). Flaring is nonetheless preferable from an environmental standpoint to venting (release of unprocessed gas into the air without combustion), because venting released into the air can react (in the presence of sunlight, such as propane and butane, which are flammable and thus an explosion hazard, as well as methane, which is a much more potent greenhouse gas than CO2). 12 At the enterprise level, performance varied widely, ranging from 2% and below at two of the three “mega” projects (Tengiz and Karachaganak) to over 50% at several small producers.
mainly in western North Dakota), which registered a significant growth in oil and gas output between 2008 and 2014 as a result of the adoption of unconventional recovery methods. From less than 200,000 b/d (9.9 MMt) of crude oil production in 2008, output reached over 1.2 MMb/d (49.8 MMt) in 2014. Flaring significant volumes of gas associated with oil production is a problem throughout the Bakken, as production of associated gas can reduce oil production. Flaring, however, can occur in cases where the volume of gas is too high to market, due to infrastructure constraints (such as insufficient gathering capacity). Flaring is typically required when the associated gas is not of sufficient quality or quantity to market, and state regulations tend to reflect this reality. Flaring regulations in more mature producing areas such as Texas and Wyoming allow operators to flare for 10 and 15 days, respectively, before requiring permits (although average actual periods of flaring allowed were somewhat longer—up to 60 days in Texas, and six months in Wyoming). In North Dakota, as traditionally associated with oil production until the unconventional revolution, the North Dakota Industrial Commission (NDIC, the state’s oil and gas regulator) has a more flexible and more forgiving attitude toward flaring than other states, reflecting the difficulty most operators have in connecting gas streams to gathering lines in the Bakken. North Dakota oil and gas regulations require that tax revenues be paid for all natural gas flaring beyond a well’s first year of production. During the first year of production, gas production is limited by field rules, with the amount of gas produced limited to the volume that a well is connected to a gas gathering system. Once a well’s first year of production ends, operators are required to cap the well, or connect it to a natural gas gathering line, or equip the well with an electrical generator that consumes at least 75% of the gas produced. North Dakota Industrial Commission policies that determine field rules and operating limits are enforced flexibly, allowing unconventional short-cycle shale oil production in the Bakken to ramp-up much more rapidly than associated gas capacity could be installed.40 For several years the existing infrastructure for the collection, processing, and transportation of gas was not sufficient to market the associated gas in North Dakota between 2008 and 2012, increasing by over 200%, to 228 million cubic feet per day (2.4 Bcm/d)—representing an economic loss of $560 million and a level of GHG emissions (7-9 MMt of CO2) equivalent to that of a large coal-fired power plant. Levels of flaring from the field have been quite high in relative terms as well (32% of all produced gas in 2005). This reflects, first, the greater technological requirements of gas processing vis-à-vis oil extraction, which means that “first oil” typically can be produced long before processing of the gas associated with it. Oil infrastructure typically consists of production separators, storage, and loading and off-loading facilities, whereas associated gas requires dehydration and treatment to remove contaminants, compression, and processing to produce pipeline-quality natural gas for the end-use market. “Dry” or high-quality natural gas is necessary for producing and delivering to end users almost exclusively via pipeline. Natural gas liquids (NGLs—such as ethane, propane, butane, and natural gasolene), separated from the dry gas during processing, require additional recovery and as well as dedicated storage and transport capacity to reach markets. Finally, the timing of incremental gas supplies from the Bakken was unfortunate in the sense that it coincided with a period of very low gas prices. Although the average annual Henry Hub gas price between 2001 and 2007 was $5.91 per MMBtu, with a low of $3.80 in 2002 and a high of $8.80 in 2005, in 2006 the market became oversupplied with natural gas and fell to $2.75 in 2012. Prices have improved only marginally since. Confronted with this initial gap between associated gas production and the requisite gathering/process- ing infrastructure, North Dakota Industrial Commis- sion established a phased flaring reduction regime, which sought to gradually reduce the share of total output flared while allowing oil and gas opera- tors to make incremental mid-stream and public and private investment decisions about gas gathering. An operator can consider whether to recover and market associated gas “on the fly” after the decision to produce has already been made, based on the expect price of gas and the field’s rate of return for oil recovery alone. If the cost to build a gathering pipe for gas is uneconomic in its own right, meaning that the cost exceeds the revenue stream that can be earned from an acceptable rate of return from the sale of gas, an operator can often claim “economic infeasibility” and continue to flare associated gas—and in some cases even avoid paying taxes on its value. The Commission set as its first establishment targets for the percentage of natural gas to be flared in April 2014: flaring was to be limited to 22% of total extraction through January 2016, and then 15% through 2021. However, these targets were revised in September 2015 by extending the compliance targets, allowing 22% to be flared through Q1 2016, 20% in Q2 and Q3 2016, and 15% for November 2016 through October 2018, 12% for November 2018 through October 2020, and ultimately to 9% beginning in November 2020. This flexible and extended compliance regime was enabled by the following considerations. The state of construction of gas processing and transport infrastructure was underway in the state. On 1 July 2013, new legislation in the form of North Dakota House Bill 1134 (HB 1134), went into effect, which relies on incentives rather than a punitive approach to the reduction of flaring. HB 1134, rather than focusing on flaring restrictions that force the economics of flaring to be tied to oil production (as other states have done), provides tax incentives for building gas gathering and processing infrastructure and for systems that utilize gas at the wellhead. Although this will take many years for such incentives to be fully realized in terms of actual investments, it can help in the near term to prevent the significant volume of gas that is flaring from being wasted. Natural gas infrastructure had caught up with overall natural gas production growth in the Bakken, and in the following year gas processing capacity had reached parity with total gas extraction. As a result, levels of flaring have now begun to fall rapidly—to 21% in 2015 and to 10% by March 2016—allowing a schedule of meetings to review the emergency targets. Whether further progress in flaring reduction can match the recent pace is questionable, however, as the price of gas is now so low in the US that the incentives for further monetization of gas from Bakken and other fields is greatly reduced. Henry Hub natural gas spot prices remained below $2.00 per MMBtu in 2017 were $3.16 per MMBtu, and were $3.19 on the New York Mercantile Exchange (NYMEX). This suggests that maximization of gas use in field operations, such as steam injection and methane recovery via carbon capture and storage, is a more wiser approach near term in the Bakken than commercial sales to outside markets.

Russia

Russia too is seeking to curtail flaring of associated petroleum gas (APG). During 2000–2013, gross APG extraction in Russia (including flared volumes) more than doubled, from 353.3 MMt to 232.6 MMt in 2014. Growth occurred on the back of a 62% increase in Russia’s oil output during the same period: from 232.6 MMt to 232.6 MMt. Flaring stubbornly remained a major problem, accounting for 21% of total APG extraction throughout that period, mainly because of the continued shift in Russian oil production to new fields in pioneering regions such as East Siberia and the Krasnoyarsk-Yamal cluster, far from existing gas infrastructure and where associated gas-to-oil ratios (GORs) are particularly high. According to the US National Oceanic and Atmospheric Administration and the Global Gas Flaring Reduction initiative (see note 50 above), Russia has led the world in the absolute amount of natural gas flared (over 20 Bcm/y) for the past several years. Russian policymakers, in recognition of the economic losses from the wasted resource (estimated at $13 billion annually as early as 2007) and the dangers of greenhouse gas emissions for the environment, intro-duced tough new measures in 2009 aimed at quickly increasing utilization rates for all companies to 95%- 24 As in North Dakota, a combination of “sticks” and “carrots” are part of the regulatory effort to re-duce flaring. Among the punitive measures are heavy penalties for above-limit flaring and lack of metering equipment. These are augmented by recently enacted tax incentives that include elevating oil companies’ associated gas production to the top of the domestic sales merit order, as well as according the derived dry gas priority access to the pipeline network. The effort to reduce flaring also has been assisted by the pace at which new oil projects are launched in east-ern and northern frontier provinces in Russia (where recovery and processing infrastructure are lacking) in the recent low oil price environment, giving the indus-try a chance to catch up and match its oil production capacities with the necessary gathering and process- ing infrastructure.

A case in point is the realization of a utilization program at the Vankor oil field in Krasnoyarsk Krai by Rosneft, which until recently was the largest single source of APG. Rosneft began selling gas for $17 per MMBtu in 2014, volumes at Vankor (above the amount

40 According to World Bank estimates, the US was the sixth largest gas flarer in the world in 2016, flaring a total of 8.9 Bcm in 2016, significantly less than the 11.8 Bcm flared in 2015.

41 In the US, the individual states largely regulate oil and gas production not occurring on federal or tribal lands.

42 The infrastructure for maximum efficiency rate (MER) production allowances are applied on an annual basis for a Bakken oil well. After this time, field rules restrict production to 250 b/d for the next 60 days, 150 b/d for an additional 60 days, and then 100 b/d until connected to a gas-gathering system. The NDIC may grant “field rules” exemptions (for six to 12 months) to operators in the early stages of production, gas volumes are usually quite high, and it may take several months before operators are ready to bring the well to production.

43 After the end of the one-year period, operators not already able to extend the period of flaring through field rule exemptions can file for an economic feasibility tax exemption with the NDIC, which releases them from making tax or royalty payments on the value of the flared gas when the gas is uneconomic to market.

44 Flaring from the Bakken was believed to have amounted to over half the US total flared volume (11.3 Bcm) in 2014. The Bakken experience in some ways is reminiscent of the USSR’s pell-mell rush to bring on West Siberian oil. There was a lag of nine months duration in the decision to inject the major West Siberian oil fields and the launch of the first gas processing plant in 1975 to utilize the associated gas. Even by 1980, only half of the associated gas being extracted in West Siberia was being utilized (see John C. Webb, Sergei Malnovskiy, and Matthew J. Sagers, Russian Oil Company Efforts to Extract Value from Growing Natural Gas Stream, HSI/Russian and Caspian Energy, Private Report, 2007, p. 15).
that can be economically useful for on-site power generation and reinjection were delivered to Gazprom’s trunk pipeline network through a pipeline that connects to a LUKOIL gas field, Nakhodkinskoye, which is, in turn, linked to the main gas pipeline network at Yamburg. Rosneft struck a 30-year deal with LUKOIL that calls for Rosneft to deliver a total of 94 bcm of (dry stripped) gas from Vankor to the Unified Gas System (UGS) entry point at Yamburg. This single agreement is primarily responsible for the spectacular increase in APG utilization in 2014 for Russia as a whole (to 87% in November 2014 from an annual rate of 79% in 2013). New projects slated for completion in 2015–16 are set to bring the APG utilization level even closer to the established target.46 In terms of its flaring intensity (cubic meters of gas flared per barrel of oil produced), Russia is on a par with China and among the better performing countries in the world.

Global Gas Flaring Reduction: Public-Private Partnership

Turning to the global experience more broadly, international efforts to address the problem of flaring have been coordinated under the framework of the GGFR Public-Private Partnership, established at the World Summit on Sustainable Development held in Johannesburg in August 2002. The World Bank plays a major role and has introduced a “Zero Flaring” initiative that coordinates the efforts of interested governments, oil companies, and development institutions worldwide to eliminate routine flaring by existing oilfields by 2030. Governments and companies that endorse the initiative will publicly report their flaring and progress toward flaring reduction on an annual basis. Eighteen countries/regions (including Kazakhstan, the United States, and Russia’s major Khanty-Mansyisk oil-producing region) and 13 major oil companies currently are involved in the Partnership.

Two of the major thrusts of GGFR activity have involved the global satellite-based monitoring of flaring and research on technologies for associated gas utilization. We focus on the latter here to identify practical solutions to be worthy of regulatory incentives. An early GGFR study,47 based on case studies in Chad and Ecuador, examined the feasibility of four options for using associated gas that otherwise might be flared: (1) power production at the oil field for transmission to the existing power grid (medium-scale); (2) power production at the oil field for electrification and reinjection (at least 15% of non-electrified rural area (small-scale)); (3) production of piped gas to larger consumers, such as heat and power plants and industries (medium-scale); and (4) liquified petroleum gas production (LPG), alone or in combination with other means of use (small-scale). Note that one option not considered—electricity generation for own use by producers in the field—is de facto already a viable economic option, albeit a limited one. But own use typically would be able to consume only about a third of the electric power that a field’s APG output could generate.

The study concluded, in general, that power supply from associated gas that otherwise might be flared could be delivered via pipeline to a load center for fuel substitution in power production and local industries were both feasible end-use options (not requiring subsidies) provided that:

- Markets are nearby (for a medium-sized oil field it would be feasible to move the gas or power as far as ~500 km to reach a market); for smaller fields delivery distances could shrink to ~50 km, depending on other parameters
- Gas volumes are sufficiently large (model calculations indicate that gas utilization from oil fields with gas yields over 2,500–5,000 m3 per day could be viable) and the cost of the fuel substituted is high (e.g., imported diesel oil transported over a considerable distance)
- Prices are not distorted by domestic fuel subsidies.

The analysis also indicated that there was little economic difference between (a) transporting gas in pipelines to an industrial gas customer or an existing power plant and (b) power generation at the site and then transmission of power, by way of power lines to the load center.

PFC Energy conducted a similar study for GGFR and the World Bank on the economics of various options for associated gas utilization in Russia shortly thereafter, which tends to call into question the findings of the GGFR study.48 It concluded:

For small fields flaring 0.1 Bcm/y or less, distributed (local) power generation is the most economic option (for other options at small fields, see the text box “New Gas Utilization Technologies for Small Producers”).

For medium-sized fields flaring 0.1–0.5 Bcm/y, the most economic option is gas processing and subsequent export of dry gas via the Gazprom pipeline system, provided inlet gas prices (at the processing site) are more than $135/Mcm.

The most economic option for large fields flaring more than 0.5 Bcm/y is power generation using a combined-cycle gas turbine and sale of electric power to the grid.

New gas utilization technologies for small producers

One of the major challenges to increasing natural gas utilization (and reducing flaring) near sites of production is one of scale, or rather the cost of infrastructure that would be required. The Bakken, for example, the economics of gathering and moving associated gas from the field to a central collection point and then to a gas processing plant depends on the distance (and costs) versus the revenue stream created from the gas stream after dehydration, treatment, and processing. The Bakken’s high geographic spread and low gas deliverability per square mile leads to higher pipeline mileage costs and correspondingly a much higher unit cost of gas gathering. Several cases in the Bakken demonstrate that it is difficult to economically justify gas gathering or electric generating infrastructure to utilize associated gas from widely scattered, small-volume fields. This technological challenge is now starting to be addressed in North America through small modular units that produce either electric power (microturbines) or liquid fuels (“mini” GTL) from the gas.

In Alberta province (western Canada), for instance, microturbines—which have few moving parts, low maintenance requirements, and can burn low-quality gases including some sour gas—came on the market in the late 1990s. The electricity they produce is used to provide power for industry operations (such as pumping, compression, or gas processing) or sold to the regional grid. In co-generation applications, which the microturbines also produce steam for industry operations or nearby activities such as drying grain or heating greenhouses. One method used to support adoption in Alberta was the waiver (introduced in 1999) of royalties on natural gas used for electricity or steam generation if the gas would otherwise have been flared.

Another new direction is the production of synthetic crude or refined petroleum products from associated gas, such as ultra-clean diesel fuel, using gas-to-liquids (GTL) technology, or the manufacture of liquefied natural gas. For a long time, GTL technology has been utilized in a number of large-scale plants globally (e.g., Shell Pearl, Sasol). This technology, associated with high capital expenditures per ton of finished product and relatively large feedstock requirements for gas. However, in recent years new technologies are emerging for small-scale “mini” GTL—modular units that use small amounts of gas (e.g., as little as 5–50 Mmcf per year) and a wide range of gas compositions. These plants also reduce the marketing problem for product since it is possible to deliver an end product, such as diesel fuel, directly to customers by truck. Depending upon feedstock characteristics and the particular catalysts that are used, in addition to diesel fuel, the mini-GTL technology can also yield various products such as paraffins, heavy petroleum fractions, etc.

Previous research by the Kazakh Institute of Oil and Gas (KING) shows (based on the Kumkyl group of fields in Kyzylorda Oblast that were analyzed) that given current capital and operating costs, an acceptable payback period (three to four years) could be achieved, mainly due to low APG acquisition costs at the field.49 However, a danger would be pressures to maintain low acquisition prices for APG to preserve the economics of mini-GTL once an investment had taken place, which could actually backfire by failing to incentivize long-term recovery of APG.

Microturbines (scalable from 30 kW to 30 MW capacity) and “mini” GTL are among the rapidly burgeoning technologies for utilization of field APG detailed in a 2017 GGFR report that provides a listing of “state-of-the-art” commercial products for reducing gas flaring at fields producing small volumes of associated gas, which would not be sufficient to warrant installation of large-scale gas processing infrastructure.50 In addition to microturbines and mini-GTL, the specific products listed include: (1) storage and modular flaring processing units (integrating dehydration, compression, cooling, and conditioning operations) providing feedstock for syngas, LNG, and NGL production; (2) fuel preparations skids for making flare gas usable in turbines or engines; and (3) small-scale CNG and LNG technologies used to compress or liquefy associated gas to increase its energy density thereby allowing transport of the gas by truck to power plants and industrial and domestic gas users where a pipeline may be uneconomic or not yet constructed, or for use as a fuel for motor vehicles.51

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46 The key uses of APG in Russia in 2013 included: (1) supplies to gas processing plants, to produce dry, network-quality gas for injection into Gazprom’s national pipeline system (Unified Gas System (UGS)) (46%); (2) flaring (21%); (3) supplies to booster compressor stations (this is also necessary for using APG for reinjection, which is itself another method of gas utilization, for moving gas further downstream since APG is generally low-pressure gas) (10%); (4) own use at production sites for power and heat generation (6%); (5) use by local consumers, including gas plants and utilities (6%); and (6) direct deliveries to UGS trunk gas pipelines (4%).


48 The report noted that this isolation was deemed most suitable for cold climates such as in Siberia, Kazakhstan, and Northern Canada, where the associated gas might substitute oil in district heating plants.


52 Included in this category is General Electric’s modular “CNG in a Box” technology that enables the rapid build-out of a network of CNG fueling stations.
Summary
We believe Kazakhstan’s successful program for flaring reduction will benefit from these recent technological advances that make a wide range of potential gas util-
ization strategies available to even small producers. The ultimately (if belatedly) successful implementation of a flexible and phased flaring reduction program in the rapidly developing Bakken field in North America, as well as Russia’s policy for combining incentives and sanctions to encourage flaring reductions, may also suggest strategies for fine-tuning of policy. As opposed to a largely punitive or sanctions-based policy for pro-
ducers not meeting flaring targets, a somewhat more flexible approach may be worthy of consideration when dealing with smaller producers with limited capac-
ty or that operate small fields remote from gas infra-
structure and markets. For these “hard-core flarers,” some combination of penalties and incentives might be tested to turn them in the direction of reduced flar-
ing. Measures that might be utilized as alternatives to (or in conjunction with) fines, taxes, and royalties might include, but not be limited, to exemptions for certain producers, requirements for improving the technical efficiency of flaring for such exempted pro-
ducers, and a program of financial incentives to assist small producers incorporate new modular and scalable technologies for small-scale gas utilization into their operations (more specific recommendations are of-
fered in the following section 5.4.3).

5.4.3 Recommendations on development goals and regulatory issues

• To better analyze Kazakhstan’s gas balance and future needs, the country needs to modify its statisti-
tical reporting to provide production and consumption figures consistent with international norms and practices. This should include publishing on a regular basis a consistent historical series on gas produc-
tion that excludes reinjected volumes, but includes all useful volumes, including those used for internal needs by the producers themselves. Data on exports should primarily reflect actual physical flows, not just customs reporting.

• Gasification of the domestic economy should con-
tinue to be pursued along the general lines currently being implemented, especially in areas served by ex-
isting trunk pipelines.

• In order to incentivize producers to supply gas to the domestic market, upstream procurement prices must be high enough to fully cover costs involved in producing, processing, and delivering natural gas to consumers. Higher end-user prices will motivate consumers to use natural gas more efficiently, and are in concert with the objective of harmonizing Kaz-
akhstan’s prices with those in Russia as part of the general movement toward the open economic space of the Eurasian Economic Union. Some form of state support for higher gas prices may be necessary over the near term, given competition in power generation from much cheaper domestic coal.

• Given the goal of creating a common gas market in the EAEU by 2025, and gas pricing developments in Russia (harmonization of prices), prices in west-
ern Kazakhstan should be set at a level approaching those in Russian gas-producing regions (e.g., Yamal-
Nenets Okrug) rather than in that country’s neighbor-
ing gas-consuming regions (Saratov Oblast); this will help ensure the competitiveness of Kazakhstan’s gas in the common economic space.

• Because the transport sector is not included in Ka-
zakhstan’s emissions trading system, it is important that the government of Kazakhstan also addresses emissions in this sector through a variety of measures designed to support LNG and LPG demand in trans-
portation, such as an alternative fuel vehicle (AFV) tax credit or differentiated excise taxes.18 Similarly, by expanding the list of sectors eligible to receive fund-
ing from the Entrepreneurship Development Fund of Kazakhstan (Damu), an entity designed to support small businesses and entrepreneurs, private owners of conventional fueling stations could be eligible for subsidized loans that would allow them to convert conventional fueling stations into ones capable of handling LNG/CNG and even LPGs.

• Given that Kazakhstan presently absorbs only a limited amount of the LPG it produces (exporting roughly three-fourths) with export markets looking increasingly saturated, policymakers should explore additional options for increasing LPG consumption when economically feasible. In addition to further use in the transport sector, this might include extending LPG availability to residential/commercial consumers in areas where piped gas is unavailable, and develop-
ing a petrochemical industry that utilizes LPG as a feedstock.

• As opposed to a largely punitive or sanctions-based policy for producers exceeding targets for gas flaring, a more flexible approach should be considered when dealing with smaller producers with limited capital or that operate in small fields remote from gas infra-
structure and markets. Exemptions from fines, taxes, and/or royalties on natural gas flaring should not be ruled out for certain producers, especially when there is no other economically viable solution for disposing of their relatively small gas volumes.

• When such flaring exemptions are granted, produc-
ers should be required to take measures to greatly improve the technical efficiency of flaring, such as enhancing burner tip design, monitoring the heating

value of the flared gas to maintain a stable flare,

• When such flaring exemptions are granted, produc-
ers should be required to take measures to greatly improve the technical efficiency of flaring, such as enhancing burner tip design, monitoring the heating

value of the flared gas to maintain a stable flare,

18 In the state of Louisiana, in the US, for example, the state offers an income tax credit of 36% of the cost of converting a vehicle to operate on an alternative fuel. A taxpayer could also opt to receive a tax credit of 7.2% for the cost of a new motor vehicle, up to $1,500. In Utah, the state offers tax credits of $15,000–$25,000 (depending on the year) for purchasing a new vehicle that runs on natural gas, electricity, or hydrogen.
6. COAL

6.1 KEY POINTS
6.2 COAL SECTOR UPDATE
6.3 INFRASTRUCTURE AND TECHNOLOGIES: KEY CHALLENGES, IDEAS, AND SOLUTIONS
6.4 REGULATION OF KAZAKHSTAN'S COAL SECTOR
6. COAL

6.1. KEY POINTS

For Kazakhstan’s coal industry, the story is not one of growth, but of managing a gradual decline.

- Production and consumption of coal in Kazakhstan in 2015 declined for the fourth straight year, reflecting weak domestic economic growth and limited prospects for expanding exports. Nonetheless, Kazakhstan remains a major world producer and coal is an essential component of the country’s energy profile, accounting for 55% of its primary energy consumption in 2016 and covering 66% of electricity generation.

- The near-term global market environment is somewhat more favorable than in recent years, due largely to events in China, where efforts to curb domestic production led to a sudden increase in import demand in early 2016 and a jump in global coal prices. However, large uncertainties surround future global demand, preventing most producers from adding new capacity.

- Although apparent levels of coal consumption in Kazakhstan are expected to decline slowly from current levels, dropping to less than 76 MMt by 2040 (compared to over 80 MMt in 2014), power-sector coal demand as a share of total demand is expected to remain relatively steady at around 60% (in standard fuel units).

- A relatively new direction for coal-sector development is coal-bed methane (CBM) production, including coal bed degassing in preparation for coal mining. Small-scale CBM production in the Karaganda coal basin is one of the options being explored for supplying gas for selected industrial applications in the local region (mine and local boiler power generation); however, the question of more widespread use of CBM for gas supply further afield (i.e., to the city of Astana) appears unlikely. At the moment, a key action needed for the development of CBM production is to establish requirements for coal bed degassing (Subsoil Code) together with requirements on restricting (capping) methane emissions by subsoil users.

- The adoption of so-called “alternative” coal technologies such as coal-to-gas (CTG) and coal-to-liquids (CTL) are facing headwinds due to the new low price environment for competing fuels (oil and natural gas) and the greenhouse gas reduction commitments of the Paris climate accord. However, some in the industry now view the climate accord as an opportunity to put advanced coal technologies such as carbon capture and storage (CCS) on an equal policy footing as support for renewables and energy efficiency improvements (discussed in Chapter 9).

6.2. COAL SECTOR UPDATE

Kazakhstan now appears to have reached a crossroads in terms of its strategy for the country’s coal industry going forward. As former Soviet Central Asia’s largest coal producer, consumer, and exporter, the country’s reserves and production capacity are robust and could support considerably higher levels of output than recorded in recent years. However, domestic consumption trends (strongly tied to electricity generation) turned slightly negative after 2012, a development reflecting weak economic growth following the decline in oil prices in mid-2014." In addition, exports have been challenged by the unique physical characteristics of Kazakhstan’s coal, the long overland distances involved in its transit to export markets, policies of neighboring countries (e.g., Russia, China) promoting energy independence or reduced dependence on imported coal, efforts to increase generation from less carbon intensive sources, as well as heightened uncertainty over global market conditions (see text box on global price environment dynamics in 2016–17). How best to utilize this abundant resource to the maximum advantage for Kazakhstan remains a difficult question.

Global Price Environment Dynamics in 2016–17

In early 2016, after a prolonged period of ample supply and muted demand growth, global thermal coal prices fell to a 12-year low. Global supply had become calibrated to meager consumption growth in the developed countries in the aftermath of the Great Recession of 2008–09 and to the accelerated rollout there of alternative sources of electricity generation (e.g., renewables and natural gas). In the major developing-country export market of China, deceleration of economic growth and constraints on coal-fired generation in more densely settled eastern provinces of the country also had led to lackluster (and sometimes even negative, as in 2014) demand growth.

However, in Q1-2016 an unexpected surge in Indian demand, followed by a sudden increase in imports by China in Q2, led to a rapid price rebound in thermal coal prices, as the limited excess capacity globally was inadequate to respond to the immediate demand increase. The catalyst for the spike in Chinese prices (where the domestic price rose from RMB 370 per ton to nearly RMB 600 in Q3-2016 and the import delivered price to southern China rose from CNY 475 to CNY 575 per ton by early October) were government efforts to support the domestic coal price by curtailing domestic oversupply through cutbacks in the number of days domestic producers were allowed to operate (from 330 to ~270 days). As a consequence, Chinese imports of thermal coal in 2016 rose from 132 MRM in 2015 to 169 MRM in 2016. The restrictions on domestic production appeared to have overshoot the mark, and by August 2016 production regulation was refocused on increasing domestic production in an effort to limit further price growth. By early October all of the previously imposed production restrictions had been lifted.

Various global benchmarks for steam coal followed the Chinese prices upward in 2016, some (e.g., Newcastle 6,000 kcal/kg NAR) more than doubling (from $53.37/t to $107.14/t) until analysts in November began to observe a reversal in the price trend (decreasing to $92.74/t in December) as a result of robust Q3 Chinese domestic production growth. The outlook for 2017 thus presents a number of uncertainties for major producers, including continuing global supply constraints (the reluctance of producers to add additional capacity in the face of uncertain demand growth) and the potential for wildly fluctuating prices following any future Chinese government interventions in domestic production intended to support predetermined price targets. The continuing relatively high price levels (Newcastle prices are projected to average $72 per ton in 2017) are, ceteris paribus, expected to constrain global coal demand growth. However, any significant reduction in prices in China could lead exporters to reduce their prices as well, either in an attempt to sustain market share there or to compete in alternative markets, such as India. Thus, by regulating its production, China now effectively plays a key role in setting international coal prices, rendering the medium-term coal price outlook relatively volatile (see Figure 6.1).

Outside of developing Asian markets, demand elsewhere in the world is projected to range from largely flat to negative. So, despite the recent improvement in the price environment, the incentive for producers to add capacity to boost exports is limited.

1 As noted earlier in the report, Kazakhstan’s GDP grow by 1.2% in 2015 and 1% in 2016; in February 2017 the Ministry of the National Economy upgraded its projected 2017 GDP growth estimate to 2.5% (from 2%), following a similar forecast by the International Monetary Fund.

2 IHS Markit Coal, Global Steam Coal Forecaster, No. 84, Vol. 3, 2016.

3 For 2017, the Chinese government plans to intervene in production, transport, or pricing only when prices for long-term contract coal fluctuate by more than 12% above or below a baseline price of RMB 335 per ton of 5,300 kcal/kg coal; see China Coal Market Briefing: First Quarter 2017, IHS Markit: Regional Power, Gas, Coal and Renewables, March 2017.
6.2.1. Market Structure

Kazakhstan’s coal industry is currently the main supplier of energy to the domestic economy, accounting for 55% of the country’s primary energy consumption in 2016. 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. The coal industry’s management structure is decentralized, with 29 companies currently listed by the Ministry of Energy as engaged in coal-mining operations; over three quarters of national output is accounted for by five large companies (see below). Industry regulation is performed by the Department of Electric Power and the Coal Industry of the Ministry of Energy (the latter formed in 2014 as part of a consolidation of energy regulatory functions within a single ministry).

6.2.2. Coal reserves

With proven reserves of 33.6 billion tons at 47 fields (recoverable “balance sheet” reserves are 34.1 billion tons) amounting to almost 4% of the world’s total, Kazakhstan is a major world producer and consumer of coal. The country possesses the eighth largest reserves of coal globally, sufficient to last at least 300 years at current rates of production. Bituminous and sub-bituminous coal (the two types categorized as “hard coal” in Kazakh nomenclature) account for 64% of Kazakhstan’s reserves (21.5 billion tons), and the remainder of reserves consists of lignite (or “brown coal” at 12.1 billion tons). The largest basins are located in the central and northern parts of the country: Ekibastuz (12.5 billion tons), Karaganda (9.3 billion tons), and Turgay (5.8 billion tons). 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 mine using open pit methods.

Although Kazakhstan’s coal reserves are large, most deposits have 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 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 its enrichment uneconomic to date.

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 heat value (5,600 kcal/kg).

6.2.3. Coal production

Kazakhstan ranks tenth among the leading coal-producing countries in the world. In 2016 aggregate coal production was 96.4MMt, a 6% decrease from 2015 (102.6 MMt) (see Figure 6.2). The decline in output continues downward in trend since 2012 (115.7 MMt), which was the highest level recorded since 1993. As in previous years, the majority of output (almost 95%) was considered hard coal; included in the hard coal total is 5.1 MMt of coking coal, used in metallurgy.

Most of Kazakhstan’s coal is produced at three giant open pit mines (Bogatyr, Severny, and Vostochnyy) in the Ekibastuz basin in Pavlodar Oblast and in four open pit mines (Borly, Shubarkol, Kushoky, and Saryadyr) in Karaganda Oblast. Most of the remaining output is from underground mines in the Karaganda basin (supporting local metallurgy) and lignite production in the Maykhuben basin.

Disaggregated by company, Kazakhstan’s largest producer is the Bogatyr Komir LLP, which mines the giant Bogatyr pit in the Ekibastuz basin. It accounts for approximately two thirds of national output. In 2016 coal production increased by 3.5% to 35.1 MMt from 33.9 MMt in 2015, despite the overall decline in coal output in the country as a whole. The second-largest producer is the Eurasian Energy Corporation JSC (one fifth of national output). Three additional producers collectively account for another one-fifth: the ArcelorMittal Temirtau Coal Company (underground mine production in the Karaganda basin), the Borly Coal Company, and Shubarkol Komir JSC. ArcelorMittal Temirtau is the only company that produces coking coal.

6.2.4. Domestic coal consumption

The use of coal is ubiquitous in Kazakhstan’s economy, especially in power generation, heavy industry, mining, and other resource extractive activities, and is present even in the residential-commercial-municipal sector. In fact, the country has the highest dependence on coal in its energy mix of any of the former Soviet republics. Since 1990 the share of coal in the total primary energy consumption balance generally
has fluctuated at between 50% and 60%. This share is expected to gradually decline, falling below 50% by 2020 and to less than 40% in 2040.\(^9\)

Apparent consumption (production minus exports plus imports) in the late Soviet period was 90 MMt (1990), but declined steadily during the upheavals of economic transition, reaching a nadir in 1999 (at 43 MMt). From there, consumption recovered more or less steadily until 2012 (85.8 MMt), but has fallen since then, to 74.8 MMt in 2015 and 73.2 in 2016 (see Figure 6.3). This appears to reflect a combination of muted economic growth in the post-2014 oil price environment, nascent energy efficiency improvements, and shifts toward alternative fuels such as natural gas and liquefied petroleum gas (LPG).

Electric power stations continue to be the largest consumers of coal, responsible for over half of total consumption. These include peaking plants (primarily for peak load needs), as well as the larger coal-fired power stations that are projected to decline by 1.5% annually over the period 2015–2040. For the industrial sector, IHS explicitly accounts for total energy demand and for development of other energy sources (gas, nuclear, or LPG) when possible for reliability and convenience, as has been the case in other industrialized countries. Thus, while apparent levels of coal consumption are expected to decline slowly from current levels, the power sector’s share of total coal demand is expected to remain steady at about 60-65%.

6.2.5. Coal exports

Since the mid-2000s, Kazakhstan’s coal exports have fluctuated in the range of 24–34 MMt annually (representing 25% or more of Kazakhstan’s total output). However, since 2010, exports have been slowly declining (from 32.6 MMt in 2010 to 27.8 MMt in 2014 to 25.8 MMt in 2016). Considerably more coal likely could be sold abroad if not for the remoteness from large export markets (see below). Russia has been the primary destination, accounting for roughly 80% of Kazakhstan’s exports in most years (see Figure 6.4). El’baktau coal accounts for over 90% of these exports (primarily to seven power stations in the Urals as detailed in The National Energy Report 2015). To some extent, this represents a legacy arrangement, in that some power plants constructed during the Soviet period in Russia were expressly designed to burn El’baktau coal. A coal balance agreement between Russia and Kazakhstan envisaged that Kazakhstan coal could continue to supply these plants with deliveries of about 29 MMt per year; however, exports to Russia in 2015 and 2016 (22 and 21 MMt, respectively) fell well below the figure specified in the agreement. Bogatyr Komir LLP, the primary El’baktau producer that exports to Russia, reported a 12.8% decline in such exports in 2016 (down to 9.2 MMt), as “some of the company’s customers switched to alternative fuels such as natural gas” (discussed in section 6.2.7).

Demand at the Russian plants consuming Kazakh coal also has been affected in recent years by reduced levels of electricity generation resulting from the recent economic downturn in Russia. In any event, industry officials now fear that, given the emphasis on energy independence in Russia’s Energy Strategy for the Period to 2030 (released 13 November 2009), coal exports to only three of these power stations (Reftinsk GRES, Omsk TETs-4, Omsk TETs-5) will continue beyond 2020. Kazakhstan also exports some coal to Ukraine and Kyrgyzstan, and small amounts are delivered to Belarus, Georgia, Uzbekistan, Tajikistan, and even some EU countries on occasion (e.g., Poland, UK, Romania, Finland). The EU exports tend to be limited to Shubarkol coal, which meets the EU’s specifications for ash content and heating value. In addition to thermal coal, small quantities of coking coal from the Karaganda basin have been exported to Russia and other countries. In January 2015 ArcelorMittal announced that it had sold its interest in West Siberian mines in Russia (used to supply steel mills it owns in Ukraine) because it could now meet the coal needs of those mills entirely (0.7 MMt annually) with output from its Karaganda operations. Upgrades to ArcelorMittal’s Vostochnaya Coal Washing Plant (including installation of two Jameson flotation cells and a horizontal belt vacuum filter) are projected to enable it to nearly double its coal concentrate output in 2017 (from 2.6 MMt in 2016 to 4.7 MMt); output in Q1-2017 was up 21% year on year. The coking coal concentrate is consumed by the company’s steel mills in Karaganda as well as exported.

6.2.6. Competitiveness of Kazakhstan’s coal in international markets

The factors affecting the competitiveness of Kazakhstan’s coal exports have remained relatively constant over recent years and include production costs, quality of coal, transportation costs to international markets, and competition from other fuels in the consuming markets, such as oil, gas, and even renewables. One of the main advantages of Kazakh coal continues to be its abundance and low cost of production (especially in the El’baktau basin). Although production costs in absolute terms have more than tripled since 1996, they remain comparatively low. The average cost of producing coal in Kazakhstan is only one-half to one-third that of other major world producers.\(^10\) Yet despite low production costs, the time coal reaches foreign consumers its price increases substantially due to transportation costs (discussed in section 6.2.7).

Kazakh coal has disadvantages other than high transportation costs. Coal that has a low calorific value is always sold at a substantial discount to standard 6,000 kilocalorie-per-kilogram coals, and El’baktau coal is relatively low in calorific value (3,800–4,000 kilocalories per kilogram). Although it is an important source

\(^9\) This expectation is derived from the IHS integrated energy balance model, employed in this report, it explicitly accounts for total energy demand and for development of other energy sources (gas, nuclear, renewables) in the economy.

\(^10\) The National Energy Report 2015, p. 245 notes that three of the Russian plants importing Kazakh coal (Verkhnetagil GRES, Yuzhnozemsky GRES, and Serov GRES) have gas infrastructure in place and can already switch between natural gas and coal as a main fuel.

\(^11\) See Table 8.1, 2014 on page 237 of The National Energy Report 2015. Data from Kazakhstan’s Ministry of Energy indicate that in 2017, the average lifting cost of Grade D long-flame steam coal is 4600 tenge ($14.80 at the current exchange rate) per ton; for Grade B it costs amounted to 4000 tenge ($12.87). For underground mining of metallurgical and specialty coals the costs varied more widely, from $23.38 to $58.88 per ton.
of coal for thermal power generation, it is less useful in industrial applications. Karaganda’s bituminous coal is of higher quality and can be used for coking; at the moment though it is mostly consumed domestically. As noted above, there is concern about weakening Russian demand for Kazakh coal by 2025, as some of the Russian generating capacity currently designed to be fueled by Elboustau coal becomes outmoded and will need to be replaced. Even before that point, Kazakh coal already is facing much greater competition in Russia from Kuznetsk basin coal or domestically produced natural gas. Ruble depreciation also undermined Kazakh coal’s competitiveness in the Russian market in 2014–15, but this was alleviated after the August 2015 free float of the tenge. Plans to launch Kazakh coal exports to China are also challenged to be economically viable, given the relatively low quality of the coal and the very high transportation costs that would be involved over such long distances (China’s main coal consumption centers are in the east, while its own coal is mined inland, in western China). Furthermore, coal demand growth in China is expected to decelerate over the next decade as a result of a variety of factors, including moderating economic growth, fuel diversification, and public pressure to reduce air pollution levels in some areas—now manifest in a specific commitment by China’s State Council to cap coal consumption growth by 2020. In fact, coal demand already is showing signs of weakening. Total coal consumption in the country declined by 2.2% in 2014, by 1.5% in 2015, and by 0.4% in 2016 and expected to essentially plateau longer term (see Figure 6.5).

As part of the effort to reduce air pollution in its eastern provinces, China also intends to shift some coal-fired generation capacity to interior locations and especially to its energy-rich Xinjiang Province and Inner Mongolian Autonomous Region in the northwest and north, respectively. This has become possible as a result of advances in long-distance electricity transmission via extra high-voltage and ultrahigh-voltage lines. Although Kazakh coal would certainly be geographically nearer to China’s main coal consumption centers, it thus appears that delivered costs of Kazakh coal are much higher than prevailing domestic ones. Due to its high ash content, the free float of the tenge.

Limited exports to Europe might also continue, if necessary, to provide additional amounts of fuel oil (mazut) to stabilize coal combustion. Exports to the neighboring Central Asian region might be increased, especially now that Kyrgyzstan—which currently accounts for 3.4% of Kazakhstan’s coal exports—has acceded to the Eurasian Economic Union. Another existing customer, Ukraine (2–3% of Kazakhstan’s coal exports) might import marginally more coal as well, as a result of a formal blockade announced on March 2017 by Ukraine’s President Petro Poroshenko on all non-humanitarian road and rail trade between Ukraine and separatist-controlled regions in the east (which are major coal producers). The primary commodity would be coking coal, as Kazakh thermal coal is largely unsuitable for use in Ukrainian coal-fired plants. Kazakhstan’s coal exports to Ukraine since 2012 have generally been marginal, at levels of 0.8 MMt or below (e.g., 596,000 tons in 2016). Limited exports to Europe might also continue, if economic growth there accelerates and there is a need for greater baseload generating capacity to accommodate renewable capacity additions. However, this may be challenging considering the EU focus on meeting carbon emission targets and overall declining coal demand outlook and thermal coal imports outlook (see Figure 6.6). Another potential market is Turkey. Turkey continues to build out its fleet of coal-fired power plants, fueled both by domestic coal and imports. In 2015, Turkey imported 31.5 MMt of hard coal for its thermal plants, steel production, industry, and domestic heating purposes—one third from Russia, one third from Colombia, and smaller quantities from South Africa (15%), Australia (8%) and elsewhere. These imports by Turkey are expected to increase in the future.

The situation with respect to coking coal, for which there is a more specialized market, could prove more favorable (especially if there is a recovery in demand for coking coal in metallurgical plants in Russia). We have already noted the development of a dedicated supply line from Arcelor Mittal’s mines in Karaganda Oblast to the company’s steel mills in Ukraine. This could stabilize fluctuations in exports on the downside, but it is not yet clear what effect this will have on overall exports.

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6.2.7. Coal transportation

The most significant obstacle to increasing exports of Kazakh coal are high transportation costs, which render Kazakhstan’s coal relatively expensive to consumers and reduce its competitiveness even in the nearest major export market, Russia. Transportation accounts for over 40% of the total delivered costs to Russian coal buyers.

Rail transport figures prominently in the movement of key energy commodities in Kazakhstan, including coal. In recent years coal has accounted for more than one-third of freight tonnage carried by Kazakhstan’s rail system, operated by the state-owned national railroad company Temir Zholy. However, oil and oil products shipments are the most profitable large-
the form of electricity to consumers in the Urals and West Siberia than it was to transport the coal used to generate the electricity there. Given recent advancements in ultra high voltage transmission of electricity in China and elsewhere, it might at first seem prudent for coal-industry officials to give more consideration to this option (electricity exports) for monetizing coal assets otherwise stranded by high surface transportation costs of high-ash coal. Other options for exporting coal-generated electricity might involve limited exports (or power swaps) with neighboring countries in the south (e.g., Kyrgyzstan, Tajikistan, and Uzbekistan) on a bilateral basis or Kazakhstan’s possible eventual participation in the CASA-1000 transmission project to South Asia. The latter project as currently conceived envisions the transmission of 1300 MW of surplus hydroelectric power generated in Kyrgyzstan and Tajikistan during the summer southward via Afghanistan to Pakistan, where summer power demand is high for air conditioning. Although geopolitical risks are substantial until stability returns to Afghanistan and western regions of Pakistan, the demand for electric power is great year-round in the Pakistan market, potentially affording Kazakhstan an opportunity to supply power in the winter months (when a market would exist not only in Pakistan, but in Kyrgyzstan and Tajikistan as well). This might entail transmission of large amounts of electricity along Kazakhstan’s north-south corridor (or in any event across the southern portion of the country from new coal- or gas-fired capacity), perhaps with great seasonal variations, and thus would require careful study in terms of possible effects on the national grid. Electricity exports will be considered in more detail in Chapter 8 (Section 8.3.2.1). In addition to considering ways of expanding exports of coal or coal-fired electricity, industry officials have been exploring options for the further utilization of coal in Kazakhstan’s domestic economy (see below).

6.2.8. Coal balance outlook
Projections of Kazakhstan’s coal balance out to 2040 reveal several important trends. Coal production slowly declines to less than 80 MMt in 2040 (see Figure 6.7). Apparent consumption follows a similar trajectory, slowly declining from over 70 MMt in 2016 to about 60 MMt in 2040 (see Figure 6.8). These trends are consistent with an outlook for an economy that is gradually utilizing energy more efficiently, slowly increasing its gas consumption, and possibly adding some nuclear generation capacity in the electric power sector after 2030. 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 in the developed world, whereby less energy consumption growth is necessary to support the same levels of GDP growth. This dynamic is now extending to the developing world as well. China’s coal demand has fallen for three consecutive years, despite rates of GDP growth in excess of 6%, whereas India’s growth in electricity demand (primarily coal generated) of 5% annually has lagged behind GDP growth (7% annually). In these and other countries, among the more important explanatory factors include structural economic change (from heavy industry toward services) as well as the use of more energy efficient devices (e.g., home appliances,

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6 Kazakhstan is shipped for roughly 30–50% less than oil and oil products for similar distances (on a ton-km basis).
7 Coincidentally, in early 2017 Kazakhstan’s Samruk-Energy company announced plans to double its electricity exports to Russia (to 4 billion kWh/year) from its Ekibastuz GRES-1 and GRES-2 power stations (the latter co-owned with Russia’s Inter RAO UES). However, opportunities to significantly expand electricity exports to the Russian market are quite limited in the long term—due to the Russian Energy Strategy’s emphasis on energy independence, the addition of substantial generation capacity in Siberia (with a new 500 kV connection to the Urals region), and the Russian conceptualization of power trade between the two countries as being only for system balancing purposes.
8 Pakistan’s current power shortfall is 6 GW on an annual basis. CASA-1000 as currently conceived would meet only 20% of Pakistan’s current power deficit. Policymakers expect Pakistan’s peak power demand to rise from 20.8 GW in 2015 to 32 GW in 2020 and 45 GW in 2030 (see Christopher de Vries Walker, Overview of Major Infrastructure Projects: CASA-1000 Transmission Line and Pakistan-UAE Water Pipeline, IHS Energy, Russian and Caspian Energy Presentation, Abu Dhabi, UAE, 4 April 2016).
6.2.9. Conclusions, notable changes since 2015

In the absence substantive improvements in prospects for increasing coal exports, the following developments represent at least limited avenues for increasing the contribution of coal to national economic activity:

- Although further growth in electricity exports to Russia does not appear likely, it is at least possible that other options for exporting coal-generated electricity might be explored, either to Central Asia on a bilateral basis or over the longer term as part of an international project such as CASA 1000.
- Ukraine might offer at least a fair-term opportunity for Kazakhstan to export more coking coal. However, such shipments would likely require rail transit via Russia, so it is not presently clear to what degree (if any) these exports could be constrained by geopolitical issues.
- Another potentially promising market could be Turkey, which imports substantial quantities of coal for power generation and industrial uses.

6.3. INFRASTRUCTURE AND TECHNOLOGIES: KEY CHALLENGES, IDEAS, AND SOLUTIONS

6.3.1. Efficiency and improved coal use

Because coal has a limited number of clearly defined uses in Kazakhstan’s economy, this section focuses on efforts to increase coal-use efficiency in each of the three major sectors: electric power and heat generation (accounting for 60-65% of coal consumption nation-wide); industry, including metallurgy (28%); and the domestic sector (6%). The ubiquitous use of coal in Kazakhstan is explained by its abundance and low cost of production. However, most new technologies that make coal enterprises more efficient and clean inevitably raise the cost of coal and make it less competitive with other fuels, such as natural gas, mazut, and LPG. In some circumstances expenditures on coal upgrades can be economically justifiable; however, this is not a given and will be an important factor in the proliferation of the technologies listed below.

Electric power. Given the preponderance of coal-fired capacity in the electric power sector, improvements in the generation, transmission, and distribution of electricity, more than any other conceivable measure, will increase the efficiency of overall coal use in the country. A key issue for the optimal level of specific fuel consumption for coal in Kazakhstan is long-term load planning and adjustment of capacity construction plans aimed at maintaining an acceptably low level of load at coal-fired plants and preventing formation of significant excess capacity. When new coal-fired capacity is added, the adoption of new coal combustion technologies should be considered. One such technology is the ultra-supercritical steam cycle (now operational in Denmark, Germany, and Japan, as well as the United States). Conventional coal-fired power plants, which make water boil to generate steam that activates a turbine, have efficiency of about 32%. Supercritical (SC) and ultra-supercritical (USC) power plants—also known as high-efficiency, low emission (HELE) coal-fired power plants—operate at temperatures and pressures above the critical point of water, i.e. above the temperature and pressure at which the liquid and gas phases of water coexist in equilibrium, at which point there is no difference between water in gaseous or liquid form. This results in higher efficiencies—above 45%. Supercritical (SC) and ultra-supercritical (USC) power plants require 5-7% less coal per megawatt-hour, leading to lower emissions (including carbon dioxide and mercury), higher efficiency, and lower fuel costs per megawatt.

Although the upfront cost of such technologies is 20-30% more expensive than a traditional subcritical unit, the additional costs are more than offset by the improved net thermal efficiency levels and by reduced emissions (in countries where carbon taxes are levied). The technologies are based on the burning of pulverized coal at very high temperatures, obtaining USC steam parameters (280 atm and 600°C), and also (over the longer term) cycles with even higher steam parameters (300 atm and 700°C). An example of coal-fired power plant with ultra-supercritical steam parameters in Kazakhstan is Unit 3 of Elibastuz GRES 2.

It is important to note that, with USC now well established, R&D is now underway to increase steam temperatures beyond 700°C, which could achieve coal-fired efficiencies as high as 50%. Known as advanced ultra-supercritical technology (AUSC), such high pressures and temperatures will require more advanced (nickel or nickel-iron) superalloys that are expensive and currently present fabrication and welding challenges. In early 2014, Alstom and Southern Company (US) announced a milestone in the development of AUSC, with steam loop temperatures maintained at 760°C for 17,000 hours during a trial at Plant Barry Unit 1 in Alabama. The loop contained an array of different superalloys and surface coatings that enabled it to withstand the exceedingly high temperatures within the boiler. Further advances in material science will be necessary for these AUSC technologies. Another promising new coal combustion technology is the integrated gasification combined cycle (IGCC), which instead of burning the coal directly uses a gasifier to convert it to syngas (H2 and CO2). The resulting gas (after treatment) is burned in a gas turbine, and the heat of the exhaust flue gases (combustion products) is used to generate steam and electricity in the steam turbine cycle. However, the technological efficiency of the IGCC technology is not very high (about 43%)—much lower than the standard efficiency for CGGTs using natural gas (57%). In addition, construction of such power plants is much more expensive than construction of conventional coal- and gas-fired plants, since the gasifier and the gas treatment system are the most metal-consuming and capital-intensive parts of the IGCC technology. IGCC technologies are at the stage of pilot testing and research, as there are a number of unresolved problems, including operation of gasifiers under pressure and high-temperature gas treatment before supply to gas turbines. Overall, it should be noted that in coal-fired power generation there is a trend towards increasing the efficiency of the conventional pulverized-coal cycle through maximizing the steam parameters, which allows achieving an efficiency of 45-47%. Existing coal-fired power plants with 300-500 MW generating capacity in Kazakhstan were designed for operation with supercritical steam parameters (237 atm, 540°C) and, therefore, are less efficient of 31-35%. Raising the steam parameters to ultra-supercritical technology upgrades (re-equipping) will increase the units’ efficiency by about 4%. With gradual modernization and technology upgrades at existing coal-fired power plants, the efficiency of coal use will grow, and, therefore, the volumes of environmental emissions and coal consumption will decrease.

District and building-level heating. In the domestic sector, a major use of coal is for the heating of urban districts and buildings. Often provision of heat and electricity are combined, when generation is from a combined heat and power plant (e.g., thermoelectrically or through a heat engine). The district heating capacity in Kazakhstan is coal-fired. As in the electric power sector, heat generation capacity is aged (e.g., 41% of TETs have been in service for over 30 years), and nearly two-thirds are in need of some type of repair or modernization.

Replacement and modernization of boilers at coal-fired boiler houses and TETs results in increased coal use efficiency. It is also possible to increase efficiency by installing supply monitoring and control systems. If air excess in the boiler is significantly higher than the optimum value for combustion of a given grade of coal, efficiency falls due to heat loss via excess air in exhaust flue gases. Air excess control systems can determine the optimum amount of air supply in order to achieve the maximum boiler unit efficiency. Such systems have been already installed at some TETs and boiler houses in Kazakhstan and resulted in lower fuel consumption.

Although natural gas is increasingly the fuel of choice in the residential sector, in unique instances alternative uses of coal, such as coal-water slurries (CWS) and coal briquettes could be possible for heating purposes. Coal-water slurries can be produced at the Sarykol field. However, due to the already low costs of briquettes in potential export markets for briquettes, such as China, South Korea, and Vietnam (and the fact that they can be fabricated from a variety of locally ubiquitous materials such as recycled paper, wood charcoal, sawdust, and rice and peanut chalk), it will likely be difficult for Kazakhstan producers to compete with locally produced briquettes in these markets.

Industry. Industry (mostly coking) accounts for about 28% of overall coal consumption in Kazakhstan.

14 For instance, the Biogas thermal power station near Yokohama, Japan houses two coal-fired units. Combined, the facilities emit 50% less NOx, 80% less sulfur, 70% less particulates, and 17% less CO2 than the previous subcritical units using a regenerative activated coke dry-type control technology (ReACT).

15 The largest IGCC plant (Puertollano), with a capacity of 335 MW, is currently in operation in Spain.
6.4. REGULATION OF KAZAKHSTAN’S COAL SECTOR

6.4.1. Review of program documents and legislation

As is evident from the discussion of overall trends in coal production, consumption, and gas saturation — as well as the heretofore limited prospects for the exports of coal and the electricity generated from it, the coal industry’s trajectory is not one of growth, but rather of gradual decline. Ongoing depuration — or degassing (or “cleats”) present in the coal, and naturally determine the cost of the CBM deposit development option. Environmentally safe substances (e.g., potassium chloride) can be used as chemical reagents for hydraulic fracturing, but they have the advantage of being compatible with the environment. The technology generally enlarges already existing fractures or “clears” present in the coal, and increases the connectivity between natural fracture networks and between these networks and the production wells. CBM production technologies require drilling more wells as compared to conventional gas fields. The types and characteristics of production wells depend on many factors — the coal geology, depth and pressure, permeability, and connectivity, and the rate of flow of the gas to the production wells. The main potential for energy savings in the production of coal is achieved by the efficient use of production equipment, which is actually equivalent to the construction of a new plant. Therefore, the potential for energy savings in metallurgy is relatively limited. In the mining sector, energy efficiency improvements can be achieved mainly through assets (equipment) modernization and introduction of systems for optimizing fuel consumption during ore extraction, and transport. In the country’s coal-rich regions, the potential also exists for industry to use coal mine methane or coal bed methane as a power source. As recently as 2013, CBM accounted for almost 2% of total combined gas and CBM production in the world. CBM production is most developed in the US (which accounted for 62% of total world output), Canada, China, Australia, India, Indonesia, and some other countries (see the National Energy Report 2015, pp. 250–253 for background). Estimates of global CBM gas in place range from 1.2 trillion cubic meters to 5.2 trillion cubic meters, depending on the economic assumptions that are employed, from 78 trillion cubic meters (Tcm) at the low end to as much as 959 Tcm. Of these amounts, some 30–60% constitute recoverable reserves. The estimate cited a global reserve figure of 260 Tcm. Unlike gas in conventional deposits, methane in coal is not trapped under pressure in the coal-bearing strata. Moreover, less than 10% typically exists as “free” gas within fractures and joints. Rather most CBM is adsorbed within the micro-porous matrix of the coal itself. Therefore, it is a loose mean that when the methane itself is viewed as the resource to be developed (and not the coal), it is commonly extracted using enhanced recovery techniques similar to the hydraulic fracturing method, which includes the rapid rise in unconventional oil and gas production, although the mechan- ics and rates of flow of the gas to the production wells vary from one environment (typical water) to another (sometimes also acids and additives) and a “proppant” (an agent that props open the fractures, typically sand, after the injection fluid is removed) is added. These processes mean that when the methane itself is viewed as the resource to be developed (and not the coal), it is commonly extracted using enhanced recovery techniques similar to the hydraulic fracturing method, which includes the rapid rise in unconventional oil and gas production, although the mechanics and rates of flow of the gas to the production wells vary from one environment (typical water) to another (sometimes also acids and additives) and a “proppant” (an agent that props open the fractures, typically sand, after the injection fluid is removed) is injected into the targeted coal zones at high pressure. The technology generally enlarges already existing fractures or “clears” present in the coal, and increases the connectivity between natural fracture networks and between these networks and the production wells. CBM production technologies require drilling more wells as compared to conventional gas fields. The types and characteristics of production wells depend on many factors — the coal geology, depth and pressure, permeability, and connectivity, and the rate of flow of the gas to the production wells. The main potential for energy savings in the production of coal is achieved by the efficient use of production equipment, which is actually equivalent to the construction of a new plant. Therefore, the potential for energy savings in metallurgy is relatively limited. In the mining sector, energy efficiency improvements can be achieved mainly through assets (equipment) modernization and introduction of systems for optimizing fuel consumption during ore extraction, and transport. In the country’s coal-rich regions, the potential also exists for industry to use coal mine methane or coal bed methane as a power source. As recently as 2013, CBM accounted for almost 2% of total combined gas and CBM production in the world. CBM production is most developed in the US (which accounted for 62% of total world output), Canada, China, Australia, India, Indonesia, and some other countries (see the National Energy Report 2015, pp. 250–253 for background). Estimates of global CBM gas in place range from 1.2 trillion cubic meters to 5.2 trillion cubic meters, depending on the economic assumptions that are employed, from 78 trillion cubic meters (Tcm) at the low end to as much as 959 Tcm. Of these amounts, some 30–60% constitute recoverable reserves. The estimate cited a global reserve figure of 260 Tcm.
Achievement of the goals is to be supported by the phased rollout of a fiscal and regulatory framework in accordance with the law "On Natural Resources and Natural Resource Use" (24 June 2010) and the Law "On Technical Regulation" (9 November 2004). However, even this more measured development plan may still be too optimistic for the coal industry.

Finally, a major state program devoted specifically for the coal industry (Roadmap for the Development of the Coal Industry and Its Prospects to 2030) has now (2017) been elaborated by the Ministry of Energy. Some indications of the directions envisioned by the Roadmap were revealed by Energy Minister Bozum-bayev in January 2017. He stated that priority would be accorded to measures to reduce adverse environmental impacts in areas of coal production and to increase the output of coal products of high quality. At the same time he stressed the importance of maintaining the current level of coal production through more comprehensive processing of coal to increase the diversification of products and uses, including the production of diesel and other synthetic liquids from coal (CTL) and the use of coal mine methane as a local power source for electricity generation. Bozum-bayev also advocated efforts to diversify the economies of “company towns” (monogorody) engaged in the production of coal, such as Ekibastuz, where projects already have been launched in such activities as transportation machinery building and the construction industry.

6.4.2. Key recommendations

Coal will remain an important part of Kazakhstan’s energy sector for many years to come, although it is not a growth story. With this in mind, we believe some of the same recommendations offered in The National Energy Report 2015 retain their relevance today:

• Pursue careful policy implementation so as to not undermine coal’s competitiveness unnecessarily. Particular attention should be devoted to the impacts of carbon pricing and changes in rail tariffs on coal exports and consumption of coal in the domestic economy.

• Continue research on ways to use coal more cleanly and efficiently, especially in power generation by incremental improvements, such as reducing emissions through improving efficiency of fuel utilization and retrofitting older capacity with stack filters. If demonstrable progress can be demonstrated on the carbon footprint, the timetable for coal’s replacement by other fuels can be stretched out.

• Although the most efficient use of Ekibastuz coal is power generation, continue technical and economic studies on the feasibility of cleaning and standardization of bituminous and brown coals from other deposits so that coal of consistent and predictable quality, emissions characteristics, and heat content will be available to potential export markets.

To these recommendations, we would add the following:

• Similar to measures taken worldwide to encourage the reduction of associated gas flaring during oil production, consider introducing legislation providing incentives: to discourage emissions of methane and other gases during coal mining and to encourage recovery of these gases for uses in electric power and heat generation, if economically feasible. Such measures might include a reduction of the tax burden on subsoil users producing and utilizing (rather than emitting) unconventional gas.

• Given Kazakh coal’s high transportation costs and challenges to competitiveness in major export markets, explore the potential for greater utilization of Kazakhstan’s coal to generate electricity domestically for export, such as to Central Asia and South Asia. The CASA-1000 project’s goal of adding regional thermal generating capacity to support hydroelectric generation in Tajikistan and Kyrgyzstan may open avenues for Kazakhstan’s participation in that project.
7. URANIUM

7.1 KEY POINTS
7.2 URANIUM SECTOR UPDATE
7.3 INFRASTRUCTURE AND TECHNOLOGIES:
   KEY CHALLENGES, IDEAS, AND SOLUTIONS
7.4 REGULATION OF KAZAKHSTAN’S URANIUM SECTOR
7. URANIUM

7.1. KEY POINTS

- Kazakhstan is the world's leading uranium producer, accounting for about 40% of global production. Unprecedented growth of uranium production from 2003 to 2016 by more than sevenfold will be followed for the first time by a decrease in production in 2017 by 10% in order to restore prices in the uranium market. The market situation associated with the fall in the price of uranium in 2016 by 40% has seriously affected the industry, even though Kazakhstan has the lowest cost of uranium mine production in the world due to the efficient and environmentally friendly in-situ leaching technology (ISL).1
- The global uranium market currently can be characterized as a “buyer’s market” (demand constrained), with a relatively small number of producers supplying a similarly small number of major clients. Kazakhstan's effort to support uranium prices by announcing plans to cut its production by over 2,000 tons (Mt) in 2017 appears to have had limited impact to date. Globally, most production is sold under long-term contract prices (less sensitive to near-term production fluctuations), and there is no indication yet that other producers are ready to move with coordinated production cuts along with Kazakhstan. However, Kazakhstan may have the capacity to affect spot prices by slowing ISL and thus limiting supply. When making decisions about how to limit supplies to market, the choice between storing uranium and cutting production should be based upon the underlying economics, and on how long the chosen strategy can be feasibly pursued (for example, on how long a producer can bear increases in variable costs in case production is cut, compared to costs of storage and financing, etc.).
- In the long term, the growth in the number of nuclear power plants in the world will be accompanied by an increase in demand for uranium. It is the new developing markets that will determine the demand for uranium in the future, whereas in developed countries, the decommissioning of nuclear power plants will significantly exceed the launch of new reactors. According to the World Nuclear Association as of May 2017, 60 reactors with a total capacity of 64.5 GW are under construction, while another 164 reactors (with a capacity of 170.8 GW) are planned for construction.
- A prolonged search for a consumer of fuel pellets by the national nuclear company Kazatomprom, following the suspension by Russia of the purchase of fuel pellets made at the Ulba Metallurgical Plant (UMP), is nearing an end. According to an agreement reached with the China General Nuclear Power Corporation (CGNPC), a production line for manufacturing fuel assemblies (containing fuel rods housing fuel pellets) with a design capacity of 200 tons of uranium annually will begin production based on a French design for PWR reactors. The launch of the fuel assembly line in Kazakhstan is a success for Kazatomprom, since initially CGNPC insisted on establishing production capacity in China.
- Kazakhstan's participation in an important international initiative to establish a Nuclear Fuel Bank (of low-enriched uranium) on its territory is an important political step to support the concept of non-proliferation of nuclear weapons. In 2017, it is planned to complete the construction of a storage facility on the site of the UMP to accommodate up to 90 tons of low-enriched uranium for the Nuclear Fuel Bank. The placement of the Bank on the territory of the UMP will not be an exceptional event for the plant, as the volumes of fuel storage at the plant earlier significantly exceeded this volume.
- The realization of the concept of achieving a closed nuclear fuel cycle (NFC) may be that nuclear power will become almost renewable; studies toward this goal are being conducted, for example, in Russia's “Proryv” (or “Breakthrough”) project. Despite the high hopes placed on the closed-cycle technologies being developed, their significant impact on the uranium market is likely to be felt only beyond the planning horizon of this report. However, in view of the potential prospects of closed nuclear fuel cycle projects and the existence of unique research and test facilities, Kazakhstan is encouraged to explore avenues for greater involvement of its scientists in joint work and research on this and other promising areas of the nuclear industry (expansion of the fuel base, high-temperature reactors, etc.).

7.2. URANIUM SECTOR UPDATE

7.2.1. Market structure

Production of uranium in Kazakhstan comes from 19 mine projects, 6 of which owned by the national company Kazatomprom, while the other 13 are joint ventures with foreign companies, including AREVA, Cameco, Uranium One, as well as with Chinese and Japanese investors. On an entitlement basis, Kazatomprom accounted for 54% of the uranium mined in 2015, followed by Uranium One with a share of 20%, AREVA with 9%, and the Energy Asia consortium of Japanese companies with 8%.1 Because Kazakhstan does not presently possess nuclear power generation capacity (only research reactors and test benches), all of the produced uranium is exported, primarily under long-term contracts. Of all the stages in the nuclear fuel cycle, only uranium mining, reconstitution, and fuel pellet fabrication are currently undertaken in Kazakhstan. Kazakhstan’s Government sets the main directions of state policy related to nuclear power generation, and is responsible for certain safety regulations (including for the development of the National Nuclear Emergency Plan). The Energy Ministry is responsible for setting and execution of state policies in the nuclear power sector, as well as for the management of the uranium production sector (including overseeing exports) and the (potential future) nuclear power generation sector. Kazatomprom, which is owned by the Samruk-Kazyna National Welfare Fund—the state corporation managing state assets—has the status of a National Company in the uranium production industry. According to the Subsoil Law, a National Company is authorized to represent the state’s interests in subsoil contracts, as well as to monitor and execute such contracts. The National Nuclear Center at Kurchatov, which operates three research reactors, undertakes research and development activities.

7.2.2. Uranium reserves

Kazakhstan’s reserves are among the largest in the world: as of January 2015, reasonably assured resources (RARs, roughly corresponding to the A+B+C1 reserves category used in Kazakhstan) that are recoverable at a cost of less than $260/kg U are estimated at 0.4 MMM (8% of the world’s total), below only Australia with 1.2 MMt and Canada with 0.5 MMt.4 Importantly, as a result of geological exploration, the country significantly increased its low-cost reserves. Kazakhstan’s resources recoverable at a cost of up to $80/kg U increased from 200 Mt as of January 2013 to 230 Mt in January 2015. In absolute terms this increase is second only to South Africa, which expanded its reserve base in this cost category by 55 Mt. For the rest of the world, reserves in this category recorded a net decrease of 73 Mt (driven by Canada, where reserves declined by 79 Mt). In terms of inferred resources—the category corresponding to the C1 category used in Kazakhstan—the country increased its reserves by 120 Mt (to 438 Mt) in the same period, as more reserves were classified as inferred at the Inkai and Moinkum deposits.

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1 The International Atomic Energy Agency (IAEA) recognizes the ISL technology as the most environmentally friendly and safe way of mining deposits.
2 Energy Asia shares are distributed as follows: Marubeni 30%, TEPCO 30%, Toshiba 22.5%, Chubu Electric 10%, Tohoku Electric Power 5%, and Kyushu Electric Power 2.5%.
3 Specifically, Kazatomprom owns the UMP, which has the capability to produce fuel pellets. During the Soviet period, UMP covered up to 80% of the USSR’s nuclear power plants’ needs in fuel pellets. After the drop in demand and the subsequent refusal by Russia to place new orders for fuel pellets, UMP redirected its operations to the production of powdered raw materials from uranium hexafluoride. The production of fuel pellets is now minimal (10 tons in 2014, 0 tons in 2015, 24 tons in 2016), with delivery directed to consumers in China.
4 The 2016 IEA/IAEA Report provides a figure of 363,200 tons for RAR (A+B+C1), with another 578,400 tons in the C2 reserve category.
### 7.2.3. Uranium production

Kazakhstan’s total uranium production increased from 22 Mt in 2013 to 25 Mt in 2016 (see Table 7.1). Kazakhstan’s leading uranium producer is state-owned Kazatomprom: in 2015 it produced 12.9 Mt of uranium (up from 11.9 Mt in 2013), which constitutes 54% of the country’s uranium mine production and 21% of the world’s total production. The remaining 46% of uranium production in Kazakhstan comes largely from mines worked by international joint ventures with companies from other countries (e.g., Canada, France, Japan, and Russia). Globally, other large uranium producers include Cameco (2015 production of 10.9 Mt, or 18%), AREVA (9.4 Mt, 16%), and Rosatom (7.8 Mt, 13%).

<table>
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<tr>
<th>Table 7.1. Aggregate uranium production by Kazatomprom’s subsidiaries, 2010-2016 (metric tons)</th>
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<td>Year</td>
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<td>2015</td>
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<td>2016</td>
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Source: Kazatomprom

Considering individual mines, the biggest addition to output came from the Kharasan-1 and Kharasan-2 mines, which between 2013 and 2015 increased production by 360 and 510 tons, respectively, while the combined output from the Tortkuduk and Moin-kum mines increased by 550 tons. At the same time, output at the Vostok and Zvezdnaya mines ceased in 2015 due to depletion of reserves.

### 7.2.4. Uranium exports

All uranium produced in Kazakhstan is exported. According to the Kazakhstan Customs Committee, China has remained the largest importer of Kazakhstan’s uranium, although its share in total exports decreased from 54% in 2014 to 46% in 2016. Reduction in purchases by China reflects a reduction in the pace of the country’s stocks replenishments. Similarly, the share of Russia decreased from 19% to 14% in the same period. In contrast, France increased purchases, as its share went up from 6% to 14%, while India, which previously had not purchased uranium from Kazakhstan, bought 2.5 Mt in 2016, or about 10% of Kazakhstan’s total 2016 uranium exports.

### 7.2.5. Global uranium market

Global RARs of conventional uranium recoverable at a cost of under $260/kgU decreased from 4.6 MMt as of January 2013 to 4.4 MMt as of January 2015 as the result of the decrease of reserves in the US by 334 Mt due to reappraisal (at the same time, reserves in Greenland increased by 103 Mt during the same period). During the same period, inferred reserves recoverable in the same cost category increased from 3.0 MMt to 3.2 MMt (see Figure 7.1). Global RARs recoverable at costs below $80/kgU went up by 12 Mt. The largest reserves increases came from Kazakhstan, South Africa, Peru, and Russia, which expanded their reserves by 30, 55, 13, and 12 Mt (respectively), while on the negative side, decreases of reserves by Canada and the US amounted to 79 and 22 Mt (see Figure 7.2). Given the global production level of 62 Mt in 2016, RARs recoverable at costs below $80/kgU would last for 20 years, while those at costs of up to $260/kgU—for 73 years. The growth in uranium production in the world over the past 10 years is associated with a reduction in the supply of enriched military uranium to the market. As can be seen from Table 7.2, the production of electricity at nuclear power plants, despite the increase in capacity by 5.4% (20 GW), even decreased by 4.5%. This fact can be explained by a decrease in the output of electricity by nuclear power plants in Germany and the suspension of nuclear power plant operations in Japan after the accident on March 11, 2011 at the Fukushima Daiichi nuclear power plant.

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<th>Table 7.2. World’s production, consumption of Uranium, nuclear power generation capacity, reactors and power generation from 2007 to 2016 (tons)</th>
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<tr>
<td><strong>Year</strong></td>
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<tr>
<td>Uranium production</td>
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<tr>
<td>Share of global uranium demand, that by production</td>
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<td>Uranium requirements (end of year)</td>
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<td>Number of operating reactors (end of year)</td>
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<tr>
<td>Capacity, GW (end of year)</td>
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<tr>
<td>Nuclear power generation, billion kWh</td>
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Source: World Nuclear Association
On the demand side, power generation remains the largest consumer of uranium, 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). The enrichment capacity increased, uranium requirements decreased by about 4%, partially reflecting stalled reactors in Japan (see below), as well as higher efficiency in fuel use. Utilities in the US and Europe are specifying lower tails assays at contracts with enrichment facilities, which means that uranium is enriched to a greater degree (for example, from 3.3% of 235U to 5.0% of 235U). Utilities can now burn uranium harder and longer. The World Nuclear Association (WNA) estimates that since the 1970s, fuel burn-up increased from 40 GWd (giga Watt-days) per ton of uranium to more than 60 GWd. As a result, utilities now want to leave only 0.5% of 235U in spent fuel, compared to 1.0% in the past. The net effect of higher efficiency is that less reactor fuel is needed to produce the same amount of electricity.

By the end of 2016, there were 447 reactors with a total capacity of 391 GW around the world. In 2016, they produced 2,490 billion kWh. Total uranium requirements by the end of 2016 were estimated at 63 Mt6. China was the main driver behind the growth in global uranium reactor capacity between 2014 and 2017; the number of operable reactors in China increased by 12, from 19 in January 2014 to 35 in January 2017, while total generation capacity grew from 16 GW to 32 GW.7 In 2016 alone, the number of reactors globally increased by 8, adding another 8.8 GW to total capacity. China added 5 reactors, with a total generation capacity of 4.8 GW. China’s ambitious plans for the expansion of nuclear generation are laid out in its 12th Five-Year Plans (FYP). However, the restarts remain politically contentious, with about 60% of Japanese polled in public opinion surveys opposing them; some restarts have been delayed by legal challenges from anti-nuclear groups. If the safety reviews and restarts proceed according to schedule—a big assumption given the uncertainty involved—IHS Markit estimates that annual generation from nuclear in Japan could rise to as much as 143.9 terawatt-hours (TWh) by 2020 (less than half the peak level in 2000).

In addition to Japan, Germany, Sweden, the UK, and the US each decreased the number of operable reactors during the period 2014–15. Each country closed one reactor, decreasing these countries’ nuclear generation capacities by a net of 1.3 GW, 0.7 GW, 1.2 GW, and 0.1 GW, respectively. Although the number of reactors and overall capacity in the United States remained stable during the 2013–15 period (the US leads the world in both metrics), as the industry was able to extend the useful lives of reactors through improvements in maintenance, the bankruptcy of the Westinghouse Electric Company in late March 2017 is a disquieting development for the industry. The filing emerged as Westinghouse’s parent company, Toshiba, takes steps to recover from massive losses incurred in the construction by Westinghouse of two nuclear power plants—Units 3 and 4 of the Vogtle Plant in Georgia—and Units 2 and 3 of the Virgil C. Summer station in South Carolina, with each unit’s capacity being 1.3 GW—both badly behind schedule and over budget. The problems are attributed to a combination of factors, including the launch of a new reactor design (AP1000), unexpected new safety requirements following the Fukushima Daiichi incident, and (given the dormancy of reactor construction activity in the US) construction delays by US contractors lacking the expertise and equipment needed to make some of the largest reactor components. Not only is the future of the two projects now in doubt, but Toshiba appears either to be seeking a buyer for Westinghouse or to refocus the company on reactor design and maintenance, rather than construction. In either event, Toshiba appears to be considering exiting the nuclear business. In fact, the nuclear segment is now operating at a loss, as the company pays down existing debt. In 2016, Toshiba posted its largest ever operating loss ($3.23bn), the company’s annual profit was the lowest in more than 20 years.

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Producers’ reaction to the low price environment included delays in new mine development as well as production cuts from, or shutdowns of, existing mines (including in Malawi, US, Canada, Australia, and Niger). In January 2017 Kazakhstan announced a planned cut in production by “over 2 Mt,” or about 3% of global mine output for 2017. Since that time, apparently responding in part to news of the production cut, uranium prices rallied to levels above $25/lb ($65/kgU) by mid-March, but averaged $24/lb ($62/kgU) by the end of the month. As most major producers, Kazakhstan sells uranium predominantly on a long-term contract basis. Spot market prices have been consistently much lower than the long-term contract prices (see Figure 7.4). Specifically, the difference between the Nuexco exchange spot price and the arithmetic mean of long-term prices reported by Ux Consulting and TradeTech, averaged $9.5 per pound in 2015 and $12.7 per pound in 2016. This is well above the cost of storage, estimated for certain industry participants at only $0.2 per pound annually.

Figure 7.4. Spot price of U3O8

Source: IPN Primary Commodities Index, Ux Consulting © 2017 IHS Markit

7.2.6. Uranium transportation

Kazakhstan’s nuclear materials transportation market is open for participation and requires two licenses: one—from the Nuclear and Energy Control Oversight Committee, and another—from the Investments and Development Ministry’s Transport Committee. The major transportation modes used are rail, automobiles, and air transportation. Transportation of nuclear radioactive materials also involves participation by security services from the Ministry of Internal Affairs.

7.2.7. Domestic use: nuclear fuel cycle and proposed reactor construction

Kazakhstan is seeking to expand uranium processing to encompass the entire nuclear fuel cycle. As of 2016, Kazatomprom and Canada’s Cameco are carrying out a feasibility study on a proposed purification facility in Kazakhstan to produce uranium trioxide (UO3) from triuraniumoctoxide (U3O8), with an annual capacity of 6 Mt for further conversion into uranium hexafluoride (UF6) at Cameco’s conversion facility in Canada.9 The two sides are evaluating the economic feasibility of this project. Also, Kazakhstan continues to participate in the uranium enrichment sector through its partnership with the Russian JSC TVEL at the Ural’s Electrochemical Integrated Plant, Russia’s largest enrichment facility. In addition to this project (called the Uranium Enrichment Center (UEC) JSC), Kazakhstan through its national company Kazatomprom has access to enrichment services via the International Uranium Enrichment Center (IUEC) in Angarsk (Russia), 10% of which is owned by Kazatomprom. In the fuel production segment, Kazatomprom and China’s China General Nuclear Power Corporation launched the construction of a fuel assembly production line at the UMP with a capacity of 200 tons annually. The $150 million project will use AREVA-licensed technology and is projected to be completed by 2020.

As to nuclear power generation, Kazakhstan explicitly stated its interest in constructing a nuclear power plant, and is conducting a study to determine the capacity, location, and timing of a plant. The advantage of developing nuclear energy for Kazakhstan is the fact that there are no greenhouse gas emissions or emissions of other harmful substances. Radioactive waste generated in the process of operation is strictly localized in a relatively small volume. Modern nuclear power plants have an order of magnitude less radiation impact on the population than coal-fired power plants. And nuclear power is a high-tech and knowledge-based industry, the development of which will give additional impetus to Kazakhstan’s economic development, including by gradually increasing the share of local content in the design, construction, and operation of nuclear power plants.

7.2.8. Uranium balance outlook

In the longer term, growth in reactor-related demand will provide support for price growth. As of January 2017, there were 447 reactors in operation and 60 reactors under construction—22 of which are in China, and seven in Russia. To compare, as of January 2015, 437 reactors were in operation and 70 under construction.

- In 2015, construction started on eight reactors (six reactors in China, one in Pakistan, and one in UAE), while ten reactors were connected to the grid (eight reactors in China, one in South Korea, and one in Russia), and seven reactors were permanently shut down (five in Japan, and one each in Germany and the UK).

- In 2016, construction of three reactors commenced (two in China and one in Pakistan), while ten reactors became operational (five reactors in China, one in each of Pakistan, India, Russia, South Korea, US), and three were shut down (one in each of US, Japan, and Russia).

The number of reactors globally that have secured approvals and funding, and are expected to become operational in the next eight to ten years, is estimated at 164, of which 40 planned reactors are in China, 25 in Russia, 20 in India, and 18 in the US (see Figure 7.5). The IHS Markit Rivalry scenario for electric generation capacity by fuel type/technology projects further modest growth in nuclear generation capacity worldwide out to 2030 and beyond—1.6% annually between 2015 and 2040.10 Although projected nuclear capacity in 2040 (592 GW) exceeds that in 2015 (391 GW) by more than 50%, the share of nuclear in total electrical generation capacity falls to 5% (from 6% in 2015).

Figure 7.5. Top ten countries with the largest additions of reactors

Source: IEA Nuclear Power

Notes: * Under Construction = First concrete for reactor poured, or major refurbishment underway; Planned = Approvals, funding, or commitment in place, mostly expected to be in operation by 2030.

The outlook for uranium demand is linked to the nuclear capacity build-out and appears to be positive during the forecast period. IHS Markit Scenarios fall in between the high and low scenarios by NEA/IAEA from 2016 (see Figure 7.6).

* The mined ore in the form of U3O8 still contains impurities and therefore needs to be purified prior to conversion to UF6. The most commonly used process is based on the solvent extraction method, which transforms U3O8 into UO3. Cameco’s conversion facility in Port Hope (Ontario province) requires UO3 as a feedstock to produce UF6.

10 The Rivalry scenario is the baseline scenario for IHS Markit projections, and assumes increased competition among energy sources as a result of price differentials, environmental concerns, technology improvements, and energy security considerations. Increased cost competitiveness and more stringent environmental regulation lead to greater powertrain and fuels competition in transportation.

Figure 7.6. Spot price of U3O8

Source: Spot price of U3O8 by order of magnitude

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The outlook for uranium demand is linked to the nuclear capacity build-out and appears to be positive during the forecast period. IHS Markit Scenarios fall in between the high and low scenarios by NEA/IAEA from 2016 (see Figure 7.6).
The low NEA/IAEA case, reflecting a "conservative, but plausible" scenario, assumes a continuation of the current policies and regulations that are cautious about the prospects for nuclear power generation. For example, under the low case scenario, Japan's nuclear generation capacity decreases from 40 GW currently to 25 GW in 2020 and further to 15 GW in 2030. As a result, global annual reactor requirements for uranium will pass 100 Mt in early 2030s. The NEA/IAEA estimates that if existing and committed (FID) mines produce at stated capacity, this should be adequate to meet global uranium demand entirely through the early 2030s under the low case, and 60% of the requirement under the high case. When identified planned and prospective mining projects are taken into consideration, however, projected production capacity will exceed requirements.

7.2.9. IAEA Nuclear Fuel Bank in Kazakhstan

Kazakhstan continues progress toward establishing an international low enriched uranium (LEU) fuel bank. The goal of the project is to prevent the spread of uranium enrichment technologies, by providing IAEA member states with access to the reserved volumes of low-enriched uranium used for fabricating fuel.

A ten-year agreement between Kazakhstan and the International Atomic Energy Agency (IAEA) from 27 August 2015 was approved by Kazakhstan’s Parliament in November 2016 and envisages construction of a fuel bank at the UMP. The bank is capable of storing up to 90 tons of low-enriched uranium hexafluoride (UF₆) fuel and is set to be launched in late August 2017. 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 (which were reduced by placing the bank on the territory of an operating plant) are shared equally by Kazakhstan and IAEA, whereas the cost of acquiring and delivering LEU to the Nuclear Fuel Bank is borne by the IAEA (in part, these costs are financed by donor funds from the US, EU, United Arab Emirates, Kuwait, and Norway).

7.2.10. Conclusions/notable changes since 2015

• Kazakhstan increased its uranium RARs in the price category of $80/kg or below, from 200 Mt in January 2013 to 230 Mt in 2015; this is the second largest increase in this reserve category of any country in the world.

• Kazakhstan plans to voluntarily reduce the country’s mine production in response to an oversupplied market and depressed price environment.

As per Kazatomprom’s Askar Zhumangaliyev, Kazakhstan’s “planned production” will be reduced “by about 10%” or “by over 2 Mt.” The effect of this cut on global uranium prices could be limited because: there is no formal agreement among the global producers on coordinated supply cuts; Kazakhstan’s planned production cut amounts to only about 3% of global annual demand; and Kazakhstan exports within a “buyer’s” market, with China accounting for about half of its total exports. For this reason, Kazakhstan is also seeking to address an excessive gap between spot and long-term prices by studying the possibility of storing uranium, which may drive spot market prices higher.

• Reflecting its efforts to expand its presence in the nuclear fuel cycle, Kazakhstan has commenced construction of a fuel fabrication facility in collaboration with Chinese investors.

The high case, reflecting an “ambitious” scenario, assumes policies favoring climate change mitigation and a dramatic acceleration of renewable energy. For example, under the low case scenario, Japan’s nuclear generation capacity decreases from 40 GW currently to 25 GW in 2020 and further to 15 GW in 2030. As a result, global annual reactor requirements for uranium will pass 100 Mt in early 2030s. The NEA/IAEA estimates that if existing and committed (FID) mines produce at stated capacity, this should be adequate to meet global uranium demand entirely through the early 2030s under the low case, and 60% of the requirement under the high case. When identified planned and prospective mining projects are taken into consideration, however, projected production capacity will exceed requirements.

7.3. INFRASTRUCTURE AND TECHNOLOGIES: KEY CHALLENGES, IDEAS, AND SOLUTIONS

7.3.1. Downstream value added

The nuclear fuel cycle has two phases. The “front end” phase of the cycle consists of (see Figure 7.7):

• mining of uranium ore and production of uranium oxide (U₃O₈) concentrate;
• conversion of U₃O₈ into uranium hexafluoride (UF₆);
• enrichment of UF₆ (i.e., the increase of the uranium-235 isotope concentration);
• fuel fabrication, which includes three separate steps:
  • reconversion into uranium oxide (UO₂);
  • production of ceramic fuel pellets;
  • combination of pellets into fuel rods

• assembly of the rods into a fuel assembly structure.

The “back end” phase includes the reprocessing, storage, recycling, and disposal of spent nuclear fuel.

Kazakhstan currently is present in the front end phase, specifically in the mining stage, as well as partially at the fuel fabrication stage (namely, in reconversion of enriched UF₆ into UO₂, and pellet fabrication at the UMP). The country is moving toward establishing its position in other stages of the cycle as well.

Almost 99% of all current mining of uranium ore in Kazakhstan is carried out from sedimentary (sandstone) rocks with the use of in-situ leaching (ISL) technology. This technology was developed in the USSR and the US independently from each other in the mid-1970s. This method generally involves injecting a leaching agent (e.g., 1–2% sulfuric acid solution [H₂SO₄]11) into the water-saturated and water-bearing formations where production is carried out.

In the United States, the ISL technology does not use an acid (as in Kazakhstan and Australia), but rather less effective alkali (mainly based on carbonates) because of the large amount of acid-absorbing minerals, including gypsum and limestone, in the water-bearing formations where production is carried out.

11. In the United States, the ISL technology does not use an acid (as in Kazakhstan and Australia), but rather less effective alkali (mainly based on carbonates) because of the large amount of acid-absorbing minerals, including gypsum and limestone, in the water-bearing formations where production is carried out.
ensuring a uniform flow to the deposit or ore body at a distance from the ore body. This is facilitated by protection in the application of ISL is the need to dispose of waste in the depleted part of the ore body). This makes it possible to significantly reduce the consumption of water and sulfuric acid. That part of the solution that is not pumped into the ore body (a part of the solution is poured off at the wellhead) is then purified before it is ready for operations about operations

3.4. Enrichment

The goal of enrichment is to increase the percentage of $^{235}U$ to 3-5% required for use in power reactors. UF$_6$ in gaseous form is the feedstock. In 2015, global enrichment capacity was estimated at 59 million SWU. The World Nuclear Association estimates secondary sources of UF$_6$ supplies equivalent to 12 Mt of uranium in 2015 and projected not to exceed 14 Mt a year through 2022. This will lead to oversupply in the conversion market and will continue to exert downward pressure on prices. There is also demand for conversion of depleted uranium from the UF$_6$ form into either U$_3$O$_8$ or UF$_4$. Deconversion allows for the storage of depleted uranium, as well as for recovery of UF$_6$ by-product for further use at conversion facilities. Kazakhstan plans to enter the conversion segment through a JV with Canada’s Cameco. As a part of an upstream uranium asset deal in 2016, Cameco transferred its technology for the purification of uranium to the joint venture on a royalty-free basis. Cameco and Kazatomprom are conducting an economic feasibility study on construction of a conversion facility in Kazakhstan that would also convert U$_3$O$_8$ into UF$_6$. At the early stages of the project, until the construction of Kazakhstan’s own plant for production of UF$_6$, UF$_6$ will be supplied to Cameco’s conversion facility in Port Hope, Ontario for production of UF$_6$. In addition, in 2016 Kazatomprom has obtained a five-year option to license Cameco’s conversion technology for the purpose of constructing and operating a UF$_6$ conversion facility in Kazakhstan on the site of the UMP.

3.5. Conversion

During the conversion stage, uranium oxide concentrate, which leaves the mine as U$_3$O$_8$, is stripped of impurities (purified) and then converted into UF$_6$, which is the feedstock for enrichment—the next phase of the cycle. The “wet” conversion method used in Canada, France, China, and Russia involves dissolving UO$_2$ in nitric acid to produce uranyl nitrate, which is then purified and the uranium stream is evaporated to get UF$_6$ through thermal decomposition. After reducing UO$_2$ to UF$_6$, and a subsequent reaction with HF, the resulting UF$_6$ is fed into a fluidized bed reactor with fluoride to get UF$_6$. In the “dry” method used in the US, UO$_2$ is purified through refining before being reduced to UF$_6$. The resulting UF$_6$ from the conversion stage has the form of gas under warm temperatures. To transport highly corrosive UF$_6$, it is turned into a liquid under low temperatures and moderate pressure, which is then shipped in steel cylinders with thick walls. Currently, the global conversion nameplate capacity is estimated at 52 Mt of uranium (in the form of UF$_6$). The conversion plants (at least) are required to ensure radioactive waste disposal and closed-loop UF$_6$ recycling. In addition, the plants are designed to meet the requirements of the International Atomic Energy Agency’s guiding principles of operation and safety.

In addition to centrifuge enrichment, laser process enrichment is a promising technology that offers low energy consumption, reduced capital costs, and short time to first fuel. In the atom by atom method, one $^{235}$U atom so that positively charged $^{235}$U ions are collected by a negatively charged plate. In the molecular process, a laser breaks the molecular bond gaining access to up to 5 million SWU of existing enrichment capacity. In 2010 and as a result, the JV acquired a 25% stake in the conversion segment, while 3%–5% from the laser process.

Kazakhstan has entered the enrichment segment through a cooperation agreement with Russia. In 2014 Kazatomprom formed a joint venture Center JV with TENEK (currently the shareholder representing Russian Federation is TVEL) on a parity basis with the initial goal of constructing a new enrichment facility. However, these plans were changed in 2010 and as a result, the JV acquired a 25% stake in the Ural Electrochemical Integrated Plant in 2013, gaining access to up to 5 million SWU of existing enrichment capacity. Since 2007, Kazatomprom also has owned a 10% share in the International Ura- nium Enrichment Center on the site of the Angarsk Electrolysis Chemical Plant, which has a total enrichment capacity of 2 million SWU per year.
7.3.5. Fuel assembly

Reactor fuel consists of ceramic UO₂ pellets, orga-
nized in columns and sealed in tubes made from zirconium alloy (fuel rods). In this form, reactor fuel cores are suitable for temperatures and intense radiation for a lifetime of several years. After enrich-
ment is completed, UF₆ is converted to UO₂ powder (a process referred to as “reconversion”), which can be handled as a “wet” or “dry” technology. For a 1,000 MW water-water reactor, 27% of enriched UF₆ is needed annually. After reconversion, the UO₂ powder may go through conditioning to ensure that uniforms, microstructure standards are met. Then the powder is processed under higher tem-
perature and a reducing atmosphere to form pellets (typically 1.5 cm high and 8 cm in diameter). One pellet for a typical reactor allows for production of the same amount of energy as a ton of steam coal. The pellets are inserted into rods made of a noncor-
rrosive material (typically, zirconium alloy). Rods are then arranged in a fuel assembly — a highly precise grid held together by a framework engineered to be resistant to corrosion, high temperatures, vibration, and large static loads. The quality of the fuel assem-
bly is determined by the composition of the grid ma-
terials, which are made of a zirconium alloy with the addition of other metals, including nickel, iron, and chromium. A 1,000 MW pressurized water reactor holds about 47,000 rods, containing over 12 million pellets in total. A fuel assembly weighs about 220 tons, and contains a substantial amount of water for cooling. In Kazakhstan entered into the fuel assembly seg-
ment in December 2016, when Kazatomprom and China General Nuclear Power Corporation (CGNPC) launched the construction of a facility at the UMP (Ust-Kamenogorsk). 51% and CGNPC 49%, will use technology sup-
pplied by AREVA and will require about $150 million in investments to launch the project by 2020. The agreement with AREVA provides for a license in fuel fabrication technology, engineering documenta-
tion, supply of the key production equipment, and personnel training.

7.3.6. Nuclear power generation

Generation of energy at nuclear power plants occurs as a result of the fission reaction of uranium nuclei (or other fissile elements) in the reactor. The central part of the nuclear reactor, including nuclear fuel (lo-
cated in fuel assemblies), the moderator, and regulat-
ing systems (neutron absorber rods), forms the core through which the coolant is pumped, transferring heat from the nuclear fission reaction to the turbine (single-circuit reactors) or through the heat exchang-
er (steam generator) to the second cooling circuit (double-circuit reactors). According to the neutron spectrum, there are reactors that use fast neutrons and on thermal neutrons. The deceleration of neutrons in nuclear thermal reac-
tors occurs at special moderators (water, graphite) to increase the probability of absorption of a neutron by the fuel. The deceleration of fast neutrons is more likely to occur on 14-N₂ nuclei with the formation of plutonium, which is 14-N₂ fission. The pressurized water reactor (PWR/VER), origi-
nally developed for use in nuclear submarines, is presently the most popular reactor type in the world, accounting for 64% of the reactors used for power generation. The main components of the primary cooling circuit, water, which is also a moderator for neutrons, flows under high pressure of 150 ATM (to prevent it from boiling inside the core). In the secondary circuit, wa-
ter boils and moves turbines to generate electricity. The technology of pressure reactors has been most popular due to internal safety features, simplicity and accessibility of the use of the coolant and the moder-
ator—water. The high power density of the core, in comparison to gas-cooled, heavy water, and boiling water reactors, made PWR technology the most acces-
sible for export, as PWR reactors have dimensions suitable for transportation by road and rail. Ability to use low-enriched fuel and a comparatively high fuel burn-up make PWR reactors the most economically preferable. In addition, the use of PWR technology results in the accumulation of spent nuclear fuel and radioactive waste in much smaller volumes than in other types of reactors. The second most prevalent reactor type is a single-
loop water-water “boiling” reactor (BWR), which differs from PWR by having only one circuit through which water (cooler and moderator) and steam under pressure is directed to turbines. About 18% of the world’s power reactors are of the boil-
ing water type, with 31 reactors operating in the US, 22 in Japan, 7 in Sweden, and 15 in other countries. The simplicity of the design, the circulation system, the equipment used, and the reduced pressure in the vessel reactor create cer-
tain advantages for the BWR, including lower capi-
tal costs for construction. However, boiling water is characterized by significantly lower critical thermal loads; therefore, the power density of the core is 1.5 to 2 times lower than in PWR, and hence the size of the BWR core significantly exceeds the size of the PWR zones of the same power. Due to the large size, transportation of the BWR reac-
tor core by rail is impossible; therefore only wa-
ter transport is used. Disadvantages include more complex construction, addition of other materials, reactor cooling due to the presence of both water and steam in the system, the contamination of the turbine which is in direct contact with the primary coolant, and possible risk of leaking at the point of connection of 65 kg, of which the reactor is inserted from below the core and require an un-
terruptable power source. The third most popular reactor type (11% of the world’s reactors, a total of 49 reactors) is the pressur-
surized heavy water reactor (PHWR), in which heavy water is used as moderator. PHWR was first devel-
oped in Canada, and is known as CANDU (Canada Deuterium Uranium). It uses natural uranium oxide as fuel, and heavy water (deuterium oxide) as the moderator. CANDU reactors, unlike PWR and BWR, are not vessel-type, but channel-type, where fuel assemblies with nuclear fuel are located in channels (pressure tubes) with a coolant. The supply and re-
moval of coolant from each of the channels is carried out by individual pipelines. One of the advantages of channel-type reactors versus vessel-type reactors is the possibility of replacing spent fuel without stopping the reactor. If heavy water is used as the coolant in this reactor, then the fuel rods operate on un-
enriched natural uranium, as well as on spent nuclear fuel of other types of reactors. The drawbacks include the high cost of making heavy water, emission of radio-
dioactive tritium, and large reactor core size. Heavy water reactors, in comparison with other types, have been less popular primarily because of the high cost of their installed capacity. In addition, an important fact is that the channels (pressure tubes) are located in the core under a constantly strong neutron flux and exposure to hydrogen, which leads to hydrode-
cracking. Therefore, the concept of the CANDU re-
actor assumes a complete replacement of the de-
moderator after 20 years of operation in order to bring the total life of the station to 40 years. This fact has a significant impact on the economics of CANDU reac-
tor construction. In addition to nuclear thermal reactors (PWR, BWR, and PHWR), fast neutron reactors are operated in limited numbers. A fast reactor (BRE-200) in Russia; BOR-60, BN-600, and BN-800). These reactors lack a neutron moderator in their core, but rather have a breeding zone where fissile elements (Pu) are produced from fertile elements (U). In view of the considerable heat release in fast neutron reactors, molten metal is used as the coolant. Kazakhstan’s only nuclear station operated between 1972 and 1999 in Aktau (also known as the city of Shevchenko). The station used a fast neutron reac-
tor BN-350 that used a sodium coolant; the reactor’s thermal power was 1,000 MW and had a net gener-
ating capacity of 350 MW. The generated power was also used to desalinate sea water and for heat supply. The life of the reactor was 20 years, and since 1999, it was operated on the basis of an annual license renewal. In 1999, the reactor was shut down and the process of decommissioning began. In terms of technological advancement, reactors are currently being developed by Generation IV International Forum (GIF), representing 14 countries that use nuclear power, selected six reactor designs believed to represent future Generation 4 reactors; three of these are fast neutron reactors, two slow neutrons (similar to currently operating re-
actors), and one epithermal. The 2015 proposed nuclear power generation should have a role in the country’s future capacity mix, as it not only would make an important contribu-
tion to baseload production, but also would improve the country’s carbon credits by offsetting coal-
fired power production. In his State of the Union address in January 2014, President Nazarbayev instructed the government to develop a plan for building a nuclear power plant. The plan, compiled in May 2014 (and further amend-
ed in November 2016), seeks to complete a feasibility study by 2018 on construction of two nuclear power stations in the city of Kurchatov (Kazakhstan region) and in the town of Ulken (Almaty region). 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 (Mangistau region) using Rus-
sia’s VVER-300 PWR-type reactor; and a 2009 feasibility study at the Kurchatov location, which recommended three locations (Ulken, Aktau, and Kurchatov). The Ministry of Energy and Energy and Natural Resources, which recommended three locations (Ulken, Aktau, and Kurchatov). Most recently, the Energy Minis-
try has considered using a Russian reactor for the Kurchatov location, while for the Ulken location Gen-
eration 3 reactor designs by Westinghouse/Toshiba, AREVA/Mitsubishi, and Hitachi/GE are being consid-
13 Water as well as heavy water, molten metal (sodium), carbon dioxide, and helium are used as a coolant.
Radioactive wastes are characterized by the amount and type of radioactivity, as well as by the time the wastes remain hazardous. There are three types of radioactive waste, which is not able to penetrate the skin; beta radiation, which is able to penetrate the form of aluminum foil; and gamma radiation, which requires the use of blocking means of greater thickness (such as concrete). The time the wastes remain radio-active depends on the half-lives of the isotopes they contain, which is the time it takes for the isotope to lose half of its radioactivity. Half-lives can range from milliseon to billions of years.

There are three types of radioactive waste. Low-level radioactive waste contains small amounts of short-lived radioactivity, and may be present on clothing, tools, and filters. Not dangerous to handle, it is usually buried in landfills. Intermediate-level waste has higher radioactivity and includes contaminated materials from reactors or reactor components. It is disposed by solidification in concrete and deep burial under ground. High-level radioactive waste, such as spent nuclear reactor fuel, contains fission products and requires cooling as well as additional protection during handling and transportation. The amount of high-level radioactive waste from a typical large nuclear reactor is about 50 to 100 kg per year.

In contrast to open pit mining, the volume of radioactive waste from in-situ leaching production (primarily used in Kazakhstan) is negligible, as all materials except for uranium are returned underground. U3O8 produced from mines is mildly radioactive. Therefore, most of the waste that requires special handling comes from reactors: a typical 1,000 MW PW reactor produces 40-50 kg of high-level waste each year. Advanced solidification technology involves turning waste into synthetic rock using naturally stable minerals. Before final disposal, high-level radioactive waste has to be immobilized to prevent leaching, so that it may last for thousands of years. The high-level radioactive residual is solidified through evaporation, mixed with glass-forming materials (i.e., borosilicate glass) to ensure it is insoluble in ground water, melted, and poured into stainless steel contain-
ers to avoid corrosion. For the recycling of this type of waste produced during the operation of a 1,000 MW PW reactor, in Kazakhstan there is a need for development of the technologies for reprocessing.

Reprocessing involves chemical separation into reprocessed uranium (RepU, mostly 235U, but also 238U depleted to less than 1%), Pu, and high-level radioactive residual, with the latter comprising 7% of the recycled output volume. The residual also contains some radio-active actinides (elements with atomic numbers from 89 to 103). Reprocessing fuel used in PW in a 1,000 MW PW reactor generates 233 kg of plutonium and 700 kg of highly active residual annually. Reprocessed uranium also contains 232U and 238U, which are neutron absorbers; thus, reprocessed uranium requires a higher enrichment rate than natural uranium for use as fuel in a PW. However, RepU can be readily used by PW reactors. Currently the WNA estimates the stock of RepU in 2015, 900 tons of Pu was was used, displacing 1720 tons of natural uranium; the projected use in 2025 amounts to 2000 and 1350 tons, for RepU and Pu (respectively), displacing 3440 tons of natural uranium; the prospects for using uranium-plutonium fuel in Russia can further increase this level.

7.3.8. Nuclear research and development

The National Nuclear Center was created in 1992 and combines two research reactors (a pulse graphite re-actor and a high-temperature gas-cooled reactor) and three test benches. In addition, the Tokamak thermonu-clear material research facility was launched in 2017 in the city of Kurchatov. Kazakhstan’s Materials science Tokamak (KTM) was launched as part of the international project ITER (International Experimen-tal Thermonuclear Reactor), and is designed for re-search and testing of materials in the energy loading modes of thermonuclear power reactors. It should be noted that in Kurchatov there is a unique base for nuclear research and nuclear energy, with a high hu-man potential. Research centers including research reactors and test benches were built in Kurchatov as part of the Soviet program for the development of a high-temperature nuclear rocket engine. In turn, the Institute of Nuclear Physics (INP) of the Republic of Kazakhstan has a VV-K water-water re-search reactor, an isochronous cyclotron, and several scientific laboratories. INP is also working on the electromagnetic and nuclear safety training center in collaboration with the US Department of Energy’s Brookhaven National Laboratory to train specialists. With its experience in operating a nuclear reactor in the past and the extensive personnel base (the INP alone employs 700 people) in its nuclear research in-stitutions, Kazakhstan has definite potential to oper-ate a future nuclear reactor. The domestic capacity and experience in nuclear industry personnel is based on the current programs in nuclear physics at Gumiév Eurasian National University and Al Farabi Kazakh National University, which cooperate closely with Russia’s leading academical institutions (such as the Moscow Physics Engineering Institute). In April 2017, Kazatomprom signed an agreement with the Kazakh National Research Technical University to cre-ate an international scientific educational center for the nuclear industry.

7.4. REGULATION OF KAZAKHSTAN’S URANIUM SECTOR

7.4.1. Review of Kazakhstan’s relevant legislation and national and international goals and targets in the uranium sector

The government reform in August 2014 changed the administration of the nuclear power sector, when the newly formed Ministry of Energy assumed responsibilities over the nuclear power sector as well as uranium production from the former Ministry of Industry and New Technologies. Consequently, the Industry Minis-try’s Nuclear Energy Committee was reorganized into the Nuclear and Power Control and Oversight Commit-tee under the Ministry of Energy. The committee exer-cises regulatory and control functions.

A new version of the Law on Nuclear Energy Use was enacted in January 2016 and replaced a similar Law from 1997 that had become obsolete. The new Law expanded safety-related measures by introducing expert evaluation of nuclear safety as well as nuclear safety personnel accreditation. The Law also introduced: rules for physical security of nuclear materials, facilities, and storage; safety rules for handling radionuclides; the Nuclear Emergencies National Plan; rules for transpor-tation of nuclear materials and radioactive substances; and rules for counting, storing, and disposing of nu-clear waste. Most of these regulations were developed and issued by the Ministry of Energy in the beginning of 2016.

Other laws governing aspects of the uranium sector in-clude:

- The Law of the Republic of Kazakhstan from June 24, 2010 No. 291-IV “On Subsoil and Subsoil Use”, which governs all key aspects related to uranium mining.

Kazakhstan’s ambition to develop a position encoun-tering the entire nuclear cycle is reflected in key stra-tegic planning documents. Published in January 2014, the Concept of Kazakhstan’s becoming one of the 30 most developed countries in the world by 2050 (Decree of the President of the Repub-lic of Kazakhstan of January 17, 2014 No. 732) calls for the development of a knowledge-based economy in the country. The current programs in nuclear physics (25-30 years) the basic industries, including oil and gas and mining and metallurgy, will be the main driving forces for promoting the economy along the path of further industrialization and the development of related industries. Among other industries, the highest priority
is given to the uranium industry and nuclear power engineering, to the task of further developing all phases of the entire value chain.

Strategic Plan for the Development of the Republic of Kazakhstan to 2020 (Decree of the President of the Republic of Kazakhstan from 1 February 2010 No. 922), determines the future directions of the state policy and strategic goals of the country. The development of nuclear power is seen as a way of producing less expensive and more environmentally safe energy. Specific goals set for the energy sector for 2020 include the start-up of a nuclear power plant and creating a vertically integrated company involved in all phases of the nuclear fuel cycle.

The Uranium Industry and Nuclear Energy Development Concept approved in August 2002 (and abolished in April 2010) resulted in the formulation of the Nuclear Development Strategy of Samruk-Kazyna National Welfare Fund for 2011-2014, with the prospect of development until 2020 (Resolution of the Government of the Republic of Kazakhstan from June 29, 2011 No. 728), which establishes specific tasks in four main target areas, including:

• For the nuclear cycle, it called for launching a conversion facility to produce 12 Mt of UF6 by 2016, starting uranium enrichment in Russia with an entitlement capacity of 2.5 million SWU from 2014, and launching production of fuel assemblies at UMP in 2020.

• For nuclear power generation, it called for completion of a feasibility study on constructing a nuclear power station in Kazakhstan by 2015 (with the station to be built by 2020 in the event of government approval).

• For nuclear science, the Program envisioned modification of the country’s three science reactors from highly enriched uranium (HEU) to low enriched uranium (LEU)—by 2018 for a 6 MW basin-type WR/K reactor and by 2020 for a tank-type research high-temperature gas-cooled reactor TVS-1 with a capacity of 35–60 MW and a pulsed graphite reactor with a capacity of 10 MW. With the help of the Russian corporation Rosatom, the modernization of the WR/K reactor was completed already in May 2016.

• For nuclear security, the Program sought to develop and implement a nuclear waste storage and recycling plan, including the creation of a Center for the Processing and Long-Term Storage of Radioactive Waste and Environmental Protection, the Program planned to open a Center for Complex Dosimetry by 2018 and a Center for Nuclear Medicine by 2015. As of November 2016, the dosimetry center was in operation, whereas the medical center project appears to be experiencing delays. The Concept for the Development of the Fuel and Energy Complex of the Republic of Kazakhstan until 2030 (Resolution of the Government of the Republic of Kazakhstan from June 28, 2014 No. 724) gives the nuclear power sector a nod as a promising sector for future technological development. The Concept indicates that closing the nuclear fuel cycle includes entering all stages of the nuclear cycle would include using fast neutron reactors that would allow for the production of fissile isotopes (breeder reactors, breeders) will make nuclear power renewable and will allow the use of broadly available isotopes of uranium (233U) and thorium (232Th).

This would resolve not only the problem of the exhaustibility of uranium resources, but also the problem of handling 238Pu and highly radioactive elements (minor actinides contained in spent nuclear fuel). Currently, the “Proryv” (or “Breakthrough”) project implemented in Russia aims at the practical implementation of a closed nuclear cycle (uranium-plutonium). Within the framework of the project, the construction of a pilot industrial power complex with a BREST-300 reactor and an on-site nuclear fuel cycle are part of a high-density nitride uranium-plutonium fuel production line. In fact, the closure of the fuel cycle occurs within a single nuclear power plant. Another direction that is being pursued under the “Proryv” project is the development of a BN-1200 fast neutron reactor with a reproduction ratio of 1.2.

It is planned that the creation of a nuclear power plant based on BN-1200 reactors will allow for realization of a closed fuel cycle that includes operating nuclear power plants based on thermal neutrons. A closed fuel cycle could be possible if the share of breeder reactors reaches 20% of the total capacity of reactors involved in the cycle; the production of fissile isotopes will provide nuclear fuel not only for the needs of the breeder reactors, but also for the thermal neutron reactors. Implementation of Russia’s strategy to create a closed nuclear fuel cycle is an ambitious project with the potential to significantly impact energy markets over the long term, beyond the planning horizon of this report.

Promising technologies

One of the obstacles to the long-term development of the nuclear energy is that uranium reserves are finite; if uranium consumption increases to 1.00 Mt/a year, known uranium reserves will last for a maximum of 50 years. Closing of the nuclear fuel cycle by using fast neutron reactors would allow for the production of fissile isotopes (breeder reactors, breeders) will make nuclear power renewable and will allow the use of broadly available isotopes of uranium (233U) and thorium (232Th).

Taking into account the intention of the Republic of Kazakhstan to enter all stages of the nuclear fuel cycle (with the exception of processing imported radioactive waste), including the production of electricity at nuclear power plants, it is important to consider safety culture issues in regulating the production of nuclear energy. The culture of security is an essential aspect, the importance of which is invariably recognized by the international nuclear community. Thus, according to the definition of the US Nuclear Regulatory Commission (NRC), a safety culture is “the core values and behaviors resulting from a collective commitment by leaders and individuals to emphasize safety over competing goals to ensure protection of people and the environment.” In turn, the IAEA defines a strong safety culture as “the assembly of characteristics and attitudes in organizations and individuals which establishes that, as an overriding priority, protection and safety issues receive the attention warranted by their significance.” In other words, the safety culture helps to avoid negligence (“counting on luck”) and to introduce an active approach to preventing potential problems and, ultimately, accidents. The culture of security is a long-established concept. In particular, the IAEA has developed safety standards based on five characteristics of a safety culture:

• safety is integrated into all activities
• safety is a clearly recognized value
• leadership for safety is clear
• accountability for safety is clear
• safety is learning driven.

A safety culture is integral part of the guidelines followed by the IAEA. In particular, the IAEA standards, the concept of a safety culture is included in such documents as the “Governmental, Legal and Regulatory Framework for Safety and Leadership” and “Management for Safety.”

Safety culture

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7.4.2. Key Recommendations

Given the high priority of the development of nuclear energy in Kazakhstan, it is recommended to:

• based on the projected balances of electricity and capacity, determine the timing of the construction of a nuclear power plant in Kazakhstan
• determine the type of reactor, capacity, and location most suitable for Kazakhstan
• taking into account the goals of the Paris Agreement, determine the share of nuclear in overall power generation and coordinate with the time-frame of electricity market development
• increase targeted funding by the state for research programs on nuclear energy and develop a strategy for the development of nuclear research, taking into account the human resources and research base
• more broadly, implement technologies to improve the efficiency of ISL production methods based on the experience of the oil and gas industry
• given the plans for the development of nuclear energy in Kazakhstan, pay close attention to the safety cultures in particular, their standardization, and the mechanisms for implementing these norms, should be reflected in the legislation of Kazakhstan.

Fuel assemblies with 235U are loaded into the special “breeding zone” of the breeder. The fission reaction (235U) produces both new fuel and new nuclear fuel. The reproduction ratio of fissile isotopes to the speed of the burn-up) of breeder reactors may exceed one, which means that more fissile elements are produced than consumed (burned out) in the core of the reactor.

In the uranium-thorium cycle, 233U can be used as a fissile element, with broadly available 232Th as a raw material; the fission reaction (232Th) produces fissile uranium 233U.
8. KAZAKHSTAN’S ELECTRIC POWER SECTOR

8.1 KEY POINTS
8.2 INTRODUCTION: PLANNING FOR POWER SECTOR DESTINATION
8.3 FUNDAMENTALS: POWER DATA UPDATE
8.4 INFRASTRUCTURE AND TECHNOLOGIES: KEY OPTIONS
8.5 REGULATION: LEGISLATION AND POLICY FOR KAZAKHSTAN’S POWER SECTOR
8. ELECTRIC POWER

8.1. KEY POINTS

With the slump in oil prices over the last few years, Kazakhstan’s pace of economic growth also slowed. For Kazakhstan’s power sector, this new reality has weighed heavily on annual power consumption, which since 2012 has been drifting within a relatively tight range around 90 TWh (terawatt-hours). And despite year-on-year power demand in 2016 perking up, it will still grow at a considerably slower average annual rate than what was experienced during the last decade. So on the face of it, the economic situation (along with recent increases in grid and available capacity) has removed any immediate impulse to add new power generating capacity. But despite little evidence of a booming energy crisis, Kazakhstan has committed to ambitious green economy goals while weighing heavily on annual power consumption, which is changing used and generated in Kazakhstan is changing consumption trends.

- Fundamentals point to changing power market mechanisms. Consider the influence of power market mechanisms on power consumption. At that, the grid network will gradually become “active.”
- Investors need incentives to improve power sector infrastructure so as to create flexible power as well as usher in the most efficient technology solutions in grid and generating capacity. Again brought into sharp focus as renewable production grows, it implies adjusting current regulation and adapting market mechanisms to unlock more of Kazakhstan’s gas potential, despite being a relatively more expensive fuel source than coal. Moreover, among many technology solutions, capacity storage technologies can play a growing role stabilizing the grid. Given Kazakhstan’s unavoidable use of coal in power production, combustion emission control technologies that destroy or remove sulfur dioxide (SO2), nitrogen oxides (NOX), mercury, particulate matter (PM), and other air pollutants, which are now a basic obligation globally, should also be the technological norm in Kazakhstan.
- A more cohesive and logical approach is needed in developing power sector rules and regulations. The current regulatory situation is disjointed and unpredictable, negatively impacting the investment climate. The current power market mechanisms barely serve the sector’s real needs or progress Kazakhstan’s stated policy targets. While maintaining current policy goals, Kazakh policymakers might consider moving towards closer harmonization with Russia’s market schemes given the strong power infrastructure link, intensifying Eurasian Economic Union integration, and Russia’s extensive market experience when trying to adopt Western-styled power market mechanisms.
- Policymakers need to be guided by realistic outlook assessments while potential investors and analysts need considerably better access to information and data. While capacity shortfalls are obviously undesirable, the cost of responding to overly optimistic forecasts can place an unnecessary financial burden on the value chain, particularly on consumers. Moreover, power sector transparency and access to data need to be dramatically improved to help spur investment confidence and offer both policymakers and investors better predictability.

8.2. INTRODUCTION: PLANNING FOR POWER SECTOR DESTINATION

As noted in the KAZENERGY NER 2015, since independence Kazakhstan has made significant progress upgrading its power sector. This is particularly noteworthy as Kazakhstan inherited an aging and fragmented Soviet-built power system that by 1991 depended on Russia and Central Asia for meeting up to 15 TWh annually. But the last decade of extensive investment bolstered its generating and transmission capacity, allowing Kazakhstan considerably greater energy security and independence (see Figure 8.1).

For instance, since 2000, Kazakhstan’s installed capacity has grown 22% while its available capacity has in fact doubled.1 Essentially, since 2002, overall investment into Kazakhstan’s power generation and national grid has dramatically improved flexibility, allowing electricity production to broadly match consumption trends, while even having small amounts of power to export to neighboring countries. Despite the great investment strides Kazakhstan has made, there are still significant grid limitations; hence Kazakhstan’s power sector is analyzed as three zones: North, South, and West (see grid map Figure 8.2).

Each zone is fundamentally different from the other, in terms of supply and demand dynamics, generation mix, connectivity, and balance.2 The grid connection between the North and South zones is limited (two 500 kV lines and a 220 kV line) but constantly improving, while the West Zone is still separated (with several links with Russia). And although Kazakhstan

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1 Terawatt hour = thousand gigawatt hours (GWh), a million megawatt hours (MWh), a billion kilowatt hours (KWh)

2 The investment surge in 2009-15 was raised through a “tariff for investment” scheme that targeted generating assets.

3 See KAZENERGY NER 2015 for detailed review of Kazakhstan’s power zones.
has improved its overall power system, it is short of flexible generation—partly owing to a high share of relatively inflexible combined heat-and-power plants (TETs in Russian) emphasizing the importance of neighboring power systems for balancing support. Notably, Kazakhstan has a large appetite for coal that fuels around 66% of the country’s power production (or about 75% of thermal production), and will remain the dominant fuel over the medium to long term owing to the particular geographical layout of the power sector. Some 92% of Kazakhstan’s coal-fired production is in the North Zone where 70% of Kazakhstan’s power consumption is situated, close to where the coal is sourced, and to date far from any meaningful gas infrastructure. Then there is the relatively lower cost of coal-fired production over gas which means gas-fired production is practically uneconomic without introducing some type of financial support mechanisms.

Nonetheless, policymakers naturally seek to improve energy system efficiency and the country’s overall green credentials while keeping energy security a priority. This means Kazakhstan must undergo a costly modernization program, which suggests promoting more flexible generation and reducing the carbon impact from coal. And this will be brought into sharp focus if Kazakhstan successfully hits, or exceeds its ambitious renewable targets (3% renewable production by 2020 rising to 30% by 2030 [11% solar and wind, 10% small hydro, 9% nuclear]).

Many influential market participants in Kazakhstan are wary of the potentially undesirable consequences that can spring from untested market ideals, particularly in underinvested power sectors. Several examples can be found from the path that Russia took, which makes it an important benchmark whose experiences and direction should not be dismissed out of hand. To that end policymakers feel somewhat caught between various power sector participants whose contrary positions appear intractable. Essentially, industrial players—who account for more than a third of overall consumption (see Figure 8.3)—are expected to shoulder the lion’s share of the cost burden, which is typical for emerging countries. 

8.3. FUNDAMENTALS: POWER DATA UPDATE

8.3.1. Electricity demand shifting emphasis

Since 2012 Kazakhstan’s overall power consumption appears to have entered a new stage of maturation—no longer growing at the relatively rapid pace experienced in 2000–12 (averaging 4.4% annually). Looking forward, we expect power demand to grow more modestly, averaging only around 1.1% annually until 2040 (see Figure 8.4). This is a mild downward adjustment from 1.2% that we expected in the KA-ZENERGY NER 2015 driven largely by our forecast of a slower pace of economic growth. Nonetheless, demand will gradually become shapelier (transforming the grid into an active network). This will happen for the following reasons:

- Consumer: increased electrification of Kazakh urban areas. With the increase of consumer incomes, homes become more power hungry with additional appliances and gadgets. This often spurs growth in the commercial sector as well. For example, the rise of retail (shops and restaurants) and small businesses in urban areas impacts the shape of demand owing to their rapid growth and specific hours of activity.
- Generation: growth of renewables and the rise of auto producers. Intermittent sources of power (wind and solar generation) require flexible conventional generation to support their output or capacity storage solutions. In addition, industrial power producers often operate small-scale gas turbines which affect grid supply and demand. Large industrials enter the power market for a variety of reasons, typically for energy security and often to negate the effects of rising power costs. Oil and gas enterprises are classic examples of auto producers, who often have an added incentive to utilize their associated gas.
- Markets: evolution of power markets. As power markets evolve with balancing mechanisms, demand response, smart metering etc., these fac-
tors can have a significant impact on the cost of hourly power and this tends to influence power consumption habits through greater efficiencies. For these reasons, Kazakh policymakers will need to adopt a power market design that can respond intelligently with timely investment, as well as encourage the most suitable technology—this is irrespective of short-term changes in power demand. Importantly, owing to Kazakh realities (similarly to what Russian policymakers experience), Kazakh policymakers should maintain a guiding hand, but not so much as to alarm potential investors.

8.3.1. The inevitable maturing of Kazakh power consumption should influence strategy

Sound power demand forecasts are important, as they often direct official investment planning (at the cost of consumers). But recent historical power demand trends may not be a good signpost for setting a long-term trajectory. Naturally, trends in Kazakhstan’s power demand are greatly influenced by global economics (and regional stability) because of the direct impact that commodity supply and demand and prices have on overall GDP and industrial activity. This means that while the recent trend in power demand was generally relatively robust, demand also endured several phases when reacting to global shocks, general slowdowns, and economic rebounds.

For instance, throughout the 1990s, after the collapse of the Soviet Union (in conjunction with deeply depressed oil prices) Kazakhstan’s power consumption plunged (see Figure 8.5), falling from above 100 TWh in 1990 to 51 TWh in 1999, while the peak demand fell from 156 GW in 1990 to 8.4 GW in 1999. But since 2000, thanks largely to resurgent global oil and commodity prices, Kazakhstan’s power consumption experienced vigorous growth with an annual average rate of 3.4%, while peak demand grew an annual average rate of 3.1%. Of course, most recently power demand has slowed considerably and is likely to remain comparatively sluggish for several years at least—owing to general global economic headwinds. For example, in 2000–12 power consumption grew at an annual average 4.4%—albeit dipping briefly in 2009 (see Figure 8.5). In spite of the economic crisis in 2008–09, by 2012, Kazakh power demand reclaimed much of the lost ground during the 1990s, reaching 90 TWh. But since 2012, power consumption has meandered somewhat, only growing annually by 0.2% while peak demand fell marginally by 0.3% (notably, overall peak demand has been considerably more volatile than consumption). Yet 2016 Kazakh power consumption surged by 1.6% compared to the previous year, with peak demand spiking 5.4%. This means Kazakh power consumption registered a new post-1999 high of 92.3 TWh while peak demand almost reached the 2012 high of 14.2 GW. The behavioral pattern for peak demand reflects a more pronounced peak demand versus consumption. This puts a spotlight on how policymakers should plan for megawatt demand versus consumption in Kazakhstan in 2016, rebounded on average annual rate of 4.4%—albeit dipping briefly in 2009 (see Figure 8.5). In spite of the economic crisis in 2008–09, by 2012, Kazakh power demand reclaimed much of the lost ground during the 1990s, reaching 90 TWh. But since 2012, power consumption has meandered somewhat, only growing annually by 0.2% while peak demand fell marginally by 0.3% (notably, overall peak demand has been considerably more volatile than consumption). Yet 2016 Kazakh power consumption surged by 1.6% compared to the previous year, with peak demand spiking 5.4%. This means Kazakh power consumption registered a new post-1999 high of 92.3 TWh while peak demand almost reached the 2012 high of 14.2 GW. The behavioral pattern for peak demand reflects a more pronounced peak demand versus consumption. This puts a spotlight on how policymakers should plan for megawatt demand versus consumption. This puts a spotlight on how policymakers should plan for megawatt demand versus consumption. This puts a spotlight on how policymakers should plan for megawatt demand versus consumption.

The heavily industrialized North Zone, which accounted for about 67% (61,768 GWh) of overall power consumption in Kazakhstan in 2016, rebounded 2.3%, after being essentially stagnant in 2011–15. Strong growth in Aktobe along with the sheer size of the North Zone masked declines in East Kazakhstan, North Kazakhstan, and Kostanay oblasts. Year-on-year peak demand in the North Zone jumped 6.5%, led by the industrial heavyweight Pavlodar Oblast, which witnessed a 10.6% spike. The 2% downturn in power consumption (year on year) in the smaller South Zone (19,013 GWh) can be traced to the power-hungry phosphate industry in Zhambyl Oblast which consumed 46% less power in 2016 than in 2014, thus hitting power demand heavily in the region and across the overall zone. Also, much of Almaty’s potential demand was hovered up by Astana’s growth in the North Zone—with the continual shift of commercial operations to Astana. Since 2010, Astana’s power consumption has grown at an average annual rate of 7.7% while Almaty city has only averaged 1.5% per year. Moreover, since 2014, power consumption in Almaty has been essentially flat while the new capital has enjoyed average annual growth of 5.6%.

8.3.1.2. Regional power demand reflects mixed picture

Although regional power demand reflects a mixed picture (see Figure 8.6), a more pronounced peak demand is evident. The North and South (power) zones were clearly influenced by the recent downturn in the economy (although slightly differently), while the West Zone has been more robust (see Table 8.1).
Zone, the region is still short of generating capacity and will regain a growth trend owing to the growth of population and commercialization. As a result, the South Zone depends on imports from the North Zone and exchanges power flows with Central Asia. With the North Zone, we observe more pronounced peak demand highs and lows in the South Zone versus megawatt-hour consumption. Growth in Kazakhstan’s West Zone is by far the most robust and consistent: in both megawatt-hour consumption and megawatt peak demand. The oil and gas-dominant West Zone (about 12% of overall power consumption) is growing rapidly and exhibited resilience during the recent economic downturn. It is also notable that although year-on-year power consumption in 2016 grew 4.3%, peak demand spiked 11.8%. Similar trends are clear when analyzing consumption and peak demand over longer periods (see Figure 8.6. and Figure 8.7.).

The overall picture evolving in Kazakhstan appears to show a familiar pattern for a maturing economy, i.e., pace of consumption slows in contrast to the pace of peak demand. Essentially this means we can expect demand patterns to continue to become shapelier.

8.3.2. Power balance: recent investment improves flexibility

Naturally, these consumption trends need to be balanced by supply. Since 2000, power production in Kazakhstan has grown by an average annual rate of 3.8% (which is a little stronger than trends in consumption [3.4%] over the same period). Altogether, since 2000 power production increased 83%, while consumption grew 70%. In our projections, we expect power production to grow in line with consumption, averaging around 1% annually until 2040 (see Figure 8.8). This is hardly surprising given that Kazakhstan has successfully bolstered its overall available capacity by some 40% since 2000 (while installed capacity grew 22%).

The dramatic increase in Kazakhstan’s available capacity in recent years has been an important achievement because until 2002 Kazakhstan’s consumption rose faster than production (see Figure 8.9). Although available capacity (illustrated in Figure 8.10) might appear to show that Kazakhstan had sufficient generation for its needs earlier than 2002, several factors restricted power from reaching the consumer. For instance, a segmented transmission network constrained power flows throughout the power system between the capacity-rich North Zone and capacity-deficient South Zone.

Note: In the above chart, the average peak demand in each zone was calculated at the exact time when maximum peak was registered in the Unified Energy System (UES) of Kazakhstan, whereas each zone (and region) typically exhibits even higher peaks than registered during the UES maximum.

*Selected areas in the north and west parts of Kazakhstan had stronger links with Russia than to Kazakhstan’s main grid.
We expect capacity increases to remain robust, particularly from renewables source (which typically have a lower overall utilization), growing on average 2% annually until 2040 (see Figure 8.11).

As a measure to improve energy security, the carrying capacity of the South zones was doubled (by adding an additional 500 kV line), allowing the South Zone to be weaned from dependence on Central Asian imports. Since 2000, power flows from the North Zone have tripled (from 2.5 TWh in 2000 to 7.5 TWh in 2016) while Central Asian net power flows have practically reversed, where Kazakhstan has become a net power exporter. An additional 500 kV line connecting the North and South zones is nearing completion and is expected to connect the Almaty area with more flexible capacity from Kazakhstan’s key hydropower assets (Shubba [702 MW], Bukhtarma [675 MW], and Ust-Kamenogorsk HPP [331 MW]), as well as supporting further capacity from Ekibastuz GRES-1 and -2 (5,000 MW).

Even though significant grid investments have improved nationwide connectivity, the West Zone remains separated from the North and South zones, still relying on several links with Russia for security of supply. But in spite of robust growth exhibited in the West Zone, net imports from Russia have been steadily declining since independence in 1991, when power imports from Russia stood at more than 50% (4,551.4 GWh) of the West Zone’s consumption needs, falling to only 1% (154 GWh) in 2016.

8.3.2.1. Role of imports and exports

During the 1990s Kazakhstan relied heavily on Russia and Central Asia for power imports (see Figure 8.12). This mode of operation was quite natural as the respective power systems were originally designed to run in parallel. And power transfers between Russia and Central Asia are still convenient for balancing purposes.

Currently, Russia and Kazakhstan exchange modest power volumes annually; above some trading volume, both countries have a balancing arrangement where they play a cross-border system services support role. This symbiotic arrangement is particularly helpful for peak support in Kazakhstan as well as potentially balancing its renewable ambition to an extent. However, this arrangement is at risk because Kazakhstan’s power balancing requirements usually occur around peak demand hours for Russia, which are the most expensive hours in Russia’s day-ahead market. And Kazakhstan’s power market is not yet sensitive to hourly pricing.

But it is also important to point out that emergencies can quickly change the power flow dynamics as was the case when the Sayano-Shushenskaya hydropower plant accident occurred in Siberia in 2009 which saw Kazakhstan playing a vital system support role for Russia’s Siberian power system for several years.

Central Asian countries, chiefly Kyrgyzstan and Uzbekistan, once played a considerable role in power exchanges but more recently, as noted above, the strengthening of Kazakhstan’s national grid has changed this dynamic considerably. Statistical evidence from KEG-OC (Kazakh power system operator and national grid operator) shows Kyrgyzstan exchanges relatively small amounts of power with Kazakhstan. This appears to be a balancing arrangement where Kazakhstan takes advantage of Kyrgyzstan’s hydropower capacity while Kyrgyzstan benefits from Kazakhstan’s thermal output (in particular the gas-fired Zhambyl GRES [1,230 MW]). Any future expansion for power trade with Central Asia is likely to depend on the outcome of the CASA-1000 transmission project and associated trade negotiations. In this event, Kazakhstan’s planned new capacity, Balkhash power plant (first stage 1,320 MW, second stage adding another 1,320 MW) could be strategically placed to support power swaps with Kyrgyzstan while playing a designated role in filling the supply gap in the South Zone.

Thus far, Kazakhstan does not trade power with China. This situation is unlikely to change owing to the western regions of China already having an abundance of capacity. For instance, as of 2016 the northwest region of China had an installed capacity of 131.7 GW with a peak load of 76.5 GW (a reserve margin of 72%), and the Chinese southwest region has an installed capacity of 76.9 GW with a maximum peak of 53.5 GW (a reserve margin of 44%). We also do not expect that the economics of building an ultrahigh-voltage power line would stack up given the geography of Kazakhstan’s power production and China’s consumption.
8.3.2.2. Power production: policymakers’ investment choice

In terms of megawatt additions, actually the main increase in Kazakhstan’s power production was from steam turbines (mostly coal-fired), which since 2000 has increased annually 3.6% on average, growing by 32 TWh to 75 TWh in 2016 (see Figure 8.13 and Figure 8.14). Notably, the top five power plants account for about 40% of total power production, of which more than 90% is coal-fired (see Table 8.2).

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<th>Table 8.2. Top five Kazakh power plants by production (GWh)</th>
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Hydropower is Kazakhstan’s second largest power generation source, accounting for around 12% in 2016. Not only does hydropower play a base load role, it is typically used to fill peak demand. Despite that, hydropower production has doubled since 2012, while available capacity grew 30%. The outlook for additional hydropower production appears relatively constrained owing to limited potential sites for major new projects.

Table 8.2.

| Source: EIB, MMEK, KEZSC | © 2017 EIB-Kazakhstan |

8.3.2.3. Role of fuel

As noted above, Kazakhstan relies heavily on indigenous coal—typically sourced close to the power plant—to fuel 66% of its power production (see Figure 8.15), although the overall share has been yielding to gas. While this mainly results from the rise of gas turbine technologies, it is also evident in steam turbine technology where the share of gas use grew from 8.8% in 1996 to 15.6% in 2016 (see Figure 8.16). Nonetheless, coal will remain the dominant fuel for generating power because Kazakhstan’s gas infrastructure is quite limited. Despite that, the share of gas in Kazakhstan’s power production is expected to rise. For instance, to tackle poor air quality, Almaty city—which accounted for around 4.7 TWh in 2016—will likely shift from coal to gas. This would mean replacing at least 650 MW of coal capacity with gas.
In recent years the gas network has improved significantly, allowing Kazakhstan to shift gas from the hydrocarbon-producing area in the west to the south, via the Beyneu-Bozoy-Shimkent pipeline (see Figure 8.17). Logistically, this allows for more access to gas in Kazakhstan’s South Zone, and importantly less dependence on neighboring countries’ gas. There are also future plans to extend a gas pipeline from Karaozek (intersecting the Beyneu-Bozoy-Shimkent pipeline near Kyzylorda) to Astana via Karaganda, as well as a planned pipeline from Kostanay to Astana via Kokshetua. If these projects are realized, gas will play a larger, albeit still modest, role in power generation.

The main drawback for using gas is its relative high cost versus domestic coal. Again, this might mean tailoring power market mechanisms to support gas, while penalizing coal through carbon trading and/or tax mechanisms. But such a move would be relatively expensive for Kazakhstan’s power consumers.

As noted above, Kazakhstan’s installed and available capacity has been rising steadily thanks to coal-fired, hydropower, and gas turbine capacity additions (see Figure 8.18). Despite ongoing capacity renovations, and that some 30% of Kazakhstan’s capacity was launched since 2001, much of Kazakhstan’s fleet is still based on aged Soviet-era technology (see Figure 8.19). For example, about 39% of Kazakhstan’s capacity was installed prior to 1980, and according to KEGOC, in 2016, 42% of Kazakhstan’s steam turbines had exceeded their designed operational life.

New coal-fired capacity has been the practical choice in Kazakhstan’s North Zone owing to the abundance of cheap local coal (see Figure 8.20). Thus, new steam turbine capacity has been generally added to existing plants or upgrades. In contrast, Aktobe Oblast has gas (joining the North Zone in 2009) and has been adding significant gas capacity since 2004. The south-western part of Karaganda Oblast, also in the North Zone, also witnessed growth in gas turbine technology with expanded oil and gas extraction (Ak sai and Akshabula).
8.4.1. Power (and heat) sector technologies: recent trends and capacity outlook until 2040

As Kazakhstan’s energy evolves and market mechanisms mature, the following technologies can play an important role in both managing power output as well as reducing Kazakhstan’s carbon footprint.

8.4.1.1. Gas Turbines: Advanced CT and CCGT

Combustion turbine (CT) based power generation (single cycle [SC] and combined cycle [CC]) is a mature, ubiquitous technology globally. Certain parts of Kazakhstan already use gas turbines, particularly areas with greater access to gas. Gas turbines will continue to displace coal-fired generation. The equipment to be widely deployed to address the global CT market for power generation applications are General Electric (GE), Siemens, Mitsubishi Heavy Industries (MHI), and Alstom. Although manufacturers tout gas turbine efficiencies exceeding 60%, the way these technologies are used in many global power sectors means real efficiency levels tend to be considerably lower.

Notably, thermal capacity in Kazakhstan’s South Zone has a fairly even mix of gas- and coal-fired capacity. And despite having access to gas the zone has a surprisingly small amount of gas turbine capacity. Depending on market incentives, the South Zone could expect a rise in gas turbine technology. Hydropower capacity in the South Zone plays a growing role too, although future expansion appears limited.

Applications

- Single Cycle (SC) combustion turbine in a stand-alone configuration, used for peaking and renewables integration; no provision for steam generation; quick start and ramping times; low thermal efficiency
- Combined Cycle (CC) combustion turbine configured in combination with a steam cycle (heat recovery boiler and steam turbine) used for base load and/or intermediate power generation duty (including renewables integration); higher thermal efficiency and longer starting times

Types of combustion turbines

- Industrial (frame)—heavy-duty, low capital cost, longer maintenance intervals; common SC unit size is 175 MW to 200 MW
- Aeroderivatives (aero)—adapted from jet aircraft engines; lightweight, higher capital cost, faster start times; higher SC thermal efficiency than frame units; common SC unit size is 40 MW to 50 MW

Key performance attributes and trends

- Size—trend has been larger megawatt unit sizes, new configurations are over 500 MW for a single 1x1 frame CC unit
- Efficiency—breaking the 60% mark in CC; turbine inlet temperature is a key determinant of thermal efficiency and maximum temperatures are limited by current materials
- Emissions—innovative inner cooling systems solutions (closed-loop steam cooling) allow for high capacity temperatures and low NOx emissions
- Start-up and ramping—faster times allow for faster or response to peak needs, as well as improved part-load thermal efficiency
- Fuel flexibility—ability to burn natural gas, distillate (typically as a backup fuel), and syngas

Levels of electricity ranges from $70/MWh (CC) to $150/MWh (SC)

8.4.1.2. Postcombustion emission control technologies

These are devices that either destroy or remove contaminants from the exhaust stream before they are emitted into the atmosphere. In many countries, there are laws that require power plants to control sulfur dioxide (SO2), nitrogen oxides (NOx), mercury, particulate matter (PM), and other air pollutants using these devices.

Control technologies organized by pollutant

- Acid gases (including SO2)
  - Wet flue-gas desulfurization (wet FGD): Removes SO2 by reacting flue gas with a sorbent material such as limestone in a dedicated mixing vessel. Wet FGDs use water to increase the contact between the reagent and flue gas.
  - Dry flue-gas desulfurization (dry FGD): Removes acid gases (primarily SO2) by spraying a basic sorbent material such as lime in a dedicated mixing vessel to produce solid or remove the salts. The salts are then removed by an ESP or FF. The lime reagent is generally more expensive than limestone used in wet FGDs.
  - Dry sorbent injection (DSI): Removes acid gases (sodium oxides [SOx], hydrochloric acid [HCl], sulfuric acid [H2SO4], etc.) by reacting flue gas with a basic sorbent material, such as trona, to produce solid salts which are then removed by an ESP or FF.
  - NOx: Selective catalytic reduction (SCR): Removes NOx, by reducing NOx to molecular nitrogen (N2) (which constitutes 80% of the earth’s atmosphere), and water using a reagent in the presence of a catalyst.
  - Selective noncatalytic reduction (SNCR): Removes NOx by reducing NOx to N2 and water using a reagent, i.e., mercury.
  - Activated carbon injection (ACI): Mercury exists in the form of SO2 and particulate forms.

ACI systems inject activated carbon into flue gas, where it adsorbs elemental and ionic mercury emissions, creating particles that can be removed by an ESP or FF. Activated carbon is a porous, highly adsorptive particle made by heat treating carbon.

Further add to the properties for specific applications.

- PM: Electrostatic precipitators (ESP): Electrostatically removes PM by attracting charged flue gas particles to the ESP. After a sufficient quantity is collected, a rapped jet of water knocks the caked-on dust into a hopper for disposal or reuse.
  - Fabric filters (FF): Physically and electrostatically removes PM from the flue gas via a filter bag and accumulated filter cake. Periodic shaking or pulses of air knock the accumulated filter cake into hoppers for disposal or reuse.
  - Multipollutant: Multipollutant control technologies integrate controls for at least two of the following emissions: SO2, NOx, PM, Hg, and CO2. The high cost and complexity of integrating multiple control technologies together drives their development.

 Coal-fired power plants have a variety of retrofit options requirements. Where possible, coal-fired power plants are installing less capital-intensive, albeit higher operating cost retrofits to avoid spending large amounts of money on generating facilities that could be made unprofitable by future regulation and/or lower natural gas prices.

DST, which has had limited applications in the power sector to date and primarily to limit sulfur trioxide (SO3), is expected to be widely deployed to address a wide range of acid gas emissions in lieu of installing more capital-intensive FGD systems. Furthermore, power plants are optimizing their existing ESPs to improve PM removal performance instead of installing new FFs.

8.4.1.3. Carbon capture and storage (CCS)

There are three key CCS technologies—postcombustion, precombustion, and oxyfuel combustion. These technologies either destroy or remove contaminants from exhaust streams before being emitted into atmosphere.

- In postcombustion carbon capture, flue gas is sent through a scrubber column where it reacts with a solvent (typically a nitrogen compound such as ammonia or an amine). The reacted solvent is then regenerated and reused, and the separated carbon dioxide (CO2) is cooled and compressed for transport.
  - In precombustion carbon capture, the fuel is gasified and then turned into CO2 and hydrogen through a water-gas shift reaction. A scrubber column using a solvent is then used to separate the hydrogen and CO2, and the hydrogen is bumed as fuel.
  - Oxy fuel combustion involves burning fuel in pure oxygen, which is cryogenically separated from air. The flue gas from an oxy fuel plant is primarily water and CO2, which can be separated without a scrubber through cooling and condensation.

Typically CCS adds 70–80% to capital costs of new supercritical pulverized coal (SCPC) plants, and 100–110% to capital costs of new combined cycle gas turbine (CCGT) plants. However, current carbon capture processes are relatively inefficient because of large parasitic power losses: 25–35% for coal, and 15–25% for natural gas.

Large-scale demonstration plants are receiving financial support in Europe, the United States, Canada, and further add to the properties for specific applications.
Australia through direct grants, tax credits, and carbon pricing policies. But declines in available funds have contributed to some project cancellations.

Key commercialization hurdles
- More commercial development is needed to reduce upfront capital and parity-cost power losses.
- Technology development is progressing more slowly than other low-carbon technologies such as solar and wind power.
- Low natural gas prices, high capital costs for CCS, and uncertain carbon pricing policies are key obstacles to development.
- Regulatory and funding uncertainty has led to numerous project delays and cancellations, slowing development.
- Complex value chain through power generation, capture, pipeline, and storage—multiple players and business models at each stage.
- Monitoring, measurement, and verification process for carbon storage is needed to allay fears of leakage from underground geological containment remains.
- Liability issues for long-term storage also need resolution.

At the same time CCS increases the fuel consumption for the heat output (as CCS increases production for own needs significantly). As a result the coal-fired power plants’ impact on environment will increase due to escalated coal consumption and ash production. In addition, a risk of CO2 leakage from an underground geological containment remains. Given high air content of Kazakh coal and current level of this technology its application by Kazakhstan’s power plants might be premature in the medium term.

8.4.1.4. Grid storage
- Grid storage is necessary for fast-reacting low-carbon solutions to intermittent wind and solar generation, together with ongoing cost reductions for batteries, have triggered a surge in storage projects (mainly initiated by public funding in Germany, Italy, and United Kingdom). IHS Markit estimates that by November 2016, 640 MW of non-traditional storage capacity was operating in Europe, equivalent to 940 MWh in energy terms. There is another 190 MW of projects that are under construction or planned, which could come online by the end of 2017, equivalent to 220 MWh of energy storage.
- Li-ion batteries are gaining ground rapidly; they were the preferred technology for the vast majority of projects in 2015 and 2016. Li-ion batteries accounted for three-quarters of project capacity (MW) installed since 2009 and half the energy storage capacity. Sodium-sulfur batteries have a higher duration time and therefore this technology’s share is lower on an energy basis than in power terms. It contributed a large addition of energy storage in MW in 2014 as the technology was chosen by Italy’s TSO Terna for its project. A single 290 MW facility installed in Germany in 1978 accounts for all the current compressed air energy storage (CAES) capacity.
- Germany and Italy have the most installed battery capacity. In particular, the large additions of Li-ion batteries by STEAG (90 MW) in 2016 together with the existing CAES facility in Germany, and installations of sodium-sulfur batteries in Italy, put these two countries in the lead. However, the focus has shifted to the United Kingdom, driven by National Grid’s Enhanced Frequency Response tender for 200 MW in August 2016, which was almost entirely supplied by energy storage projects, mainly Li-ion. Germany’s storage policy is currently concentrating more on residential storage than grid-scale.
- Deployment of grid-scale batteries has mainly been driven by transmission capacity relief (Italy) and frequency regulation (Germany, United Kingdom). Grid storage capital expenditure (capex) currently ranges from below $1,000/kW to above $4,000/kW, depending on technology and duration.
- Shorter-duration projects are lower cost, because they require much less storage capacity; they almost always use Li-ion or flywheels, which are the best options for frequency regulation.
- Lead-acid remains the least-cost battery technology, but its very low cycle life keeps it from being competitive in most grid applications.
- Two zinc-based batteries on the cusp of commercialization are the next-lowest-cost option, although they still must build up a track record and are challenged by both cycle life and efficiency.
- Li-ion is a higher-cost option today, but costs are falling rapidly, and both cost and life and efficiency are superior to lower-cost options.
- Flow batteries have a much longer cycle life than Li-ion, but efficiency is poor, and costs are not falling as quickly.
- Sodium-sulfur batteries have historically been the least-cost option, but they are the only technology available with a seven-hour duration, and costs have not changed much in over a decade of deployment. Flow battery storage with the storage capacity of 60 (kWh) has been installed at Kachpahag solar power plant in testing mode; however plans to balance the output of renewable power plants (solar and wind) with the cycle life and capacity of 100 MW have not been finalized (likely owing to the technology costs).
- Highly efficient battery technologies are capable of improving renewable integration, however at present the cost and efficiency of these technologies are yet to improve several fold to be economically viable in renewable integration.
- A battery technology breakthrough could come from quantum electronics, still it is unclear when they will become available for the industrial use.

8.4.1.5. Microgrids
Essentially, microgrids are local power systems that deploy a collection of technologies in the following environments:
- Military installations
- Universities
- Hospitals
- Neighborhoods
- Municipalities
- Office campuses/parks
- Desalination

These technologies enable the centralized control and digital communication necessary to coordinate generation, demand, storage, direct load control, electricity distribution, and imports of electricity from the bulk power system.

A microgrid has the capability to operate as an electric island for reliability, efficiency, economy, or environmental purposes.

Key potential benefits
- Mitigate power outages and protect against cyber attacks
- Integrate renewable and distributed generation resources
- Increase efficiency by reducing fuel dependency, fuel costs, and emissions

8.4.1.6. Small modular reactors (SMRs)
Small nuclear reactors technology (less than 300 MW operating thermal capacity) has received less complicated equipment delivery, with reactors delivered preassembled. But SMRs need to demonstrate that modular design and factory construction have an economic advantage over competing large-scale, conventional base-load generation options (including conventional coal and gas). The economics:
- Reactors can be built in clusters, with additional reactors added over time as demand increases.

8.5. REGULATION: LEGISLATION AND POLICY FOR KAZAKHSTAN’S POWER SECTOR
Kazakhstan’s electric power sector is subject to extensive and factory regulation that defines price- and tariff-setting policies, anti-monopoly regulation, energy efficiency and environmental protection, wholesale and retail market rules, as well as related investment, health, safety, and labor regulation. Kazakhstan’s progress on power sector reforms since independence has been generally patchy: the power market design still lacks effectiveness and overall design efficiency on both the wholesale and retail levels. Despite some critical legislative amendments made in 2015, they were not all fully implemented.

The power sector strategy, although now incorporating some modern-day concepts, such as renewable generation and provisions for carbon reduction, still lacks consistency, detail, and long-term predictability. In the last decade Kazakhstan’s policymakers have felt compelled to prioritize response to urgent infrastructural needs (e.g., a tariff-investment scheme during 2009–15) to accommodate selected high-priority initiatives (e.g., support of renewable generation) irrespective of wider policy commitments. The lack of policy consistency meant regulation has not been effective enough to mobilize long-term investment.

8.5.1. Review of the power sector policy documents and commitments
The series of power sector reforms outlined in 2008, in particular with regards to a price-optimized wholesale–sale power market structure (to incorporate day-ahead, balancing, system services, and capacity markets) as well as performance-based grid tariffs and retail market competition, have either stalled or were substituted by mechanisms introducing tight price control (e.g., a system of price caps, return to cost-plus transmission tariff, etc.). Although in 2015 the legislation on many long-awaited power market concepts (capacity market, balancing market, retail market) was introduced, for the most part it disregarded the changing pattern of supply and demand, continued to support (power, capacity, heat energy) price distortions, lacked vital details, and remained inconsistent with the framework programs and commitments that Kazakhstan has undertaken to date, namely:
- External Policy Concept 2014–2020
- Prioritizing Kazakhstan’s economic integration within the Eurasian Economic Union.

14 See IHS CERA Technology Snapshot: Small Modular Reactors.
15 See Decree of the President of the Republic of Kazakhstan from January 21, 2014 No. 741 “On the Concept of the Foreign Policy External Policy Concept 2014–2020”.
16 See Decree of the President of the Republic of Kazakhstan from August 1, 2014 No. 874 “On approval of the State Program of Industrial and Innovative Development of the Republic of Kazakhstan for 2015-2019 and on amending Presidential Decree No. 957 of the President of the Republic of Kazakhstan from March 19, 2010 “On Approving the List of State Programs”.
17 See Decree of the President of the Republic of Kazakhstan from January 21, 2014 No. 741 “On the Concept of the Foreign Policy of the Republic of Kazakhstan for 2014-2020”.

The electric power and capacity markets’ policies would have to incorporate this environmental imperative alongside security of supply and value for consumers as overarching goals.

Any change in market power regulation will have to coincide with a new investment cycle in Kazakhstan’s power generation. The latter is not only driven by the cost of new technologies (building renewable sources of energy, smart grid, new gas and nuclear capacities, storage solutions, and adaptation for the power sector’s specific needs, etc.), but by the fact that Kazakhstan’s power sector is “locked-in” to high carbon production and consumption patterns. Therefore, the new investment is needed to fund a breakaway from them.

The “green economy” initiative also coincides with a change in consumption patterns (peaker load de-centralized), which means Kazakhstan must revalue the way it thinks power will be generated, delivered, and consumed by 2030. The creation of specific market mechanisms to address the power sector’s capacity balance planning and grid development; electricity production and consumption, including flexible and available capacity, system services, and balancing market regulation.

For example, the approved plan of adding several large coal-fired base load power plants contradicts both the “green energy” path and the existing consumption and production patterns (renovable energy). It would also require potentially constraining certain types of technology that currently contribute to Kazakhstan’s higher carbon footprint most, i.e., coal-fired heating power plants (the latter would be a particular challenge in the absence of a broader heat energy market policy, and related social implications), while ensuring system stability and readiness to integrate disruptive intermittent generation.

Kazakhstan, like many other countries, is facing the challenge of providing promised “price caps for power producers” (power on the wholesale level) are set by the Ministry of Energy on the government’s behalf, while KREMIZK establishes a whole range of operational tariffs at the retail market (sold to end-users) for electric power and heat energy, as well as tariffs for the electric power and heat energy distribution, transmission, and sales. However, the committee’s dependent status and insufficient funding means it merely acts as an intermediary between the market participants, translating the government’s view on natural monopolies’ pricing, rather than initiating a change in tariff methodologies to create a better performance and quality of service.

In addition, current limited state financing impairs the committee’s ability to monitor and check natural monopolies’ activity.

8.5.2.4. Market Council (SovetRynka)—Electric Power Association (KEA)

Representative body that would represent and defend the interests of Kazakhstan’s wholesale electricity (capacity) market buyers and sellers has failed to materialize fully, although respective legislation creating a market committee (feminized as SovetRynka in Russian) was introduced in 2015. De facto, the interests of the power producers and large consumers are represented through the KaziChemEnergetika Association (www.kazenenergy.com), the National Chamber of Entrepreneurs (Alateken), the Republican Association of Mining and Metallurgical Enterprises (AGMP) and others. Although SovetRynka (run by the Electric Power Association [KEA], www.kea.kz) monitors the market and acts as a link between the market participants and the Ministry of Energy, it has become yet another platform for policy issues other than being a consolidated force to lead and implement changes related to the power market structure design, and/or power, capacity, and emissions trading.

In part, this is due to the restricted authority and functions imposed on KEA by the Ministry of Energy, limiting it to power market monitoring and collecting market opinion on legislative changes. Although, in preparation to 2019 capacity market launch KEA reviewed the power plants’ investment programs.

8.5.3. Wholesale electricity and capacity markets

Kazakhstan’s power market consists of wholesale and retail markets where currently electric power and capacity is treated as a single product. However, from 2019 this will change with the launch of a capacity market. This change would redefine the structure of the wholesale electricity market and power price dynamics by using specific market mechanisms to compensate investors separately for fixed and variable costs. For instance, the purpose of the wholesale electricity price (for the commodity of power and heat energy) would be to cover generators’ variable costs (mainly fuel) while a capacity price should cover generators’ fixed costs (such as payoffs, maintenance, investment etc.).

8.5.3.1. Wholesale electric power market

The wholesale power market operation is governed by the Electric Power Sector Law and the Wholesale Power Market Rules (Market Rules) approved in 2015. Although the Market Rules define and describe
8.5.3.1. Bilateral agreements (decentralized trade)

Almost 90% of Kazakhstan’s power is sold via bilateral power purchase agreements (PPAs). PPAs are signed between power producers and large industrial consumers, as well as between power producers and electricity supply companies (ESCO), provided they meet the average minimum price, and have grid access. The market participants can, at their discretion, define PPA counterparties, prices (as long as they do not exceed the price cap for the power plants in question), and volumes. As a rule, PPAs are signed for one year (in line with an annual price cap adjustment). There are a number of factors that drive the choice of decentralized power trading over that of centralized power trade, namely:

(i) Regulation

a. According to the market rules, participation in the centralized trade is voluntary. Given the slowing rate of demand and available capacity, power producers are keen to lock consumers into PPAs.

b. Volume, terms, and the price of electric power in bilateral agreements (within the price cap) are set by the parties.

c. The price-capping does not recognize the difference in the cost of power supply to hourly marginal costs (base, half-peak, peak).

(ii) Structure of the market participants’ assets

a. Vertically integrated industrial groups own a substantial share of generation. Bilateral agreements for these vertically integrated companies provide price stability throughout the value chain.

b. Technical aspects

a. Combined heat-and-power plants’ (TETs) fuel-to-power cost efficiency deteriorates with a decrease in heat energy output. Power-only production makes TETs uncompetitive at the centralized power market.

b. TETs are not motivated to trade power centrally, as the electric power produced by TETs is a by-product of the energy that TETs generate as their primary product.

c. The system operator/Regulator does not have the ability to decommission on the basis of technological or economic inefficiency.

(iii) Economic aspects

a. With the exception of hydropower during the spring flood period, consumers do not have access to cheaper power at a centralized platform. Although PPAs contain an hourly schedule, intraday pricing is not sensitive to supply and demand and thus power plants tend to commit to structured agreements. This is one consequence of not having a properly functioning balancing market as well as enforced price-capping.

b. Agreements between power producers or between energy sales companies and industrial consumers are the activity is considered speculative trade and causes price inflation for consumers.

Notably, in Kazakhstan almost 50% of wholesale power is traded by a handful of power plants, but centralized Western experience that does not necessarily mean a market environment cannot be achieved using a centralized marketplace.

8.5.3.2. Centralized power trading

Out of a total of 83.5 billion kWh supplied to consumers in 2016 (according to the actual production and consumption balance), about 10.3 billion kWh was sold centrally at an auction administered by Kazakh operator of electric power market (KOREM). According to KOREM, the share of centralized power trading has increased from 7% in 2014 to 12% in 2016, driven by the availability of spare capacity (capacity that was not contracted bilaterally as a result of declining industrial power demand) (see Table 8.3).

<table>
<thead>
<tr>
<th>Volume, billion kWh</th>
<th>2014</th>
<th>2015</th>
<th>2016</th>
</tr>
</thead>
<tbody>
<tr>
<td>Total volume of electricity supplied to consumers</td>
<td>83.1</td>
<td>82.1</td>
<td>83.5</td>
</tr>
<tr>
<td>Total volume of centralized trade</td>
<td>6.02</td>
<td>2.49</td>
<td>10.26</td>
</tr>
<tr>
<td>Share of centralized trade in overall power supply to consumers</td>
<td>7%</td>
<td>3%</td>
<td>12%</td>
</tr>
</tbody>
</table>

Table 8.3. Change in centrally tradable electric power

The participants of the centralized market are power producers that sell exceptions that were not locked into PPAs, and power consumers (industrial or energy companies) that buy power from centralized market on a short (day-ahead and intraday market), medium (week, month, quarter), and long-term (year) basis—essentially three marketplaces.

Day-ahead market (DAM)

The day-ahead market (DAM) is an auction of price bids and volumes submitted by the power producer and consumers a day in advance. According to the day-ahead market price merit order, the buyers’ (consumers and KEGOC) bids are ranked from the highest to the lowest and matched to the sellers’ (power producers) from the lowest to the highest until the demand is fully met, for every hour. The last accepted seller’s price offer that satisfies the demand sets the (clearing) price for all power exchanges during that hour. Changes in centrally tradable electric power

In other words, a power producer cannot choose to buy power from a centralized market should it make more economic sense than generating. Participation in a centralized market is voluntary with the exception of the market sale of hydropower capacity during flood periods. Prior to entering into trading, KOREM ensures power consumers (buyers) are solvent (available funds) by requesting a financial guarantee. The buyers and sellers of power can trade on the centralized market on a short (day-ahead and intraday market), medium (week, month, quarter), and long-term (year) basis—essentially three marketplaces.

Intraday trading allows for adjustments to be made to the daily operating schedule three hours before the physical delivery of electric power (gate closure). Intraday trading is a continuous double auction. The buyer and seller of power have the right to cancel any trading arrangements that have been reached prior to gate closure. KOREM confirms the buyer and seller pairs and the power prices, and submits this information to the system operator for technical assessment and adjustments required to the daily operating schedule. Nevertheless, the system operator has no influence on meeting the overall demand based on efficiency (with the cheapest power generation available and dispatching more expensive generation only if demand spikes). In other words, the system operator’s role in unit commitment (i.e., the determination of


The daily operating schedule represents a document by the system operator that outlines the hourly schedule of electric power production and consumption for every calendar day in accordance with the information from the bilateral agreements and centralized auction.
which resources to start up or shut down driven by security and economic dispatch decisions) is limited to unit dispatch for system stability.

Medium- and long-term trading

Medium- and long-term trading are forward agreements for the physical delivery of electric power over longer periods, namely a week, a month, a quarter, and a year ahead. They are differentiated further by:

- Baseload power supply, seven days a week
- Peak load power supply, working days

The auction for medium and long-term power trading is held in two unrelated trading sessions:
- The first session is held between 09:30 and 11:30 during weekdays
- The second session is a continuous double auction held between 14:30 and 16:30 during weekdays.

The trade participants could participate in either or both trading sessions. The schedule of medium- and long-term trading is approved by KOREM. The pairs of sellers and buyers sign PPAs upon receiving the information on volumes and prices from KOREM.

Long-term trading is of interest to both power consumers and power producers given the current abundance of spare capacity. This is because the power consumers hope to enter into long-term PPAs at a more competitive price, while the power producers hope to lock in additional consumers.

8.5.3.4. Wholesale electricity price formation

Since 2009 wholesale power prices are semi-regulated. Essentially this means that the power price is set to a state-set price cap ("maximum tariff") irrespective of the power system or sector indicators. All power plants in Kazakhstan, regardless of their ownership, were divided into 13 groups (from 2016, 17 groups) with each group assigned a price cap according to their cost drivers (marginal cost of fuel for thermal plants and water tax for hydropower plants, as well as distance from fuel source) and set profit margins (to cover investment obligations).

From the point of view of power trading, both centralized and decentralized, power producers are not allowed to sell power at a price exceeding their respective price cap. Even in the day-ahead power market, when a marginal price could settle above some of the power plants’ price caps (e.g., for large hydrothermal plants whose price caps are half that of thermal power plants) the volume of electric power that could be sold above the price cap cannot exceed 10% of total plant’s output. Price-capping also means that producers’ prices do not fall to marginal cost when there is a surplus of capacity and rise when demand approaches available generation, whether intraday or over longer periods (driven by economic environment).

The Kazakhstan Electricity Power Industry Law, the power price can exceed the price cap at the balancing market (once it is finally launched) and for inflexible generation. The price cap system was conceived in 2009 as a temporary seven-year measure to boost investment into the face of a looming capacity shortage. In return for higher (maximum) tariffs, each power plant committed to a medium-term investment program between 2009 and 2015 that was subject to an annual increase to accommodate investment plans and inflation. Investment programs were sanctioned to fund upgrades, maintenance, overhaul, and new construction of generating assets.

The price cap (maximum tariff) scheme was billed as "tariff-for-investment", and according to the Ministry of Energy the scheme increased investment power generation more than fivefold, and attracted over 1 billion tenge of new investment. In 2009–15 Kazakhstan reinstated and launched 2,957 MW of new generating capacity, with a further 350 MW of new generating capacity commissioned in 2016 (see Table 8.4).11

By 2016 the goal of the tariffs-for-investment scheme was successfully accomplished: the power system had built up almost 3,000 MW of excess generating capacity. Although the capacity market was meant to replace the tariff-for-investment scheme in 2016, the delay in launching the capacity market until 2019 forced the government to extend the price-cap scheme; but now stretching to 17 groups of power producers.

8.5.4. Renewable generation in the wholesale market structure

The government remains committed to its renewable targets outlined in the Strategic Plan for the Development of the Republic of Kazakhstan to 2020, the Concept on the transition of the Republic of Kazakhstan to the Green Economy Concept on the transition of the Republic of Kazakhstan to 2050. Similarly to other countries, to boost renewables development, Kazakhstan has opted for preferential treatment of renewable technologies, i.e., policy support. Although Kazakhstan had planned that 1% of electric power would come from renewables by 2014, in 2017 only 0.8% of electric power is being generated by renewable energy sources (RES). The key factors slowing renewable project development have been:

- Long (12–18 months) process for technical approval of the projects
- While this measure could help accelerate construction of renewable capacity, the integration of renewables in the planned quantities by 2030 into Kazakhstan’s infrastructure under the current power market design (with regards to the balancing and system services markets, as well as suggested capacity mechanisms) is likely to be a challenge (see KAZENERGY NER 2015, section 10 on technological issues and the economic implications arising from RES integration). In developed power markets, with strict regulation and deep penetration of modern technologies, integration of about 15% of renewable production into an energy system is workable but still challenging for some system operators, given the high levels of intermittency. For Kazakhstan’s power sector where the overall rules and regulations are immature, and generating assets and old infrastructure still require considerable technological upgrade, scaling up renewable production is likely to pose both a technological and economic test.

Table 8.5. Feed-in tariffs for renewable energy sources (2014)

<table>
<thead>
<tr>
<th>RES</th>
<th>Tariff (tenge/KWh without VAT)</th>
</tr>
</thead>
<tbody>
<tr>
<td>Wind</td>
<td>22,68</td>
</tr>
<tr>
<td>Solar</td>
<td>34,61</td>
</tr>
<tr>
<td>Hydro (up to 35 MW)</td>
<td>16,71</td>
</tr>
<tr>
<td>Biogas</td>
<td>22,23</td>
</tr>
</tbody>
</table>

Table 8.4. Changes to installed and available capacity

<table>
<thead>
<tr>
<th>Installed capacity MW</th>
<th>Available capacity, MW Winter</th>
<th>Summer</th>
</tr>
</thead>
<tbody>
<tr>
<td>2009</td>
<td>19 127,9</td>
<td>14 821,0</td>
</tr>
<tr>
<td>2010</td>
<td>20 440,5</td>
<td>15 291,0</td>
</tr>
<tr>
<td>2011</td>
<td>21 798,1</td>
<td>15 765,0</td>
</tr>
<tr>
<td>2012</td>
<td>20 442,0</td>
<td>16 425,0</td>
</tr>
<tr>
<td>2013</td>
<td>20 591,5</td>
<td>17 108,0</td>
</tr>
<tr>
<td>2014</td>
<td>20 844,2</td>
<td>16 945,0</td>
</tr>
<tr>
<td>2015</td>
<td>21 320,2</td>
<td>17 500,1</td>
</tr>
</tbody>
</table>

11 Source: Statistical Committee of RK.
13 Should the power plants fail to cover investment needs from the sale of electric power under a maximum tariff (price cap), such power plants were entitled to an individual/specially calculated tariff (subject to receiving the Ministry of Energy’s approval regarding the technical scope of works and investment rationale). Once the capacity market is launched in 2017, the price cap would replace the individual/specially calculated tariffs. In other words, until 2019 the wholesale power price would be calculated based on the power producers’ costs and profit (maximum tariff), or costs, profit, and investment (for individuals) specially calculated tariff.
14 Source: Statistical Committee of RK.
15 By July 2013 the total installed capacity of renewable projects approved for implementation reached 3,756 MW with 2 GW more looking for approval. Of the approved 3,756 MW wind accounts for 1,267 MW, solar for 991 MW, and small hydro for 779 MW. Longer term, and according to the Green Economy Concept, the Kazakh government hopes both renewable and alternative (nuclear) sources of power could grow to 50% of its power output.
16 See the Law of the Republic of Kazakhstan of 4 July 2009 No. 165-1 ‘On Support of the Use of Renewable Energy Sources’, renewable energy sources in Kazakhstan include wind, solar, small hydropower (up to 35 MW), geothermal, and bio fuels. The agreement duration for purchasing renewable power is 15 years. Renewable power producers are allowed to sell their electric power either (i) centrally via a Financial Settlement Agreement...
ment Center (FSC) at fixed feed-in tariffs, or (ii) via bilateral agreements at all prices agreed upon between the parties (with no right to switch to power sale via FSC). FSC sells power to the so-called “conditional” consumers, represented by:

(i) Coal, oil and gas, and nuclear (coal, gas, and oil, nuclee-
lar and sulphur) power producers35
(ii) Market participants who export electric power from Kazakhstan36
(iii) Energy plants with installed capacity above 35 MW (launched before 1 January 2016)
Should RES act as a source of heat energy, the heat energy purchase agreement is signed for RES payback periods of 10 to 15 years.
Both modernized and new RES are granted preferen-
tial right of access to either the power grid network or heat energy network, although RES developers are to assume the costs for construction of the grid from RES to the grid connection point.

8.5.1. Renewable electricity price formation
According to the Electric Power Sector Law and the Law on Supporting Renewable Energy Sources (RES Law) the Center of Financial Settlement (CFS) buys all generated renewable power at feed-in tariffs. The choice of CFS as single buyer of renewable power is driven by the desire to distribute the cost of renewable energy simply and evenly. Interestingly, there are no RES power producers of energy supply companies, but conventional power producers who pay for the renewable power in proportion to their output delivered to the grid.37 This out-of-the-market treatment of RES is the result of a financial, dispatch, and administrative unification which is not uncommon globally, although the payment scheme is unique to Kazakhstan. How-
ever, together they have created the highest level of investment stability for developers in renewable gen-
eration.38 For instance:

• The renewable power purchase agreements could be signed three years prior to renewable capacity commissi-
nation.
• Renewable tariffs are fixed for every type of RES (wind, solar, hydropower up to 35 MW, geothermal, and bio fuel) for 15 years, and are subject to annual re-indexation to inflation, and changes to the tender exchange rate. Subject to RES type, fixed tariffs are three to ten times higher than those of conventional power producers.
• RES enjoy free of charge connection to the dis-
tribution grid and are exempt from existing grid upgrade payments (that might be required for the connection of a RES), as well as power transmission tariff. However, RES developers take on the full cost of building a line to the nearest connection point.
• RES developers also receive tax benefits (corporate tax, property tax, land tax) and investment subsidies (30% of actual costs related to installation and equipment).
• RES developers could be exempt from customs duties and receive state grants (in relation to free use of land, buildings, equipment, and transport).

Conventional power producers reimburse the cost of renewable power by including it into the cost of their power production. In other words, the cost of renew-
able power is accounted for during the price cap calcu-
lation.39 Essentially, the conventional power plants bear a joint responsibility for the mandatory payment for renewable power.40 Nevertheless, this scheme distorts the wholesale power price and obscures the true cost of power production.

Similar to electric power, RES are exempt from envi-
ronmental taxes and are not subject to any environmental levies. The costs of the environmental levies are considered tax deductions and is calculated in relation to the amount of avoided emissions (expressed as CO2 equivalent).

The Center of Financial Settlement (CFS) pays RES producers rates below their variable costs.41 The resulting tax losses are recouped through the CFS contribution to federal budget.42

In 2013 Sulfate plant in Kazakhstan launched a sulfur power plant (SKZ-U) As part of Its 16 MW steam turbine runs on
steam produced by the manufacturing plant.

For instance:

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steam produced by the manufacturing plant.

8.5.5. Wholesale capacity market
According to Kazakhstan’s latest Concept for the Devel-
opment of the Fuel and Energy Complex of the Repub-
lic of Kazakhstan until 2030, the government plans to attract 7.5 trillion tenge, or about $51 billion (in 2014 prices) of mostly private investment into power sec-
ctor. The government recognizes that to achieve this, Kazakhstan will need to create incentives that would attract private sector investment. The launch of a capacity market is seen by the government as a means to achieve this.

The benefits of running a separate capacity mech-
anism include:

• Creating long-term pricing signals for consumers and investors
• Resolving the chronic “missing money” problem in the wholesale power market (capacity due for sale at the capacity market has been estimated at 1,221MW) due for commissioning in 2014/2015, bringing the total amount of excess capacity to around 2,560 MW.43 Taking all of the above into account, and given existing capacity mix, chang-
ing consumption profile for a shapelier one, as well as Kazakhstan’s broader derecralization policy commit-
ments including RES integration, and the fact that the capacity market reform is incomplete (with regards to the balancing market launch, potential improvements to the existing wholesale market model and the sys-
tem services market), the formal capacity market model introduction could be either premature or fail to meet the power sector objectives long term. To that end, Kazakhstan’s policymakers may review the CRM objectives and mechanisms to ensure security of supply is met by more flexible and cleaner capacity.

8.5.5.1. Currently proposed capacity market model
Out of all CRM mechanisms available, Kazakhstan has opted for a capacity market. According to the rules of Kazakhstan’s proposed capacity market, capacity is treated as a service provided by the power producers in accordance with the agreements on maintaining a certain megawatt capacity in a state of readiness to generate.44

According to the regulation the wholesale capacity market participates include:

• Wholesale power producers
• Power transmission companies

35 In 2013 Sulfate plant in Kazakhstan launched a sulfur power plant (SKZ-U) As part of its 16 MW steam turbine runs on steam produced by the manufacturing plant.
37 According to the RES Law the renewable power producers could choose to sell their electric power directly to power con-
sumers via bilateral agreements at prices agreed upon by the parties, but by doing so such RES would lose their right to sell their power centrally via CFS.
38 See Article 9, clause 4 of the Law of the Republic of Kazakhstan from 4 July 2009 No. 165-IV “On Support of the Use of Renewable Energy Sources”.
39 While this scheme is feasible for stand-alone power producers, the power plants owned by the industry would find it impossible and uneconomic to do without access to their own end-product market (in which many in Kazakh energy market are export oriented). Industries who own power plants and are willing to build RES for own needs only might minimize the cost of renewable power in this manner, but would also need to meet the overall RES target. Considering this, in 2011 Kazakhstan introduced an amendment was introduced by Law No. 89-IV “making changes and amendments to some pieces of legislation in the Republic of Kazakhstan” which states that projects by industrial groups should fit within renewable energy facilities for RES that are subject to current legislation and not be subject to RES that are not subject to RES. RES facilities are included in the tariffs of energy transmission services in the manner established by the legislation of the Republic of Kazakhstan on natural monopolies and regulated markets.”
The current capacity market design model envisions three sources of capacity revenue: 

- **New capacity:** selected through a tender to mitigate the risk of capacity shortages
- **The pool of existing power plants:** selected through a centralized auction for maintaining existing capacity in sound condition ready to meet demand
- **Modernized power plants:** generating capacity that has signed investment agreements

A different treatment of old and new capacity in Kazakhstan is not uncommon and is practiced in Europe and Russia. It is mainly driven by the desire to minimize the overall capacity cost to end-consumers. By linking marginal price formation the existing capacity is paid at the same price as a new capacity it creates an inevitable windfall for the former, as the new capacity is more expensive.

Both existing and newly commissioned generating capacity are subject to an annual certification by the system operator to certify their technical capability to produce and establish their available capacity. Kazakhstan might consider that an emissions performance standard (EPS) should be applied to both new and existing capacity to moderate carbon-intensive generation’s access to the capacity market (or at least to get priority capacity payments). However, an EPS application is not envisaged in the current model. And with no CRP provisions for cleaner technology requirements, even when it comes to new capacity additions, Kazakhstan’s shift towards a green economy seems less likely.

Participation in a centralized wholesale capacity market is obligatory for all power producers irrespective of their plants’ ownership and structure. The capacity model does not envisage any bilateral agreements for capacity in addition to the auction, unlike the practice in neighboring Russia. This means that energy-intensive industrial consumers that own generating plants and benefit from vertical integration would be forced to buy capacity from the market and are likely to be at a disadvantage (due to capacity merit order described above and pricing described below). Wholesale consumers purchase capacity in accordance with their total peak demand at a capped demand, with a separate capacity price for the capacity market and supported by the new heat energy market legislation and changes to the heat energy tariff methodology.

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8.5.6. Balancing market

Participation in the balancing market is obligatory for all market participants.\(^{18}\) However since 2008 the balancing market in Kazakhstan has been operating in a single market model. In 2015 the Ministry of Energy determined that the actual launch yet again further to 2019, citing potential power price volatility, lack of flexible capacity, and insufficient commercial metering as reasons for the delay.\(^{19}\) The ongoing simulation reflects physical balancing of electrical power production and consumption by the system operator. However, it does not imply financial settlement of imbalances when Kazakhstan draws on Russia’s power system (for now both countries agreed to adhere to net zero flows).

The anticipated rollout of the balancing market in 2019 presumes Kazakhstan will have dramatically improved system adequacy and full digital metering. But both areas remain an issue, which is likely to affect the balancing market’s operation (in order to accurately calculate late imbalance charges, a complete set of metered data is required) and price formation (particularly if Kazakhstan continues to draw on Russia’s resources). Price formation requires having sound policies in existence, as this should reflect the costs of system balancing in real time.

The overall approach assumes that the imbalances must reflect the cost of flexible power for frequency control for replacing capacity rapidly with reserves at a very short notice. Whether Kazakh policymakers opt for single imbalance pricing (same payments for those who both cause and reduce imbalance) or dual imbalance pricing (penalizing parties who cause imbalances at a different rate to rewarding those who reduce imbalances) are possible options with respective advantages and disadvantages. But the key is that the principles of price formation and system operational curtailments are transparent (and at least-cost for consumers).

8.5.7. System services market

The core principle of the System Services Market is to maintain the national standards of power system reliability and electric power quality, defined in the “Rules on the System Operator’s Services and the Operation of the System” (the “System Services Market Rules”).\(^{20}\) According to the System Services Market Rules, the system operator provides the following services to wholesale market participants on a contractual basis: (i) Technical maintenance and operational readiness of the national grid for the transmission of electrical power (i) Technical dispatch services (ii) Capacity reservation services (iv) Power production and consumption balancing services.

In accordance with the above-listed services the system operator receives compensation in the form of a regulated capped tariff (calculated per kWh), namely: (i) power transmission services, (ii) technical dispatch to the grid and consumption of electric power, and (ii) balancing of power production and consumption.\(^{21}\) The magnitude of KEGOC’s system service needs differ by season (with higher system services in autumn-winter as a result of increased consumption). All of the above services that fall under national monopoly regulation, are set by KREMKZ, and are the same for all consumers. The System Services Market Rules however, are non-transparent on compensation for services (wholesale power producers and power consumers) to balance the system, or envisage such payment in the future, particularly with the planned growth of variable sources of power production (wind and solar generation). These services are ancillary to those procured through the balancing market and typically cover: • Reactive power • Frequency response • Black start • Reserve services (operational, supplementary, and demand control)

The system services actions are taken by the system operator for system management, rather than for pure energy balancing. Traditionally the system operator has a number of procedures at its disposal to minimize the price impact of system balancing actions on the power imbalance price calculation. The latter puts a lot of emphasis on the system operator’s impartiality and resources, as well as transparency of decision making.

8.5.8. Retail market

8.5.8.1. Electric power (and capacity)

The retail market in Kazakhstan is governed by the Electric Power Sector Law and the Retail Market Rules and the ESOs’ Law.\(^{22}\) According to these regulatory documents the retail market participants include: • Retail power producers • Regional electric distribution companies (RECs) that operate regional electric grids and provide electric power distribution services. They are natural monopolies and by law are required to provide non-discriminatory access to their grids. • Energy distribution companies (EDOs) that operate small distribution networks. • Energy supply companies (ESOs) that purchase electric power from either energy distribution companies or power producers and sell it on to the end-consumers in accordance with power supply agreements. • Retail consumers consuming less than 1 MW of average daily (base load) capacity.

ESOs’ service areas typically coincides with the boundaries of a small distribution network where its consumers are connected. An ESO with a high share of household consumers receives the status of a guarantor supplier. Its service area encompasses the entire REC territory, and it undertakes the responsibility of power sales to all end-consumers that have power distribution contracts with the REC. The ESO has the right to terminate a power supply agreement with an end-consumer two months in advance by notifying its intention to the guaranteed supplier, energy distribution company, and the anti-monopoly regulator. However, the retail market rules do not have a similar provision for end-consumers, although it is required by the retail market rules. In other words, large consumers consuming above 1 MW daily average or (base load) capacity, and equipped with automated commercial metering systems could opt to buy electricity either from the wholesale market or from an ESO. However, smaller power consumers who consume less than 1 MW (average daily base load) are more reluctant to change the supplier even if they are unhappy with the quality of service or reliability of supply. The latter is a particularly sensitive issue since energy distribution companies have to control over the quality and reliability of power distribution by EDOs and RECs, while RECs and EDOs do not sign agreements with end-consumers: ESOs sign power supply agreements with end-consumers, and while RECs in particular, are responsible for the quality of distributed power and monitoring of consumption schedule, as they own and control the distribution grid.

The power sales function was singled out from the distribution companies’ activities in 2004 to promote competition that was hoped to drive electricity prices down at the retail level. However contrary to the plan, and in the absence of performance-based (incentive tariff) regulation for power sales and distribution business, 25% of all ESOs already enjoy a monopolistic status. This is a result of RECs, large power consumers, and power producers creating their own affiliated ESOs. Power producers support such an arrangement as it secures the retail sale of power, while ESO’s tariff structure does not incentivize them to look for the most competitively priced power. The intention to streamline the structure of the distribution segment, in particular to decrease the number of EDOs was announced in 2015.\(^{23}\) And although it was not until April 2017 that Parliament had the first reading of the changes to the law on EROs consolidation (by absorbing small EDOs) it was finally passed on 29 June 2017. EROs consolidation would enable them to take under control the current cascading growth of end-consumer tariffs.\(^{24}\) It is likely that out of the current 160 EDOs, 130 will remain operating by 2020. The reduction of the number of EDOs will put some downward pressure on distribution costs through optimization; nevertheless, the overall tariff reduction is unlikely in view of the forecasted power consumption growth outpacing the upgrade rate of the distribution network and infrastructure, particularly smart (grid and meters) technology integration in the view of the age and general condition of distribution grids.

The penetration of intermittent generation places additional stress on the distribution grid network. The power sector regulation with regards to RES (renewable energy sources) support already envisages free RES connection to the distribution grid as well as a mandatory access to the grid. Whereas electricity and capacity would be traded separately on the wholesale market from 2019, on the retail market these two products would still be packaged together in the energy supply agreements for end-consumers. The sale and distribution of electricity (and capacity) is executed in accordance with the daily operational schedule that the system operator puts together their own daily operational schedules based on data from power sales companies and consumers (that have already coordinated their consumption with the power producers), and approves them with the system operator.

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\(^{19}\) See Minister of Energy and Mineral Resources Order No. 269 of 30 November 2007; see also the Ministry of Energy Order No. 676 of 30 November 2015.


\(^{22}\) See Ministry of Energy Order No. 111 of 20 February 2015 “On Rules of retail market operation and services provision.”

\(^{23}\) See Presidential address on the “Nation’s plan of 100 specific steps to realize five institutional reforms,” May 2015 Step 51.

\(^{24}\) Of the total number of 160 EDOs in Kazakhstan, the regions with the highest numbers include: Karaganda Oblast with 42, Akмолa with 10, East Kazakhstan and Kostanay with 13 each, Mangistau with 17, Atyobe with 8, and Almaty with 9.

\(^{25}\) See rules on Electric power tariffs differentiation by the time of the day and consumption volume for the individual consumers by the energy supply companies and order by the Agency on Natural Monopolies regulation (now KREMKZ) No. 57-CD of 20 February 2009 (last updated on 02 September 2016).
8.5.8.2. Retail tariff policy and price formation

The system of retail tariffs in Kazakhstan is complex: tariffs vary by province, consumer group, and time and consumption volume.64 Retail consumers are grouped into (i) population, (ii) budget funded, (iii) industrial consumers with connected capacity of 7.5 kW and above, and (iv) other legal entities with connected capacity up to 7.5 kW. KREMZX (and its regional branches) is the main regulatory body responsible for approving retail tariffs for consumers group. Following the presidential address on the further transition to a market price formation in all sectors of the economy, state price regulation was canceled in “regulated” markets from 1 January 2017. But to prevent social unrest from higher-end consumers’ price increases, the government has retained price regulation in “socially significant” segments (which includes retail sales of electricity to 2020).65

Transmission tariff

According to KEKGO, its key objective as a national grid operator is to ensure reliable operation of the national grid and develop it in the interests of KEGOC own-growth and the needs of the Kazakh economy.66 And KEGOC as a system operator has set out its mission as namely “ensuring reliable operation and efficient development of UES Kazakhstan in accordance with modern technical, economic, environmental, and health standards”. So KEGOC’s objectives as a system operator are similar to those in most other countries which are to achieve the transition to a lower carbon energy system while maintaining security of supply. KEGOC’s activity as an operator of the national grid and a system operator with regards to the dispatch and balancing services is regulated by the Natural垄断s Act.

Transmission tariffs are set in accordance with the “cost-plus fixed profit” methodology based on KEGOC’s estimation of operational and investment costs as well as a return on investment. The above cost is calculated as a ratio of allowed revenues (oper and allowed profit) to the volume of services that KEGOC provides. When calculating the allowed profit, KREMZX works off KEGOC’s asset base (the value of assets used for the provision of services adjusted to the optimization ratio to arrive at the assets actually employed in provision of services multiplied by the rate of return). Since 2013, KEGOC’s tariffs are set five years ahead (currently 2016–20) and are known as maximum cap (predefined) and base tariffs. According to KREMZX, the five-year tariffs provide better certainty in terms of costs and investment planning for KEGOC, the methodology does not incentivize KEGOC to optimize costs or beat KREMZX’s expectations. Although KEGOC’s long-term strategy envisages improvement of system average interruption duration index (SAIDI) and system average interruption frequency index (SAIFI) indicators, and losses reduction, these parameters are not linked to KEGOC’s revenue. The cost-plus methodology does not have inbuilt incentives that would link KEGOC’s earnings and tariff to company performance.

In support to the operational activity of selected industries in 2016, KREMZX developed a system of reducing ratios applicable to transmission and dispatch tariffs (ranging from 0.71 to 0.99) and differentiated by company. Although developed as a temporary measure, moving forward KEGOC believes its tariffs would continue to be subject to “temporary” reducing ratios.

Since 1 August 2010, KEGOC’s transmission tariff is calculated for retail based on the volume transmitted and ignores distance. By applying this methodology KEGOC has granted power consumers non-discretionary access to the national power grid (uniform transmission charges throughout the trading region—also known as a “postage stamp”—is common globally).

Distribution tariff

Although electric power grids and particularly distribution networks are at the core of an ongoing energy transition (emergence of smart meters and smart grids, impact of renewable energy sources, electric vehicles, and decentralized storage), distribution tariffs in Kazakhstan are devoid of losses reduction incentives to manage the system and invest into it more efficiently. After a trial period of tariff-setting using benchmarking, the regulation for distribution companies contemplates a “parity tariff”, with the only difference that from 2016, KREMZX sets maximum tariffs for five years ahead.

The regulator (KREMZX) approves economically justified expenses, and adjusts allowed revenues based on operational expenditure.

Investment for distribution companies is funded by depreciation, reduction of technical losses, and current year’s profit.

In this system distribution companies are forced to artificially inflate tariffs, and are not incentivized to be cost efficient.

Under this approach, operators are not compensated for owning and operating electricity distribution assets, investment is limited to maintenance programs, and long-term borrowing is restricted. Although there is no single approach to distribution methodologies globally, they all tend to have fixed capacity and energy components (although they might vary significantly), a concept still not considered in Kazakhstan.

8.5.9. Heat energy market

The heat energy market in Kazakhstan remains intertwined with the market power with 2,207 sources producing heat energy, ranging in output from 3 to over 1 million heat hour.67 Heat energy producers in Kazakhstan primarily include TETs and heat boilers. Thermal power plants account for 64% of total heat energy production.

Largest consumers of heat energy are: commercial-municipal sector; residential (households); and industry. Heat energy is sold via heat energy supply agreements and sales fall under the natural monopoly activity and are regulated by the law on natural monopolies. KEGOC’s tariffs are set in accordance with the “cost-plus fixed profit” methodology based on KEGOC’s estimation of operational and investment costs as well as a return on investment. The above cost is calculated as a ratio of allowed revenues (oper and allowed profit) to the volume of services that KEGOC provides. When calculating the allowed profit, KREMZX works off KEGOC’s asset base (the value of assets used for the provision of services adjusted to the optimization ratio to arrive at the assets actually employed in provision of services multiplied by the rate of return). Since 2013, KEGOC’s tariffs are set five years ahead (currently 2016–20) and are known as maximum cap (predefined) and base tariffs. According to KREMZX, the five-year tariffs provide better certainty in terms of costs and investment planning for KEGOC, the methodology does not incentivize KEGOC to optimize costs or beat KREMZX’s expectations. Although KEGOC’s long-term strategy envisages improvement of system average interruption duration index (SAIDI) and system average interruption frequency index (SAIFI) indicators, and losses reduction, these parameters are not linked to KEGOC’s revenue. The cost-plus methodology does not have inbuilt incentives that would link KEGOC’s earnings and tariff to company performance.

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Although electric power grids and particularly distri-
energy sources
• Heat energy sources reliability, safety, and efficiency standards
• Heat energy sources and system development principles (in provinces, towns and settlements)
• Heating season readiness procedures
• Connection to the heat-energy network
• Change of ownership and responsibility for the heat energy assets, etc.

Although in 2015 the government declared its intention to “create a new system of legal and economic relations between producers and suppliers of heat energy by 2030,” the changes are needed much sooner to support the capacity market rollout, segment rejuvenation, and the transition to more efficient investment. It has become an issue for the heat energy network companies and heat energy producers when it comes to the large heat energy consumers. A number of large consumers own, operate and consume heat energy from their own heat energy sources while remain connected to the centralized heat energy network for backup. This means that their centralized heat energy consumption is minimal while the heat energy network companies and heat energy sources incur significant expenses related to heat energy losses and keeping heat energy equipment ready to meet demand. The tariff for the heat energy network companies responsible for the transition and distribution of heat energy is governed by the law on natural monopolies and relevant methodology on heat energy tariffs setting. Similar to electricity transmission and distribution, the heat energy network tariff is set in accordance with the cost-plus methodology (economically reasonable costs and allowed profit) and calculated as a ratio of costs and profit to the annual volume of heat energy to be delivered to the consumers. Similarly, to electricity network tariffs, the heat energy network tariffs are not performance based, is not split into capacity and service charges, and lacks incentives that would stimulate cost cutting, better quality of service and more efficient investment.

8.5.9.1. Heat energy producers, consumers, and network companies price formation

The TETs’ tariff for the combined production of power and heat energy is set according to a cost allocation methodology. In the KazEnergy National Energy Report 2014-2015, it was recommended that the issue of heat energy costs distortion by thermal power plants through allocating variable costs between heat and power, and legalizing the “cross-subsidization” of heat energy by electric power. Since January 2017, the government is easing state price regulation of the heat energy sector. Heat energy tariffs will continue to be differentiated by consumer groups (population, budget funds, and other), with further breakdown of the population into those who have or do not have heat energy meters and those who live in buildings where the installation of heat energy meters is technically impossible. Since 2012 heat energy tariffs are 20% lower for those consumers who have a heat energy meter installed. However, the heat energy tariffs for consumers (population) are calculated based on the size of the premises occupied rather than actual heat consumption, so any individual improvement in efficiency by a resident might not result in a reduction of the heat energy bill (although it could help heat energy network companies reduce commercial losses). The heat energy tariff for legal entities however does not account for the cost of maintaining connected capacity. It has become an issue for the heat energy network companies and heat energy producers when it comes to the large heat energy consumers. A number of large consumers own, operate and consume heat energy from their own heat energy sources while remain connected to the centralized heat energy network for backup. This means that their centralized heat energy consumption is minimal while the heat energy network companies and heat energy sources incur significant expenses related to heat energy losses and keeping heat energy equipment ready to meet demand.

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8.5.10. Conclusions and recommendations

8.5.10.1. Policy approach: make security of supply, value to consumers, and decarbonization applicable to all power market mechanisms

8.5.10.1.1. Integrating power sector trilemma into new power sector development plan to 2035, with a view to 2050

Kazakhstan faces a familiar global trilemma in its electric power sector: security of supply, value to consumers (versus cheaper power), and environmental sustainability. Although Kazakhstan’s power sector regulation is extensive with a plethora of sound initiatives covering most of these aspects, they tend to operate in isolation from the current policy and not coordinated with the market mechanisms. An integrated approach should be applied to overall power sector planning, market mechanisms, tariff regulation, and use of technology (inclusive of demand and grid). As part of this change, Kazakhstan should accelerate a heat energy market reform and introduce performance-based tariff methodologies for electricity, heat energy, and transmission and distribution. Considering all of the above, a new concept for power sector development to 2035 with a view to 2050 should be developed.

8.5.10.1.2. Incorporate recognizable structures and mechanisms with proven track record viable in post- Soviet space

The development of consistent and transparent regulation and recognizable power market mechanisms are likely to impact positively on the investment viability of Kazakhstan’s power market. With this in mind, Kazakhstan should continue to pursue its goal in rolling out the capacity, balancing, and improving the system services markets. However, it will take time to adapt these concepts to Kazakhstan’s content. This means the cost of capital will likely remain high (due to the uncertainty around their efficiency in Kazakhstan and overall inconsistency of initiatives within the overall policy). Russia, which has a lot in common with Kazakhstan when it comes to the power sector and social policies, has already successfully adapted foreign power market mechanisms and introduced new heat energy market regulations, as well as performance-based regulation for the grid and sales.

We recommend building on Russia’s experience of various historic, structural, and technological changes (formation of price zones, energy systems and energy companies within a single energy system; single-mode economy, transitional and degradation- alphas, reforms, and mixed ownerships) and apply the recognizable practices (inclusive of those recognized by international community) to Kazakhstan’s reality (technological platform, transparency and clarity of price formation at the wholesale market, system services market, heat energy [while retaining areas of directive regulation], and grid and sales tariff formation). At that we by no means advocate direct copying of Russia’s experience.

8.5.10.2. Wholesale electricity and capacity market recommendations

While Kazakhstan will prioritize certain aspects within power market mechanisms and methodologies, driven by its own policies and commitments, the adoption of Russian approaches (where appropriate) would likely save time, and cost, the additional benefit of ensuring easier integration into the Eurasian Economic Union space. We recommend that Kazakhstan harmonizes with Russia, and draws on more of the latter’s power market experience, particularly when it comes to the following aspects:

• Wholesale power price formation and transparency
• Power market access
• Merit order
• Inefficient capacity treatment
• Data and information accessibility

8.5.10.2.1. Goal to lift administrative price caps and remove incentives for accurate power price signals for both dispatch and investment and should be carefully removed.

The wholesale power price should encourage cost-effective decarbonization, and provide certainty for low-carbon investment

8.5.10.2.2. Renewable generation: shift from an out-of-the-market support mechanism for renewable generation towards market-driven carbon price signals

As the penetration of renewable energy sources in Kazakhstan grows, it is anticipated that renewables will have a significant effect on wholesale electricity prices. We recommend that Kazakhstan considers moving away from direct RES support schemes towards market-driven signals (RES would naturally benefit from the market price under marginal price formation). A shift from feed-in-tariffs (FIT) to feed-in-premiums (FIP) would enable to integrate RES better into power market (as operators receive a premium to the revenue from the power sale at the market). A shift to FIP also means that RES take on the risk of negative wholesale prices if they generate part of their revenue from the sale of power at the market) and may help to deter renewable asset owner from over supplying the market during certain times. In the future, we would recommend shifting fully
from an administrative tariff setting to descending clock auctions to achieve the most competitive price offers. The RES payment scheme through conventional generators in Kazakhstan distorts the price power and provides over-recharging from the true cost of power production, and as a result transparent competition between the power plants. With this regard, we would recommend shifting to RES payment directly provided via energy supply companies. At that, to support energy intensive export oriented industry, we recommend taking on board the international experience of lessening or exempting such consumers from RES-related obligations. The first option would be more acceptable in Kazakhstan given the potential burden on other consumers. We would recommend assessing the effectiveness of RES in other countries, if the power price would be limited on the point of view of reaching the targets, but from its impact on the consumer power price while maintaining the secure operation of the energy system.

Such approach to RES would open electricity and capacity markets to all technologies (including RES) both the supply and demand sides (demand response resources and storage).

8.5.10.2.3. Centralized sale of wholesale electric power

For the purpose of load merit and price transparency, we recommend that Kazakhstan consider mandatory sale of electric power on the wholesale market for power plants with installed capacity over 35 MW that are connected to the central grid. Industrial consumers that own power plants could be exempt from the mandatory sale of electric power on the wholesale market, subject to meeting all of the following requirements:

Group 1

• Industrial consumers whose average monthly power consumption constitutes more than 75% of the average monthly output of a power plant that they own, and to which they are connected via own grid

• Not more than 40% of electric power needs could be supplied by the wholesale market

• The difference between the average calendar month's power production by its own plant a year before did not exceed its own demand by more than 35 MW.

Group 2

• Oil and (associated) gas or (and) its products (the sub-products of industrial process) are used as a main fuel for the electric production

• Industrial consumers whose average monthly power consumption constitutes more than 75% of the average monthly output of a power plant that they own, and to which they are connected via own grid

• Such power plants represent a technologically unified process with main industrial production and without such power plants the industrial production term long is either not feasible or problematic

• The difference between the average calendar month's power production by its own plant a year before did not exceed its own demand by more than 35 MW.

System plants, thermal plants (with regards to the volume produced in the heating mode only) until new heat energy regulation is introduced), RES, and hydropower would have a loading priority followed by all other plants, including heating plants' priority in volume not related to heat energy production. The volume attributed to the free bilateral agreements is accounted for but is not "price setting." All wholesale market participants can act as both buyers and sellers of electric power to fulfill their obligations under the purchase agreements the most cost-efficient way.

8.5.10.2.4. Wholesale power prices should be marginal and location

We recommend the day-ahead auction is run on pay-as-clear basis, meaning all successful market participants would be paid the same price per unit of MWh in their respective power zone. Priority is given to the lowest producers' offers and highest consumers' bids, with the exception of the price accepting bids by heat energy. The highest bid that satisfies the demand (which is likely to be the TETs' volume not attributed to heat mode operation, would set the price for the power zone).

We do not recommend introducing an emissions rice floor (a minimum price for carbon emissions produced in electricity generation) to inflate the price of fossil fuel generation. It would have the effect of distorting the wholesale price while increasing consumer prices. Instead the carbon focus should be applied to the capacity market or emissions trading schemes outside the power market.

The new structure would imply a greater responsibility for the system operator and the commercial operators, involving both advanced commercial and technical decision-making.

The real-time production and consumption is balanced at a balancing market. The balancing price determines whether the buyers and/or sellers' fluctuations are driven by their own or external (system operator) initiative. Price formation for fluctuations at their own initiative penalizes inaccurate planning and remunerates precise fulfillment of system operator's orders.

We recommend introducing regulated agreements to match the consumption by residential consumers for the price-cap transition period. They cannot exceed a set percentage of power producers' power sales on the wholesale market, and will be phased out gradually.

8.5.10.2.5. Renewable energy to contribute to the system services market

We recommend that RES bear the costs of intermittent generation (based on their reliable output, and accounting for meteorological data). In this way RES would not only contribute to system stability but also would be encouraged to invest into storage solutions to limit their exposure. This approach would also minimize the passing of system costs on to consumers via their power bills.

8.5.10.2.6. Reviewing capacity market design to incorporate the power sector trilemma

We recommend Kazakhstan policymakers not only reevaluate the capacity market objective and design before it is launched (in its current form), but also state its purpose to address the power market trilemma. Since the capacity market is likely to be a critical element for the economic and commercial environment in which power producers and consumers will operate for decades to come, it is essential it is designed correctly and launched at a time when it is required. The "Hot power market reforms" failed to remove the threat of security of supply.27

Kazakhstan's capacity market should allow all forms of capacity to participate on an equal footing, not just fossil fuels, but renewable and demand-side technologies. At that, we recommend capacity at selection (remuneration) should be subject to meeting the emissions standard as a technical requirement, to realize a more flexible, cleaner, and secure generation for the future.

The emissions performance standard is likely to exclude a certain generation from accessing the capacity mechanism (auction). Such power producers might choose to (i) forgo the capacity earnings and rely only on electricity sales, or (ii) initiate re-

capital expenditure, and as buyers and sellers of electric power to fulfill their obligations under the purchase agreements the most cost-efficient way.

27 The choice of a capacity market design should be based on the modeling of (i) profitability of the assets (the impact of returns from the power prices, the power sales, auxiliary services, and capacity market as a single interactive process), and (ii) the impact of different designs on the power prices, power plants revenues, capacity retirement, and cross-border flows (Russia and Central Asia).
i.e., spends less money than the allowed revenue, yet is still able to distribute and operate within regulations and standards, then the company retains the benefit for a price control period, thereby incentivizing the company, and vice versa.18 We argue moving towards a “totos” concept (based on the full economic consequences of decision making without differentiating whether expenditure was classified as operational or capex) that would allow for a reduction of regulatory constraints on capex (where investment decisions often favor construction of new assets rather than use alternatives involving opex. This approach would reward companies according to the skills with which they serve the market, and not simply a return on investments that may, or may not, be necessary. This means that the allowed revenue is based on the regulator’s forecast of how much the capex needs should be driven by future business needs and not a depreciation formula as is currently practiced (with depreciation being the source of investment for transmission distribution companies).

We recommend establishing a direct link between allowed revenues and service quality to create additional efficiency drivers when it comes to the number and duration of interruptions and guaranteed performance standards. And a further link between the allowed revenues and investment efficiency and innovation (new technologies and operating practices) to keep investment spending under control and assure continued improvement of the grid. Extended price control periods (from four to eight years) allow companies to plan investments with some (but not complete) certainty as to future revenues: a critical advantage over cost-plus regulation given the capital-intensive nature of the electricity distribution sector, and its long investment cycles. We recommend reassessing the network tariff structure and shifting to a two-tier network tariff that would enable to recovery of (i) the costs of network operators are only at risk for factors within their control, and such aspects as taxes, inflation, and debt service costs are passed on to power consumers and (ii) the power system and contributing to regulation adaptation to support innovation and competition in the future. Promoting innovation, flexibility, and smart/distributed-side solutions. New technologies could open up a number of innovative solutions to existing system issues. It is important that such solutions are effective and the decision is impartial.

8.5.10.4.1. Changes in system operator’s functions

As the system, technology, power market, and the way power is produced and consumed in Kazakhstan evolve, so will the way the system is managed. The rapid change in global power markets, owing to the rise of new technologies, changes to environmental regulation (leading to growth in renewable penetration) and in particular in light of Kazakhstan’s transition to a greener economy.

8.5.10.4.2. Creating an independent KREMiZK

We propose that KREMiZK be subject to rigid price regulation (leading to growth in renewable penetration) and decision making (inclusive of long-term planning). Therefore, accounting for international practices in enhancing the system operator’s effectiveness we recommend considering placing financial incentives on it with regards to the following activities:

- Demand forecasting
- Wind generation forecasting
- Balancing requirements
- Transmission/balancing charges
- Requirements for ancillary services
- Incentives and non-financial incentives for the following activities:
  - Developing UES Kazakhstan long-term development plan accounting for various technologies responsible for system reliability as they become available, updated regularly.
  - Public regulation on commercial and physical operations of UES Kazakhstan

8.5.10.5. Addressing data disclosure and transparency

Although data disclosure and open consultation on the sector’s future development investments with participants are common practice in developed markets, sharing power market and UES operational data in Kazakhstan is not viewed one of the Ministry’s key priorities, and in many cases, would be considered a criminal offense. Except for the Ministry of Energy and KEGOC, detailed truepower market and analytical data are not publicly available. We suggest better, more regular and fuller data and information disclosure in public sources such as the Statistical Committee and system operator should be acknowledged in the Power Sector Law. The statistical data should be supported by quarterly and annual public reporting on commercial and physical operations of the power system by the system operator (KREMiZK, and SOVREDKA on electric power market operations, and KREMiZK on aspects of the heat energy market operation.

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9. GREENHOUSE GAS EMISSIONS, ENERGY EFFICIENCY, AND GREEN ECONOMY GOALS

9.1 KEY POINTS
9.2 GREENHOUSE GAS EMISSIONS, CARBON INTENSITY, AND CLIMATE CHANGE UPDATE
9.3 PATHWAYS TO PARIS: STRATEGIES FOR REALIZING KAZAKHSTAN'S 2030 GHG EMISSIONS REDUCTION GOALS
9.4 RECOMMENDATIONS ON DEVELOPMENT GOALS AND REGULATORY SYSTEM
9. GREENHOUSE GAS EMISSIONS, ENERGY EFFICIENCY, AND GREEN ECONOMY GOALS

9.1. KEY POINTS

- In terms of GDP carbon intensity (1.44 kg of CO₂ emitted per [2010 US dollars] of GDP), Kazakhstan is one of the most carbon-intensive economies in the world. However, this is not unexpected given the heavy natural resource orientation of its economy.
- Kazakhstan’s intended nationally determined contribution (INDC), submitted in compliance with the Paris climate agreement concluded in late 2015, includes an unconditional target of reducing greenhouse gas (GHG) emissions economy-wide by 15% below 1990 levels by 2030, and a conditional target of 25% below 1990 levels by 2030. To fulfill its unconditional INDC, Kazakhstan needs to reduce its GHG emissions by 53.4 MMt to 302.8 MMt of CO₂ equivalent by 2030.
- In 2013, Kazakhstan was the first country in Asia to introduce a greenhouse gas (CO₂ only) emissions regulation system, modeled after the European GHG emissions regulation and trading system. The carbon trading market operated for two years (2014–15), but was suspended with restrictions on GHG emissions put on hold until 2018 when a newly revised system is set to go into effect. However, due to continued ambiguity of regulation and seemingly unresolved questions surrounding the new rules of the trading system under a very tight implementation schedule, re-launch of emissions trading is not likely to produce the desired effect without changes in the principles of demand and supply formation in the carbon trading market.
- Given that as much as four-fifths of total GHG emissions come from the electric power sector, mainly from coal-fired plants, over the near term policymakers should focus on measures to curtail emissions based on the existing mix of generating capacity. In order to incentve energy efficiency improvements and cleaner generation, Kazakhstan needs to take into account its own and the EU experience when its internal carbon trading market resumes in 2018.
- Because of improving energy efficiency, considerable advances have been made by Kazakhstan between 2000 and 2015 in reducing GHG emissions on a per capita basis and as a unit of GDP, despite appreciable economic growth. IHS Markit projections of Kazakhstan’s GHG emissions from the energy sector, based on continued energy efficiency improvements and a gradual shift toward natural gas, renewables, and (over the longer term) nuclear power capacity in the electric power sector, show a dramatic reduction in emissions per unit of GDP, down to roughly half the present level by 2040.
- Kazakhstan can attain about half (an almost 8% reduction) of its unconditional Paris-agreement GHG emissions target by following a “business-as-usual” approach—i.e., pursuing policies already in place or planned for implementation. We present an alternative scenario whereby Kazakhstan can not only attain its full 15% emissions reduction under the Paris agreement but even get halfway to its conditional target of 25% through a much greater improvement in aggregate energy efficiency, a more pronounced reduction in coal consumption, and a more rapid build-out of wind and solar.

9.2. GREENHOUSE GAS EMISSIONS, CARBON INTENSITY, AND CLIMATE CHANGE—UPDATE

This section examines environmental impacts resulting from the extraction, processing, and consumption of energy resources that are directly related to the issue of greenhouse gas emissions. It does not focus in any detail on other environmental impacts from energy production and use, such as oil sludge contamination, radioactive contamination associated with oil production as well as uranium mining and processing, ash and slag waste management at coal-fired power plants, and non-GHG air pollution and water pollution at sites of extraction and processing of mineral resources. For a discussion of these topics, please see The National Energy Report 2015, Chapter 13, section 13.2.

9.2.1. Global climate change

The basis for the global effort to control greenhouse gas (GHG) emissions is the 1990 report of the Intergovernmental Panel on Climate Change (IPCC), which confirmed the threat of global climate change due to human activity. For the purposes of the report, global warming is defined as an increase of the average air (atmospheric) temperature of up to 3°C by 2100 (as compared to the 1990 level) and the consequences thereof. According to IPCC experts, the main factor affecting average annual air temperature rise is the increasing concentration of greenhouse gases (mainly carbon dioxide) in the atmosphere as a result of extensive human use of fossil energy resources.

The last 50 years have seen unprecedented (in 200,000 years) growth of carbon dioxide concentrations in the atmosphere. In 2016 the CO₂ concentration in the Earth’s atmosphere exceeded 400 parts per million (ppm), or 0.0392%.

The greenhouse effect, which consists of the trapping of a part of the Earth’s thermal radiation, is a consequence of the differential permeability of some atmospheric gases to short- and long-wave radiation and is responsible for the formation of a sufficiently warm climate on our planet. The main source of the greenhouse effect in the Earth’s atmosphere is water vapor. If there were no greenhouse gases in the Earth’s atmosphere, the average surface temperature would be -15°C. However, the greenhouse effect causes the average surface temperature to increase by 30°C, of which 20.6°C, or about 70% is attributed to the presence of water vapor in the air and 7.2°C (or 24%) is due to the presence of carbon dioxide. Therefore, greenhouse gases are very important for the planet’s climate formation.

The Earth’s climate has been constantly changing throughout human history: periods of cold weather have given way to warmer periods, and vice versa. Research data show that the average atmospheric temperature 10,000 years ago was 2–2.5°C higher than the current value (the Atlantic Climatic Optimum) and in the 8th–12th centuries was 1°C higher than the current value (Medieval Climatic Optimum).

The current physical long-term climate forecast models cannot take into account all the variety of direct and inverse effects related to an increase in greenhouse gas concentrations, and therefore the accuracy of long-term climate forecasts remains quite low. However, at the moment, the theory of carbon dioxide concentration’s influence on climate change is accepted as the base theory at the global level (the climate consensus) and environmental and energy policies of most countries are aimed at limiting greenhouse gas emissions.
9.2.2. Greenhouse gas emissions in Kazakhstan

According to Zhasyl Damu, Kazakhstan’s total GHG emissions plummeted during the 1990s (from 356.2 MMt in 1990 to 161.9 MMt in 2000) (see Figure 9.1). The fairlying emissions during this period reflected primarily the contraction of Kazakhstan’s economy. GHG emissions subsequently rebounded alongside economic growth in the 2000s, reaching about 289.7 MMt in 2010 and peaking in 2014 at 319.8 MMt, but declined in 2015 to 310.2 MMt. Not surprisingly, the energy sector constitutes the largest share of GHG emissions, with a 79% share in 2015, down from a peak of 88% in 2010. Agriculture represents the second largest source of GHG emissions, generating 29.1 MMt or 9% of emissions in 2015, while mining produced 17.6 MMt, or 6% of total emissions. The energy sector is the largest emitter of carbon dioxide, while agriculture primarily emits methane and nitrous oxide (see Figure 9.1).

Emissions of carbon dioxide (CO₂), the most abundant greenhouse gas after water vapor, are used in the calculation of carbon intensity, a widely utilized international measure of the “greenness” of a country’s economy. In terms of the most recent data for GDP carbon intensity from the European Commission’s Emissions Database for Global Atmospheric Research (EDGAR), in 2015, Kazakhstan along with three other Central Asian Republics (Kyrgyzstan, Uzbekistan, and Kyrgyzstan), ranked among the 10 most carbon intensive economies in the world (see text box: “Carbon Intensity of Economy Measures CO₂ Emissions per Dollar of GDP”), emitting 1.44 kg of CO₂ per 2010 US dollar of GDP (see Figure 9.2). As with energy intensity, individual countries’ CO₂ emissions are strongly influenced by the structure of their economies. Coal accounts for roughly 55% of Kazakhstan’s primary energy consumption, and the absolute level of its consumption is projected to hold fairly steady out to about 2025. This share is high relative to the world average (29% for 2015 in terms of MMtoe), but again is a reflection of Kazakhstan’s natural resources-based economy in which large quantities of energy are expended per unit of GDP. This has important implications for the country’s CO₂ emissions, as compared to coal (ignite), complete combustion of the same volume (in energy equivalent terms) of natural gas releases 1.8 times less carbon dioxide, and of fuel oil (mazut) 1.4 times less carbon dioxide (2006 IPCC Guidelines).

Because coal-fired generation accounts for roughly two-thirds of Kazakhstan’s installed capacity, over the next 20 years it will be difficult to significantly change the structure of energy production and consumption. Despite the increasing role of natural gas in electricity generation, at the very least coal will account for over half (~58%) of electric power generation out to 2040. At the same time, when adding new generating capacity in Kazakhstan, a policy of increasing the sector’s environmental friendliness will be followed, accord- ing priority to energy-efficient coal-fired generation (including to boilers with ultrasupercritical steam parameters), natural gas, and (to a certain extent) renewables. However, radically altering Kazakhstan’s fuel balance in order to substantially change its carbon emissions trajectory can only do so much, as the rate at which power infrastructure is replaced is rather slow, and, among other things, the low cost of the mined coal makes it the fuel of choice for power generation. Longer term, construction of a nuclear power plant (1200 MW) will also contribute to reduction of greenhouse gas emissions. Still, it would seem prudent over the near term to focus on other measures that could be used effectively to curtail emissions based on the existing fuel balance. These are outlined in the next major section of this chapter (see section 9.3 below), which describes a number of pathways that Kazakhstan could follow toward achieving emissions reductions consistent with its commitments under the Paris climate agreement reached in 2015.

9.2.3. Climate change policy: UNFCCC 2015 Paris agreement update

The United Nations Framework Convention on Climate Change (UNFCCC), adopted in 1992, created an international framework for action on climate change, and in 1997 the Kyoto Protocol established a legally binding framework for (signatory) developed countries to reduce their GHG emissions by meeting specific reduction targets, with the ultimate goal of holding the mean global temperature increase to no more than 2°C above the pre-industrial level. Despite the participation of 83 signatory countries, progress toward a coordinated international effort to reduce emissions subsequently slowed, as not the leading CO₂-emitting country at that time (United States) nor presently (China) ratified the Protocol. However, on 12 November 2014 the United States and China signed an agreement to jointly reduce their emissions by strengthening adherence to environmen-
The conditional target is contingent upon Kazakhstan receiving additional international investments and green climate funds, technology transfer of low-carbon technologies, and otherwise some flexibility due to its status as an economy in transition.

Signatories to the agreement are not allowed to begin the process of withdrawal within the first three years following the agreement’s entry into force. Any official withdrawal possibility being one year after this date (and coincidentally one day after the 2020 US presidential election). A new administration, should it be so inclined, could apply for re-admission to the agreement in late January 2021, and could be re-admitted following a 30-day waiting period.

The Trump administration specifically announced it would eliminate further US funding for the Paris agreement’s Green Climate Fund, to which the previous administration of President Barack Obama had pledged $3 billion ($1 billion of which has been disbursed), and would withdrawal, as part of its internal restructuring and climate change policy review. The US Energy Department also closed, as part of an internal reorganization in June 2017, the Office of International Climate and Technology, which provides technical advice to other nations seeking to reduce GHG emissions. The new budget proposed by the Trump administration also eliminates the US Department of State’s Global Climate Change Initiative as well as State Department contributions to world development banks that finance green projects.

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Kazakhstan’s high energy intensity and current energy mix (the highest dependence on coal of any of the former Soviet republics) afford both a challenge to GHG reduction and an opportunity for considerable future improvement. Given that the energy sector contributes the bulk of the total GHG emissions, while agriculture, the second largest contributor is responsible for only about 10%, the focus on this report will be on the energy sector and GHG emissions from economic activity using energy. IHS Markit estimates of energy-related GHG emissions by fuel source for selected years for the period 1990–2040 are shown in Table 9.1. Between 1990 and the present tracks rather closely that of Kazakhstan’s economic output during that period, registering a steady decline during the recessionary 1990s, before climbing sharply as the economic recovery gathered steam after 2000 (see Figures 9.1 and 9.2), and then tapering off after 2012. It is noteworthy that coal accounted for 66% of total GHG emissions in the economy’s energy use in 2016 (159 MMT of a total of 240 MMT).
Table 9.1. Estimated greenhouse gas (GHG) emissions for Kazakhstan for energy-related economic activity, 1990–2040 (million metric tons)

<table>
<thead>
<tr>
<th>Year</th>
<th>Emission coefficient, metric tons per thousand TEE consumed</th>
<th>Total</th>
<th>Coal</th>
<th>Oil/petroleum products</th>
<th>Natural gas</th>
<th>Primary electricity</th>
<th>Other fuels</th>
</tr>
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<tbody>
<tr>
<td>1990</td>
<td>3.81</td>
<td>188.7</td>
<td>195.4</td>
<td>104.3</td>
<td>136.7</td>
<td>161.0</td>
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<tr>
<td>1995</td>
<td>2.93</td>
<td>59.6</td>
<td>33.3</td>
<td>20.5</td>
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<td>2000</td>
<td>2.12</td>
<td>25.1</td>
<td>21.7</td>
<td>18.3</td>
<td>39.1</td>
<td>27.3</td>
<td></td>
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<tr>
<td>2005</td>
<td>--</td>
<td>0.0</td>
<td>0.0</td>
<td>0.0</td>
<td>0.0</td>
<td>0.0</td>
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<tr>
<td>2010</td>
<td>6.00</td>
<td>5.5</td>
<td>6.0</td>
<td>3.2</td>
<td>2.9</td>
<td>2.1</td>
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GHG emissions/thousand $ GDP (2005 dollars)

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<tbody>
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<td>2015</td>
<td>237.7</td>
<td>295.6</td>
<td>295.9</td>
<td>296.3</td>
<td>297.2</td>
<td>297.4</td>
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<td>297.8</td>
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<td>300.6</td>
<td>300.8</td>
<td>301.0</td>
<td>301.2</td>
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</tr>
<tr>
<td>2020</td>
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<td>190.5</td>
<td>190.9</td>
<td>191.3</td>
<td>191.7</td>
<td>192.0</td>
<td>192.3</td>
<td>192.6</td>
<td>192.9</td>
<td>193.2</td>
<td>193.5</td>
<td>193.8</td>
<td>194.1</td>
<td>194.4</td>
<td>194.7</td>
<td>195.0</td>
<td>195.3</td>
<td>195.6</td>
<td>195.9</td>
<td>196.2</td>
<td>196.5</td>
<td>196.8</td>
<td>197.1</td>
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<tr>
<td>2025</td>
<td>34.3</td>
<td>47.1</td>
<td>49.0</td>
<td>50.7</td>
<td>52.0</td>
<td>53.4</td>
<td>54.8</td>
<td>56.2</td>
<td>57.6</td>
<td>59.0</td>
<td>60.4</td>
<td>61.8</td>
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<td>67.4</td>
<td>68.8</td>
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<td>71.6</td>
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<td>74.4</td>
<td>75.8</td>
<td>77.2</td>
<td>78.6</td>
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<tr>
<td>2030</td>
<td>39.3</td>
<td>41.3</td>
<td>43.1</td>
<td>45.8</td>
<td>47.4</td>
<td>49.0</td>
<td>50.4</td>
<td>51.8</td>
<td>53.4</td>
<td>54.9</td>
<td>56.4</td>
<td>57.9</td>
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<tr>
<td>2035</td>
<td>1.0</td>
<td>1.5</td>
<td>1.6</td>
<td>1.7</td>
<td>1.8</td>
<td>1.9</td>
<td>2.0</td>
<td>2.1</td>
<td>2.2</td>
<td>2.3</td>
<td>2.4</td>
<td>2.5</td>
<td>2.6</td>
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<td>2.9</td>
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<td>3.5</td>
<td>3.6</td>
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</tr>
<tr>
<td>2040</td>
<td>1.1</td>
<td>1.0</td>
<td>0.9</td>
<td>0.8</td>
<td>0.7</td>
<td>0.6</td>
<td>0.5</td>
<td>0.4</td>
<td>0.3</td>
<td>0.2</td>
<td>0.1</td>
<td>0.0</td>
<td>0.0</td>
<td>0.0</td>
<td>0.0</td>
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<td>0.0</td>
<td>0.0</td>
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</tbody>
</table>

Note: *Estimated greenhouse gas emissions for Kazakhstan (business as usual) (See Table 9.1.)*

However, the link between emissions and economic growth is weakening, and this trend will continue in the future. Although Kazakhstan’s GDP is projected to increase at moderate rates over the remainder of the forecast period (with an average annual GDP growth rate of 2.4% between 2015 and 2040), GHG emissions associated with energy consumption increase more gradually over this period, averaging only 0.2% per year, reaching about 263 MMT by 2040. If the ratio of GHG emissions from energy consumption to total GDP decreases (to about 15% in 2010), then total GHG emissions for Kazakhstan would increase to about 297 MMT by 2020, to about 307 MMT in 2030, and to about 320 MMT by 2040.

An important reason for the decelerating growth in emissions relative to GDP growth is that the energy sources used to satisfy incremental energy demand in the future will become cleaner. Natural gas—whose GHG emissions coefficient (metric tons of GHG emitted per thousand tons of oil equivalent consumed) is only about 55% that of coal, 72% of oil, and 35% that of such “other sources” as peat and wood—will accommodate a significant amount of new energy demand in the economy going forward, while supplanting the “other sources.” As can be seen in Table 9.1, the growth in natural gas’s contribution to Kazakhstan’s overall GHG emissions increased for more rapidly (2.4% annual average growth rate between 2015 and 2040) than any of the other sources. Although at first glance, this “achievement” may seem dubious, it is accompanied by a dramatic reduction in GHG emissions (by about half) per unit of the country’s economic output (lowermost row in Table 9.1).
The following major section of this report outlines measures Kazakhstan might take, in addition to “business as usual,” to meet its INDC under the Paris agreement. These “pathways to Paris” involve (a) the adoption of low-carbon, energy efficiency technologies for stationary sources of emissions (power plants and buildings) as well as (b) in transportation; and (c) the strengthening of the policy environment for emissions reductions—both through the creation of incentives and via systems for imposing costs on GHG emissions (carbon tax, emissions trading system) (see Figure 9.5).

9.3. PATHWAYS TO PARIS: STRATEGIES FOR REALIZING KAZAKHSTAN’S 2030 GHG EMISSIONS REDUCTION GOALS

In a very real sense, the goals of environmental protection and energy efficiency are highly compatible. The less energy that must be consumed to sustain a given level of economic activity, the lower the quantity of energy resources that must be extracted and consumed, and the lower the environmental impact. Kazakhstan has made enormous strides in the overall efficiency of energy consumption per unit of GDP (see Figure 9.6). Despite its relatively high overall energy intensity (linked in no small measure to the natural resource orientation of its economy, its high-latitude location, and large land area), Kazakhstan’s aggregate energy intensity declined spectacularly, by 3.6% on average annually, during 2000–15. This was facilitated, first and foremost, by rapid economic growth, accompanying broad investments, and general modernization (as broad economic improvements often are the most important energy efficiency measures). In addition to these general efficiency improvements, energy intensity also fell as a result of key initiatives undertaken during this period: establishment of a National Energy Register (NER) of major industrial enterprises/facilities and public buildings (facilities with energy consumption exceeding 1,500 tons of fuel equivalent per year); the performance of energy audits at these facilities; the formulation of energy-efficiency measures based on these audits; the compilation of an additional Energy Efficiency Map; a pilot project and launched in earnest in 2014—was suspended in February 2016 to allow more time for the system administrator and regulators to develop a new system for emissions reporting and to further improve the market for the trading of greenhouse gas emissions quotas. A new system incorporating improved reporting procedures is scheduled to re-launch in 2018 (described below).

For investments in energy efficiency via service contracts from licensed providers of efficiency services. 11 DSM Market estimates energy efficiency based on all GHGs from the energy sector only, while Figure 9.2 shows “carbon intensity” based on only CO2 emissions from fossil fuel use and cement production. 12 It is important to note that in some industries, modernization rather than retreating or piecemeal technological fixes is essential to increasing efficiency. In ferrous and nonferrous metallurgy, for example, more than 90% of energy consumption is directly related to process technologies. The main potential for energy saving thus lies in a full upgrade or replacement of the process equipment, which is actually equivalent to construction of a new plant. Similarly, in the mining sector, energy efficiency improvements can be achieved mainly through core equipment replacement and introduction of systems for optimizing fuel consumption during ore extraction, handling, and processing. 13 The attraction of investments in energy savings through energy service contracts corresponds to the Step 59 of the comprehensive “100 Concrete Steps” modernization plan unveiled by President Nazarbayev shortly after his re-election in 2015. The Energy Efficiency Map was created to aid the implementation of this step. It indicates sources of funding for specific projects for improving energy efficiency and details plans for their implementation.

9.2.5. Conclusions, notable changes since 2015

As a signatory to the Paris climate agreement in 2015, Kazakhstan has renewed its commitment to reduction of its GHG emissions—by 15% of 1990 levels (conditional) to as much as 25% (both voluntary commitments).

- Kazakhstan has undertaken an additional commitment (Kigali agreement) to reduce its consumption of hydrofluorocarbons (not covered in the Paris agreement) by 5% (relative to 2011–2013 average levels) by 2020 and 35% by 2035. Kazakhstan also has the opportunity to voluntarily participate in the second phase of an ICAO agreement covering GHG emissions from international passenger air travel.

- Kazakhstan’s GHG emissions regulation system (carbon trading market)—rolled out in 2013 as a pilot project and launched in earnest in 2014—was

- ☐ Policy stimulating private sector investment in energy efficiency and modernization
- ☐ Policies for households
- ☐ Business sector policies
- ☐ Solar, wind, and other renewables
- ☐ Carbon capture, use, and storage (CCUS)
- ☐ Nuclear
- ☐ Fuel switching and early retirement for thermal capacity
- ☐ Storage

- ☐ Electrification
- ☐ Improved efficiency
- ☐ Natural gas and coal for heavy-duty segment
- ☐ Storage

Source: DSM Market © 2017 DSM Market

Table 9.2. Estimated greenhouse gas (GHG) emissions for Kazakhstan for energy-related economic activity, 1990–2040 (million metric tons) - alternative scenario

<table>
<thead>
<tr>
<th>Year</th>
<th>Total</th>
<th>Coal</th>
<th>Oil / petroleum products</th>
<th>Natural gas</th>
<th>Primary electricity</th>
<th>Other (fuel, wood, etc.)</th>
<th>GHG emissions/tonnes $ GDP (2015 dollars)</th>
</tr>
</thead>
<tbody>
<tr>
<td>1990</td>
<td>278.0</td>
<td>188.7</td>
<td>19.5</td>
<td>104.3</td>
<td>126.7</td>
<td>161.0</td>
<td>2.4</td>
</tr>
<tr>
<td>1995</td>
<td>208.5</td>
<td>149.5</td>
<td>20.5</td>
<td>32.2</td>
<td>48.2</td>
<td>27.3</td>
<td>2.9</td>
</tr>
<tr>
<td>2020</td>
<td>146.4</td>
<td>231.7</td>
<td>31.7</td>
<td>18.3</td>
<td>39.1</td>
<td>27.3</td>
<td>1.8</td>
</tr>
<tr>
<td>2025</td>
<td>211.7</td>
<td>4.0</td>
<td>6.0</td>
<td>2.8</td>
<td>2.1</td>
<td>1.7</td>
<td>1.6</td>
</tr>
<tr>
<td>2030</td>
<td>238.6</td>
<td>5.0</td>
<td>0.0</td>
<td>0.0</td>
<td>0.0</td>
<td>0.0</td>
<td>1.3</td>
</tr>
</tbody>
</table>

Note: Emission data for energy-related economic activity (data in parentheses), calculated by DSM Market.
However, the service contracts have thus far proven challenging to implement, both because of difficulties in determining an accurate monetary value for a given set of services, and because energy metering systems are not adequately equipped to satisfy the requirements of energy contract providers (energy audits before and after the implementation of energy efficiency services are an essential part of the service process).

In February 2015, the signing of the first energy service contract (ESC) was announced as a way to replace the JSC «Kapost» lighting system was announced with a more efficient, non-fossil fuel energy sources (hydro, nuclear, wind, solar) will account for 18% of total electricity generation in Kazakhstan. However, this contract was signed between enterprises (with partial state participation) directly without carrying out a tender. Experience to date demonstrates that the main challenge to attractive investment is the complicated service procurement procedures, which are regulated by legislation for subsoil users, state companies (including in Samruk-Kazyna holding), state enterprises, and natural monopolies.

9.3.1.2. Carbon capture and storage
Although global operational carbon capture and storage (CCS) capacity is projected to increase to 58.7 MMt by 2020, the challenges (high development costs, unsupportive national policies, technological uncertainty) have not yet been sufficiently counterbalanced by progress in other areas (industrial waste-gas recycling at the plant level, expansion of a market for CO2 in enhanced oil recovery via re-injection) to signal a major improvement in prospects for the technology. Only about 15 large-scale projects for carbon capture and storage are in operation worldwide in early 2017, and 2016 was a year of setbacks for the technology, both in terms of project viability and in policy support. Low oil, gas, and coal prices limited the economic rationale and funding available for energy companies to employ the technology (e.g., to recover CO2 for injection into underground strata during enhanced oil recovery), and as a result only one large-scale project worldwide entered operation in 2016, two were cancelled, two more put on hold, and nine had start dates postponed for a year or more. The total project count (in operation, under construction, under development [FID], and planned) is shrinking rather than growing, from over 70 in 2012 to under 40 in late 2016.

Advocates of the technology (such as the Global CCS Institute) argue, however, that CCS is essential to efforts to combat climate change. More specifically, they argue that given the current structure of primary energy consumption, coal use in the global economy cannot be curtailed rapidly enough to achieve the GHG emissions reductions targets of the Paris climate agreement without further development of CCS and its widespread adoption in industry. As such they are lobbying for CCS to be accorded “policy parity” among the measures governments should pursue (e.g., energy efficiency improvements, renewable energy development) to achieve their Intended Nationally Determined Contributions under the Paris accord. Proponents argue that, given the scale and size of incentives and subsidies afforded renewable energy, CCS capacity could be built out rather quickly.

As reported in The National Energy Report 2015, the introduction of carbon dioxide capture and geological storage technologies does not seem appropriate for coal-fired power plants in Kazakhstan at the current stage of technological development. Despite the fact that modern technologies enable the capture of 85–95% of carbon dioxide, their use at coal-fired power plants is currently unfeasible from both ecological and economic points of view due to: (a) an increased fuel consumption by 14–40%; (b) increased overall pollutant emissions (due to increased fuel consumption); (c) a rise in electricity generating costs by 30–90% and (d) growth in plant construction costs by 30–90%.

9.3.1.3. Energy and heat efficiency in buildings: developments in the European Union

As noted in the National Energy Report 2015, a major opportunity for improving overall energy efficiency (and reducing GHG emissions) in Kazakhstan’s economy can be found in housing and public buildings. Average residential energy consumption (270 kWh/m2) in Kazakhstan exceeds that in Europe (100–120 kWh/m2) as well as in Russia (210 kWh/m2). The reason, apart from climate, is the need for upgrading the housing stock. Roughly 70% of the buildings in Kazakhstan were constructed between 1950 and 1980 and do not meet modern requirements for thermal insulation, which results in losses of as much as 30% of delivered heat. Another promising area in the housing and utilities sector that affords considerable potential for energy savings is lighting, which accounts for roughly 39% of total electricity consumption in the residential sector.

The Law on Energy Saving and Emission Efficiency (2012) is an important step forward in efforts to improve energy efficiency in buildings. For new residential construction, it specifies that materials must be used, and automated heating systems and utility metering devices installed. For existing residential structures, the Law requires that such materials, heating systems, and devices be installed during capital repair or reconstruction. However, due to the shortage of funds for repair and reconstruc tion of buildings and structures, such measures to date have been implemented on a very limited scale.

The need for improved energy efficiency in the residential sector and public buildings is not unique to Kazakhstan, but is a common problem worldwide, as this has been one of the “last frontiers” to be addressed in the campaign to increase energy efficiency. Nowhere in the world has the push been stronger than in Europe, which has taken the lead in the effort to improve energy and heat efficiency in buildings. For this reason, a focus on recent EU policy in this area may prove helpful as Kazakh policymakers consider meeting their energy efficiency and emissions goals. In the EU, buildings are responsible for 40% of energy consumption and 36% of CO₂ emissions. While occupants of new buildings generally consume fewer than three to five liters of heating oil equivalent per square meter per year, those in older buildings use about 25 liters on average, with some buildings using as many as 60 liters (currently, about 35% of the EU’s buildings are over 50 years old). By improving the energy efficiency of buildings, EU officials believe they can reduce total EU energy consumption by 5–6% and lower CO₂ emissions by about 5%.

9 For a more detailed discussion of investment trends in renewable energy, see Chapter 2.2.


14 For a more detailed discussion of investment trends in renewable energy, see Chapter 2.2.
Respectibility for improvements in energy efficiency in the European Union’s building sector is divided between the European Commission and the member states. Several EU directives set the overall framework and define certain minimum standards, but significant flexibility in terms of implementation and compliance remains with the member states. For example, each member state defines its own building codes, which should nonetheless comply with the overall EU framework.

Four main EU directives, evolved from earlier legislation, have an impact on European energy demand in the residential sector and public buildings. These include:

Energy Efficiency Directive (EED). The EED, adopted in 2012 and enacted into national law in June 2014, sets a common framework for all member states to follow the European Union to progress toward its 2020 energy efficiency target (equivalent to a 20% savings versus business-as-usual). It requires member states to achieve specified levels of energy savings during 2014–20 through energy audits, metering and billing, energy efficiency services, and other measures. The single most important element requires member states to achieve a 1.5% savings annually through an Energy Efficiency Obligation Scheme (or equivalent schemes).

More specifically, the Energy Efficiency Obligation Scheme requires energy companies in the EU countries to achieve yearly energy savings (power volume reductions) of 1.5% in annual sales to final consumers. In order to reach this target, companies need to carry out measures that assist final consumers in improving building energy efficiency. These may include improving the heating systems in consumers’ homes, installing double-pane windows, or better insulation roofs to reduce energy consumption. EU country governments may also implement alternative policy measures that reduce final energy consumption.

Ecodesign Directive. The Ecodesign Directive defines minimum energy efficiency standards for appliances sold in the European Union. It is the directive responsible for the phase-out of incandescent light bulbs across Europe as well as for the tightening of standards regulating standby losses. The original 2005 directive covered 19 categories of appliances, each of which sold more than 200,000 units per year and therefore had a significant environmental impact. The scope of the directive was widened in November 2009 to cover energy-related products as well as energy-using products. This is a significant expansion, as it allows European-wide minimum performance standards to be set for products such as windows and building insulation.

After much debate and significant delay, Ecodesign and labeling regulations for space heaters, heat pumps, and water heaters were adopted in September 2013. In terms of the latter, the new standards increase the efficiency of new natural gas water heating units by 20–30% over the current average. Some major residential gas markets—e.g., the Netherlands and the United Kingdom—had already implemented rules that enforced the purchase of condensing boilers (water heaters fueled by gas or oil) but in others, such as Germany, the share of condensing boilers was still very low. Since 2015, European legislation calls for all new boilers to be condensing.

Energy Performance of Buildings Directive (EPBD). The 2010 EPBD sets minimum standards for the heating requirements of all new buildings. From the end of 2020, all new buildings in the European Union should be nearly zero-energy buildings (NZEB), with public buildings required to meet the standard two years earlier. The general concept of a zero-energy building is one with zero net energy consumption, meaning that the total amount of energy used by the building on an annual basis is roughly equal to the amount of renewable energy created on the site (e.g., from solar panels). When existing buildings undergo major renovation, the renovated portion is also required to meet the NZEB requirements.

Additional provisions under the EPBD include: (1) energy performance certificates to be included in all advertisements for the sale or rental of buildings; (2) the establishment of inspection schemes for heating and air conditioning systems or measures with equivalent effect; (3) minimum energy performance requirements for new buildings, for the major renovation of existing buildings, and for the replacement or retrofit of building elements (heating and cooling systems, roofs, walls, etc.); and (4) the compilation of lists of national financial measures to improve the energy efficiency of buildings.

Energy Labeling Directive. The Energy Labeling Directive complements the Ecodesign Directive (discussed above), which sets minimum efficiency standards. The original 1992 directive was restricted to household appliances, but in 2010 the scope was expanded to cover all energy-related products. The Energy Labeling Directive requires that appliances be labeled to show their power consumption in such a manner that it is possible to compare their efficiency with that of other makes and models; similarly, energy-related products that have a significant direct or indirect impact on consumption of energy or other essential resources and that afford adequate scope for increased efficiency should be labeled, when such labeling may stimulate end-users to purchase more efficient products. The intention is that consumers will prefer more energy efficient appliances over those with a higher consumption, resulting in less efficient products eventually being withdrawn or decommissioned.

Proposed New Legislative Package. In December 2016 the European Commission adopted the Clean Energy for All Europeans legislative package. This proposed a binding target for 2030 of a 30% energy savings at the EU level and included proposals for a revision of the EED and the EPBD to bring them up to date with the 2030 energy and climate goals, to check their effectiveness, to simplify and improve the legislation, and to facilitate implementation at the national level. The recast EPBD will strengthen the requirements for long-term strategies for the renovation of existing buildings to decarbonize the building stock by 2050. This latter provision is important, because although IHS Markit estimates that 40 million new homes will be built in Europe by 2040, there are more than 240 million existing homes, and many have quite poor energy performance (see Figure 9.7).

Figure 9.7. Energy demand by homes in Europe

The backed Heat Strategy suggests a refurbishment should aim to reduce energy consumption in existing homes to 60–80% of the IHS Markit estimates that 200 million homes are above this timeframe.

Source: IHS Markit ©2017 IHS Markit

Measures to improve collection of data on the energy performance of buildings are also included, as is a new Ecodesign Working Plan for 2016–19. The EU Council and Parliament currently are debating the proposals. Reaction from the Council thus far has been that the requirements for decarbonizing the building stock by 2050 are too demanding.

In aggregate, the measures described above represent what can be considered the most advanced set of policies globally that is oriented toward improving energy efficiency in buildings.

9.3.1.4. Recent energy efficiency initiatives and achievements in Kazakhstan

In the period from mid-2015 through mid-2017, the Republic of Kazakhstan initiated a number of energy savings programs in collaboration with international actors focused on stationary (non-transportation) sources of GHG emissions, which appear to have similar objectives to the EU initiatives outlined above. In April 2015 the International Energy Agency (IEA), Kazakhstan’s Ministry of Energy, and KazEnergy signed a memorandum of understanding aimed at strengthening mutual cooperation among the parties in the de-
The district heating sector is one of the priority areas for Kazakhstan. The loan will allow the Housing Services Development Fund to install heat meters in residential buildings in East Kazakhstan Oblast. The EBRD announced that program implementation had been delayed. Of the 19 originally designated projects, the designs for 6 had been approved but tenders for these projects were canceled by August 2016 due to a lack of bids. A re-tender is expected to be launched soon, and the designs of the remaining 13 projects will be updated and resubmitted for approval. A second stage envisages extension of the program to 25 additional facilities for which pre-arrangements are ongoing.

In a more regionally focused initiative, in late March 2016, the governor of East Kazakhstan Oblast, Danial Akhmetov, and the EBRD Country Director for Kazakhstan Janet Heckman signed a KZT 7.7 billion ($23.9 million) agreement to replace street lighting in Oskemen and Semey with more energy efficient fixtures. The new fixtures are expected to reduce regional lighting expenditures by 60%.

Arguably the most important of these initiatives, however, was launched in 2017. The EBRD announced a loan of KZT 170 billion ($527 million) to accelerate the installation of heat meters in residential buildings in Kazakhstan. The loan will allow the Housing Services Development Fund to install heat meters in individual residential buildings and later start a pilot phase for installation of wholesale electricity meters. The new meters will not only help save heat and electricity in Kazakhstan, but will also help district heating companies to optimize supply and reduce system losses. The district heating sector is one of the priority areas for EBRD-sponsored action.15 Currently only about 45% of households in Kazakhstan are equipped with heat meters, varying greatly from region to region. The EBRD-supported project seeks to achieve more than 80% coverage nationwide over the next two to three years.

Kazakhstan’s most important recent achievement in energy savings policy has been the reduction in the proportion of incandescent light bulbs from 74% to 18% of the total between 2012 and 2016. The change was also made possible because of the halving of the cost of energy-saving, LED bulbs. Beyond lighting, there are numerous energy-saving technologies that, when installed correctly and in the right sequence, can result in savings for households, such as cars and trucks, such savings are accounted for nearly four-fifths of total demand. Therefore ongoing changes in automobile powertrains and in forms of personal mobility are expected to dramatically improve fuel consumption and GHG emissions. In assessing developments in transportation, and road transportation more specifically, IHS Markit divides the global vehicle fleet into two broad categories: personal and commercial.

Personal vehicles or light-duty vehicles (LDVs) are the largest market for liquid hydrocarbon fuels with gasoline being the dominant fuel option. These vehicles are generally owned by individuals and have low utilization rates and relatively long service lives (typically between 11 years and 20 years). Commercial vehicles, also known as medium-duty vehicles (MDVs), and heavy-duty vehicles (HDVs) are typically owned by municipalities and businesses. In contrast to LDVs, these vehicles have high utilization rates with much shorter effective lives (three to five years). Diesel serves as the main fuel option for these vehicles, such as trucks and buses.

As a market, commercial vehicles account for 30% of on-road transportation fuel demand. The majority of on-road commercial vehicle fuel demand is associated with on-road freight transportation by long-haul tractor-trailers. Commercial vehicle fleet operators make decisions very differently from the personal vehicle market. While both care about costs, personal vehicle consumers often place more value on less-tangible factors such as aesthetics that include vehicle accessories, design, brand, and lifestyle. When a fleet operator is buying a vehicle, its main focus is the vehicle’s performance, reliability, and cost.

Natural gas metering in Kazakhstan also faces a range of difficulties, as a considerable number of metering devices lack built-in temperature correction capabilities. Therefore, it is necessary to account for temperature effects in the wet gas metering by applying standard temperature parameters (20°C, 760 mm Hg). Thus consumption figures are underestimated, especially in colder periods of the year when natural gas consumption peaks. In order to solve this problem in some regions (Mangystau, Astana, and Kostanay oblasts) the national operator KazTransGasAlmaik has proposed introducing special correction factors that would take into account the average monthly temperature; however, a court blocked the move in February 2017.

The use of natural gas in transport, however, is also without challenges. Fortunately, a low-20% reduction of power in internal combustion engines due to the lower calorific value of the gas-to-air mix (as compared to the gasoline-air mix) that reaches the engine. However, in injection engines, the losses of power are less significant.

15 See Kevin Birn, Tiffany Groode, and Hossein Safaie, Where Will Transportation Drive Global Oil (and Oil Sands) Demand?, IHS Markit Strategic Report, December 2016.
16 The use of natural gas in transport, however, is also without challenges. Fortunately, a low-20% reduction of power in internal combustion engines due to the lower calorific value of the gas-to-air mix (as compared to the gasoline-air mix) that reaches the engine. However, in injection engines, the losses of power are less significant.
17 For further details, see Section 5.3.2. of this report on natural gas in transportation.
Despite the expected increase in the size of the global LDV fleet by as much as 50% globally, the effect on refined products consumption and GHG emissions is not expected to be commensurate; a number of compounding factors are currently expected to act as a drag on refined product demand growth. These include the development of increased vehicle fuel efficiency, and the proliferation of alternative powertrains and fuels.

The amount people drive, measured as vehicle-miles traveled (VMT), is by far the most influential factor affecting automotive fuel demand, especially in the short term. For instance, during the Great Recession, global gasoline consumption growth receded from 1.3% in 2007 to 0.4% in 2008. The main reason for the slowing demand growth was that people simply drove less. People who were unemployed stopped driving to work. Households on a budget reduced driving for shopping, entertainment, and holidays. This shift in people's everyday behavior had a quick and pronounced impact on global oil demand, which was 2% lower in 2009 compared with 2007 (5% lower in North America). Conversely, increases in VMT can cause demand to respond quickly. For example, in response to lower US gasoline prices in 2015, demand increased 2.7%, even though economic growth remained sluggish. Compared with 2014, the average person in 2015 drove almost 4% more, leading to higher gasoline demand.

JHS Markit believes driving habits around the world are slowly changing. In developed countries—such as the United States, Japan, and Europe—a mature market is a place where everyone who wants a car—by and large—has one. Consequently vehicle use (and VMT) might not change dramatically in the long run. Conversely, the declining all-in costs resulting from alternative forms of mobility (such as autonomous vehicles and ride-hailing; see below) could lead to more vehicle miles traveled. For developing countries, the conventional wisdom held that increasing personal income would lead to a similar vehicle ownership and use pattern as unfolded in the developed countries. Driving automotive sales and refined product demand to new heights. However, this seems increasingly unlikely. One of the key differences is the aforementioned effect of urban congestion, poor air quality, and increasing cost of living.

Concerns over energy security, air quality, and climate change have led legislators to develop and expand fuel-economy standards to reduce fuel consumption and emissions. In fact, Kazakhstan has systems intended nationally defined contribution under the Paris climate agreement. In fact, Kazakhstan has systems to address the challenge of reducing carbon emissions from many thousands of individual point sources of greenhouse gases. As with the case of vehicle fuel economy standards discussed above, the relatively low levels of available fuels, or substandard fuel quality. What the two examples above demonstrate is that despite these standards and measures, vehicle fuel economy is often hindered by either the low octane levels of available fuels, or substandard fuel quality.
Other things, to variable levels of preparedness of vehicle producers/importers and refiners to undertake the necessary upgrades to meet them. The challenge, therefore, becomes that of coordinating upgrades in the vehicle fuel mix in the country with improvements in the technological specifications of Kazakhstan’s vehicle fleet. A positive development is the expected completion of a modernization program at Kazakhstan’s three refineries in the second half of 2018, enabling production of considerably larger volumes of higher octane gasoline and diesel fuel. Even in the very near term, therefore, the transition from lower to higher grades of gasoline for internal combustion engine (ICE) powertrains can support substantive GHG emissions reductions. Longer term, Kazakhstan’s ongoing efforts to support a transition to alternative fuels in transportation (e.g., natural gas) sets the stage for accelerated emissions reduction as vehicles with electric powertrains (either hybrid or fully electric vehicles) find their place in the market. Although Kazakhstan’s private vehicle fleet is currently small and growing, it has been experiencing noticeable changes in the past few years, with important implications for overall fuel consumption. In 2014 just under three quarters of privately owned vehicles were over 10 years old; in 2017 their share declined to around 60% (see Figure 9.10). Gasoline fueled vehicles dominate Kazakhstan’s light vehicle fleet, constituting 94% of the total only in 2017. However, the share of mixed-fuel vehicles (presumably mainly LPGs) has increased over the last five years from under 1% in 2012 to over 3% in 2017.

Another noticeable mobility trend in Kazakhstan is a growing share of kilometers traveled by bus passengers, which has grown by almost 11% per year on average during the past decade. This trend is bodes well for municipal governments that are seeking to upgrade their bus fleets and associated infrastructure to cleaner fuels. In terms of goods shipments, rail transport remains predominant, with a 46% share of all freight turnover. Kazakhstan Temir Zholy should continue the effort of replacing the older locomotive fleet with more efficient units produced through its joint venture with Alstom. Given the regional interconnectivity of railroads, Kazakhstan should use platforms such as the Eurasian Economic Union to promote improved regional standards for greater energy efficiency among railroad operators and railcar and engine manufacturers.

Despite changes in vehicle miles traveled and fuel efficiency, as well as the gradual penetration of alternative powertrains used in on-road transportation (see the following section), energy forecasters such as the US Energy Information Administration (EIA) and the International Energy Agency (IEA) expect overall crude oil demand will continue to grow in base cases, albeit at a slowing pace out to 2040. However, impacts of these changes on demand for refined products used primarily as transportation fuels are more salient. Total global gasoline and diesel demand (by all vehicle types in transportation and in all other economic sectors) peaks under the IHS Markit base case (Rivalry) scenario in about 2025, and remains stagnant thereafter; demand for gasoline by LDVs in transportation peaks by 2030 and declines slowly thereafter (see Figure 9.11).Electricity begins to capture a tangible share of road fuel demand from this time forward.

These projections do not fully take into consideration another transportation-related development that could well have an effect on vehicle fuel demand and emissions—but which cannot at present be precisely predicted. More specifically, this “wild card” involves emerging new forms of mobility in which vehicles move consumers as a service, without travelers needing to own vehicles themselves. The price points of ride-hailing and vehicle sharing are expected to fall below that of private automobile ownership in many areas, especially congested urban areas with high traffic volumes and limited parking availability. During 2016, Uber, the first-mover in ride-hailing, had an estimated valuation of $68 billion—greater than the market capitalization of any of the “big three” US automotive companies (see Figure 9.12). By October of that same year, Uber and other ride-hailing companies such as Lyft, June, and Via, were driving 500,000 passengers per day in New York City alone, triple the number of daily passengers driven during the previous year. Didi, the primary ride-hailing company in China, averaged 20 million rides per day during the second half of 2016. With the average ride being around 5 miles, this equates to approximately 100 million miles per day.

In both the IEA and EIA outlooks, global oil demand increases about 20 MMb/d to exceed 120 MMb/d by 2040. Global crude demand growth beyond 2030 will be sustained by increasing demand for other refined products. Naphtha is projected to have one of the highest product growth rates between 2016–40, driven by petrochemicals demand. Jet-kero demand also grows substantially over the forecast period as air travel expands in developing markets.

**Figure 9.10. Breakdown of Kazakhstan’s light vehicle fleet, by year of production**

**Figure 9.11. Global LDV gasoline demand by region: Rivalry base case**

**Figure 9.12. Market capitalization of top automakers, ride hailing, car sharing, and ride-sharing companies, May 2017**
These new forms of mobility, although often still more expensive than public mass transit, could lower emissions on a per capita basis if they replaced private automobile ownership. This is particularly applicable in parts of the world where private automobile ownership is not yet universal; for example, ride-hailing is expected to become a dominant mode of vehicular mobility in the urban areas of emerging market countries. However, its global effects on GHG emissions from transportation are not immediately apparent; in New York City one unanticipated consequence attributed directly to ride-hailing has been a decline in public mass transit ridership, increasing both traffic congestion and emissions over the near term.27

Driverless or autonomous technology could also help spread the benefits of mobility as a service, but it is not needed as a major road transportationabler of change. Removing the private driver from the car would lower the cost of ride-hailing, thereby opening up access to new population segments. Technology companies such as Apple and Google, which hold some of the largest cash reserves globally, are focusing on development of autonomous capabilities, and these investments could lead to new and surprising innovations in autonomy and connectivity. Ultimately, on a global scale, it is not yet clear how these new forms of mobility will affect the number of personal miles traveled, the number of vehicles needed to cover those miles, or how many of those miles will be fueled by gasoline and diesel, as opposed to electricity—or even natural gas or hydrogen. What is clear is that the old equation involving cars, miles, and fuel consumption—relatively stable for about a century—could change, perhaps radically, in the coming decades.

9.3.2.2 Electric/hybrid transport

Helped along by government policy, alternative vehicles, especially electric vehicles, have started to gain traction in the market. Policies intended to bolster energy security, address climate change, and improve urban air quality are working to increase the adoption of electric vehicles around the world. The world has encouraged large investments in battery technology by both the public and private sectors. Investments are starting to pay off with the cost of vehicle-based lithium batteries declining almost 30% from 2012 to 2015. IHS Markit expects sales of both battery electric and hybrid vehicles to increase over time, although their aggregate fuel demand will take longer.

According to the IHS Markit Global Energy base case (Rivalry) Scenario, by 2040 all alternative powertrains (natural gas, hybrid vehicles of all types, battery electric vehicles, and hydrogen) could capture nearly half (46%) of all world sales of new LDVs, at which time they would account for almost 30% of the entire LDV fleet (see Figure 9.8 and Figure 9.13).28

Figure 9.13. Global LDV fleet by powertrain: Rivalry base case

According to IHS Markit, over the period from 2016 through 2025 world sales of hybrid and electric LDVs are expected to increase tenfold, to 21.2 million units, at which time they will account for just under 20% of all new vehicle sales. However, of these sales, the bulk (16.0 million units) will be electric hybrid vehicles. Sales of plug-in hybrids (PHEV) are projected to rise to 0.8 million units, and fully electric vehicles to about 0.8 million units as well. The latter will register the most rapid market gains, albeit from a very small current sales base. Longer term forecasts vary widely; IHS Markit’s base case scenario envisions fully electric vehicle sales rising to 4 million units by 2030 and to about 16 million units by 2040, at which time they are projected to account for 9% of all cars on the road.

Western Europe, the first region to adopt hybrid and electric vehicles on a large scale, will remain the dominant regional market (representing 44% of total world demand), but growth is expected to be faster in the Asia-Pacific region, with China leading the way, with 70% growth in sales in 2016.29 Similar trends are expected in the European Union and China, a major factor accelerating the adoption of hybrid and electric vehicles has been high levels of particulate pollution from diesel-powered vehicles. Although the adoption of diesel vehicles in Europe in recent decades has been supported officially for environmental reasons (higher mileage and lower carbon emissions relative to gasoline), planners did not foresee the serious increase in non-transport pollutants as a result of widespread diesel use in transportation (e.g., half of the UK’s private vehicle fleet is diesel powered).30

In Kazakhstan, battery electric vehicles currently remain an exotic product limited to the luxury segment of its car market, according to KazAutoProm and the Union of Kazakhstan’s Automotive Industry. In 2016, 35 electric cars were sold in Kazakhstan, 9% more than in 2015. Although purchases are not supported by subsidies as in many other countries, incentives include zero import duties for the period between September 2016 and August 2017, as well as registration and utilization fees that are only half those for traditional vehicles. In addition, electric cars are exempt from transport tax in Kazakhstan. KazAutoProm noted that the aforementioned incentives have not to date resulted in a noticeable increase in the demand for electric-powered cars. In addition to the high prices (ranging from $23,000 to over $100,000), demand is limited by the country’s harsh climate and lack of charging stations and service. Although most electric vehicles are imported, a small number are produced in Kazakhstan (in Q1 2017 KazAutoProm estimated that one-third of vehicles [all types] purchased in the country were produced domestically).31 Kazakhstan’s first fast-charging station for electric vehicles opened in Astana in July 2017. The station has 50 kW capacity, and can recharge 24 kW batteries from 30% to 80% in 15 minutes.

Hybrid vehicles also are now entering the country’s mass transit fleet. In May 2017 IVECO Bus completed the first delivery (for final assembly in Kostanay) in a contract for the supply of 210 Urbanway and Urbanway Hybrid buses for use in the city of Astana during Expo-2017 and thereafter. The Urbanway Hybrid future combine electric power with a Euro-VI internal combustion engine. This increases their fuel efficiency by up to 30% relative to conventional diesel buses, while remaining competitive with a Euro-VI internal combustion engine. This increases their fuel efficiency by up to 30% relative to conventional diesel buses, while remaining competitive with a Euro-VI internal combustion engine. In early 2017 Samruk-Kazyna announced that deposits of lithium, used in the production of lithium (Li) ion and Li-ion polymer batteries that power electric vehicles, had been discovered in East Kazakhstan, Almaty, and Kyzylorda oblasts. Although no comprehensive assessment of the country’s lithium resources had been completed at date, the Akhtemetko field in East Kazakhstan Oblast alone is estimated to hold 26,000 tons of lithium carbonate, sufficient to meet about 3% of global lithium production

Global demand for lithium is projected to rise from 188,000 tons in 2015 to 334,000 tons in 2025. Electric vehicle batteries are expected to account for about 38% of total Li demand in 2025 (up from 14% in 2015), as the commonality of lithium batteries is expected to make electric vehicles fully price competitive with those powered by internal combustion engines by the middle of the next decade. The demand for lithium in production of grid-connected energy storage systems will also increase, from 400 tons in 2015 to 3,800 tons in 2025, accounting for over 6% of total demand for the metal.

Another potential source of lithium in Kazakhstan and elsewhere is the production water from oil and gas operations. The Canadian company MGX Minerals is currently exploring the commercial feasibility of “petrolithium”—the extraction of lithium from production waters (at concentrations as low as 67 mg/liter) via a complex process of nanofiltration and filtration—at pilot projects in Alberta and Utah. The petrolithium technology requires some pre-treatment of production water (removal of oil, colloid, and metals) prior to the extraction of lithium; this affords some environmental benefits as well as additional costs. However, these costs are expected to be more than offset by the income stream generated from lithium production. If commercial feasibility is attained, MGX is expected to seek partnerships with oil majors and/or major service providers to install the technology near major water collection and reinjection sites. In the meantime, it might be prudent for Kazakh producers to monitor levels of lithium in production waters to identify whether potentially promising sites exist.


28 It is important to note that the share of hybrid/plug-in electric vehicles in alternative powertrains is quite substantial and without it the remaining alternative options (natural gas, battery electric vehicles, and hydrogen) account for only 7% of the total LDV fleet in 2040.


30 The first domestically produced electric vehicle was a KIA Soul EV crossover, produced by Asia Auto at the end of 2014. In July 2016, a group of JAC electric cars rolled off the assembly line of SaryarkaAutoprom in Kostanay.

31 See the official statement from the Union of Kazakhstan’s Automotive Industry.
What is the Carbon Footprint of Electric Vehicles Compared to Conventional Ones?

In an early effort to gain insight into the potential impact of the shift to largely or fully electric vehicles on GHG emissions, IHS Markit compared CO₂ emissions of plug-in hybrid electric vehicles (PHEVs) with a number of different powertrains and sources of energy used to generate the electricity used to charge the vehicle’s electric motor. The comparisons involving ICE powertrainers were further subdivided into (a) those in compliance with then-current (2008) vehicle fleet average fuel economy of 23.5 miles per gallon for passenger cars and light-duty trucks; or (b) the then-current Corporate Average Fuel Economy (CAFE) standard for new light-vehicle emissions (27.5 mpg); or (c) the 2020 new vehicle CAFE of 35 mpg. The exercise revealed that the emissions reductions yielded by PHEVs depended greatly on the fuel consumed to generate the electricity used to charge the vehicle’s battery. Electricity generated in a supercritical pulverized coal-fired power plant actually yielded no improvement in overall CO₂ emissions (~3.5 tons of CO₂ emitted per vehicle annually) compared to internal combustion engines with a fuel efficiency meeting the now-current 2016/2020 CAFE standards (3.4 tons). Emissions reductions only materialized when cleaner fuels were used in the power generation used to recharge the battery: natural gas (from combined cycle gas turbines at ~2 tons emitted per vehicle annually) or nuclear/ wind/solar (hydro at ~0.7 tons). Figure 9.14. The results of the IHS Markit study thus indicate that achieving a notable reduction in carbon emissions from electric vehicle use is possible through significant gasification of electricity generation and enhancements to the electricity grid.

9.3.2.3 Hydrogen and fuel cells in transport

Another group of technologies, some already in use and others in the R&D phase, utilizes hydrogen as an energy carrier/medium in the conversion of energy for use in fuel cells. Fuel cell–powered vehicles afford a potentially promising means of reducing vehicle emissions, as they are powered by a chemical reaction in the fuel cells rather than combustion; thus they do not emit GHGs or conventional combustion products into the atmosphere—water and heat are the only byproducts.

Among the hydrogen technologies currently in use, the most widespread at present is known as steam hydrocarbon reforming (or steam methane reforming). Natural gas is reacted with steam to form synthesis gas (consisting of H, CO, CO₂), from which pure hydrogen is extracted. A similar “reforming” technology reacts synthesis gas produced by coal combustion at a coal-fired power plant with steam to produce hydrogen as well as electricity, thereby lowering the carbon footprint at the plant. Finally, in a process known as renewable liquid reforming, a renewable liquid fuel (e.g., ethanol) is reacted with high-temperature steam to produce hydrogen.

Although these reforming technologies all are operational to one degree or another, they are viewed as “interim” rather than long-term solutions for a number of reasons. Hydrogen has a relatively low energy density, requiring twice the energy to produce an equivalent unit of work vis-à-vis many other power sources currently in use (coal, nuclear, and even solar PV), and there can be substantial energy losses during the production-delivery-application chain. In addition to energy losses, steam hydrocarbon reforming is not viewed as a long-term solution even in the fuel cell, only as a means to join hydrogen production to fuel cells as an emergency and “interim” measure. Other reforming technologies include hydrogen from water splitting; and photoelectrochemical water splitting. These technologies, while interesting from an environmental standpoint, still are experimental as researchers seek to elevate low solar-to-hydrogen energy conversion ratios to potentially commercially viable levels.

Another important dimension that must be considered in hydrogen energy technology involves developments in end-user demand, and most importantly the market for hydrogen-powered, fuel-cellled vehicles. The first commercially produced hydrogen fuel-cell vehicles began to be sold by Toyota and leased by Hyundai in 2015. Vehicles currently produced are expensive ($58,500 for the Toyota Mirai in California), as production has yet to advance to mass levels affording economies of scale. There is also only very limited hydrogen fueling infrastructure in place (e.g., 23 stations accessible to the public in the United States in 2016, 20 of them in California). By mid-February 2017 total cumulative sales worldwide amounted to 2,840 vehicles, concentrated in Japan, the US, Europe, and the United Arab Emirates.

In the end, fuel-cell vehicles at present are poorly equipped to compete with battery electric vehicles (BEVs). Because of inefficiencies involved in the initial transfer of energy to hydrogen, its storage, and its subsequent conversion to electricity in the fuel cell, only about 30–40% of the original energy is estimated to remain. At least limited transport demand is foreseen in the future, however, for use in applications where zero-emissions are a requirement (e.g., in enclosed spaces such as warehouses).

9.3.3.1 Review of program documents and legislation

The basic legal document governing emissions of greenhouse gases, as well as many other environmental issues, is the Ecology Code of the Republic of Kazakhstan (9 January 2007, with subsequent amendments and additions). Among its 47 chapters are three devoted to state regulation of GHG emissions (including allocation and trade in quotas) and establishing a system for monitoring these emissions.

Kazakhstan’s national target for GHG emissions reduction is contained in its INDC, submitted after its affirmation of the Paris agreement in late 2015 (an unconditional target of reducing GHG emissions economy-wide by 15% below 1990 levels by 2030). The INDC additionally states Kazakhstan’s Republic’s goal to support for inclusion of market-based mechanisms in the Paris agreement and notes the possibility of introducing a carbon-trading mechanism recognized by the UNFCCC and the INDC for GHG emissions reduction target. In support of its INDC submission, Kazakhstan will re-launch its emissions trading system for GHG emissions in 2018 after a...
A number of other programs and strategies are in place to help the country achieve its long-term vision, rather than providing a regulatory framework. For example, the National Energy Strategy 2020, which was approved in December 2013, specifies that the carbon price should be lower than $10 per ton by 2030. This is intended to make the country more competitive in the global market and to encourage investment in alternative energy sources.

The National Energy Strategy 2020 is designed to bring about a significant increase in the use of alternative energy sources, from 3% in 2020 to 30% by 2030. This will require a significant increase in investment in alternative energy technologies, such as solar, wind, and geothermal power. The strategy also aims to reduce the country’s emissions of greenhouse gases, with a target of reducing emissions by 14% by 2020 and 40% by 2030.

To achieve these goals, the government has implemented a variety of programs and strategies. For example, the National Plan for the allocation of greenhouse gas emissions quotas for 2014–15, allocations were made to enterprises based on their historical emissions. The plan also established a mechanism for allocating emissions allowances on Kazakhstan’s “Caspian” Sea, which is part of the country’s Plan for the allocation of greenhouse gas emissions for the period 2014–20.
The small size of the carbon market also presented a liquidity challenge. Only 1.27 MMt of CO₂ were traded in 2014 at an average price of KZT 301 (€1.12) in 2015 with 1.125 MMt at KZT 765 (€1.53) per ton. Only 15 trades were recorded in the first five months of 2015 (mostly driven by market participants rather than openly through an electronic trading system); prices of the allowances were volatile and not transparent, and saw highest levels for oil and gas producers, ranging between KZT 1000 and 1600 ($0.40–$8.91) and making it hard for participants to establish meaningful benchmarks. Finally, questions arose concerning the origins of the quotas traded on the market during a period (2014–15) when national coal output was declining, electricity generation fell at certain power stations, and overall output was relatively weak. This led some researchers to suspect that a portion of the quotas was sold by enterprises solely as a result of a reduction of their output (accompanied by falling emissions). Although such sales are clearly prohibited by Point 8, Article 94.2 of the Ecological Code, the mechanism for its enforcement appears to have been inadequate: enterprises registering allowances on the trading platform were not required to report the reason why allowances were granted (i.e., the actual causes for their emissions reductions). The actual extent of such activity became difficult to determine following a Ministry of Energy decree of 18 March 2015, which stated that quota allocations for enterprises could be “adjusted” in the following cases: (a) changes planned in the basic character and functioning of the enterprise; and (b) the introduction of new production programs that increase output. The lack of sufficiently precise criteria regarding interpretation of the first provision creates the possibility of its misapplication, which could allow some enterprises to rationalize production cuts as “changes in the character of production.” In the lead-up to the new platform, work on revising the quota allocation system, and on 30 December 2015 it issued decree no. 1138 “On Confirmation of a National Plan for the Allocation of Quotas for Emissions of Greenhouse Gases for 2016–2020,” intended to supplement previous legislation and to go into force almost immediately thereafter on 1 January 2016. However, the problem outlined above had not been adequately addressed.

In February 2016 Kazakhstan’s Deputy Energy Minister Asset Magauov announced that the emissions trading system would be suspended until 1 January 2018 “due to system imbalances.” The decision was intended to give all parties additional time to make refinements to the system in response to the aforementioned challenges and for the industrial enterprises to make adjustments, refinements, and preparations. Although enforcement efforts would be suspended, the country’s Ecological Code required the 140 enterprises (accounting for roughly 90% of total CO₂ emissions) covered by the ETS’s third phase to continue to report their emissions. Although the ETS was to date only CO₂ emissions that were regulated within the system, the participating enterprises also report emissions of methane, nitrous oxide, and perfluorocarbons, which have even less clarity concerning exactly which greenhouse gases are subject to regulation within the ETS. Wording in the two 2012 decrees establishing these benchmarks for, and limiting trade to, only CO₂. If additional gases are to be traded and regulated in the future, these should be specified clearly and uniformly defined in written law, and be well understood by all government agencies, sub-agencies, and enterprises that participate in carbon trading scheme.

As part of an effort to support the re-launch of a national emissions trading system, the Ministry of Energy jointly with the World Bank began preparations for the establishment of an electronic system for reporting GHG emissions. This is intended to allow emitters to report online, while third-party verifiers can independently audit the reported data, and JSC Zhasyl Damu is expected to be introduced by late December 2017, immediately before the system is to launch in January 2018.

The new electronic system for reporting GHG emissions will support the new emissions trading system, which will function through an electronic exchange, which facilitates trading of allowances among participants in the Kaz ETS. The exchange will function through the platform of the newly opened Astana stock exchange operated by the Astana International Financial Center (see above).

The exchange will make it possible for enterprises to purchase additional quota allocations at auction from the “units of internal trading” (or PSAs in Kazakhstan) or to purchase emissions below an established baseline or benchmark. Sales prices at the auctions are to be determined freely by the parties involved in the transactions, reflecting the supply and demand for quotas at the time the auctions are held. In the event of the absence of a market price quote on the day of a transaction, a price will be determined by a quote based on an independent international supplier of information on carbon offsets. An additional change to the ETS in 2018 is that enterprises are to be able to choose the mechanism of allocation of their allowances: either “baseline” method utilized previously or through a benchmarking procedure. The latter, based on a practice in the EU emissions trading system, determined a price for each period in order to ensure that the system acts as a benchmark when setting an enterprise’s free allocation. The benchmarks are product specific (e.g., for gas compression, there would be separate benchmarks for electric power plants, iron and steel mills, and petrochemical facilities). In a general sense, in the EU ETS, the expected price in 2012 of an average GHG emission performance of the top 10% “best-performing” installations producing a specific product is used as the benchmark, which in principle will receive all of the allowances they need; enterprises that do not would be required to purchase additional National Plan quotas for, and limiting trade to, only CO₂. If additional gases are to be traded and regulated in the future, these should be specified clearly and uniformly defined in written law, and be well understood by all government agencies, sub-agencies, and enterprises that participate in carbon trading scheme.

Other outstanding issues in the operation of the new trading system include no special terms or conditions for the production of new projects, early starting production or for the participation of upstream projects that are legally PSAs. Accounting for upstream projects is particularly important for the oil and gas companies, as their production is ramping up, and historical benchmarks for operations are largely unknown. A key consideration is that technical PSAs in Kazakhstan are only allowed to buy and sell the products they extract from the subsoil (such as oil, gas, and sulfur), but not carbon credits.

9.3.3.4. Experience gained in the operation of the EU emissions trading system

The tribulations of the European Union ETS, the first such system of its kind (launched in a trial phase in 2005 and in full operating mode since 2008) and upon which Kazakhstan’s current system is intended to partly emulate and learn from the lessons. The system has struggled for years under an enormous surplus of spare allowances that has depressed prices and, as a consequence, has offered paltry incentives for investment in carbon-reducing technologies. Early projections of future emissions in the EU system used to set emission caps proved to be inflated, allowing the market to accumulate large quantities of additional reserves, which depressed prices and reduced the attractiveness of investing in low-emission production. Similarly, the unanticipated effects of the Great Recession depressed overall economic activity in Europe to a greater extent than expected, which their emissions in 2009 where CO₂ prices fell to around €0.10 relative to 2008, cutting the price of additional allocations nearly by half (from €29.20 per ton in July 2008 to about €15 in mid-year 2009). The continued downward trajectory of prices since then (to below €4 per ton in autumn 2016) indicates that participants in the market are realizing that the surplus of allocations in the system will remain.

The experience with the EU ETS indicates that, despite some best efforts to replicate a “market environment,” emissions trading is an extremely complex process characterized by repeated ad hoc adjustments over one or two years at a time. The price currently set by the EU system is not adequate to spur investment in clean energy technologies, which requires for a strong supervisory body that can undertake measures to prevent an excess of surplus allowances in the system. Other outstanding issues are the price volatility (either by setting a floor to support prices or a ceiling to prevent them from rising excessively). Despite a floor and ceiling set for, in Europe there is believed to be a “politically acceptable” price range—estimated at €15–20 per ton of CO₂—above and below which additional regulatory measures to prevent an excess of surplus allowances in the system. The price currently set by the EU ETS is not high enough to incentivize investment but not so high as to force enterprises to curtail production. Unfortunately, the price set by trading in the EU ETS has not fallen within this range except for brief periods (only during 2006 and again for the first half of 2008).

As a result, member countries are taking or considering similar steps (both voluntary and mandatory) to reform the system. In 2012 the United Kingdom introduced the concept of a “carbon floor price” for its electricity generation sector. Initially conceived at roughly €30/ton of CO₂, it was to consist of a Carbon Price Support component, paid by the generating enterprises, if the EU ETS carbon price to reach the national floor. However, later (2014) the government announced that the Carbon Price Support component would be capped at a maximum of £18 (~€20) per ton/CO₂ through 2021 to limit the competitive disadvantage faced by UK-based generators in the electrical power sector (originally thought to be roughly €30 per ton of CO₂), to which the going ETS price would be added.44 Other outstanding issues in the operation of the new trading system include no special terms or conditions for the production of new projects, early starting production or for the participation of upstream projects that are legally PSAs. Accounting for upstream projects is particularly important for the oil and gas companies, as their production is ramping up, and historical benchmarks for operations are largely unknown. A key consideration is that technical PSAs in Kazakhstan are only allowed to buy and sell the products they extract from the subsoil (such as oil, gas, and sulfur), but not carbon credits.

44 Additional quotas also may be obtained—outside the exchange—from the State Register of Carbon Units, which is designed to accommodate the growth of production at existing enterprises. The National Plan for 2010–2020 assigned 746.5 MMt of free emissions allocations to the 140 participating enterprises and set aside an additional 21.9 MMt of reserve quotas.
of the emissions cap than previously specified. However, the proposals were contentious and were weakened at a subsequent meeting of the Commission in February 2017, they are now subject to consultations between the Committee, the Council of the EU, and the full European Parliament.

9.4. RECOMMENDATIONS ON DEVELOPMENT GOALS AND REGULATORY SYSTEM

9.4.1. New system of regulation of GHG emissions

While we commend Kazakhstan’s intention to re-launch a revamped emissions trading system as a sign of its commitment to the goals of the Paris climate agreement, some measure of caution is in order. This reflects not only the nature of the problems experienced in the EU ETS as well as concerns among system participants in Kazakhstan. The problem of differentiating between emissions reductions achieved due to compliance measures (e.g., increased energy efficiency, installation of emissions control technologies) and reduced production without compliance (prohibited) must be addressed more rigorously. In addition, some operators in the mining and extraction industry are not confident that the new rules will provide sufficient emission quotas for enterprises that have changing production profiles, potentially frustrating planned growth projects. They also point out that the system does not presently provide instruments to manage compliance that are available in emissions trading systems in OECD jurisdictions—namely, borrowing and banking, domestic offsets, or additional free allowances for trade-exposed sectors (exporters; see below).

Furthermore, enterprises involved in mineral extraction argue that the “level playing field” in such sectors as coal mining and oil and gas extraction, in which differences in geology and field conditions greatly affect emissions levels, are not correctly distinguished (e.g., some deposits are intrinsically more costly because of reduced fuel expenditures). And, in addition to the immediate buying and selling of emissions credits at auction, enterprises might be able to receive “loans” of quotas for payment at a later date, or create “savings accounts” of emissions credits which could be sold at a later date.

Finally, we recommend consideration of the merits of introducing additional compliance mechanisms existing in such systems elsewhere, but not yet implemented in the Kazakh system. First, providing for the “borrowing and banking” of emissions credits would allow participants to adopt a longer-term perspective toward financing emissions reductions, reducing their fiscal uncertainty on an annual basis. In other words, in addition to the immediate buying and selling of emissions credits at auction, enterprises might be able to receive “loans” of quotas for payment at a later date, or create “savings accounts” of emissions credits which could be sold at a later date.

Domestic offsets are a second compliance mechanism. These are credits for emissions reductions or for undertaking mitigation strategies that are not explicitly covered in the ETS (e.g., GHG emissions reductions by system participants at smaller plants not listed on an ETS register; reforestation and carbon sequestration initiatives). Such offsets are currently under consideration in Kazakhstan and would add a layer of flexibility for enterprises striving to achieve compliance. Offsets are a feature of a number of emissions trading systems worldwide (EU, Chinese regional pilot systems, US Regional greenhouse gas initiative, California/Quebec system, South Korea, Tokyo region) and typically have been allowed to cover between 3% and 10% of a company’s total emissions.

Third, there is the question of granting free additional allowances for enterprises in trade-exposed enterprises in Kazakhstan’s export sector. These enterprises otherwise may suffer economic losses due to increased costs for foreign enterprises in countries either lacking an ETS or carbon tax, or having one with a more lenient compliance regime.

From a longer-term perspective, much of the theory of environmental policy considers policy instruments (e.g., a carbon tax versus an emissions trading system) as alternatives, rather than complements. However, in practice combinations of instruments possibly could be employed, with new instruments supplementing—rather than replacing—the existing mechanisms of regulation. Some of the reasons reflect real-world constraints. The present in theory the multi-dimensional nature of many pollution problems may mean that the availability of multiple instruments and differing benefits and effective regulation. Perhaps “one size” (or system) indeed does not “fit all,” and it may also be less risky to proceed incrementally, adding new instruments within or outside the emissions trading system rather than altering its structure repeatedly.

Given the numerous legal and operational questions surrounding the carbon trading scheme, Kazakhstan should consider delaying implementation until all ambiguities are resolved. Given the numerous, complex questions surrounding the emissions trading scheme, carbon tax might be better suited for Kazakhstan, especially given its administrative ease of implementation.

9.4.2. Environmentally friendly transport

Because the transport sector is not included in Kazakhstan’s emissions trading system, considerable effort should be made to also reduce emissions in transportation. In addition to enforcing existing fuel economy standards and maintaining an emissions inspection regime for existing vehicles, Kazakhstan should accelerate the move toward higher grades of gasoline and diesel fuel, and enhance monitoring and control over fuel quality to ensure compliance. A recent study by ExxonMobil in the United States concluded that improving the fuel economy of conventional vehicles is the single most cost-effective means of carbon abatement in the US economy, a measure that actually has a negative net cost because of reduced fuel expenditures. And, although Kazakhstan’s vehicle fleet is not nearly as large as in the US, the low quality of petroleum fuels available for existing petrol stations in Kazakhstan is a powerful common denominator that impedes efforts to both improve fuel economy and reduce emissions.

Given the predominance of coal in the country’s primary energy consumption and the dominance of coal-fired capacity in the electric power sector (Chapters 6 and 8), improvements in the generation, transmission, and distribution of electricity will make a major contribution toward increasing the efficiency of overall energy use in the economy. Arguably, however, the new frontier for energy savings lies in improvements in energy efficiency in public buildings and in the residential sector. An important initiative in this area was launched in 2017, in the form of an ERDB-supported program to accelerate the installation of heat meters in residential buildings in Kazakhstan. The new meters will not only help save heat and electricity by allowing targeted heating companies to optimize supply and reduce system losses.

There is also a need to streamline administrative responsibilities. Many government bodies are
involved in oversight and regulation of energy efficiency with considerable overlap. These include: (1) the Institute of Electric Power Development and Energy Savings (under the Ministry of Investment and Development), a think tank that administers the energy efficiency audits of industrial enterprises and public buildings under the Law on Energy Efficiency; it also conducts research on ways to make energy service contracts in the residential sector easy to implement with clear guidelines, and enters into partnerships with international organizations to attract educational and financial resources to Kazakhstan to stimulate the development of energy-saving practices domestically; (2) the Kazakhstan Institute of Industrial Development, also under MID; (3) the Ministry of Energy, which undertakes its own energy savings and environmental initiatives; and (4) even Samruk Kazyna, which is implementing its own energy efficiency programs, particularly in the area of sustainable development.45

Each of these bodies tends to view energy savings from its own specific perspectives and goals. Thought should be given to whether some of these activities could be consolidated (perhaps within the Ministry of Energy), or at least whether an inter-governmental body might be created through which the various activities of the MID, Ministry of Energy, and Samruk Kazyna might be better coordinated.

This lack of coordination imposes an additional administrative burden on industrial enterprises in Kazakhstan. The typical large heavy industrial enterprise may simultaneously be subject to reporting and inspections relating to the ETS, to energy efficiency audits, as well as inspections from various government agencies relating to emissions, energy intensity, and energy efficiency.46 Because many of these agencies and contractors employ different metrics in measuring performance or compliance, there is a certain level of redundancy, leading to wasted efforts and resources devoted to reporting and compliance.

While such problems are by no means unique to Kazakhstan, we recommend identifying areas where duplication occurs and taking further steps to streamline industry’s efforts to achieve compliance. To the extent possible, government agencies should have a uniform methodology, or where methodological processes differ, there should be a clear understanding throughout agencies and enterprises of where such differences occur and why.

A cogent and uniform system for monitoring various indicators will help to improve quality of data, assist policymakers in policy formation, and help enterprises reduce the administrative burden of tracking emissions reductions and energy efficiency gains. Basically, there needs to be greater harmonization and alignment of conceptual principles and processes, methodologies, and bureaucratic responsibilities. One example of a possible simplification might involve the creation of a single platform by which enterprises could track both efficiency gains and emissions.

44 Compliance with SamrukKazyna’s program of sustainable development is increasingly influential in corporate decision-making, as it is now a factor in assessing overall corporate performance.

46 In 2016 the Committee for Industrial Development and Industrial Safety increased inspections of industrial enterprises to meet energy efficiency requirements, including compliance with “energy consumption standards.” In cases where enterprises were found to exceed “energy consumption standards,” the relevant legislation provides for fines calculated as a percentage of the volume of energy consumption exceeding the norm. But as described in the National Energy Report 2015, a single energy consumption standard for all industrial enterprises is not applicable due to the highly diverse operating conditions at industrial enterprises.
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