KAZAKHSTAN ASSOCIATION OF OIL, GAS AND ENERGY SECTOR ORGANIZATIONS «KAZENERGY»

THE NATIONAL ENERGY REPORT

KAZENERGY 2019

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KAZENERGY

Ladies and Gentlemen,

Kazakhstan is currently facing a challenging task of transitioning to a new economic model of sustainable development, in which the fuel and energy sector will require significant investments in modernization and transformation.

Today, the oil and gas sector continues to play an important role in Kazakhstan's economy. In 2019, the share of oil production and refining segment in the country's GDP is projected at 15%, and the share of oil and gas industry related sectors – at 21%. With improvement in the oil and gas markets globally, these indicators will continue to grow in the foreseeable future.

Against the backdrop of growing demand for energy resources and an emerging political and economic confrontation between the world powers, which are key partners of Kazakhstan, there is an increase in the degree of instability in the global oil and gas markets, as well as in competition for long-term supplies of hydrocarbons. Under these conditions, Kazakhstan is methodically developing not only its hydrocarbon industry, but its alternative energy as well, and the country remains a stable supplier of energy resources and a reliable international partner for global consumers.

At present, Kazakhstan is an attractive country for foreign investment in the oil and gas sector. The country's position in the overall business environment rankings is generally favorable and improving compared to other countries. Thus, I am confident that Kazakhstan will succeed in meeting new global challenges and threats.

The new edition of the National Energy Report is devoted to these challenges and new opportunities, presenting an impartial view of leading foreign experts on the prospects for development of Kazakhstan's energy sector and ways to improve pricing and tariff policies.

I believe that the competence and independence of the view presented in this Report will be useful in shaping the state energy policy.

I wish you success!

Sincerely,
Timur Kulibayev
Chairman
KAZENERGY Association

Dear Readers:

We greatly appreciate the opportunity for IHS Markit to be invited once again to work on the new 2019 edition of the National Energy Report for Kazakhstan. This report builds on the previous editions, but addresses new and emerging issues. Its format is changed and is more focused. This time the report provides analysis of key select questions facing the energy sector in Kazakhstan, such as attracting new investments, ensuring ample gas supply for the domestic market and exports, managing the upcoming integration within the Eurasian Economic Union (EAEU), meeting the Paris Accord commitments, and addressing the emerging issues relating to renewables integration and the nascent capacity market in the power sector.

While Kazakhstan's economy has experienced considerable development and some diversification in the almost three decades since independence, hydrocarbons and other energy resources remain central in the national economy and will for some time to come. Largely due to higher global oil prices, the share of the energy sector in national GDP edged back up to about 23% in 2018 (compared with 27% in 2010 and 19% in 2016). The development of the oil and gas industry in particular has served Kazakhstan very well, generating economic activity and 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. It has also strengthened Kazakhstan's relations with its neighbors and established the country as a major force in the global oil industry and a significant participant in world markets and global affairs.

But the world has changed, and the pace seems to be accelerating. Beginning in the early 2000s, global commodity markets were dominated by the "commodity supercycle" of strong demand and high prices, driven by explosive growth in the emerging market nations and especially China. Kazakhstan, as a major natural resource producer, greatly benefited from the supercycle. That period of rapidly growing demand for nearly all types of mineral resources and raw materials has now ended. As part of this shift, the oil market has pivoted from strong demand and tight supply to weaker demand and oversupply. This was accentuated by the historically unprecedented rapid growth of US shale oil, which has made the United States the world's largest oil producer, ahead of Saudi Arabia and Russia. International efforts to manage oil production have expanded and, on balance, been successful. 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 during 2016–18. Kazakhstan doubled its reduction target for the second round of OPEC+ cuts starting in January 2019, which will continue into 2020. Global oil supplies were also curbed by the re-imposition of sanctions on Iranian exports in mid-2018 and supply disruptions in Venezuela, and Libya. Still the resurgence of US supply as a result of the shale boom continues to challenge the OPEC+ initiatives to limit oil supply and keep the global market in balance, as does the weakness in the global economy and the effects of what has been called the new "trade war."

International oil and gas companies are cognizant that global supply growth could again place downward pressure on prices in the near future. They are responding by embracing technology in a major way, applying powerful technological innovations (big data, cloud computing, artificial intelligence) to cut costs and boost production. Companies will still compete for new opportunities, but they are being much more selective with new projects, increasing the competition among resource-holding countries for available investment. The large independents, which used to be a major source of investment in new global supplies, have drastically shifted their investment to the United States, and some of the majors have also rebalanced their investment portfolios back to the United States. As a result, we expect that host countries will continue to offer flexible fiscal terms and adjust local content requirements.

After the depressed conditions in 2014–16, a new cycle of investments in the upstream oil and gas industry has begun, and changes in the outlook and modes of operation of major industry players are becoming clear. While focusing on operational cost-efficiency, many oil and gas majors are moving in the direction of becoming more diversified energy companies (some, such as Equinor, have changed their names to reflect this). In addition to hydrocarbons, they are branching out into activities like renewable energy production; electric vehicle charging; carbon capture, use, and storage (CCUS); and electricity and natural gas distribution.

A major impetus for this is the challenge posed by increased pressures about climate change: shareholders are demanding that public companies establish and disclose greenhouse gas reduction targets for their products and operations—more specifically, to account for the impact of compliance with climate agreements on their balance sheets. These calls are expected to grow louder in coming years, as the initial optimism surrounding the 2015 Paris Climate Agreement is now being confronted with "inconvenient facts": both greenhouse gas emissions and world coal production increased in 2017 and 2018, after falling for the previous three years (2014–16).

Thus, the highly competitive environment for international energy investment that we described in the previous National Energy Report (NER 2017) is expected to continue into the foreseeable future—and become more competitive. This means that Kazakhstan should redouble its efforts to create an attractive environment for investment in the next generation of fields that will eventually augment the output of the current "mega" projects. Being "competitive" refers both to terms and to decision-making processes.

One of the key themes that emerges repeatedly in this report (NER 2019) is the tension between the government's efforts to maintain low electricity, natural gas, and refined products prices for consumers and the need to devise policy that can incentivize production, processing, and distribution of these resources, so that the revenues derived are sufficient to finance reinvestment in the sector. This is a delicate balance that must be addressed in many countries, and we seek to keep that in mind when presenting our recommendations. The pending formation of single EAEU markets in oil and oil products, natural gas, and electric power will add further complexity to decisions on pricing.

We hope that this current Report will contribute to an ongoing process of decision-making and policy formation in Kazakhstan that meets the challenges outlined in the Report and continue to advance the economic and social well-being of the country and its people.

Dr. Daniel Yergin
Vice Chairman IHS Markit

Appreciation

The National Energy Report 2019 was prepared for KAZENERGY by IHS Markit and Avantgarde Group, but incorporates the work of many experts, both within Kazakhstan and abroad. These specialists are affiliated with a broad array 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 highly important and gratefully acknowledged.

We especially thank the Avantgarde Group represented by its General Director, Ruslan Mukhamedov, as well as Oleg Arkhipkin, who were actively involved in preparation of the Report and provided the content of the chapters on electric power and on environment and climate protection. Much of Avantgarde's chapter on electric power was developed by Ekaterina de Vere Walker of SEEPX.

Numerous specialists within and outside Kazakhstan also reviewed individual chapters of the Report corresponding to their individual areas of expertise. We genuinely appreciate their suggestions and comments.

We especially thank Uzakbay Karabalin, Deputy Chairman of the KAZENERGY Association, Bolat Akchulakov, General Director of the KAZENERGY Association, Rustem Kabzhanov, Executive Director of the KAZENERGY Association, Talgat Karashev, Executive Director of the KAZENERGY Association, and Rustam Zhursunov, Deputy Chairman of the Board of the National Chamber of Entrepreneurs of Kazakhstan "Atameken." This Report would not have been possible without their active assistance, advice, 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 Malika Alzhanova for assistance in the translation of the chapters on electric power and environment.

In addition to the individuals and organizations mentioned above, we extend our special thanks to a large number of organizations (industrial enterprises, energy producers, power plants, etc.) and their employees who contributed to preparation of the Report, often participating through in-person discussions with the principal investigators:

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In closing, throughout the preparation of this report we have treasured our interaction and continued collaboration with many remarkable and talented colleagues in Kazakhstan, whom we respect and admire. We are particularly honored to present this report during the convocation of KAZENERGY Energy Week and the KAZENERGY Eurasian Energy Forum, hosted in Nur-Sultan and devoted to important issues of Kazakhstan's energy future.

In conclusion, it has once again 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, providing a solid foundation for the welfare of its people. On behalf of IHS Markit, the authors of this Report anticipate a bright and highly successful future for the people of Kazakhstan.

In Appreciation,

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1. Introduction

1. Introduction

Kazakhstan is a prominent, world-class 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 the production of uranium, and consistently ranks among the top 10 producing countries for coal and top 20 for oil. Since 2010, it has increased its crude oil output by over 13% and commercial gas output by over 50%, reinforcing its position as a global player in the hydrocarbons sector; furthermore, most of incremental oil production within the Commonwealth of Independent States (CIS) over the next decade, for example, is expected to come from Kazakhstan rather than Russia.

Despite the country's progress toward diversification, energy will continue to be critically important to Kazakhstan's economy. The oil and gas sector alone accounts for a fifth of the country's GDP (21.3% in 2018), about two-thirds of total export earnings (70% in 2018), and nearly half of state budget revenues (44% in 2018). The energy sector also has been the primary destination for foreign direct investment (FDI) within the country. Therefore, cogent, robust, and prudent regulations, coupled with appropriate implementation mechanisms, are as critical as ever for the future management of Kazakhstan's energy resource endowment and long-term sustainability.

Many spheres of the energy sector in Kazakhstan (crude oil, natural gas, refined products, electricity) are at a point in their development where they require well-informed and conceived policies and approaches, with an emphasis on incentives rather than penalties. The National Energy Report 2019 (NER 2019) clearly illustrates that the successful future development of Kazakhstan's energy sector largely rests in the hands of policymakers, as they wield the power to unleash the underlying potential of Kazakhstan's energy sector. It is no small task to coordinate various priorities and for decision-makers to think through the implications of different policies and initiatives. NER 2019 describes key challenges faced by each of the energy sectors in Kazakhstan that it covers and provides recommendations for the way forward, which we hope will be of value.

Although greater economic diversification naturally remains an important objective for most commodity-exporting states like Kazakhstan, the country's underlying comparative advantage in the oil and gas sphere still should be carefully built upon. For this reason, NER 2019 (as NER 2017 before it) advocates investments in exploration, production, and export capacity of hydrocarbon energy resources whenever such investments make economic sense in the current environment and given the foreseeable future outlook and investment conditions. In the upstream sector, this reasoning applies equally to major planned expansions in the country's existing "mega" projects, development of prospective new fields, and enhanced recovery operations at more mature fields.

Kazakhstan is also a founding member of the Eurasian Economic Union (EAEU) (and its organizational predecessors), and the organization's common energy markets initiatives, including the electricity market (established formally in 2019), as well as the common oil, oil products, and natural gas markets (slated for implementation in

2025). The creation of these common markets will unite economies of five member-countries (Armenia, Belarus, Kazakhstan, Kyrgyzstan, and Russia), with Kazakhstan and the Russian Federation being the two resource-rich heavyweights. Still, the relative size of the Russian economy and its energy sector will effectively set many of the conditions towards which EAEU policies will likely gravitate. Common energy markets envision harmonization of prices, tariffs, and downstream taxes, and uniform access to markets and infrastructure. Therefore, Kazakhstan's policymakers will need to make tough decisions to keep the country's energy sector competitive in these new markets.

1.1. The National Energy Report 2019

The National Energy Report 2019 focuses on key issues facing the energy sector in Kazakhstan. It builds on, and updates, research presented in two earlier national energy reports—NER 2015, which provided a comprehensive analysis (covering all sectors of Kazakhstan's energy industry) and NER 2017, which concentrated more selectively on four key dimensions in each of the sectors (update, outlook, infrastructure, and technologies). NER 2019 adopts a slightly different approach. Although it provides a wealth of statistical data in assessing major trends and developments since the publication of NER 2017, it differs from the previous reports in that: (a) the sectoral coverage is limited to oil/oil products, natural gas, electric power, and energy-sector impacts on the environment; and (b) the emphasis is on the major challenges confronting the energy industry both globally and within Kazakhstan, which have emerged with greater clarity since the previous reports. This approach was taken in part because the fundamentals of Kazakhstan's key energy sectors have not changed significantly since the publication of NER 2017; also, each of these sectors face a series of important structural, pricing, and regulatory questions driving its development.

As in the previous Reports, NER 2019 provides an updated assessment of the general outlook for each of the major energy sectors, evaluating the most recent energy-industry targets, forecasts, and plans contained in official state and Ministerial documents (e.g., Concepts, Strategies). In many cases, official outlooks are compared with proprietary IHS Markit forecasts and scenarios. When IHS Markit forecasts differ from state and industry projections—such as in the case of future natural gas demand from methane-based petrochemicals production— explanations of the divergence in perspectives are provided.

An important component of each sector-themed chapter is the discussion of existing and potential legislation surrounding energy activity. In NER 2019, various components of the draft Ecology Code are analyzed—from gas flaring fines, to taxes on emissions from stationary sources, and so-called Best Available Technology (BAT) standards—and its potential implications for energy producers and consumers if adopted in current form. The report also generates recommendations that could improve the country's investment attractiveness, energy security, and the functioning of its energy markets.

A key theme that emerges in the Report is the imperative for Kazakhstan to amend its regulatory framework so as to create a system that stimulates activity and incentivizes stakeholders throughout the value chain—from exploration and field development to production, to gas processing and crude oil refining, and to electric power production and distribution. Further, end-users must be financially incentivized to use energy products efficiently and in environmentally friendly ways. These challenges are intricately connected with pricing and fiscal policy. A general refrain from across the spectrum of stakeholders was how various government initiatives or actions were not adequately thought through or implemented so that they synchronized effectively with overall governmental social and economic goals.

1.2. Global Trends Point to Continuing Flux in Energy Systems

In addition to its more focused approach on a limited set of energy sectors and a more problem-oriented perspective, NER 2019 updates new directions in global energy trends and developments, reflecting the evolving international environment since the publication of NER 2017. Major developments, with important implications for Kazakhstan, include:

• **The oil price environment, although more favorable relative to the slump from mid-2014 to mid-2016, remains fragile; this reinforces the importance of cutting costs and creating competitive conditions to attract external investment.** The IHS Markit oil price outlook expects Brent prices to average only $66/bbl in Q3 2019 and $64/bbl in 2020, considerably below the $100-$120/bbl that prevailed between 2011 and early 2014. Nonetheless, major international oil and gas companies managed to generate positive cash flows in 2018 for the first time in five years by applying powerful technological innovations (e.g., big data, cloud computing, artificial intelligence) to dramatically cut costs and boost production of the lowest-cost barrels. Through 2040, IHS Markit expects the global oil price (real Dated Brent) to average only around $67/bbl. In this environment, investments in new development are likely to be less interesting than investments in known fields, changing the international competitive environment, with direct impacts on host countries such as Kazakhstan.

• **Concerns about climate change push oil and gas majors to shift operations.** In the wake of the Paris Climate Agreement of 2015, international oil and gas companies (IOCs) are under pressure from shareholders to establish greenhouse gas reduction targets for their products and operations and incorporate compliance with climate agreements into their balance sheets. In response, most companies are increasingly focusing on diversification, expanding their operations into such areas as renewable energy production; carbon capture, use, and storage; and electricity and natural gas distribution, among other ventures. Between 2019 and 2021, IHS Markit estimates that IOCs are likely to spend around $7 billion on average annually on carbon-reducing activities, amounting to 5% of total CAPEX for these companies during that time.

• **Global natural gas demand, led by LNG, is expected to grow, and so is investment in renewable energy.** Natural gas accounted for 40% of global energy demand growth in 2018. Within gas, LNG consumption globally, but especially in Asia, is slated to rise much more rapidly than gas consumption overall. Meanwhile, installed wind and solar photovoltaic [PV] capacity grew at spectacular rates over the past decade, on the order of 20% and 49% annually, respectively (albeit from a low starting point). Going forward investment in new renewable capacity will still expand, but not at such spectacular rates. IHS Markit projects that the aggregate commissioning of new renewable capacity between 2019 and 2025 (1,100 GW) will be roughly equivalent to the total existing in 2018.

• **Despite climate change concerns, greenhouse gas emissions rise (alongside global coal production).** Greenhouse gas emissions rose in 2017 and 2018, after falling for a brief three-year period (2014–16) immediately before and after conclusion of the 2015 Paris Climate Agreement. Not surprisingly, global coal production followed an identical trajectory, driven by an uptick of coal consumption in the Asia Pacific region, particularly China and India.

These two markets accounted for three quarters of total world coal demand in 2018 and will inevitably play a critical role in any long-term climate change solution.

1.3. Accomplishments and Challenges for Kazakhstan

These changes in the international energy environment have brought into sharper focus a number of challenges requiring effective policy responses in Kazakhstan since publication of NER 2017. However, a number of accomplishments should also be acknowledged to balance the perspective.

• **All three "mega" projects" now solidly on a growth path.** The successful ramp-up and debottlenecking at Kashagan, the launch of the major Future Growth Project at Tengiz, and an amicable, comprehensive settlement of long-standing issues at Karachaganak have propelled Kazakhstan's oil sector into a new position, setting the stage for further development, not only of these three projects, but others as well.

• **Recovery in global oil prices, largely engineered by the OPEC+ arrangement, demonstrates Kazakhstan's new position in global oil markets.** Higher oil prices are again driving robust economic growth in Kazakhstan, and are sufficient to spur a new round of upstream interest and activity. But to finance the next generation of new fields, particularly major planned projects, such as Kalamkas-more–Khazar co-development, companies will likely have to seek financing outside of Kazakhstan. The government of Kazakhstan, in turn, must ensure that it takes every step possible to provide the most attractive investment environment.

• **Refinery modernization program, completed in 2018, is a major accomplishment.** The completion of the $6 billion refinery modernization program at Kazakhstan's three major plants—Atyrau, Pavlodar, and Shymkent— allowed Kazakhstan to meet its goals of reducing import dependency on Russia, improving gasoline quality, and expanding domestic refining capacity. In 2018, total Kazakh refinery throughput burgeoned by 10.2% while gasoline output jumped by 17.2%. The improved product slate can accommodate domestic demand for light products, and perhaps allow for exports to neighboring markets.

• **However, continued over-regulation of Kazakhstan's downstream oil sector seriously impairs industry development.** Retail product prices remain heavily administered not withstanding official price liberalization, and periodic product import and export bans constitute another major market distortion. The national oil company, KazMunayGas (KMG), and other resource holders and give-and-take providers supply feedstock to the three refineries under a tolling system that ensures high margins for refiners, allowing them to pay down loans associated with refinery modernization.[1] But the current tolling system leaves upstream suppliers with effectively no incentive to divert crude to the domestic market, resulting in a netback for domestic crude deliveries that is well below export netback parity.

• **Formation of a single oil market in Eurasian Economic Union also presents harmonization challenges.** Artificially low prices for refined products

[1] Here and elsewhere in the text, tolling and processing terms are used interchangeably and refer to the arrangement where crude suppliers pay refiners a tolling fee to process the crude, and retain title to the resulting refined products for subsequent sale.

incentivize the redirection of Kazakh motor fuels to consumers in neighboring states. Within the single economic space, prices will likely move towards export parity, similar to what exists in Russia as well as in countries that import Russian oil and products (e.g., Belarus, Kyrgyzstan, and Armenia). Kazakhstan's refineries, currently insulated from market forces by the tolling system, will have to compete with those in Russia that operate based on market mechanisms. In light of these challenges, IHS Markit recommends allowing domestic crude prices to rise to the level of export netback parity by 2025, while gradually phasing out the current refinery tolling system (and instead making refiners merchant operators who buy crude and sell products). Kazakhstan should consider allowing domestic wholesale product prices to reach the average level among EAEU member states (essentially export parity netback), increasing excise taxes to harmonize with the other EAEU members, and minimizing product import-export restrictions.

• **Completion of Beyneu-Bozoy-Shymkent (BBS) natural gas pipeline in 2015 set the stage both for ramp-up of exports to China (2018) and gasification of previously un-served regions (in 2021).** Completion of the Beyneu-Bozoy-Shymkent (BBS) pipeline in 2015 connected the western gas-producing regions of the country to gas-consuming regions in southern Kazakhstan. As such it set the stage for increased domestic gas consumption both in southern Kazakhstan and in the central and northern parts of the country, as its Karaozek compressor station along its route will serve as the western terminus of the SaryArka pipeline (under construction), which will deliver piped gas to such major cities as Zhezkazgan, Karaganda, Nur-Sultan, Kokshetau, and Petropavlovsk. It also triggered a dramatic increase in Kazakhstan's pipeline exports to China, as BBS links to the Central Asia-China gas pipeline system (CAGP) at Shymkent. Original capacity of the BBS line was 10 Bcm/y, but capacity was expanded to 15 Bcm/y in late 2018 upon completion of two additional compressor stations. In 2018, Kazakh exports to China rose to 5.2 Bcm, from 0.6 Bcm in 2017, and an agreement between the two countries concluded in 2018 calls for exports to increase to as much as 10 Bcm annually over the period 2019–23.

• **However, a tight domestic gas balance presents difficult choice between export growth and increased domestic consumption.** Despite the increased opportunities to grow both exports and domestic consumption, Kazakhstan's gas supply remains constrained. Over the coming years, commercial production is expected to grow very little, while more robust growth is likely in domestic consumption and export opportunities continue to beckon. The constraint on commercial supplies will thus force Kazakhstan to make hard choices between achieving high levels of exports to China or making more gas available for domestic use. The underlying source of the problem is a combination of low prices for producers of associated gas offered by state-owned KazTransGas (KTG) and low end-user prices set by Kazakhstan's State Committee for Regulating Natural Monopolies and Competition Protection (KREMiZK). These low prices dis-incentivize production of commercial gas and discourage its efficient use by consumers. How this plays out will have critical implications for KTG, which in recent years has relied on export revenues to offset financial losses it incurs when providing gas to the domestic market even as it builds out domestic gas distribution infrastructure. Artificially low domestic prices also will impede Kazakhstan's efforts to harmonize its prices with those of Russia in the lead-in to the Eurasian Economic Union's planned single gas market (2025).

• **In the chapter on the electric power sector, which was written by Avantgarde and SEEPX Energy and reviewed by IHS Markit, the authors argue that the roll-out of the new capacity market, renewable power auctions, and an ongoing transition to an incentive tariff system are designed to provide sustainable funding for system expansion, maintenance, and renovation.**

- The capacity market in Kazakhstan, launched on 1 January 2019, is a service market whereby the Single Buyer, represented by KEGOC's Financial Settlement Center (FSC), specifies power plant capacities, including through auctions, and sells the selected capacity at a single price to wholesale buyers—large consumers and electric grid companies. As a result, the costs of new generation, expansion, and modernization of power plants are evenly distributed among all consumers over an extended period. This is designed to provide a more stable financial environment for power companies to modernize, reconstruct, and expand, as well as to commission new assets.
- In 2017, amendments were introduced to the Law on Support of Renewable Energy Sources, providing for the organization of auctions for new renewable energy projects (replacing the system of fixed tariffs that existed previously). The investor who bids the lowest price for electricity wins the right to develop a specific renewable project, with the electricity sold at the price established in the auction.
- Upon adopting the new Law on Natural Monopolies in 2018, transition to the incentive tariff regulation has been approved for a number of electric grid companies, although the majority still uses the existing cost-plus methodology for tariff determination. The incentive tariff system is based on a regulated asset base (RAB) methodology that allows for better predictability of electric grid companies' operation due to long-term tariff-setting (five years or more). The electricity tariff is calculated to reflect the actual value of realized investments (capital base), operational expenditures related to its maintenance and development, as well as profit for asset management and on new investments (i.e., a regulated profit).

• **However, these new power mechanisms require further adjustments.**

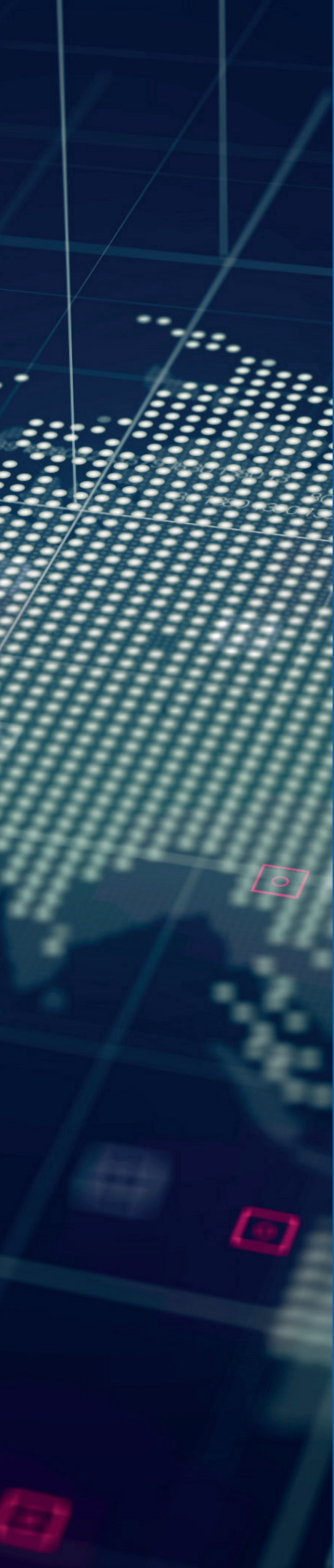
- The lack of specific technological, technical, and environmental requirements for the capacity market and resources ensuring its operation risks freezing the established sector architecture that hinders its innovative development and may fail to provide sufficient flexible generating capacity that the country needs. Further, the current marginal capacity tariff does not cover the actual fixed costs and profits of power plants, and the capacity market has no mechanism for displacement of technologically outdated capacities or facilities whose operation does not comply with the goal of transitioning to a green economy.
  - o Expenditures by traditional power plants on the purchase of electricity generated from renewable energy sources are expected to rise rapidly, to 15–30% of their total expenditures by 2021 if current renewable generation targets are achieved. This, when combined with rising fuel costs and other expenses, could put the traditional power sector in a critical financial situation. Increasing payment arrears in purchase of electricity from renewable sources could thus affect the financial stability of the electric power sector more broadly.
  - o With respect to the transition to incentive tariff mechanism, although there has been a gradual improvement in the electric grid companies' activities over the last five years, the lack of clear principles of energy efficiency stimulation and service quality improvement in the tariff calculation methodology makes Kazakhstan's incentive tariff regulation mechanism

significantly different from global practice.

• **Ecology Code.** The most consequential development focused on environmental protection since the publication of NER 2017 is development of the new Ecology Code, which is slated to be introduced to Kazakhstan's parliament in September 2019 (and adopted in mid-2020). If passed in its current form, the Ecology Code would not only increase the financial burden on the energy sector, but likely fail to help Kazakhstan achieve its goals under the Paris Climate Agreement.

- The overall climate policy set out in the draft Ecology Code does not represent any significant changes from current practice. For example, the carbon trading system introduced in 2017 remains in place, but there are no new measures to increase liquidity in the system and perhaps create a viable carbon market.

- In general, environmental initiatives must be planned and implemented so that they synchronize with overall governmental social and economic policy. The additional financial pressure on specific industrial sectors (e.g., electric power) with no modification in the social dimension of pricing policy is inconsistent, and may have an overall negative effect. Therefore, the actions and plans of government bodies in the environmental, social, and economic domains have to be coordinated.



2. Overview of recent global energy trends and outlook for production and consumption of energy

2. Overview of recent global energy trends and outlook for production and consumption of energy

This chapter of The National Energy Report 2019 analyzes major political and economic trends influencing the production and consumption of energy, especially hydrocarbons (oil, oil products, and natural gas) around the world, including identification of key differences in trends and outlook for major world regions. While the focus of analysis is on hydrocarbons, electric power and renewable energy also are discussed in the context of global energy consumption trends, and the extent to which advances in power technologies and changes in environmental policies are altering the end-user energy mix.[1] Much of the discussion of these topics is framed in the context of concerns about global climate change, and specifically initiatives undertaken in the aftermath of the Paris Agreement to address these concerns. These global trends (and outlook for energy production and consumption worldwide) provide an important lens through which to view and contextualize developments in Kazakhstan's oil, refined products, natural gas, and power markets that are presented in the chapters that follow.

2.1. Key Points

• Global primary energy consumption grew strongly in 2017 and 2018, led by solid growth in gas demand in North America and reversal of declines in coal demand (particularly in Asia).

• Major international oil and gas companies now are facing calls by their shareholders to establish and disclose greenhouse gas reduction targets for their products and operations—more specifically, to account for the impact of compliance with climate agreements on their balance sheets. In response, these companies are increasingly focusing on diversification and increasing cost-effectiveness rather than growing reserves, by forging partnerships with large technology firms to apply powerful technological innovations (big data, cloud computing, artificial intelligence) to cut costs and boost production.

• Natural gas accounted for 40% of global energy demand growth in 2018. Over one quarter of world output is now from North America (Canada, Mexico, and United States), where the shale boom has led to rapid growth in both gas consumption and demand. Within gas, LNG consumption globally, but especially in Asia, is slated to rise much more rapidly than gas consumption overall.

• Renewable energy has now reached several major mileposts. Most notably, the cost of the lowest priced solar photovoltaic (PV) and onshore wind contracts fell below $25 per megawatt-hour (MWh); these are competitive with fossil fuel–fired capacity in many locations. Within the renewables sector, offshore wind power is poised for explosive expansion, with capacity currently under development more than double existing installed capacity. Yet progress in renewable energy remains highly concentrated in power generation, with far less growth in heating, cooling, and transport.

• Despite efforts to curtail coal production and consumption globally in an effort to reduce greenhouse gas (GHG) emissions, both actually increased in 2017 and 2018, after falling for a brief

[1] For more on global trends in electric power and in environmental protection, see Chapters 5 and 6 of this report.

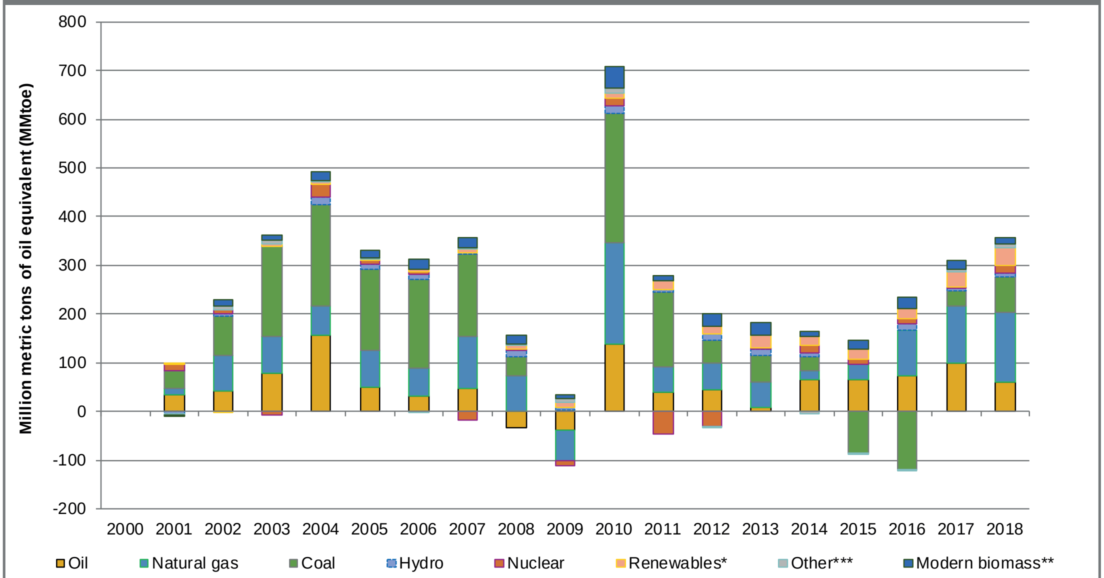
three-year period (2014–16) immediately before and after conclusion of the 2015 Paris climate accord. The outsized driver for these trends was the Asia Pacific region, which includes the world's two largest coal consumers (China and India) and accounted for three quarters of total world coal consumption in 2018.

The global economic environment in 2018 through mid-2019 can be described as broadly positive, although moderating later in the period. Global real GDP growth was 3.2% in 2018, with IHS Markit estimating further moderation to 2.9% in 2019 and to 2.8% in 2020 and 2021. Moreover, a number of uncertainties in various parts of the world could weigh on the global economy and portend even slower growth to the extent they materialize:

- Low interest rates in the developed world, leaving central banks little room for policy stimulus
- Tense US–China trade tensions and broader tariff issues
- Political gridlock in the United States
- Turmoil in a number of energy-producing states, including Venezuela, Libya, and within the Persian Gulf region, including Iran
- Uncertainties about the terms of Brexit in Europe
- Poor US–Russia relations
- Relatively high and rising private and public debt in many countries.

Yet, despite the muted outlook surrounding global economic activity, primary energy consumption grew strongly in 2017 and 2018, by above 300 million metric tons of oil equivalent (MMtoe) for the first time since 2010 (see Figure 2.1. Annual changes in global primary energy demand by fuel type, 2000-18). The spike was led by strong growth in gas demand (North America) and reversal of recent declines in coal demand (particularly in Asia). Fossil fuels remain the dominant component in global primary energy demand (13.8 trillion tons of oil equivalent), accounting for about 80% of the annual increase. The strong recent growth of gas consumption is consistent with IHS Markit global demand growth projections to 2050, when renewables will also become an integral part of future supply (see Figure 2.2. World: historical and projected primary energy demand

Figure 2.1. Annual changes in global primary energy demand by fuel type, 2000–18

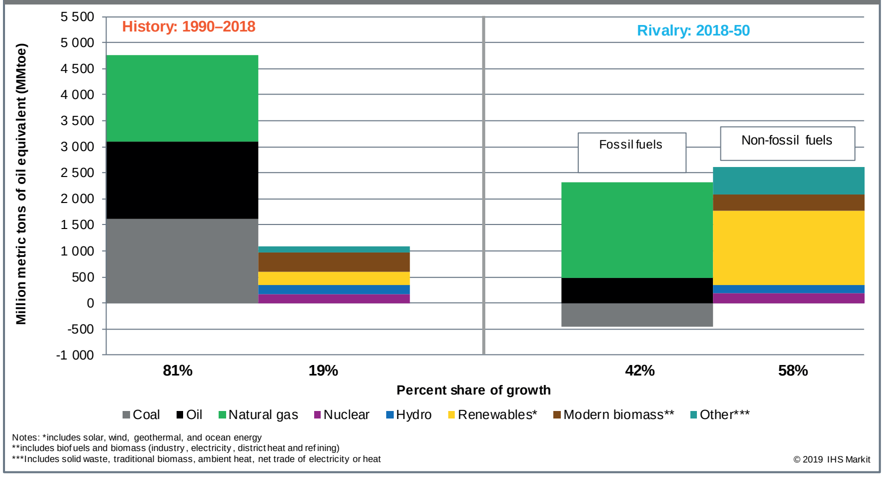


Notes: *includes solar, wind, geothermal, and ocean energy
**includes biofuels and biomass (industry, electricity, district heat and refining)
***Includes solid waste, traditional biomass, ambient heat, net trade of electricity or heat
Source: IHS Markit

growth by scenario).[2] According to the IHS Markit base-case scenario (Rivalry) used in this report, even at the end of the forecast period, fossil fuels still account for more than half of total primary energy consumption, led by natural gas, estimated at ~40% above present levels.

The following sections of the chapter outline key global trends in the production and consumption of the major energy commodities, beginning with oil.

Figure 2.2. World: Historical and projected primary energy demand growth by scenario

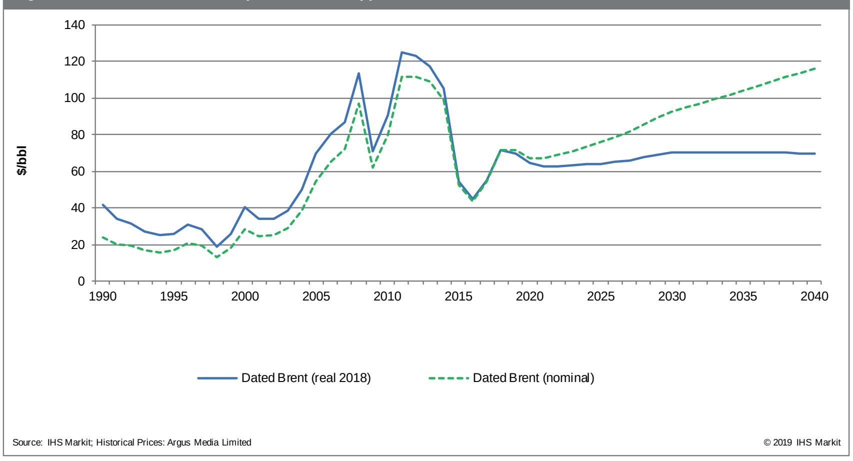


2.2. Global Oil Markets: Concerns about Supply Picture Whipsaw Markets in 2018, but Near-Term Signals Remain Supportive For Producers

2.2.1. Price and Supply Trends

The (initial) OPEC+ agreement reached in late 2016 between OPEC and major non-OPEC producers (most notably Russia, but also Kazakhstan and Azerbaijan), which went into effect in 2017 and was later extended into 2018, took approximately 1.8 million barrels per day (MMb/d) off the market, reduced inventories, and boosted prices. Brent prices during this period responded, opening at $56.82 at the start of 2017 and $66.65 in 2018, before spiking up mid-year 2018 and peaking at $86.07 in early October (see Figure 2.3. Annual Dated Brent (FOB North Sea) price outlook to 2040).

Figure 2.3. Annual Dated Brent (FOB North Sea) price outlook to 2040

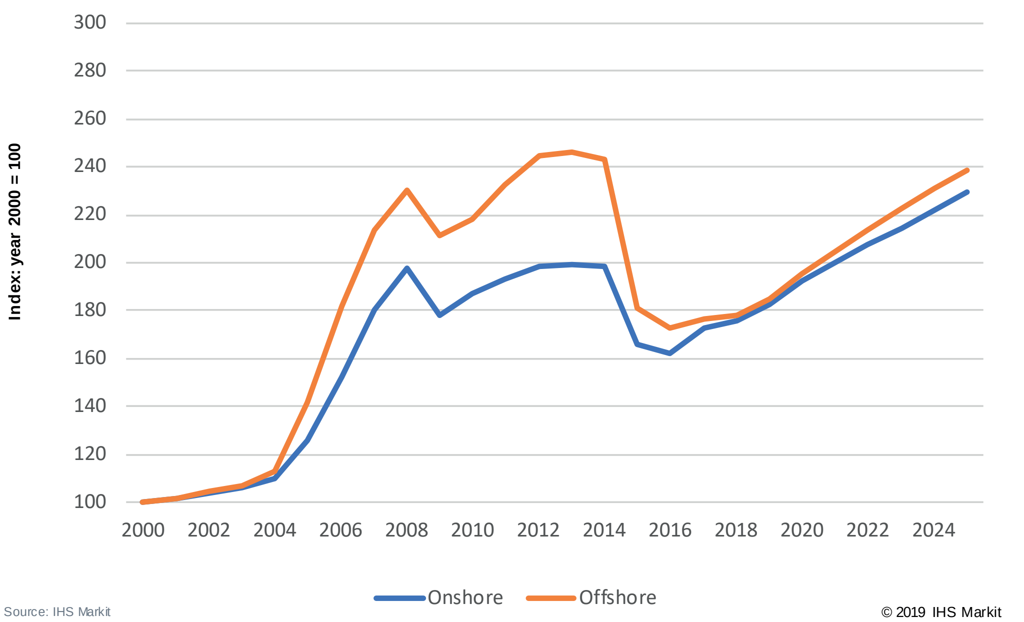


[2] Figures 2.1. and 2.2 are derived from Susan Farrell, Rick Vidal et al. "Global Scenarios Workshop at CERA-Week," 11 March 2019, IHS Markit Global Scenarios Presentation, pp. 7 and 30.

The immediate catalyst for the mid-year price spike was the announcement in May 2018 by the US Trump administration that it would exit the Iran nuclear agreement (Joint Comprehensive Plan of Action, or JCPOA) concluded in summer 2015 with the P5+1 group of countries, which allowed Iran relief from sanctions on its oil exports in exchange for a drastic reduction of Iran's stockpile of enriched uranium and acceptance of a regime of international inspection of its nuclear facilities.[3] Subsequently, the United States announced that it would unilaterally re-impose sanctions on Iranian exports on 5 November 2018. The sanctions relief accorded by JCPOA had allowed the Iranians to gradually increase exports from approximately 1 MMb/d to 2.2 MMb/d in the first half of 2018, but the uncertainty over how much supply would be taken off the market by the resumption of sanctions and uncertainties about production levels in Venezuela, Nigeria, and Libya—combined with a curtailment in output in Alberta, Canada—sent prices upward.[4]

However, by late summer 2018, three developments favoring increased global supply had begun to place downward pressure on crude prices. First, production in the US, which is not part of any OPEC+ agreement, continued to grow rapidly as producers' break-even costs (both shale drillers and offshore producers) are now considerably lower, given cost-cutting and efficiency improvements effected during the price downturn of 2014–16 (see Figure 2.4. Upstream Capital Cost Index based on nominal dollars).[5] In 2018, US liquids production increased by 2.1 MMb/d, and US crude exports to international markets had increased to a level (2 MMb/d) approaching the recent Iranian peak (2.7 MMb/d). US production in 2019 is expected to expand by 1.2 MMb/d to 12.0 MMb/d, and possibly to 13.9 MMb/d in 2020 (if prices are supportive).

Figure 2.4. Upstream Capital Cost Index (UCCI) based on nominal dollars



Source: IHS Markit

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[3] P5+1 countries include China, France, Russia, United Kingdom, United States, and Germany.
[4] In the run up to the re-imposition of the sanctions, Iranian exports were reported to have fallen to 1.1 MMb/d in November 2018, but increased to 1.3 MMb/d in December. The curtailment in Canada was associated with inadequate pipeline capacity to move output to export markets.
[5] IHS Markit estimates that 80% of new production that will come onstream in the lower 48 US states in 2019 and 2020 will have a break-even price of below $50/bbl (WTI).

Second, in response to entreaties by US President Donald Trump in summer 2018 to Saudi Arabia and other OPEC producers to raise output to lessen the burden on US gasoline consumers,[6] and partly due to a reduction in discipline among OPEC and other producers in the high price environment in the run-up to re-imposition of the Iranian sanctions, OPEC+ production cuts began to be relaxed in June and additional non-US supply (~1 MMb/d) entered the market. By December 2018, world production had risen to 100.6 MMb/d, 2.8 MMb/d more than the year before. For the year as a whole, global consumption rose by 1.5%, to 9.9 MMb/d.

Finally, when the United States actually did re-impose sanctions on importers of Iranian crude in November, it granted temporary exemptions to eight major importers (China, India, Japan, South Korea, Turkey, Taiwan, Greece, and Italy) to allow them more time to adjust their purchases. As a result, Iranian exports did not fall as much as most observers expected. These supply-side developments, as well as indications of a slowing of synchronized global economic growth and crude oil demand, led to the return of an oversupplied market in the fall, and resulted in the Brent price retreating 37% from its peak to $53.80 by 31 December 2018.[7]

In a return to their familiar role as a swing producer, the OPEC+ signatories on 7 December 2018 announced a new agreement on production cuts, 1.2 MMb/d relative to October 2018 levels, distributed 0.8 MMb/d among OPEC members and 0.4 MMb/d among the other signatories.[8] The cuts, which went into effect on 1 January 2019 and were to last six months, supported prices, together with the announcement by the US administration in April 2019 that it would not extend the previously granted sanctions waivers on imports of Iranian oil beyond 1 May. IHS Markit estimates that sanctions on Iran and Venezuela, turmoil in Libya, and curtailment of Canadian heavy oil output due to inadequate pipeline capacity could remove as much as 3 MMb/d from global supply during 2019.[9] In early July 2019, the OPEC+ cuts were extended another nine months, through March 2020. This could exert some pressure on prices, given projections of steady, if small, demand growth. Given these conditions, the IHS Markit oil price outlook calls for Brent prices to average $66/bbl in Q3 2019 and $64/bbl in 2020.

Global oil supply depends first and foremost on the level of global demand, but also on technological advancements and price levels. Over the longer term, much of the world's supply growth depends on the Gulf-5 (Saudi Arabia, Kuwait, the UAE, Iran, and Iraq). As North America's growth slows late in the 2020s, these Middle Eastern countries will contribute the majority of global long-term supply growth in the 2030s and 2040s.

- Global supply growth is leveraged to tight oil in the United States—and the Permian Basin in particular—well into the 2020s; the Permian Basin alone (in the United States) accounts for more than 40% of oil supply growth to 2023.
- A $60–70/bbl real oil price (2017 US dollars) incentivizes sufficient long-term supply, given our ongoing assessment of the global cost supply curve. Each subsequent review[10] tends to show more supply is available at lower costs, due to a combination of more supply from lower cost providers and falling overall cost levels across the board. As a result, most of the gross supply needed in our long-

[6] Although the higher prices were beneficial to US producers, the focus in the United States for political reasons is on the consumer given the predominant role of consumption in the US economy.
[7] IHS Markit base-case forecasts show demand growth declining from 2.0 MMb/d in 2017 to 1.5 MMb/d in 2018, 1.4 MMb/d in 2019, and rising slightly to 1.5 MMb/d in 2020.
[8] Among the non-OPEC signatories, Russia agreed to cuts of 230,000 b/d, Kazakhstan 40,000 b/d, and Azerbaijan 20,000 b/d. For a more detailed discussion of the implications of these cuts for Kazakhstan's oil production more broadly, see Chapter 3.2 later in this report.
[9] In May 2019, Iranian exports had fallen to what IHIS Markit estimates is ~490,000 b/d, a steep drop from March and April levels that averaged 1.6 MMb/d as importers scrambled to fill up on Iranian crudes ahead of the ending waiver period.
[10] See IHS Energy, Ahead of the Curve: The oil cost curve and what it tells us, October 2015; IHS Strategic Horizons: The New Global Cost Curves for Oil, 18 September 2017; Global Oil: Cost curve for crude in 2018 shows marginal inflation from 2017, 17 July 2019; IHS Market, Crude Oil Markets, Global Crude Oil Cost Curve: July 2019 update, 2 July 2019.

term demand outlook can be supplied at $70 or below, and this consequently informs our expectations of equilibrium prices in global markets longer term.

• But continued upstream exploration remains critical to long-term supply availability, despite a long-term plateau in demand. By 2040, roughly 11 MMb/d of crude production comes from discoveries that have not yet been made. Furthermore, with average base production declines of about 3%, the call on new crude and condensate production by 2030 is roughly 31 MMb/d, or nearly 40% of all of last year's crude oil output.

Although the supply picture is thus generally positive for producers—the major international oil companies generated positive cash flows in 2018 for the first time in five years—they are under pressure to increase returns to shareholders and exercise capital discipline. This could constrain capital expenditures (and affect production by as much as 1 MMb/d) at least over the medium term. More importantly, it has implications for investments in new ventures development, increasing the competitive environment for such countries as Kazakhstan.

2.2.2. Push for Oil and Gas Majors to Diversify and Respond to Climate Change

Potentially even more disruptive are calls by major institutional investors (e.g., pension funds, insurers, mutual fund companies) for major integrated oil and gas companies (BP, Chevron, Eni, Equinor, ExxonMobil, Repsol, Shell, and Total) to establish greenhouse gas reduction targets for their products and operations—more specifically, to account for the impact of compliance with climate agreements on their balance sheets.[11] The more radical of these investors argue that meeting the 2015 Paris climate accord's more ambitious goal of limiting global mean temperature rise by 1.5°C relative to pre-industrial levels would require peak hydrocarbon consumption to occur soon after 2020, a reduction by 20% by 2030, and by half by 2050.[12] Under such a scenario, the book value of reserves held by the major oil companies would plummet, as a substantial portion could never be produced, but rather "left in the ground." Therefore, the investors posit that, from a fiduciary perspective, the companies' standard goal of "growing reserves" is now outmoded, and must be replaced by more forward-looking strategies.

Indeed, most international oil majors appear to have taken aboard some of the criticisms, and have attempted to diversify their operations into such areas as: renewable energy production; carbon capture, use, and storage (CCUS); and electricity and natural gas distribution. There is also an emphasis on greater natural gas production and shifting their oil production to less expensive barrels. A short list of some of the more recent initiatives includes:

• A joint investment by Chevron, Occidental, and BHP in Canada-based Carbon Engineering, a company that removes CO_2 from the atmosphere for oilfield reinjection or to produce synthetic fuels

• Plans by Equinor to increase capex on renewable energy production from currently 5% of the total to 15–20% (by 2030)

• Announcements by Royal Dutch Shell and BP that executive compensation will be linked to GHG reductions in their operations

• The purchase by Royal Dutch Shell of Britain-based First Utility, an electricity and natural gas distributor

• A $200 million investment by BP in Lighthouse, a solar power developer.

Investments in renewable energy and

[11] Total, Shell, and BHP were among the companies that soon attempted to respond in their annual reports; see the IHS Climate and Carbon Insight, Climate-Related Financial Disclosure Continues to Gain Momentum, 5 April 2019.
[12] Most forecasts of actual oil and gas demand show that it continues to grow by 1–2% annually out to at least 2030.
[13] Low-carbon spending includes capex and R&D in: the manufacturing and generation of renewable energy; biofuels; storage; alternative transportation/electric vehicles; hydrogen and fuel cells; energy efficiency; decarbonization; natural gas as it pertains to the generation, transmission, and distribution sectors; carbon capture, utilization, and storage; and emissions reduction in oil and gas operations.

other low-carbon activities among the global integrated oil and gas companies have become increasingly material in recent years. IHS Markit currently forecasts nearly $7 billion in average annual spending in the low-carbon sector among this peer group between 2019 and 2021, accounting for approximately 5% of total corporate capital expenditures (CAPEX) for these companies during that time.[13] This higher spending has led to questions about the profitability of investments in sectors outside of the traditional oil and gas business.

In order to better understand the returns proposition of these businesses and how they compare to the oil and gas sector, IHS Markit has calculated returns metrics across several low-carbon and utilities segments from a sample of 97 low-carbon companies and 64 utilities companies worldwide.[14] An analysis of operating returns on average capital employed (ROACE) among these different sectors since 2010 shows that oil and gas has generated some of the highest returns during that time, with a median annual operating ROACE of 8.5%. Returns in this sector compare favorably with other sectors in which several of the global integrated companies have substantial investments, including energy conversion and efficiency (8.2%), the utilities sector (6.8%), storage (6.1%), low-carbon power generation and distribution (5.3%), and solar manufacturing (4.2%).

At the same time, the oil and gas sector has experienced the highest volatility in returns since 2010, with a standard deviation of returns of 7.8%—ahead of 7.5% for solar manufacturing, and well above each of the remaining sectors. These results are consistent with general expectations of the low-carbon businesses and utilities being lower return, but with more stability. Overall, it appears that the low-carbon sectors can play a role in the portfolios of the global integrateds, by providing lower but still material returns, reduced volatility, and diversification benefits. Among the low-carbon and utilities sectors analyzed here, most have little or negative correlation with oil and gas returns, with the exception of electric vehicles, which had a 78% correlation for operating ROACE since 2010—potentially resulting from the benefit that both sectors receive from higher oil prices.

2.2.3. Technological Innovation

In concert with the emphasis on increasing cost-effectiveness rather than growing reserves, there appears to be a growing partnership between international oil companies (IOCs) and large technology firms (in Silicon Valley and elsewhere) to apply powerful technological innovations (big data, cloud computing, artificial intelligence) in order to cut industry costs, enhance safety, and to boost production. The parties initially viewed one another with a certain degree of mutual skepticism on sustainability and climate change issues, making the oil and gas industry "late in the game" in embracing these innovations. By one estimate, because of the tendency of the oil/gas industry to narrowly compartmentalize data rather than integrating it under a more holistic approach, it is effectively utilizing only 1–5% of the data potentially available to it.[15] This is now beginning to change, with a number of initiatives now being launched:

- BP is now combining real-time information from wellhead and other sensors with its own models and analytics, which it estimates boosted output by 30,000 b/d in 2018.
- ExxonMobil is now partnering with Microsoft Cloud to employ staff more efficiently, and to monitor methane leaks.
- Amazon is now working with oil services firms such as Halliburton, and

[14] See the IHS Markit Companies & Transactions, Upstream Competition Insight, Can Low-Carbon Be Profitable? Understanding the Value Proposition of Alternative Businesses for Oil and Gas Companies, 3 June 2019.
[15] Coverage of IHS Markit's CERAWeek 2019, Houston, Texas, USA, as reported in "Oil Rush," The Economist, 16 March 2019.

with majors such as Shell, on data-storage initiatives.

- Google's parent company Alphabet has established a new energy group, which has concluded contracts with Total and Anadarko Petroleum.
- Leveraging advances in computing and big data, majors during E&P are now able to perform important seismic work (i.e., mapping faults) in a matter of hours rather than months, using a fraction of resources.
- At Tengizchevroil (TCO), for example, vehicles are equipped with face-monitoring sensors that can detect when the driver is falling asleep, and signal the seatbelt to ping the individual, thereby alleviating risks associated with human fatigue. TCO also uses Integrated Operating Centers (IOC) technologies from Wipro to collect, manage, and disseminate data across operating segments.

2.2.4. International Maritime Organization (IMO) 2020

Downstream developments also are shaping the industry globally. A major development that is already affecting refinery operations is IMO 2020, a push toward cleaner transportation (bunker) fuels in the international shipping industry that will take effect on 1 January 2020. On that date, the International Maritime Organization will ban the use of fuels with a sulfur content above 0.5% (compared to the current threshold of 3.5%), unless ships are equipped with special sulfur-cleaning "scrubbers." This potentially will remove demand for up to 2.5 MMb/d of high-sulfur bunker, while at the same time it is not entirely clear whether refineries can ramp-up output of the very low sulfur fuel oil (VLSFO) in time to fully cover demand, given significant retooling costs. There also are concerns about the effects on ships' engines of possible blending of different grades of bunker fuel in an attempt to conform to the 0.5% threshold should same-batch supplies not be available at smaller ports. "On-grade" (compliant with sulfur threshold) does not necessarily equate with "fit-for-use" (in terms of calorific value, or composition of chemicals in the fuel). These uncertainties, as well as potential future IMO regulations (e.g., on CO_2 emissions) could dampen future fuel oil demand should shippers decide instead to invest in LNG-powered vessels when older vessels are removed from service.

2.3. Natural Gas: New Supplies Weigh on a Market Previously in Balance

2.3.1. Overview and Price Trends

The world consumed some 3.85 trillion cubic meters (Tcm) of natural gas in 2018, up 5.3% from 2017; average annual consumption growth over the preceding 10-year period (2007–17) was 2.2%. Natural gas alone accounted for 40% of global energy demand growth. Over one quarter (27.2%) of world output was from North America (Canada, Mexico, and United States), where the shale boom (primarily) was responsible for a 9.8% increase in output in 2018, nearly double the growth rate of the next fastest growing region (Middle East, 5.7%).

Given abundant supply, key global benchmark gas prices (in Asia, Europe, and North America) have fallen significantly worldwide since November 2018. Asian LNG spot prices fell below \$4.30/MMBtu in April 2019, the lowest level since April 2016, and just over one-third of their value six months earlier. This primarily reflects moderation in Chinese LNG demand growth, due to slowing in China's overall economic growth as well as abundant seasonal supply (resulting from overstocking of reserves in anticipation

[16] Globally, in 2019 it is expected that an additional liquefaction capacity of 49 MMt will be commissioned.

of shortages this past winter). European spot prices fell too, with levels dropping by half from September 2018 to March 2019. Elsewhere in Northeast Asia, Japan and South Korea, the world's first and third largest LNG importers, respectively, also face uncertain demand growth over the short term as the return of nuclear into the energy mix could eat into the role of gas (and coal) in the power generation sector.

The declining prices in Asia also reflect increasing looseness in the global LNG market; new liquefaction supply coming online globally (most notably from the United States and Australia) has outstripped global demand growth, traditionally led by Asia.[16] Some LNG cargoes destined for Asia have been redirected to the balancing market of Northwest Europe to find a home, as the Asian premium vis-à-vis Europe has narrowed. As a result, European LNG imports rose to an average of 6.7 MMt per month during the period October 2018–March 2019 vis-à-vis 4.0 MMt previously (October 2017–March 2018), despite 2018 being the third consecutive year of record Russian pipeline gas deliveries to Europe. Thus the competition between Russian pipeline gas and LNG in this market is likely to have an outsized impact on the global gas trade over the near term. IHS Markit estimates that strong LNG imports into Europe (averaging 7.3 MMt per month) will continue to compete with established pipeline supply to compensate for progressively decreasing domestic production. Over the longer term, we expect European prices to trend toward the US long-run marginal cost (LRMC), as the US is the world's marginal LNG supplier.

US natural gas prices, generally benchmarked by the Henry Hub (HH) index, also declined in 2019, falling from the winter spikes in November 2018, when exceptionally cold weather led to a higher demand, coupled with relatively low storage levels. However, by the first quarter 2019, US gas production had ramped up significantly, leading to a more comfortably supplied market, indicated by prices dropping back down to below \$3.00/MMBtu by late January and to a March average of approximately \$2.95/MMBtu. The development of new plays and a ramp-up in associated gas have allowed for unprecedented natural gas production growth over the past decade in the United States. Gas output from the Lower 48 states increased from 52 billion cubic feet per day (Bcf/d) (the equivalent of 546.1 Bcm/y according to the BP Statistical Review) in 2007 to 83 Bcf/d (831.8 Bcm/y) in 2018. Although the rate of production growth had already begun to taper by September 2018, the United States is expected to sustain high natural gas production levels (at or near 90 Bcf/d [902 Bcm/y]) into the 2020s. The United States is now a net gas exporter (3 Bcf/d [31.5 Bcm/y]), as opposed to importing nearly 20% of its needs a decade ago, which substantially changed the global supply picture.

2.3.2. LNG Consumption to Rise Much More Rapidly than Gas Consumption Overall

Over the longer term, and as reflected in the IHS Markit primary energy consumption projections above, gas production and consumption are expected to expand vigorously, spurred by the consolidation of a global market for natural gas brought about by expanding LNG trade. Continued growth in US LNG exports and a general rise in spot LNG deliveries led to global LNG trade setting a record for the fifth consecutive year in 2018, reaching 316.5 MMt according to the International Gas Union (the equivalent of

[17] https://www.igu.org/news/igu-releases-2019-world-lng-report.
[18] On 10 May 2019, the Trump administration, claiming that China reneged on commitments from previous negotiations, announced it would increase tariffs on \$200 billion of Chinese imports from the 10% imposed in September 2018 to 25%. On 13 May 2019, China's Ministry of Finance announced that China will increase tariffs on \$60 billion of US goods effective 1 June 2019. This is the fourth time since mid-2018 that China raised tariffs on selected US goods in response to the US's tariff increases on China.
[19] See the IHS Markit Regional Power, Gas, Coal, and Renewables Insight, New Tariffs on US Energy and Petrochemical Products into China, 24 May 2019.

431 Bcm according to the BP Statistical Review).[17] This marks a significant increment of 28.2 MMt, or 9.8%, from 2017—the third-largest annual increase ever (behind only 2010 and 2017). IHS Markit projects global LNG demand to increase from about 320 million metric tons (MMt) in 2018 to 465 MMt (~625 Bcm/y) by the mid-2020s and to reach more than 630 MMt (~850 Bcm/y) by the mid-2030s. Cost competition will be a key driver behind future projects moving forward. Given the large potential for US exports (both due to the high number of competing proposals and the vast low-cost gas resource base), US LNG is expected to set a key benchmark that all future supply will have to compete with (i.e., to act as the marginal supplier).

Global LNG trade is not expected to be affected greatly by the escalation in Chinese tariffs on imports of LNG from the United States, from 10% in 24 September 2018 to 25% on 1 June 2019. These tariffs are part of Chinese response to the ongoing trade dispute between the two countries.[18] The United States is currently not a major supplier of LNG to China, and the United States is expected to easily find alternative markets given the high LNG demand globally; similarly, China can readily find other suppliers for this small portion of its import demand. In 2018, the United States accounted for only 4.1% of China's LNG imports, a figure that had dropped to 1.4% in Q1 2019.[19]

2.3.3. Domestic Gas Production Slides in Key Markets, with Imports Filling the Gap

Global trade of natural gas is rising, spurred not only by the growing trade in LNG, but also by new international pipelines, especially out of Russia. The corollary of this increased trade is that indigenous gas production—that is, gas produced and consumed in-country—is losing market share at a global level, at least outside of North America. The main driver of this trend is rising gas demand in China and India, which has overtaken the ability of these markets to source all their gas demand indigenously. In the case of China, this demand growth is leading to sharply rising import dependency.[20]

Second, mature markets with a long history of natural gas production—such as the Netherlands and the United Kingdom—have passed their plateau production and are in a secular, long-term decline. The same is true of some emerging economies (e.g., Pakistan and Thailand), where production appears to have reached maximum levels just as their demand is set to soar. Additionally, many legacy LNG exporters are struggling to maintain exports while also meeting their rising domestic needs—e.g., Algeria, Indonesia, Malaysia, and Trinidad. Both Malaysia and Indonesia are now turning to LNG imports.

The decline of indigenous production in many of these markets is a result of two factors: geology and policy. In terms of geology, many countries may either lack resources or have reached a stage of basin maturity where decline inevitably sets in. However, in many cases, the shortage of production is exacerbated by policy decisions that are not setting the appropriate incentives to spur investment. We believe that the latter factor is particularly salient in Kazakhstan and explore possible policy responses in subsequent chapters on oil and natural gas. While the rocks are the sine qua non of hydrocarbon production, economic incentives are the catalyst. Moreover, the responsiveness of production to price

[20] See IHS Markit, Global Gas Strategic Report, Under Our Feet: Lessons in how to spur indigenous gas production, 2 April 2019. China consumed 280 Bcm in 2018, up 18% from 2017; 125.7 Bcm of this was imported.
[21] Unless otherwise noted, the term renewable energy refers to solar, wind, bio-power, and geothermal energy.
[22] See REN 21, Renewables 2019, Global Status Report, Paris: REN21 Secretariat; BP Statistical Review of World Energy 2018, https://www.bp.com/content/dam/bp/en/corporate/pdf/energy-economics/statistical-review/bp-stats-review-2018-full-report.pdf; and BP Statistical Review of World Energy 2019, https://www.bp.com/content/dam/bp/business-sites/en/global/corporate/pdfs/energy-economics/statistical-review/bp-stats-review-2019-full-report.pdf.

signals is too often underestimated. In most countries, including Kazakhstan, gas and electricity end-user pricing is a politically sensitive issue, and the pass-through of increasing costs is problematic. In the case of developing economies, policymakers must address tough issues involving affordability. This challenge should not be confused or conflated with the issue of efficient pricing incentives, but all too often it is.

2.4. Renewables: Mileposts Being Reached Despite Headwinds

Compared to the well-established energy carriers of the previous century (oil, gas, and coal), rates of growth and capacity installation in renewable energy[21] have been spectacular in the new century, since 2000 (albeit from a small base). Installed solar photovoltaic (PV) capacity globally in 2018 had reached a total of 505 gigawatts (GW), with capacity additions over the 10-year period 2006–16 growing at an average annual rate of 49%. Installed wind turbine capacity was somewhat larger (591 GW in 2018), with capacity additions growing at roughly half the rate of solar (20% annual average during 2006–16).[22] When the metric is generation, rather than capacity, trends are broadly similar: global solar generation was 584.6 terawatt-hours [TWh] in 2018, and grew by 28.9% annually during 2007–17; wind generation was 1,270.0 TWh, growing by 12.6% annually. And IHS Markit projects that aggregate new renewable capacity coming on line globally during the next six years 2019–25 (1,100 GW) will be roughly equivalent to the total existing in 2018.

The year 2018 witnessed several important mileposts in the development of renewable energy:

- The cost of the lowest priced solar PV and onshore wind contracts (bids won through auctions) fell below $25 per megawatt-hour (MWh); these are competitive with fossil fuel–fired capacity in many locations.
- The number of countries generating power from offshore wind increased to 15, with others (e.g., Portugal) slated to join in 2019.
- Lease auctions in December for offshore wind acreage in the US Northeast (coast) set records for aggregate volumes.
- Germany announced a plan to completely phase out coal by 2038.
- Considering only (non-hydropower) renewable electric generation capacity, at least 45 countries have topped the 1 GW mark, while 17 countries have more than 10 GW combined of wind power, solar PV, bio-power, and geothermal power. At least nine countries produce more than 20% of their electricity from wind energy and solar PV.

Yet, despite these milestones and past rapid rates of growth, renewables accounted for only one-third of the increase in total electric power generation in 2018 (albeit accounting for more than three-fifths of new capacity additions). [23]

And progress in renewables remains concentrated in power generation, with far less growth occurring thus far in heating, cooling, and transport (e.g., less than a third of all countries worldwide have mandatory building energy codes in place regulating heating and cooling efficiency). And global new investment in renewable power and fuels (in this case including hydropower projects of 50 MW capacity and smaller) was $288.9 billion in 2018, a decrease of 11% compared to the previous year.[24]

[23] Renewable power now accounts for one-third of global generation capacity globally (https://www.irena.org/newsroom/pressreleases/2019/Apr/Renewable-Energy-Now-Accounts-for-a-Third-of-Global-Power-Capacity).
[24] Investment in solar power, which was $139.7 billion in 2018, was down 22% from 2017, due largely to lower unit costs for solar power and to changes in China's photovoltaic (PV) market. Wind power investment increased 2% in 2018, to $134.1 billion.
[25] See the IHS Markit Strategic Report, Renewable Cost Reductions: China at Scale in New World of Rivalries: Reshaping the energy future, 18 April 2019.

2.4.1. China's Example: Policies to Achieve Scale Economies Lead to Cost Reductions

Much of the underlying story behind the rapid roll-out of renewable energy globally involves cost reductions through achieving scale economies, which are only possible when policies are aligned to support widespread adoption. One of the best examples is China.[25] China now accounts for one-third of global renewable capacity, adding 44 gigawatts (GW) of solar photovoltaic (PV) and 21 GW of wind capacity in 2018 alone (half of the world's total additions for both technologies in that year). China's renewable fleet generates enough electricity today to power Germany, the world's fourth-largest economy. Yet only 10 years ago China had almost no PV projects and only a few thousand wind turbines, 80% of which were manufactured by foreign suppliers.

The catalyst for renewables development was the desire to reduce air pollution in China's eastern cities and particularly Beijing, which would be in the global spotlight during the 2008 Beijing Summer Olympic Games. The Chinese government recognized that the generation cost for renewables is driven primarily by up-front capex—equipment and construction. For wind and solar PV, for instance, capex accounts for 85–90% of the cost. To make renewables more competitive, the main task was to reduce capex.

One lesson China had already learned in becoming a manufacturing superpower was that mass-producing a standardized product with full supply chain support can result in economies of scale and rapid cost reductions. To get to such scale in renewables, higher demand would be needed. Authorities issued policies to spur renewable energy investment and development, starting first with wind power. Binding targets were placed in the country's five-year plans, and provincial authorities devised preferential fiscal policies for renewables. In 2009, Beijing introduced feed-in tariffs (FITs) for wind power. Over the next decade, capacity grew twentyfold.

Solar power development came later, but its growth was faster, partly because Chinese solar panel manufacturers had already been supplying the global market. Beijing announced a FIT for utility-scale solar PV in 2011, and in two years, installed PV capacity in China had grown sevenfold, to 15 GW, the second largest in the world after Germany. The government then announced distributed PV incentives to encourage businesses and households to install solar panels on rooftops. In 2018, half of the country's new PV plants were distributed projects. By the end of 2018, installed capacity in China reached 175 GW for solar and 184 GW wind; both are by far the largest in the world.

To pay for the renewable subsidies during the build-out, the government set up a renewable energy fund based on a surcharge in retail electricity tariffs. In other words, consumers bore some responsibility for paying for the renewable subsidies. The renewable energy fee surged from 0.001 yuan/ kWh in 2006 to 0.019 yuan/kWh by the end of 2018, but its growth rate was nonetheless dwarfed by the swift uptake of renewable power. As a result, the renewable fund accrued a mounting shortfall, estimated by IHS Markit at 150 billion yuan ($21.8 billion) by the end of 2018.

As wind and solar costs have declined, and in order to address the shortfall in the renewable energy fund, the Chinese government over the past decade has started to wind down incentives. Between 2009 and 2018, Beijing reduced the wind power FIT by as much as 22%, with the aim that tariffs would reach parity with coal plants by 2020. It also cut the FIT for utility-scale solar projects by 40–56% between 2011 and 2018. This pressured equipment suppliers to continue making technological

[26] See the IHS Markit: Regional Power, Gas, Coal, and Renewables Insight, China's Renewables Policies: Paving the road toward a subsidy-free market, 27 May 2019.
[27] During 2019–20, IHS Markit expects China's wind and solar capacity additions to stabilize between 20–21 GW and 41–43 GW, respectively.

improvements and cutting costs. As China shifts to auctions (tenders; see below) as the financing method for new renewable power additions, prices of generated power are expected to fall further.[26]

Although subsidies (including FITs) were the preferred mechanism early in the history of the renewables roll-out globally, auctions (tenders) are now the most widely used allocation mechanism for renewable power capacity additions. The main advantage of tenders is that competitive bidding helps drive down prices by increasing cost transparency, and as a result, reduces procurement costs for off-takers and subsidy costs for governments. Countries that account for 80% of global capacity growth to 2025 have launched or announced tenders as one of the options for capacity additions.

In China, a major step in this direction was taken in April 2019, when China's National Energy Administration (NEA) released two draft policies—the Work Plan for Promoting Grid-Parity Wind and Solar Photovoltaic (PV) Power without Subsidy and the Notice of Requirements on Wind and Solar PV Power Construction Management. These policies divide the renewable market into grid-parity (unsubsidized) and subsidized projects, and provide detailed guidance on renewable market development. As incentives, grid-parity projects will receive prioritized access to the national electricity grid, guaranteed full generation dispatch for 20 years, easier land access, reduced grid-access charges, and cheap financing.

The policy guidance in each market segment will stabilize wind and solar capacity additions (and thus financing costs) over the next few years and longer term.[27] For solar PV, the government has established a 3 billion ($440 million) yuan subsidy budget in 2019 for which solar PV projects requiring subsidies will need to bid. Tender power price is the determining factor in the bidding process, with winners receiving 20-year contracts. The government has now largely suspended new solar investment in the northwestern and northern parts of the country, where curtailment of excess electric power generation is highest. For wind power, under the policies announced in April 2019, the central government will use 2020 installed wind capacity targets to rein in capacity additions. For 2019, provinces with installed capacity, under construction, and approved capacity exceeding their 2020 targets will only approve unsubsidized new projects. Moreover, for offshore projects, only those approved before 18 May 2018 and starting construction by 11 April 2019 can receive the fixed national FIT.

Grid-parity project promotion and subsidized project bidding should help alleviate the renewable subsidy burden and provide sustainable long-term growth. In the long term, IHS Markit expects China's wind and solar capacity to reach 1,279 GW and 891 GW, respectively, by 2050. Ultimately, it is not clear whether China's experience, relying first largely on top-down administrative measures before transitioning subsequently to more market-compliant ones, provides a successful template for all countries seeking a renewables build-out.

2.4.2. Electric Vehicles: On the Verge of Attaining Scale Economies?

A similar scale effect as that for renewable energy in China is being envisioned for global battery-electric vehicle (EV) production. EVs have until recently been viewed (and priced) as a high-end niche product, with small production runs, with even the

[28] Roughly 2 million EVs (pure battery-electric vehicles and plug-in hybrids) were sold globally in 2018 (roughly 1 in every 50 light transport vehicles).
[29] See the IHS Markit Oil Markit Briefing The Truth about EVs and Gasoline Demand, 14 February 2018.
[30] Seven countries in Europe and two in Asia connected a total of 4.5 GW in 2018 (the same as in 2017), increasing cumulative global capacity by 24%, to 23.1 GW. Wind turbines operating offshore represented only 4% of total global wind power capacity at year's end, but offshore additions in 2018 accounted for 8% of all new capacity.
[31] See the IHS Markit Event, Power and Renewables, Global Offshore Wind: Trends and outlook to 2050, 16 May 2019, pp. 3 and 11.

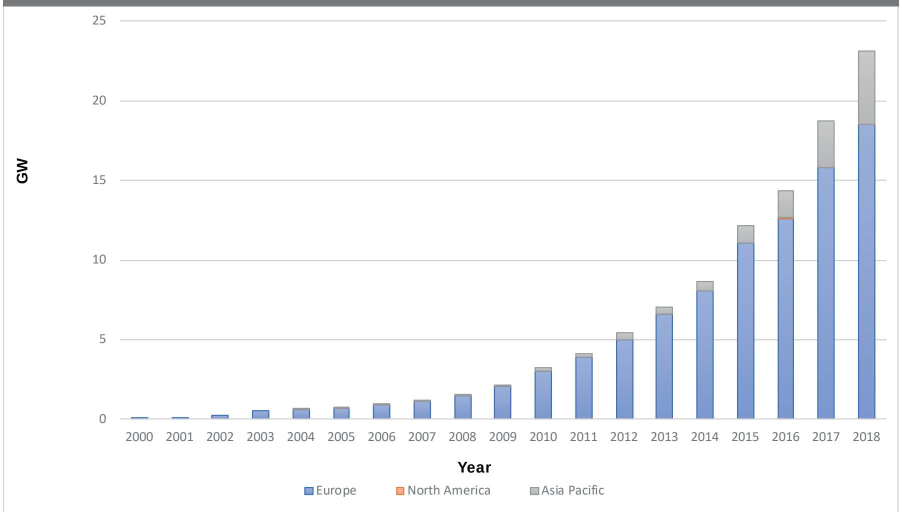
"affordable" Tesla Model 3 selling for $35,000 in the United States (250,000 units were produced in 2018).[28] However, the scale of EV production globally is on the verge of massive expansion, with such automobile majors as General Motors, Mercedes, Nissan, VW Group, Renault, and Hyundai all gearing up for massive roll-outs. The resulting competition and scale economies should allow prices of many models to fall to levels consistent with higher consumer demand. The global stock of electric cars reached more than 5.1 million units in 2018, a 63% increase over 2017, but still a miniscule proportion of the overall global fleet. It will be many years before EVs make a significant dent in global motor fuels demand; the factors that remain dominant on this front are still the size of the total fleet, the distances each car drives, and especially the fuel efficiency of the vehicles.[29] Moreover, EV markets remain highly concentrated, with China alone accounting for nearly 50% of the global EV stock.

2.4.3. Offshore Wind Poised for Explosive Expansion

Although due to the higher capital costs involved, offshore wind got off to a late start vis-à-vis its onshore counterpart, it is making up ground rapidly. Over the past five years, global offshore wind installed capacity has more than tripled, with average annual installations exceeding 3 GW (see Figure 2.5. Global offshore wind installed capacity, cumulative).[30] It is heavily concentrated in Europe, and just three countries—the United Kingdom, Germany, and mainland China—account for more than 80% of total offshore wind installed capacity globally. Thus, the potential for further expansion is fairly high.

Over 61 GW of capacity is currently under development (more than double current capacity). And the competitiveness of offshore wind is expected to continue to improve: the cost of the technology is expected to fall by half by 2050 (from over $80/MWh levelized cost of electricity to $40/MWh), reflecting ongoing technology advances (including larger turbines) that are increasing energy production per turbine, and improving plant efficiency and output. IHS Markit projects 450 GW of new offshore wind capacity will be added over the period 2019–50, at a cost of ~$1 trillion, with mainland China overtaking Europe as the capacity leader after 2040. North America remains a minor player, despite increased interest, such as in the US Northeast noted above (see Figure 2.6. Offshore wind installed capacity by region, 2010–50).[31]

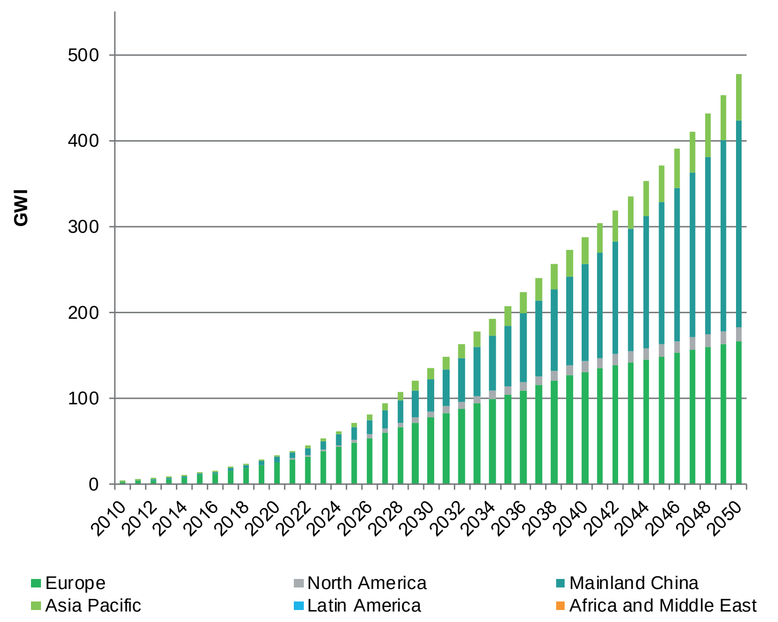
Figure 2.5. Global offshore wind installed capacity, cumulative



Notes: cumulative installed capacity fully connected to the grid

Source: IHS Markit

Figure 2.6. Offshore wind installed capacity by region, 2010-2050 (GW)



Notes: China excludes Honh Kong, Macao and Taiwan
Source: IHS Markit

2.4.4. Innovations in Battery Technology on the Horizon Could Greatly Expand Storage Capacity

The key weakness of solar and wind is their intermittency: they are only available when the wind is blowing and the sun is shining. Therefore, a major breakthrough in the ability to store electricity would greatly increase the overall utility of renewables. The major battery used for storage in both EVs and renewable power grids to date is the lithium ion battery, comprising nearly 85% of all new battery storage capacity installed annually.[32] Its widespread adoption has been impeded to some extent by the natural scarcity of the lithium mineral, its propensity to catch fire or explode (therefore requiring external cooling mechanisms), and (as a consequence) its relatively high price. Nonetheless, advances in technology lowered the cost per unit of storage of lithium ion batteries by 80% between 2010 and 2017 (total energy installation cost ranges from $250 to $400/kWh), and global manufacturing capacity reached just over 130 GWh in 2018, with the bulk of production based in Asia and nearly 60% in China.

In September 2018, US-based NantEnergy announced that it had developed a less expensive alternative—a rechargeable zinc-air battery based on a relatively more abundant mineral that requires no external cooling and can store electricity at a cost at or below $100/kWh.[33] The battery can hold a charge for as long as 72 hours.

This battery has been tested so far for six years in two applications: (a) a World Bank–funded project in which an assembly of zinc-air batteries, in conjunction with an array of solar panels, provided a microgrid for 110 villages in nine countries in Asia and Africa; and (b) power storage for over 1,000 communications towers in the United States and Southeast Asia. However, the company plans to eventually expand the use of the batteries to home energy storage (starting in the California and New York) and, beyond

[32] Other major solid-state battery technologies (according to new capacity installed in 2016) include lead batteries (5% of total), sodium sulfur batteries (4%), and "other" (2%). The total installed energy cost of sodium sulfur batteries ranges from $263 to $735/kWh. See https://www.iea.org/tcep/energyintegration/energystorage/
[33] Zinc is twenty times more abundant in nature than lithium.
[34] See REN 21, Renewables 2019, Global Status Report, Paris: REN21 Secretariat, p. 162.

that, potentially to EVs, buses, trains, and scooters. But it is important to note that introduction of battery technology is a long-term process that involves trial and error – power producers and policymakers should keep this in mind when considering potential implementation.

2.4.5. Distributed Renewables (Battery Networks and Other Technologies) Provide Modern Energy Services to Both Developed and Emerging Economies

Another recent focus of research in battery technology has been the management and control of networks of batteries to provide grid balancing services (in developed economies) or access to power in remote areas not connected to the grid. In the case of the former, the German transmission system operator TenneT in 2018 approved the trial of an aggregated 1 MW battery composed of distributed residential batteries that will provide balancing services to the German grid.[34] The aim is to increase the size of this "virtual" storage unit to include 30,000 home storage systems that are installed mainly in parallel with solar power capacity.

In the case of the latter (service to remote areas), distributed renewables for energy access (DREA) systems are increasingly being used to provide access to electricity in remote areas. In 2017, more than 122 million people obtained access to electric power for the first time, mainly through off-grid solar systems. By that year, the global population lacking access to electricity fell below a billion, with 96% of those still lacking access living in sub-Saharan Africa and developing Asia. An estimated 5% of the population in Africa and 2% of the population in Asia has access to electricity through off-grid solar PV systems. Development finance institutions increased their support to DREA in 2018, directing some 7% of their total investment in energy projects to off-grid systems.

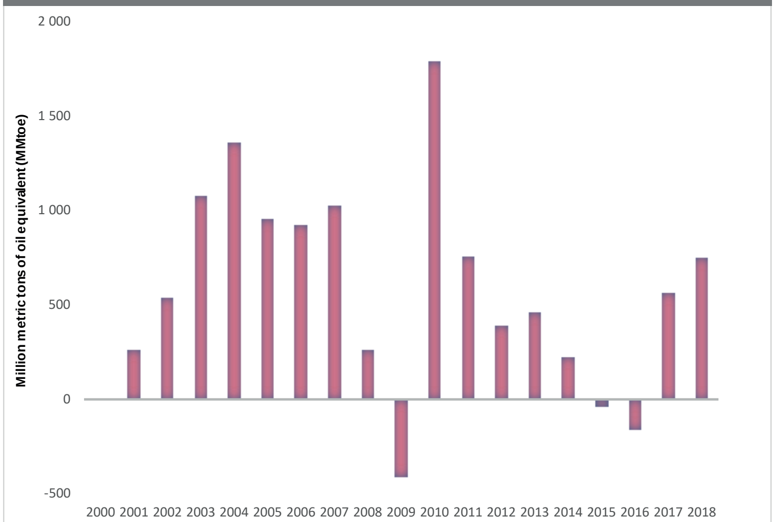
Solid-state batteries are but one of many frontiers in energy storage. A wide variety of other technological approaches to managing power supply exist, and are undergoing further development, with the goal of increasing the resilience of energy infrastructure and reducing costs to energy providers and consumers. These include such special-use technologies as: flow batteries, which use the energy stored in electrolyte solutions to increase battery cycle life and accelerate response times; flywheels, which capture rotational energy to deliver instantaneous electricity; compressed air energy storage; thermal (heat) energy, which derives from a substance whose molecules are vibrating more rapidly as a result of a rise in its temperature; and pumped hydro, which relies on large-scale reservoirs of water (or other materials) and gravity to generate electric power[35]. In general, the costs of energy storage tend to be higher than the lithium ion batteries: from $315/kWh to $1680/kWh for different types of flow batteries and between $1500/kWh and $6000/kWh for flywheels; the storage costs of compressed air and pumped hydro are difficult to calculate, as the cost is site-specific and depends largely on the environmental characteristics of the reservoir (of air or water).[36]

[35] For more on these technologies, see the website of the Energy Storage Association (http://energystorage.org/energy-storage/energy-storage-technologies).
[36] International Renewable Energy Agency (IRENA), Electricity Storage and Renewables: Costs and markets to 2030, October 2017 (https://www.irena.org/-/media/Files/IRENA/Agency/Publication/2017/Oct/IRENA_Electricity_Storage_Costs_2017_Summary.pdf?la=en& hash=2FDC44939920F8D2BA29CB762C607BC9E882D4E9).

2.5. Coal: Production and Consumption Still Increasing Despite Climate-Related Curtailment Efforts

Despite efforts to curtail coal production and consumption globally in an effort to reduce GHG emissions, both actually increased in 2017 and 2018, after falling for a three-year period (2014–16). Although major benchmark coal prices trended upward during this period, before crashing in mid-2018, coal remains highly cost competitive in electric power generation in many countries around the world, still accounting for 40% of capacity (and 38% of generation) globally. Global coal production in 2018 was 3916.8 million metric tons of oil equivalent (MMtoe; or roughly 7.7 billion metric tons), up 4.3% on 2017, and growing by 1.3% annually on average over the preceding 10-year period (2007–17). Coal consumption was 3772.1 MMtoe (~ 7.65 billion metric tons), up 1.4% on 2017. The outsized driver underlying these trends was the Asia Pacific region, which includes the world's two largest coal consumers (China and India); the region accounted for 75.3% of total world coal consumption in 2018. Not coincidentally, the years 2017 and 2018 were also notable as years in which GHG emissions increased (by 2% in 2018), interrupting a similar three-year period (2014–16) of declining global GHG emissions (see Figure 2.7. World growth in energy-related CO2 emissions, 2000–2018)[37].

Figure 2.7. World growth in energy-related CO2 emissions, 2000–2018



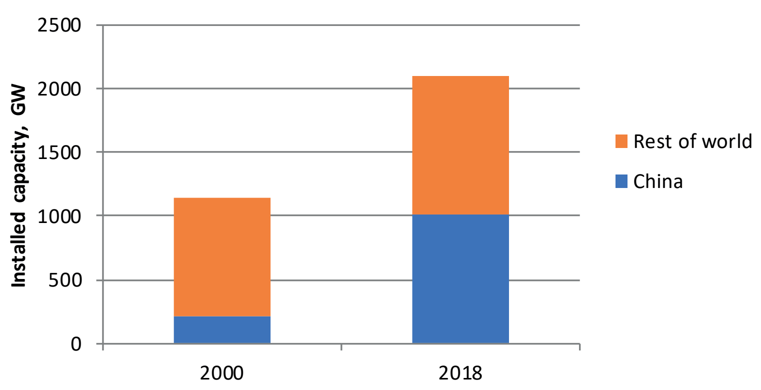
Source: IHS Markit

2.5.1. Power Generation in China and India: Key Drivers of Coal Consumption Trends

Given this seemingly close linkage between global coal consumption and GHG emissions, a key question for global climate policy involves how quickly China, which alone consumes 50.5% of the world's coal, could meaningfully reduce its consumption, particularly in electric power generation (see Figure 2.8. Installed coal-fired power capacity in the world (2018)).[38] But what is problematic is that China's coal-fired fleet is actually one of the youngest in the world—87% was built within the past 15 years; and 55% was built within the past 10 years. Assuming a 30-year technical life for these plants, China's 1,000 GW coal fleet—enough to power the EU-28—may not retire until 2035–50.[39] But their retirement could create enormous room for other fuels and technologies.

[37] See the IHS Markit Global Scenarios Presentation, Global Scenarios Workshop at CERA-Week, 11 March 2019, p. 33.

Figure 2.8. Installed coal-fired capacity in the world, 2018



However, there could also be unprecedented challenges for power supply should this much reliable dispatchable power supply be retired in just a short period. If this capacity was replaced mainly by renewables, not only China would need to build 2,000 GW of new wind and solar capacity but it would also need substantial storage capacity to back them up. These very big numbers would challenge the creative energy of any country. Beyond the question of whether China has sufficient renewable energy resources to accommodate this scale of growth are the implications of such a build-out on world demand for materials needed to build the storage and battery capacity. It is likely that other carbon-neutral technologies (e.g., nuclear in particular) would need to play a role in this transition, and probably even some non-carbon-neutral ones (piped gas and LNG).[40]

Meanwhile, the addition of new and more efficient domestic coal production capacity over recent years means that by end-2018, China's total coal production capacity had grown by some 200–300 MMt/y. China is moving into supply overcapacity, while improved transportation links between the coal country and the main demand centers means that China is expected to be in a situation of domestic oversupply starting in 2019. This will put downward pressure on domestic coal prices.

In India, the world's second largest coal consumer, power plants' coal imports increased by 9% in the 2018–19 financial year (ending 31 March 2019) after three years of declines, according to data from the country's Central Electricity Authority (CEA). Power plants' coal imports rose to 61.7 MMt in the financial year, up from 56.4 MMt, primarily due to a surge in purchases by government-owned plants to meet domestic supply shortages in the wake of higher electricity demand.

2.5.2. Coal Demand in Europe Declining: Can Renewables Fill the Gap in Power Generation?

Unlike the conditions favoring growth in coal consumption in much of Asia (and Africa too), European coal demand is firmly in decline as policy measures on coal become increasingly hostile. In early 2019, for example, Germany's coal commission defined a clear and gradual phase-out path for coal-fired power. All coal-fired capacity will exit the power market by 2038—a major development as

[38] See the IHS Markit Regional Power, Gas, Coal, and Renewables Event, China's Coal-Fired Power Retirement: Transforming the long-term future of energy, 9 May 2019, p. 5.
[39] 794 GW of Chinese coal plants—or 79% of the current coal fleet—will reach technical retirement age between 2030 and 2045. However, coal plants often are not retired based strictly on technical life, and instead their operations are extended by replacing certain equipment. In the United States, for example, over half of the coal plants currently in operation are 40 years or older.
[40] See the IHS Markit Event: Regional Power, Gas, Coal, and Renewables, China's Coal-Fired Power Retirement: Transforming the long-term future of energy, 9 May 2019.

coal is the main source of power supply (43 GW of capacity, accounting for 35% of total generation in 2018). New gas additions—mostly combined heat and power (CHP)—will replace roughly half (20 GW) of the equivalent retired coal capacity. Renewables will also grow: 175 GW of renewable and storage additions are expected by 2050. However, the pace of additions will be just short of meeting the 65% renewable target set for Germany in 2030: IHS Markit projects that renewables will cover 62.6% of gross power demand by then. Despite these investments, the coal phaseout (coupled with the cessation of nuclear generation at the end of 2022) will make Germany a net power importer—a development that will reverberate across 10 other European nations that currently import electric power from Germany.

Spain is following Germany's lead, where the plan is to phase out one-half of the country's 11 GW of coal-fired generation capacity by 2020 and to focus on gas-fired generation to fill much of the gap. France, in turn, plans to shutter its remaining four coal-fired plants by 2022.

2.6. Implications for Kazakhstan

Although trends in global energy are diverse and not completely unambiguous, a few key themes emerge that are particularly salient for Kazakhstan, echoing topics discussed in greater detail later in the report.

- The environment for upstream investment globally is highly competitive. Major international oil and gas companies are under pressure to increase returns to shareholders, exercise capital discipline, and account for the impact of compliance with climate policies on their balance sheets. They also are emphasizing diversification of their overall energy portfolios (renewables; carbon capture, use, and storage (CCUS); electricity and natural gas production and distribution) and their focus has shifted toward increasing cost-effectiveness rather than growing reserves. Undertaking these compliance and diversification initiatives is expected to have a muting or depressing effect on their capital expenditures, especially in new ("greenfield") ventures. In such an environment, it is important that Kazakhstan continues to ensure it adopts favorable policies that offer attractive conditions for investments by IOCs for development of new projects.
- In concert with the emphasis on increasing cost-effectiveness rather than increasing reserves, there is a growing partnership between IOCs and large technology firms to apply powerful technological innovations in order to cut industry costs and to boost production. It will be important for companies in Kazakhstan, including KMG itself, to keep up with these trends to boost production at existing fields, particularly in attenuating the decline of legacy fields. To a certain extent, it may be possible for Kazakhstan to leverage its partnership with the IOCs at the "Big 3" (and others) to assimilate and master these technologies (including those for working unconventional deposits).
- In many countries, end-user pricing for hydrocarbons and electric power is a politically sensitive issue, and the pass-through of higher costs is problematic. In the case of developing economies, policymakers must address tough issues involving affordability as well. In Kazakhstan, in particular, these issues are now at the forefront, as producer prices are not currently high enough to incentivize the supply of domestic crude to refineries or natural gas to the domestic market. Neither are end-user prices sufficiently high to incentivize efficiencies in energy processing, transport, and consumption. The current administrative measures designed to direct supply toward demand in Kazakhstan's domestic market will need to be replaced with more market-oriented policies in order to harmonize with those that are set to be in place within the single oil/oil products and gas markets within the Eurasian Economic Union by 2025.

3. Kazakhstan's upstream oil sector and its domestic refined products market

3. Kazakhstan's upstream oil sector and its domestic refined products market

This chapter examines key oil sector changes and continuities in Kazakhstan since the previous National Energy Report (in 2017), considers the general outlook for Kazakhstan's oil industry to 2040, and offers recommendations for how best to achieve certain major goals—particularly generation of new investment and creation of a common Eurasian Economic Union (EAEU) oil market by 2025. The chapter begins with an overview of primary findings and conclusions, and then looks in more detail at the implications of the OPEC+ deal for Kazakhstan, the country's evolving oil balance dynamics, and implications of the EAEU harmonization process.[1]

3.1. Key Points

- An important common denominator across the sector is the need for more thorough pricing and other regulatory reforms, both to attract new investment in an extremely competitive global market and pave the way for successful EAEU integration. The reform agenda should include full liberalization of crude and refined product prices, liberalization and implementation of market mechanisms for resource allocation, as well as further fine-tuning and improving of existing tax and subsoil legislation.
- Kazakhstan officially joined the OPEC+ initiatives ("Vienna Alliance") to rein in oil production and rebalance global markets during 2017–19, and has benefited from the resulting recovery of world oil prices. Although Kazakhstan doubled its reduction target for the second round of OPEC+ cuts starting in January 2019, the most decisive factor in the Kazakh oil production profile remains the planned schedules of the Kashagan, Tengiz, and Karachaganak "mega" projects that in aggregate account for a large (and growing) share of total national output (around 60% in 2018), rather than any explicit actions by Kazakh authorities in support of Vienna Alliance targets.
- Even so, Kazakhstan's oil (crude and gas condensate) output returned to a growth trajectory during 2017–18 after declining three years in a row, and reached 90.4 MMt (1.90 MMb/d) in 2018, due largely to the ramp-up of Kashagan. The IHS Markit outlook is for expansion of total Kazakh oil production by around 39% during 2019–35, centered primarily at Tengiz and Kashagan, after which aggregate production is expected to stagnate and decline. Key factors in this production outlook include the eventual realization of Phase 2 for Kashagan and new Caspian offshore projects (with the launch of the Kalamkas-more–Khazar co-development plan a key harbinger) as well as the scale and effectiveness of mature onshore field redevelopment.
- The smaller, independent oil producers in Kazakhstan clearly could play a greater role in the country's oil balance, partially mitigating fluctuations in output due to timing and inherent uncertainties in "mega" project development schedules. But realization of this potential depends on greatly improved business conditions for the smaller companies.
- Kazakh crude oil exports rebounded during 2017–18, and totaled 70.2 MMt (1.46 MMb/d) last year. Oil export dynamics going forward are expected to mirror the national oil production trend given limited incremental domestic demand for crude—resulting in a total increase in Kazakh crude oil exports of

[1] For background on issues discussed in this chapter, see Chapter 7 of the National Energy Report 2015 and Chapters 3 and 4 of the National Energy Report 2017.

nearly 50% over 2019–35, followed by moderate decline.

• Thanks to investment in expansion, the CPC pipeline (that transits Russia to the Black Sea) has handled an increasing share of Kazakh oil exports recently (around 75% of the total in 2018), and is expected to remain the chief outlet for Kazakh oil exports through at least 2040. But pipeline constraints and Kazakhstan's "multi-vector" export strategy mean that some Kazakh oil will also be evacuated via other routes. In particular, during the period 2019–40 Kazakhstan is expected to ship larger volumes via the Kazakhstan-China pipeline (KCP), and probably will eventually resume shipments via the Baku-Tbilisi-Ceyhan pipeline (BTC). Kazakhstan's oil is well positioned to compete in expanding Asian oil markets, while European demand for Kazakh oil is expected to endure.

• The completion of the $6 billion refinery modernization program at Kazakhstan's three major plants—Atyrau, Pavlodar, and Shymkent—underpinned an expansion of total Kazakh refinery throughput by 10.2% in 2018 to 16.4 MMt (341,000 b/d), along with a lightening of the average refined product barrel, reflected in a 17.2% jump in Kazakh gasoline output last year. The IHS Markit base case is for only a moderate increase in refining going forward, with the improved product slate allowing rising domestic product demand for light products, such as gasoline and diesel, to be met, with perhaps even a slight surplus for export of light products to neighboring markets.

• The refinery upgrades have succeeded in significantly lessening Kazakhstan's traditional reliance on imports of light products from Russia—thereby substantially enhancing the security of Kazakhstan's refined product supply—and existing Kazakh refinery capacity should be sufficient to meet domestic oil product demand through at least 2030. The promise of large-scale Kazakh exports of light products is likely to remain elusive, though Kazakhstan may well compete for niches in selected regional markets (e.g., Kyrgyzstan, Uzbekistan).

• Continued over-regulation of Kazakhstan's downstream oil sector seriously impairs industry development. The national oil company, KazMunayGaz (KMG), and other resource holders and give-and-take providers supply feedstock to the three main refineries under a processing system that pays for plant modernization and ensures high margins for refiners, but fails to incentivize refiners to further improve efficiencies and optimize the product slate. The current processing system leaves upstream suppliers with insufficient incentive to deliver crude to the domestic market—particularly given artificially low prices in domestic refined product markets, resulting in a netback for domestic crude deliveries that is well below export netback parity. Retail product prices remain heavily administered notwithstanding official price liberalization, and periodic product import and export bans constitute another major market distortion.

• In the lead-up to the planned 2025 formation of a common EAEU oil market, IHS Markit recommends Kazakhstan follow Russia's lead and eliminate crude export duties altogether, allowing domestic crude prices to rise to the level of export netback parity, while gradually phasing out the current refinery processing system (and instead making refiners merchant operators who buy crude and sell products), permit domestic wholesale product prices to reach the average level among EAEU member states (essentially export parity netback), increasing excise taxes to harmonize with the other EAEU members, and minimizing all product import-export restrictions.

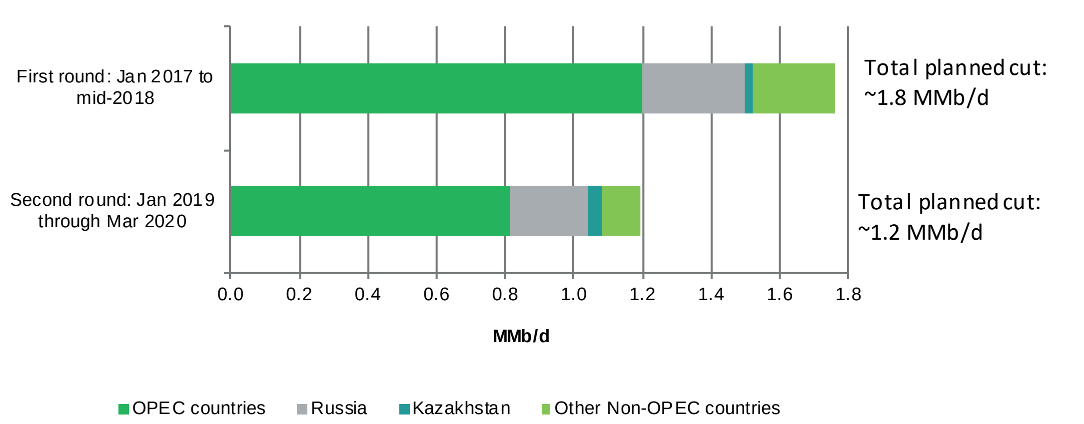
3.2. Implications of the OPEC+ Deal in 2017–19 and Global Oil Market Trends for Kazakhstan

The latest OPEC+ oil production cuts program, starting in January 2019, is in several respects a reprise of the first joint reductions effort (launched in early 2017 and continuing through mid- 2018), while now (as during the first round of cuts) the production schedules of Kazakhstan's three "mega" projects—Tengizchevroil (TCO), the North Caspian Operating Company (NCOC), and the Karachaganak Petroleum Operating BV (KPO)—have so far had a much greater impact on Kazakhstan's overall oil production profile than any explicit actions by Kazakh authorities in support of OPEC+ targets. But this time the stakes are potentially higher—given Kazakhstan's decision to double its official contribution to the OPEC+ reductions program compared with the first round of cuts—while significant changes in the broader macroeconomic and global oil market context spell a new set of risks and opportunities for Kazakhstan.

3.2.1. Overview of OPEC+ Arrangements

The second round of cuts agreed by the Vienna Alliance is smaller than the first round overall—down from a planned reduction of 1.8 MMb/d set in the first half of 2017 (subsequently extended to mid-2018) to a target of a 1.2 MMb/d aggregate cut in the first half of 2019 (now supposed to continue through March 2020). But in marked contrast to this general trend, Kazakhstan doubled its planned cut in the second round compared with the first—to a total of 40,000 b/d this time (see Figure 3.1: Distribution of OPEC+ oil output reduction targets: First and second rounds). As a result, Kazakhstan's share of the total OPEC+ cuts target also rose substantially in the second round (from 1% to 3%) as did Kazakhstan's share of the cuts among various key sub-categories of OPEC+ deal participants, including FSU producers (from 6% to 14%) (see Figure 3.2: Changes in Kazakhstan's share of OPEC+ cut targets within key categories of OPEC+ producers).[2]

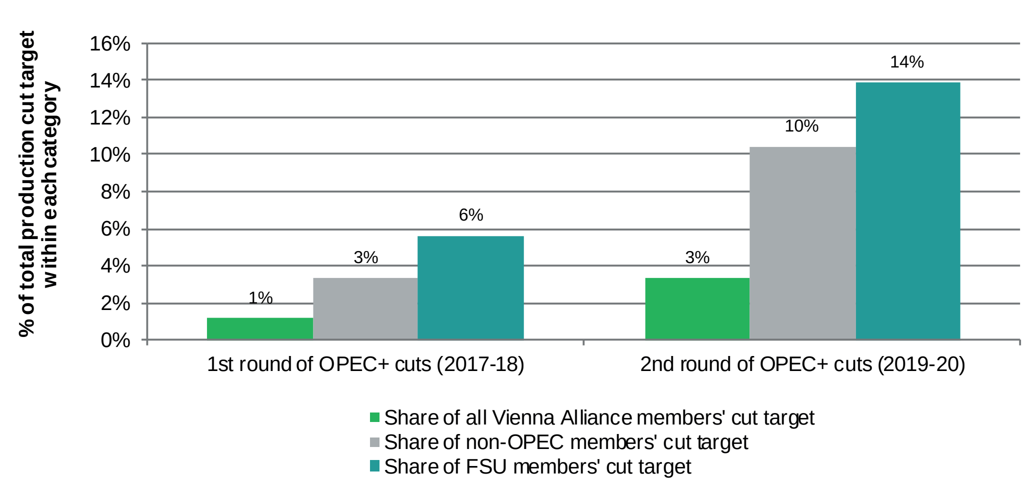
Figure 3.1. Distribution of OPEC+ oil output reduction targets: First and second rounds



Source: IHS Markit

[2] "Oil" production (and export) volumes include crude oil and gas condensate (with the latter defined as gas liquids produced in the fields). Statistics of Kazakhstan and the former Soviet republics typically report oil production volumes in metric tons, but the OPEC+ agreements quantify production changes in barrels per day. Estimates of Kazakh crude oil and gas condensate volumes in barrels as reported in this chapter are generally based on an average conversion ratio of 7.6 barrels per ton, but these are only approximate values.

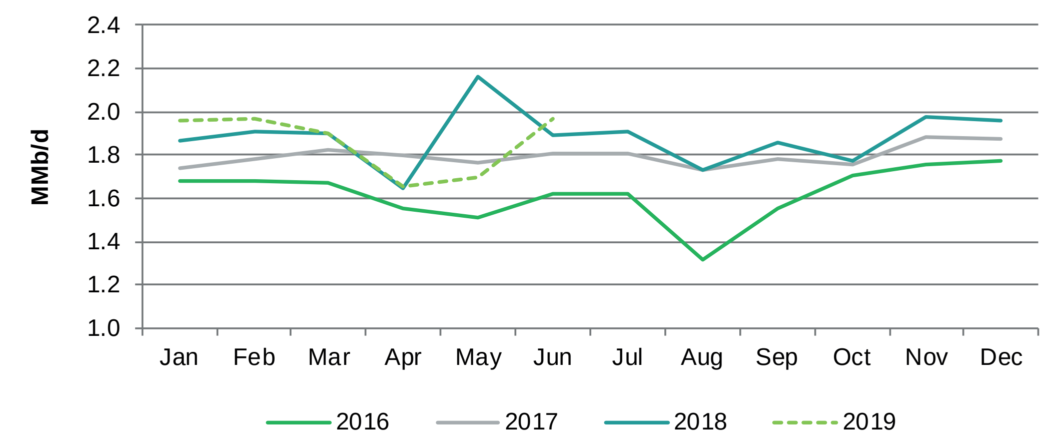
Figure 3.2. Changes in Kazakhstan's share of OPEC+ cut targets within key categories of OPEC+ producers



Source: IHS Markit

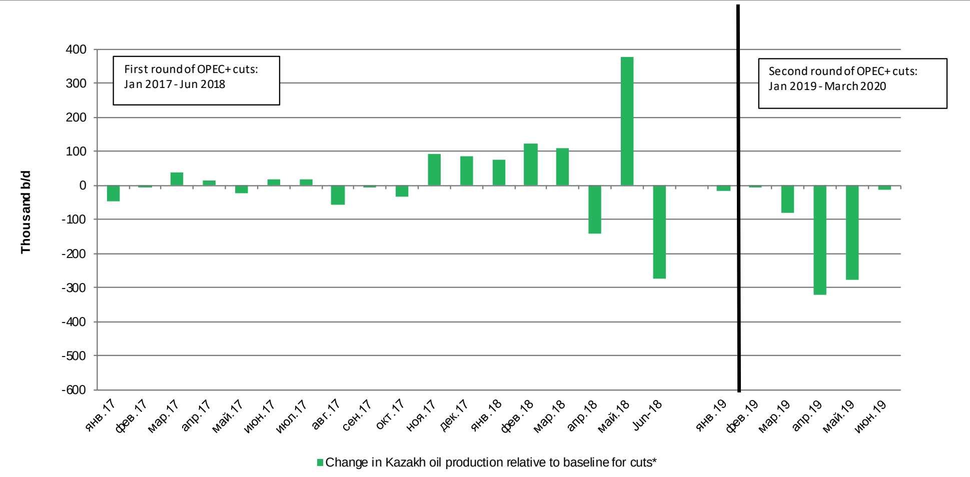
positive impact on global prices during each round of cuts. Kazakhstan actually increased its overall oil production during the first round of OPEC+ cuts in 2017–19, but managed to reduce output in the first half of 2019—reflecting the changing dynamics of Kashagan in particular. In the earlier round of reductions, the ongoing ramp-up of Kashagan eclipsed any decline at legacy fields. During the second round of cuts in the first half of 2019, in contrast, a major Kashagan maintenance program in April–May enabled Kazakhstan to initially meet its 40,000 b/d OPEC+ reduction commitment (and indeed greatly exceed the target during this period) (see Figure 3.3: Monthly Kazakh crude oil and condensate production, 2016–19, and Figure 3.4: Monthly changes in Kazakh oil production relative to baselines for cuts during periods of planned OPEC+ reductions).

Figure 3.3. Monthly Kazakh crude oil and condensate production, 2016-19



Notes: Converted at an average of 7.6 bbl/ton.
Source: IHS Markit, Infotek

Figure 3.4. Monthly changes in Kazakh oil production relative to baselines for cuts during periods of planned OPEC+ reductions

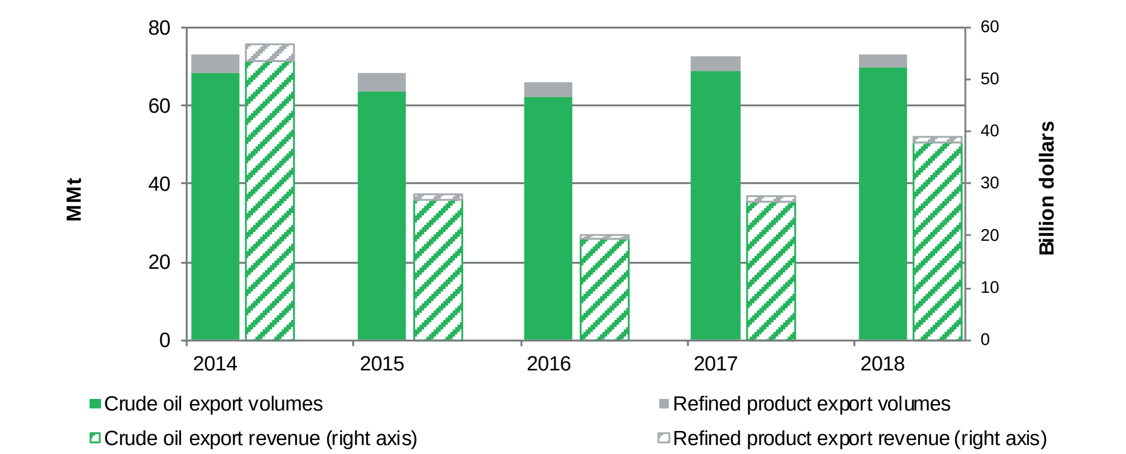


*November 2016 baseline for Kazakhstan's planned 2017-18 reduction of 20,000 b/d; November 2018 baseline for Kazakhstan's planned 2019 reduction of 40,000 b/d.

Source: IHS Markit, Infotek

The price trajectories for Kazakhstan's primary export streams—CPC Blend and Urals Export Blend (Urals), which consist of a different cocktail of Kazakh and Russian crude streams—have basically mirrored the aforementioned price trend for Brent during the period of the OPEC+ deals. For example, the average annual price of CPC Blend—now accounting for the bulk of Kazakh crude exports—rose by around 61% during 2017–18 compared with the 2016 average, reaching an average of about $70/bbl in 2018. The net result for Kazakhstan of the price rise over 2017–18 was a $18.7 billion increase in combined crude oil and refined product export earnings in 2018 compared with 2016, with the bulk of this concentrated in crude revenue (see Figure 3.5: Kazakhstan's crude oil and refined product export volumes and revenues, 2014–18). The $38.9 billion generated by crude oil and refined product exports in 2018 represented 63.8% of Kazakhstan's total export revenues.

Figure 3.5. Kazakhstan's crude oil and refined product export volumes and revenues, 2014-18



3.2.3. Prospects for Continuation of the OPEC+ Accord and Its Longer-term Impact

The Vienna Alliance has a strong incentive to maintain the current production limits agreed in July 2019, at least through the end of 2019, given considerable downside risk to oil prices otherwise. None of the OPEC+ members really can afford a steep prolonged decline in world oil prices, due to the heavy dependence of their economies and government budgets on hydrocarbon revenues, and absent ongoing production constraint, oversupply is likely to re-emerge in global oil markets.[3]

But competing priorities cloud the outlook for collaboration among Vienna Alliance members in the medium to longer term, as the case of Kazakhstan itself illustrates. On the one hand, the OPEC+ policies have yielded clear benefits for Kazakhstan on the whole in the form of increased oil export revenues resulting from higher oil prices. Kazakh authorities have also repeatedly stressed the importance of the stability of world oil prices, to which OPEC+ production management contributes, insofar as volatile oil prices complicate budget planning for the government even more so than the oil companies. Further tactical Kazakh cooperation with other Vienna Alliance members is therefore likely in the near term. But the Kazakh "mega" project schedules still take precedence. Moreover, Kazakhstan has little incentive to participate in anything more than the current loose OPEC+ coalition. Larger-scale Kazakh efforts to cut production in support of OPEC+ goals are theoretically possible, but this would tend to stunt Kazakh oil industry development. Moreover, in such a scenario the smaller independent producers in Kazakhstan would likely be compelled to cut production as well, clouding the longer-term growth prospects of this industry segment. In contrast, output of the "Big 3" fields should remain relatively stable, if not growing, given investment decisions already made by the international consortia leading these projects.

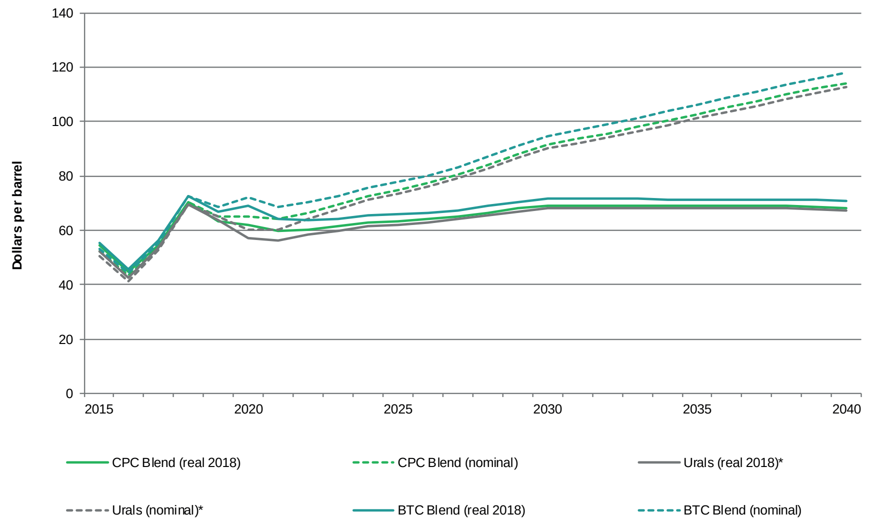
The impact of the OPEC+ initiatives on Kazakhstan, and its degree of collaboration with other Vienna Alliance members, depends ultimately on the longer-term evolution of the global liquids supply-demand dynamic. If there is global oversupply in the longer run, the Vienna Alliance will likely need to continue to cap output in support of prices, and it will be relatively difficult for Kazakhstan to consistently comply, let alone undertake additional cuts.[4]

The IHS Markit base case is for a relatively flat real Brent price going forward, and a comparable trajectory for CPC Blend, Urals Blend, and BTC Blend (see Figure 3.6: Long-term price outlook for selected Kazakh crude oil export streams). Kazakhstan will likely remain engaged with OPEC+ on production management questions for some time to come.

[3] The risk of oversupply in the near term is tied in part to planned pipeline capacity additions from the Permian Basin in the United States, facilitating a new surge in US shale oil production: IHS Markit expects that new large-diameter pipelines launched by the second half of 2019 will ultimately deliver 2.3 MMb/d of additional oil.

[4] The current IHS Markit base case (Rivalry) scenario to 2050 is for global oil demand to rise from the 2018 level of around 101 MMb/d to a plateau of around 117 MMb/d during 2036-40 before easing down to approximately 113 MMb/d by 2050. Prices need to be sufficient to incentivize enough supply to meet demand growth, and in our base case oil prices gravitate to a range of $67–70/bbl for Brent in real 2018 US dollars in the long term. Our analysis of the global cost curve indicates that there is sufficient supply available at this price range to meet projected demand. But there is much potential for divergence of market fundamentals and prices from such a trajectory during shorter-term periods within the overall scenario time frame. In fact, there is always some risk of market imbalances recurring, with the result that ongoing ad hoc adjustments of OPEC+ production policy may be needed to restore the balance.

Figure 3.6. Long-term price outlook for selected Kazakh crude oil export streams



Notes: *Urals historical data and scenario are based on average for Urals NWE CIF and Urals FOB Novorossiysk.
Source: IHS Markit, Argust Media Limited (for historical prices)

3.2.4. Oil Market Outlook for Key Global Regions

The IHS Markit base case (Rivalry) scenario envisions the following key oil market dynamics in selected major regions during the period out to 2040.[5]

• **Asia-Pacific markets remain the chief center of incremental global oil demand—supplied primarily from outside the region.** The Asia-Pacific region registers a net oil demand rise of 34.8% during 2019–40, to 48.6 MMb/d. But dynamics within the region vary widely. Non-OECD Asian demand increases by 50.1% to 41.7 MMb/d, reflecting expansion of Indian and Chinese demand in particular. In contrast, OECD Asian oil demand drops 16.5% to 6.9 MMb/d during the same period, reflecting mainly the structural decline of Japanese oil demand. At the same time, Asia-Pacific oil production falls overall by 23.1% to 4.99 MMb/d during 2019–40.

• **European demand and indigenous production both fall, leaving overall European import volumes relatively stable.** European demand drops overall by 15.9% to 13.2 MMb/d. Meanwhile, the expected contraction in European production (essentially North Sea output) amounts to 1.23 MMb/d during this period, representing a 41.2% decline, for total production of just 1.76 MMb/d in 2040.

• **North American oil demand slowly contracts overall, while production reaches a maximum in 2030.** Demand falls by 7.3% to 23.0 MMb/d during 2019–40. Regional output reaches a maximum of 24.2 MMb/d in 2030, and then falls to 23.1 MMb/d by 2040. This nevertheless represents a net production increase during 2019–40 of 33.3%.

3.3. Recent Evolution of Kazakhstan's Oil Balance and Outlook to 2040

Key Kazakh oil balance developments include the return of oil production and exports to a solid growth trajectory during 2017–18. Kazakh oil production and exports remain on a growth trajectory throughout most of the period to 2040 in the IHS Markit base-case scenario, while aggregate domestic

[5] See the IHS Markit Strategic Report, Rivalry: The IHS Markit view of the energy future (2019–50), July 2019.

product demand and especially domestic refining increase more moderately.

3.3.1. Overview of Oil Balance Trends

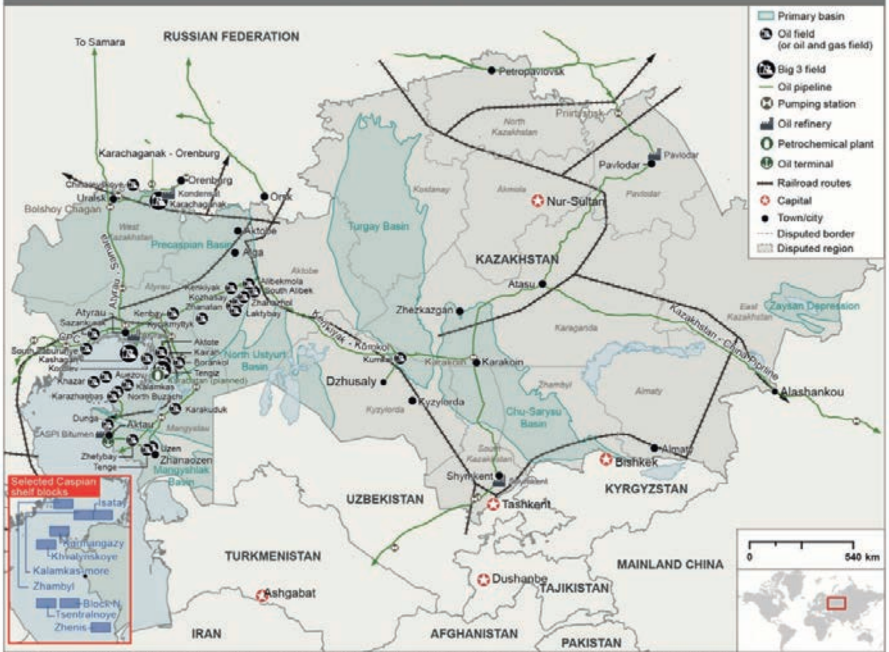
Oil production reached a record level in 2018 (see Table 3.1: Crude oil and condensate balance for Kazakhstan for details on Kazakhstan's oil balance during 2010–18; and Figure 3.7: Kazakhstan's oil sector). The positive production dynamic reflected the ramp-up of Kashagan in particular, with most of the incremental output directed to global markets via CPC. On the downstream side, domestic apparent product demand has continued to rebound since 2015, spurring increased Kazakh refining. Even more striking has been the lightening of the average Kazakh refined product barrel—in conjunction with completion of modernization programs at the three major refineries—alleviating Kazakhstan's dependence on Russian product imports.

Table 3.1
Crude oil and condensate balance for Kazakhstan
(million metric tons)

	2010	2011	2012	2013	2014	2015	2016	2017	2018	% change 2017-18
Production	79.7	80.0	79.2	81.8	80.8	79.5	78.0	86.2	90.4	4.8
Apparent consumption	19.7	17.5	17.2	16.7	11.6	14.7	14.7	16.7	20.2	21.5
Refinery throughput	13.7	13.7	15.1	15.3	16.4	15.0	14.9	14.9	16.4	10.2
Direct use of crude/unidentified*	6.0	3.8	2.1	1.4	-4.8	-0.3	-0.2	1.8	3.8	116.1
Exports**	67.5	69.6	68.1	72.2	69.7	64.8	63.4	69.6	70.2	0.8
Outside the Former Soviet Union	65.8	67.9	67.4	71.4	68.3	62.0	62.6	68.7	69.5	1.1
Via Russian pipeline system (non-Makhachkala)	15.5	15.4	15.4	15.4	14.6	13.5	15.0	15.9	14.8	-7.3
Via CPC	28.5	28.3	25.3	28.7	35.2	39.0	42.4	49.4	54.3	9.9
Via Atasu-Alashankou pipeline	10.1	10.8	10.4	11.8	4.8	4.4	2.8	2.7	1.4	-47.7
Via railroad	5.7	7.3	6.1	8.7	1.8	0.3	0.5	0.4	0.3	-15.1
Via Russian railroad (to Finland, etc.)	5.7	7.3	6.1	8.7	1.8	0.3	0.5	0.4	0.3	-15.1
Via Kazakh railroad to China	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	
Via Caspian	9.3	5.8	7.6	6.0	5.2	3.2	2.2	1.2	0.9	-21.3
through Azerbaijan/Georgia	5.2	2.3	3.8	3.2	3.5	1.6	0.6	0.7	0.0	-100.0
To Baku-Tbilisi-Ceyhan (BTC)	0.0	0.0	0.0	0.6	2.4	1.1	0.0	0.0	0.0	
To Iran (including direct shipments by rail)	0.5	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	
To Novorossiysk (via Makhachkala)	3.6	3.4	3.8	2.8	1.7	1.6	1.6	0.5	0.9	83.3
Former Soviet republics***	1.7	1.7	0.7	0.9	1.4	2.8	0.8	0.9	0.7	-21.4
Russia****	1.2	1.2	0.7	0.9	1.4	2.8	0.8	0.6	0.5	-20.0
Via Karachaganak-Orenburg pipeline	1.2	1.2	0.7	0.9	0.7	0.7	0.8	0.6	0.5	-20.0
Imports	7.4	7.1	6.1	7.2	0.5	0.1	0.0	0.0	0.0	0.0
Outside the Former Soviet Union	--	--	--	--	--	--	--	--	--	
Former Soviet republics	7.4	7.1	6.1	7.2	7.0	7.0	7.0	10.1	10.0	-0.7
Russia****	7.4	7.1	6.1	7.2	7.0	7.0	7.0	10.1	10.0	-0.7
to Kazakhstan-China pipeline (swap)	2.6	0.2	0.0	0.0	7.0	7.0	7.0	10.1	10.0	-0.7

*Balancing item: includes Karachaganak stabilization losses, other field losses, stock changes, processing by small mini-refineries, and any unrecorded deliveries.
**Total crude exports in the table are those reported officially in Kazakh trade statistics and includes both crude oil and condensate. There are differences with other reported totals, such as by the Ministry of Energy, for a number of reasons. For example, the figures issued by the Ministry exclude shipments of "compensation crude" to Russia that were made in 2014-15. Reported export totals may differ from the sum of reported exports via individual routes due to differences in source data: the national-level data on export trade are generated by customs-based statistics, whereas data on exports by individual routes are based on transportation and logistics statistics.
***Does not include seaborne deliveries to Ukraine via Black Sea.
****Russian oil swap volumes in 2014 (7 MMt) are included in import and export flows for Kazakhstan for comparative purposes with flows in 2013.
Source: IHS Markit, Kazakhstan Ministry of Energy and Committee on Statistics

Figure 3.7. Kazakhstan's oil sector (selected key elements)



Source: IHS Markit/1747249

IHS Markit's outlook assumes that decisive steps will continue to be taken by Kazakhstan to remain attractive to upstream investors. This was, of course, the primary goal of the revisions made recently to the Subsoil and Tax codes, but further improvements are still needed. So far, significant additional investments have been coming mostly through existing projects (with investment stability arrangements, such as PSAs), although some successes have been registered in new offshore exploration contracts. But the latter are in their very early stages. It is critical to note that Kazakhstan's oil sector needs continued reforms to remain attractive in the current highly competitive international upstream environment, especially for new projects.

• **Further "mega" project expansion is the main factor in additional production and export growth, but this comes to an end after about 2035 in the base case.** National oil production and exports grow by around 39% and 49%, respectively, during 2019–35 in our base case, with output reaching a maximum in 2035 at about 126 MMt (2.65 MMb/d) and exports reaching about 105 MMt (2.18 MMb/d). A production and export decline then sets in, as ongoing contraction of output at mature fields outweighs any further contribution from newer acreage. In particular, TCO's production profile now envisions a less attenuated decline post 2035. Still, the overall decline rate for Kazakhstan remains relatively moderate over 2035–40 in the base case—the annual fall in production averages around 1.1% during this period—as the decline of older fields is attenuated through application of new technology that has proven successful on such fields elsewhere in the world. Our outlook assumes that the "Big 3" are all able to extend their contracts on acceptable terms beyond 2035.[6]

Increased Kazakh consumption of lighter products underlies our base case of domestic demand growth

[6] The criticality of timely contract extension for longer-term investment can be seen in the recent evolution of the development plan for the Dunga field in Mangistau Oblast. In July 2019, Total, the project operator, announced plans to launch a third phase of Dunga development with its partners following a 15-year extension of the field PSA to 2039.

and expansion of refinery output. IHS Markit refined product consumption forecasts for Kazakhstan indicate a further rise in aggregate product demand, by 29.5% to 18.5 MMt (360,000 b/d) by 2040, reflecting growing gasoline, diesel, and jet fuel consumption. This is a key factor driving up refinery throughput, on the order of 17.5% to 21 MMt/y (429,000 b/d) by 2040. In other words, we expect that crude consumption (and refinery throughput) will remain tied to trends in light product demand, though there is also some potential for increased exports of surplus products to regional niche markets.

3.4. Crude Oil and Gas Condensate Production Dynamics

Kazakhstan's oil output returned to a growth trajectory during 2017–18 after declining three years in a row, due mainly to the ramp-up of Kashagan. The IHS Markit outlook is for further substantial growth of Kazakh oil production during 2019–35, centered primarily at Kashagan and Tengiz, after which a secular decline sets in. But key uncertainties in the production outlook include the progress of new offshore projects on the Caspian shelf (a harbinger is the pending Kalamkas-more–Khazar co-development project), the eventual launch of Kashagan Phase 2, the scale of new investment in mature field redevelopment, and the evolving role of the smaller independent producers. In this regard, the unfolding impact of Tax Code and Subsoil Code amendments that took effect in 2018 remains to be seen, as well as the new Ecology Code that is slated to be in place by mid-2020.

3.4.1. Liquids Reserve Base

Kazakhstan has a large oil resource base, including several major identified deposits and the prospect of substantial oil reserves yet to be discovered, particularly in the country's offshore sector of the Caspian Sea. As of 1 January 2018, the State Commission on Reserves (GKS) listed Kazakhstan's petroleum liquids (oil and gas condensate) reserve base (state balance) at 4.95 billion metric tons (37.6 billion barrels).[7] Of this, 4.5 billion tons are crude oil reserves, while the rest (420 MMt) is gas condensate (see Table 3.2: Kazakhstan's proven and probable oil and condensate reserves, 1 January 2019 (Thousand tons)). Thus, compared with the 1 January 2016 reserve totals noted in the National Energy Report 2017, the state reserves balance has decreased by 342.6 MMt.

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

	A+B+C1	C2	A+B+C1+C2
Crude oil	2,899,783.2	1,630,194.2	4,529,977.4
Condensate	332,650.2	87,846.0	420,496.2
Total	3,232,433.4	1,718,040.2	4,950,473.6

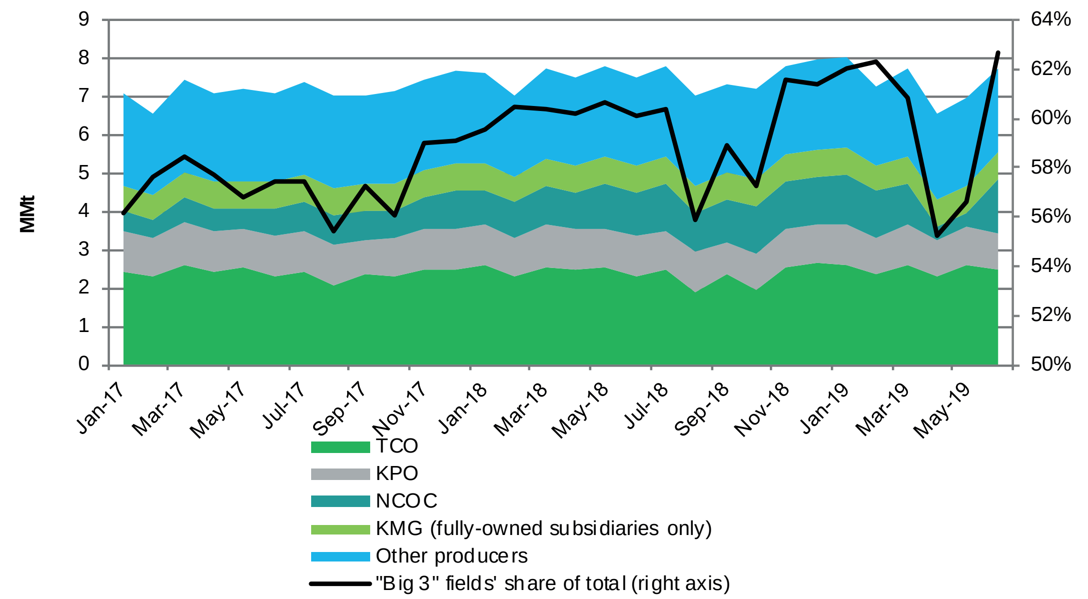
Source: State Commission on Reserves (GKS)

3.4.2. Recent Production Trends and Outlook to 2040

The 4.8% rise in Kazakh oil output in 2018, to 90.4 MMt (1.90 MMb/d), was driven mainly by the Kashagan project; overall, Kazakhstan's "Big 3" expanded their aggregate output by 8.8% to 54 MMt (1.12 MMb/d) in 2018—accounting for 60% of the Kazakh total (up from 57% in 2017) (see Figure 3.8: Monthly oil production of selected companies in Kazakhstan, 2017–19; and Table 3.3: Kazakhstan's "Big 3" upstream projects (key selected features).

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

Figure 3.8. Monthly oil production of selected companies in Kazakhstan, 2017–19



Source: IHS Markit, Infotek

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

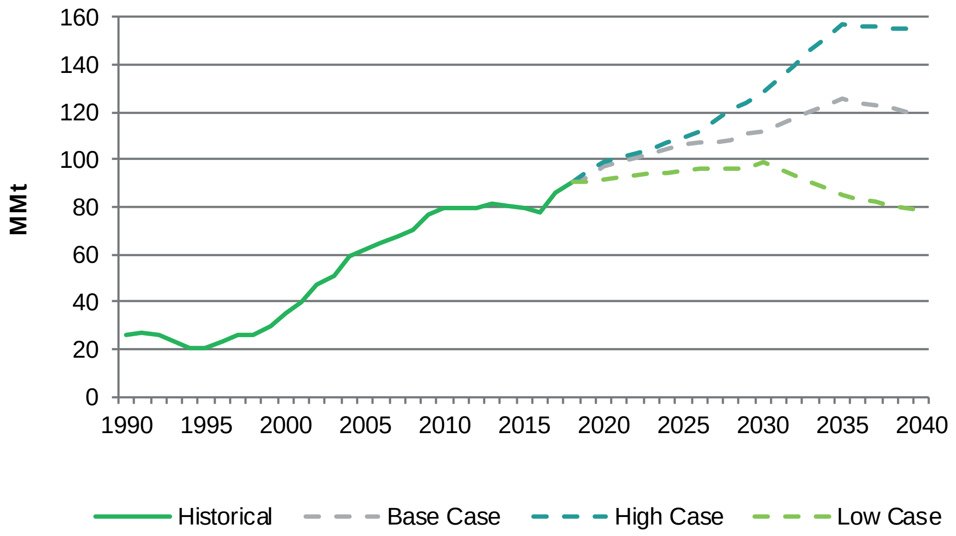
Project	Shareholders	Contract term	Capex incurred to date	Fields	Liquid reserves	Liquids production in 2018	Local content
TCO*	Chevron (50%), ExxonMobil (25%), KMG (20%), and LukArco (5%)	1993-2033	over $135 billion	Tengiz, Korolev	3.4 billion tons (27.1 billion bbl) of recoverable reserves, of which 3.2 billion tons (25.4 billion bbl) in Tengiz	28.6 MMt (623,000 b/d) of oil	share of local employees: 81% of TCO employees, and 91% of FGP workforce
NCOC**	KMG (16.88%); Eni, ExxonMobil, Shell, and Total with 16.81% each; CNPC (8.33%), and INPEX (7.56%)	1997 – 2041	over $60 billion	Kashagan, Kashagan Southwest, Aktote, Kairan, Kalamkas-more	1-2 billion tons (8-15 billion bbl) of 2P crude oil reserves	13.22 MMt (281,000 b/d) of oil	46% of goods and services acquired from local entities (those with 95% Kazakhstani residents)
KPO**	Shell (29.25%), ENI (29.25%), Chevron (18%), LUKOIL (13.5%), and KMG (10%)	1995 –2037	over $22 billion	Karachaganak	1.2 billion tons (10.0 billion bbl) of condensate	12.2 MMt (278,000 b/d) of condensate	Kazakhstani residents comprise 95% of technical workforce, and 77% of project leadership

*Technically, TCO is a JV but it is structured like a PSA, though not administered by the government's PSA LLC (representing the country's interests in PSA projects).

**PSA project
Source: IHS Markit

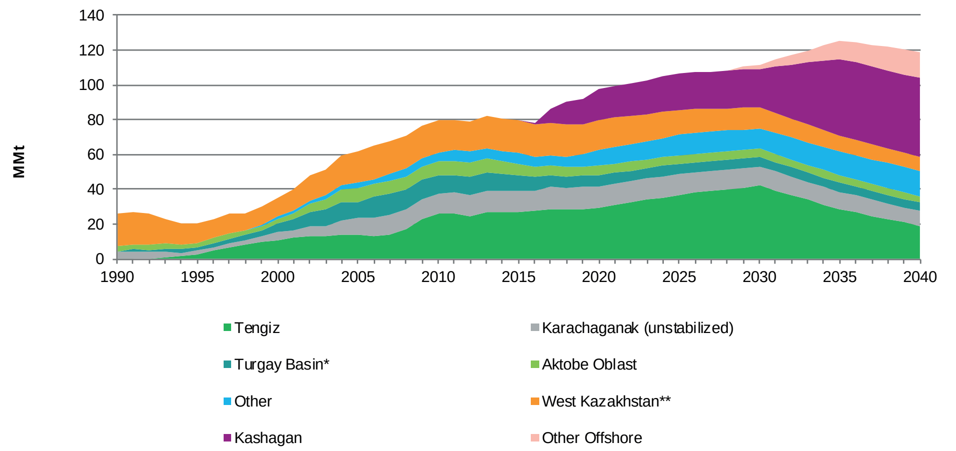
Much growth is still ahead, tied largely to the ongoing Tengiz expansion as well as debottlenecking efforts at Kashagan's existing Phase 1; we also still think that ultimately Phase 2 of the Kashagan project will be realized. Meanwhile KPO is likely to hold Karachaganak field output relatively steady going forward following its autumn 2018 approval of a new phase of field development and resolution of a long-standing commercial dispute with Kazakh authorities (see Figure 3.9: Outlook for Kazakhstan's oil production by scenario; and Figure 3.10: Kazakhstan's oil production outlook, base case.)

Figure 3.9. Outlook for Kazakhstan's oil production by scenario



Source: IHS Markit (Eurasian Oil Export Outlook) © 2019 IHS Markit

Figure 3.10. Kazakhstan's oil production outlook, base case



*Includes Amangeldy in Zhambyl Oblast; **West Kazakhstan production (not to be confused with the Kazakh oblast of the same name) covers the output of five legacy producers: UzenMunayGaz, MangistauMunayGaz, EmbaMunayGaz, CNPC International/Buzachi Operating, and KarazhanbasMunay. These producers are grouped together because of their location, similar crude quality, and general production dynamics as mature operators.

Source: IHS Markit (Eurasian Oil Export Outlook) © 2019 IHS Markit

Tengiz consortium (TCO)

Located in Atyrau Oblast, Tengiz is the largest Kazakh field by production, and likely to remain so for at least another decade. Although the field's output dipped in 2018 by 0.3%, to 28.6 MMt (623,000 b/d), TCO is carrying out a major expansion that will lift output by over 40% once on stream. The Future Growth Project, Wellhead Pressure Management Project (FGP-WPMP) was approved by TCO in 2016 with a total estimated capex of $36.8 billion. First FGP oil is now expected around 2021–22, and should add a total of 12 MMt/y (260,000 b/d) to the field's overall production capacity during the next decade. The main equipment for FGP is being manufactured in Kazakhstan, Italy, and South Korea, and pre-assembled in modules for transportation to the Tengiz site for final assembly.

Kashagan consortium (NCOC)

The Kashagan field, located around 80 km offshore from Atyrau, has entered a phase of more measured growth after its initial surge. Output in 2017—the first full year of operations following Kashagan's resumption of production in autumn 2016—amounted to 8.3 MMt (an average of 176,000 b/d). Kashagan's 2018 output was 13.2 MMt (an average of 281,000 b/d), for an annual increase of nearly 60%. NCOC suspended output during part of April and May 2019 to conduct extensive maintenance and repairs—the first production stoppage since the 2016 restart—and in June soon after resumption of operations NCOC announced that the field had reached the 370,000 b/d designed production level for Phase 1. With some debottlenecking during the turnaround, daily production since then has exceeded 400,000 b/d on occasion (average daily production in June was 365,000 b/d and in July it was 375,000 b/d). Our base case envisions additional expansion above the initial Phase 1 design level, to about 450,000 b/d before 2025, particularly through an increase in gas compression and injection capacity. We also believe that NCOC will also eventually sanction a second Kashagan phase. We anticipate the ramp-up of Phase 2 after 2030 (contingent on PSA renewal), enabling Kashagan to reach maximum annual output of about 45 MMt (955,000 b/d) in 2040. Kashagan is still essentially the only producing field in the Kazakh sector of the Caspian shelf, but there are plans to bring on stream NCOC's Kalamkas-more offshore satellite field within the framework of a joint project involving co-development of the adjacent Khazar field, licensed to the Caspi Meruerty Operating Company (CMOC), also known as the Pearls PSA.[8] Co-development would be led by NCOC, which estimates that the two fields could achieve combined output of up to 4.5 MMt/y (94,000 b/d). The total project cost is estimated at ~$5 billion. The joint project, if approved by the government, could ignite the next generation of offshore Kazakh development. Specifically, joint development of the fields would reduce capex by sharing an offshore processing hub, crude oil pipeline, and an onshore crude oil terminal. NCOC-CMOC are conducting the pre-FEED technical study through the third quarter of 2019. The goal is to get the development plan approved by the government later this year, allowing FEED to commence in 2020.[9] The next stage would be a Final Investment Decision (FID) within the next couple of years, followed by the launch of production in the 2025–27 timeframe.

Karachaganak consortium (KPO)

Located in West Kazakhstan Oblast, the Karachaganak field registered a 2.6% decline of (gross) liquids production in 2018, to 12.2 MMt (278,000 b/d). But in September 2018 KPO announced an agreement to sanction the Karachaganak Debottlenecking Project (KGDBN), which is designed to extend Karachaganak's liquids production plateau. Specifically, additional gas output (on the order of 4 Bcm/y) is planned within the framework of KGDBN to be used for reinjection into the field reservoir in order to maintain field pressure and make possible incremental production of 10 MMt (around 83 MMbbl) of liquids over the contract period. In the IHS Markit base scenario, Karachaganak liquids output decreases gradually from 2020 onwards (the decline rate averages less than 2% per year), with the result that liquids production in 2040 still amounts to around 9 MMt/y (about 195,000 b/d).

KazMunayGaz (KMG)

The national oil company KMG NC is among the largest producers in Kazakhstan on an equity basis, largely due to its holdings in the "Big 3." In contrast, the fields operated by KMG's fully-owned subsidiaries—consisting of legacy assets—are largely in decline. In 2018, total KMG equity crude production was 23.6 MMt (491,000 b/d). KMG's shares in the "Big 3" contributed 38% of this, while KMG's 100% owned subsidiaries, UzenMunayGaz (UMG) and EmbaMunayGaz (EMG), produced 5.5 MMt (114,000 b/d) and 2.9 MMt (60,000 b/d), respectively, but their production has been essentially flat since 2012. The mature UMG and EMG fields appear to have avoided a steep drop in output so far despite the fact that KMG has not undertaken any major rehabilitation measures to attenuate decline. But the risks of a sharper decline rate longer term, without extensive redevelopment efforts, are high, and are illustrated by the production trends at KMG's partially owned mature assets in Kyzylorda Oblast, where output fell by an annual average of 13% in 2012–18.[10]

In a 2018 bond prospectus, KMG signaled the company's intent to maintain production levels by undertaking "various field development projects, including the drilling of new wells, the completion of well workovers and the introduction of secondary enhanced oil recovery and well stimulation techniques." Some KMG subsidiaries have conducted horizontal drilling, while technology priorities going forward include adoption of certain digitization measures. Use of heavier rigs could also enable KMG to realize considerable potential in deeper, pre-salt layers at some existing KMG fields in western Kazakhstan. Heavier rigs needed for such projects are not currently available in Kazakhstan (outside of the "mega" projects), and acquisition of such equipment is not currently a KMG priority, but the company recognizes the imperative to drill deeper in the longer term.

At the same time, structural-regulatory and field management issues are challenging KMG's operations, and KMG lags in reserves replacement and capex. Employee benefits constitute 53% of KMG lifting costs, versus an average of 24% in Russia (in IHS Markit's estimate). Meanwhile, certain provisions of the Subsoil Code governing KMG restrict the company's ability to strategically optimize its upstream portfolio and operations (see below).

KMG is currently planning an initial public offering (IPO) of its stock that would involve selling up to 25% of the stock, currently held by National Welfare Fund Samruk Kazyna (NWF SK), to international buyers.[11] KMG's upstream unit, KMG E&P, held a stock offering of its own in 2006 (raising over $2 billion), but earlier this year was delisted and became a fully-owned subsidiary of KMG again, to establish one large, integrated company for the forthcoming IPO.

China National Petroleum Corporation (CNPC)

[8] CMOC shareholders are Shell (40%), Oman Pearls Company (20%), and KMG (40%).
[9] Co-development would ultimately require some minor, technical changes to the customs, subsoil, and tax codes (largely related to administrative accounting of gas molecules transferred between fields for reinjection).
[10] See the IHS Markit Upstream Companies and Transactions Profile, KazMunayGaz: Upstream strategy assessment, June 2019.

State company CNPC is another key player in the Kazakh upstream, where its main assets include majority stakes in CNPC-AktobeMunayGaz and PetroKazakhstan, and parity ownership of North Buzachi with LUKOIL as well as a stake in NCOC.[12] In 2018, the Chinese-owned equity share of Kazakhstan's oil production was just under 18% (including not only CNPC but other Chinese companies), which was lower than in the prior years due to KMG EP share buyback by the parent company KMG, where China Investment Corporation held 11% until 2018.

Smaller companies

In 2018, 78 smaller ("independent") companies produced 9 MMt (182,000 b/d) of oil or 10.5% of the total output in the country. This segment of producers has not increased production over the past several years. For example, in 2012, production by these independents amounted to 8.8 MMt or 11.1% of the total output; their aggregate output has been on the order of 8–10 MMt/y in recent years, or about 10% of national output. The potential for the independents' production growth is limited by many factors in a fairly difficult investment environment. Regulatory, fiscal, and contractual rules continue to impact smaller producers more strongly than larger companies.

These smaller producers tend to be Kazakh entities for the most part, while independent foreign investors have tended to exit the country or never invested. Notable exceptions, however, have included a number of Chinese investors, during a time when Chinese companies were investing very actively in a variety of projects. Creating an environment that is attractive to a more diverse pool of investors (both domestic and foreign) is important for Kazakhstan.

Smaller independents could expand their output with additional exploration activity to prove up additional reserves at their existing licenses, greater employment of specialists, and more effective application of technology. For example, more extensive adoption by the independents of international reserves classification standards—i.e., PRMS methods—could also boost their overall competitiveness and attractiveness. While over 90% of oil produced in Kazakhstan comes from companies using PRMS reporting, many smaller independents still use the Soviet reserves classification method, pushing back against a universal PRMS requirement, citing expensive reserve audits and retraining.

3.4.3. Impact of New 2017–19 Legislation on the Upstream Investment Climate

Kazakhstan has taken important steps in recent years to rationalize legislation and regulations that impinge on upstream investment. In particular, the 2016 introduction of an explicit oil export duty formula based on a sliding scale linked to the world oil price made for a more predictable fiscal regime overall (the prior method for adjusting export taxes was ad hoc and non-transparent), while 2017 changes to the Tax Code and Subsoil Code that took effect in 2018 included new fiscal incentives for selected upstream investment and some improvements in subsoil auction procedures.[13]

But Kazakhstan recently ranked at only the 61st spot (out of 131 countries) in the rating of E&P attractiveness developed by IHS Markit's Petroleum Economics and Policy Solutions (PEPS) team—with an overall score of 4.43 (out of 10), comprised of a blend of scores of 4.72, 3.32, and 6.07 for E&P risk, fiscal risk, and oil and gas risk, respectively. Such mediocre scores do not put Kazakhstan at the top for most international investors.

[11] KMG is owned by NWF SK (90%) and the National Bank of Kazakhstan (10%).
[12] For additional background on CNPC's upstream activity in Kazakhstan, see the National Energy Report 2015, pp. 99-101.

Additional regulatory changes are clearly required to attract new investment in an extremely competitive global market, particularly further refinement of the Tax and Subsoil codes and reformulation of the problematic draft Ecology Code (see Gas Chapter).

Tax Code

It was hoped that the revised Tax Code, effective from 1 January 2018, would greatly stimulate upstream exploration and investment. One key innovation was the introduction of an alternative tax option (alternativnyy nalog na nedropolzovaniye), whereby investors in selected technologically complex projects—continental shelf and deep horizons—may choose to pay a tax based on financial results (i.e., profits) in lieu of a variety of subsoil user taxes and payment obligations that otherwise apply (specifically, the mineral extraction tax, excess profits tax, rental tax, and reimbursement of the Kazakh government for historical costs).[14] The alternative tax rate ranges between 0% and 30% of the difference between a company's gross income on an annual basis and allowable deductions, depending on world oil prices (with a zero rate applying at a price of less than $50/bbl, and a 30% rate taking effect at prices above $90/bbl). As noted above, the special tax treatment of offshore areas has already contributed to a noteworthy increase in interest in new offshore exploration projects (e.g., on the part of LUKOIL in the Zhenis and IR2 blocks, and ENI at the Abay block).

But remaining shortcomings of the regular Kazakh oil sector fiscal regime include a relatively high total tax take compared to international experience, together with a high upfront take—meaning that the tax burden is not proportional to the risks borne by investors, particularly at different stages of the project cycle. Importantly, the Tax Code lacks provision for a stable long-term contractual framework for large, high-risk projects with long gestation periods for investment, such as offshore blocks, and fails to fully encourage adoption of new technologies to arrest declines at mature fields.

Ultimately, Kazakhstan would be best served by replacement of the current upstream tax system based primarily on gross revenues or production with one centered on profits more generally; i.e., extension of the profits-based taxation option beyond the limited acreage currently qualifying for such fiscal terms. Fiscal regimes centered around profits are able to automatically adjust to changes in production costs and prices, and therefore also provide relatively effective incentives even for development of comparatively costly hard-to-recover reserves (which will likely comprise a growing share of total Kazakh reserves going forward).

Subsoil Code

Overall, the changes to the Subsoil Code were intended to make the investment environment more attractive by streamlining and fast-tracking procedures for awarding and finalizing contracts, combining exploration and production contracts, as well as introducing more transparency to the contract enforcement process. But the improvements have been largely offset by lackluster implementation, and refusal to provide meaningful subsoil data to the marketplace in a transparent and timely manner. Moreover, auctions launched in 2018 were scaled back considerably compared with original plans, and only moderately successful when they did occur, selling a handful of smaller, onshore blocks to local companies. Specifically, in an April 2018 auction 48 blocks were initially offered but 37 were removed

[13] For detailed analysis of the legislative reforms, see The National Energy Report 2017, pp. 69–73.
[14] https://nalogikz.kz/taxcode/2018/87

without explanation the following month, while a June 2018 bid round for onshore blocks resulted in the granting of licenses for 9 blocks at bids of less than $10 million (essentially to smaller, local players).

Three major problematic features of the Subsoil Code are the signing bonus requirement for most licenses, the restrictions on KMG's upstream portfolio management, and the heavy regulation of company procurement activities:

•**The signing bonus requirements in connection with subsoil auctions diverges from general global practice, especially for countries with Kazakhstan's upstream profile.** Kazakh authorities attach primary importance to the factor of up-front bonuses when awarding subsoil rights through an auction. Such bonuses may be suitable in instances where there is strong competition by investors for highly prospective acreage and where the geology is already relatively well understood. But this is not generally the case in Kazakhstan, where prospects put up for auction are not typically very well known, and where a requirement for large-size up-front bonus payments can have a deleterious impact on overall project economics.

• **The requirement that a state-designated national company—KMG—have at least a 50% participation share in new E&P contracts for so-called strategic fields deprives KMG of the flexibility needed to optimize its upstream portfolio, and limits Kazakhstan's ability to attract new international investment.** Strategic fields are defined as those with "geological" oil reserves of over 50 MMt (365 million bbl), gas reserves of over 15 Bcm, or an offshore Caspian field. But the national company lacks the right of refusal, thus preventing it from managing its own technical portfolio. The 50% threshold also inherently limits the number of potential stakeholders in a given project.[15]

•**The Subsoil Code maintains, and in some ways strengthens, the relatively heavy government regulation over subsoil users' procurement activities, but new WTO rules will require more flexibility.** The Subsoil Code's overriding emphasis on local content solutions for project equipment and services runs counter to WTO rules, and is not necessarily effective in promoting investment. Subsoil users are required to acquire 50% of goods and services (including electricity and transportation fuels) from the local market, and this is generally met. However, rules governing the procurement of specific upstream equipment from "local" entities, which are defined as local based on headcount, are exceedingly rigid. Kazakhstan's WTO transition period extends through 2021, and new rules set to come into effect on 1 January 2022 include a stipulation that up to 50% of leaders/managers of companies can be foreigners (doubling the current threshold of 25%).[16] For international oil companies, using more local goods, services, and employees may mean significant cost savings. Still, it is important for companies to have flexibility in procurement.

[15] Brazil's national oil company regulations may serve as a template for further reform in Kazakhstan: the Brazilian government has granted Petrobras the right of refusal, allowing the company to select projects that it finds attractive.
[16] At last report, local content in the NCOC, KPO, and TCO projects amounted to 50%, 60%, and 60%, respectively, while for TCO FGP the figure was 32%. KMG reports its local content at 90%.

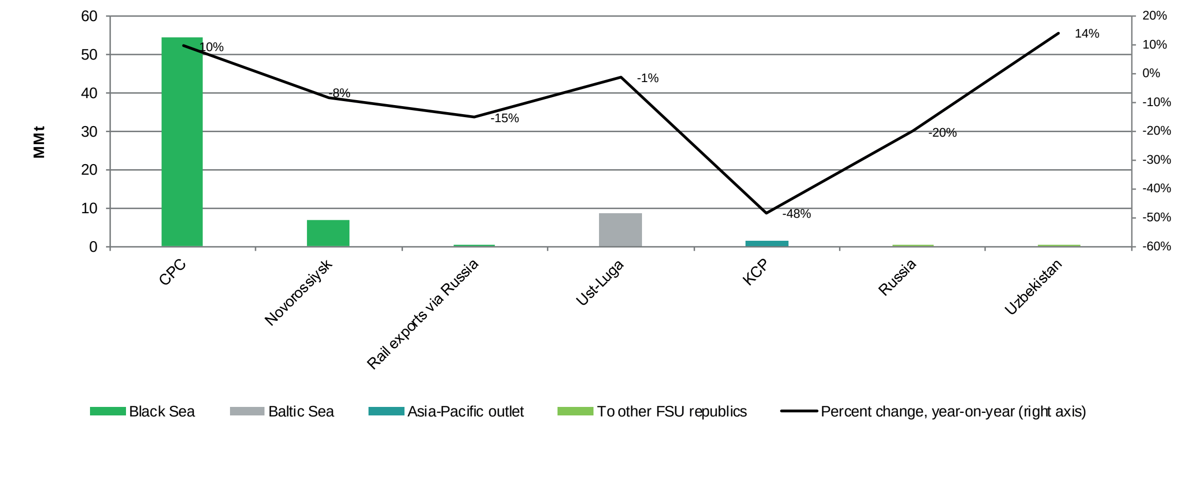
3.5. Crude Oil and Condensate Transportation

Oil transportation is an important issue for a land-locked country like Kazakhstan, especially since oil exports loom so large in overall disposition. Kazakh crude oil exports rebounded during 2017–18, and are expected to follow the national oil production trend longer term given limited incremental domestic oil demand. Thanks to investment in expansion, the CPC pipeline transiting Russia has handled an increasing share of Kazakh oil exports recently, and is expected to remain the chief outlet for Kazakh oil exports through 2040. But Kazakhstan's "multi-vector" export strategy means that Kazakh oil also will be evacuated via other routes. KCP is expected to handle increased export volumes during the scenario period, while Kazakhstan is expected to eventually resume shipments via BTC as well.[17]

3.5.1. Recent Export Trends and Outlook to 2040

In 2018, Kazakhstan exported 70.2 MMt (1.46 MMb/d) of crude, representing 78% of Kazakh oil output last year. Historically, most of Kazakhstan's crude has exited via Russia, and in 2018 well over 90% of Kazakhstan's crude exports still transited Russia by pipeline or rail, primarily via the CPC pipeline to the Yuzhnaya Ozereyevka terminal on the Russian Black Sea coast (see Figure 3.11: Distribution of Kazakhstan's crude oil exports by route, 2018). But Kazakhstan's "multi-vectoral strategy" of utilizing multiple export routes for its oil means that a growing share of the total over 2019–40 is going to be channeled via non-Russian routes, which together account for nearly 20% of the total in 2040 (see Figure 3.12: Kazakhstan's crude oil exports outlook by route/destination to 2040

Figure 3.11. Distribution of Kazakhstan's crude oil exports by route, 2018



Source: IHS Markit, Argus

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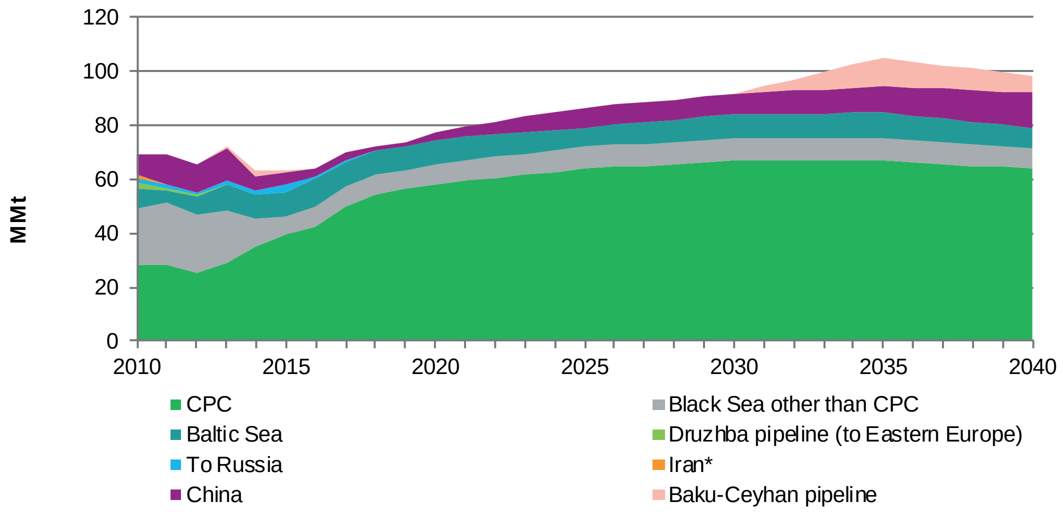
[17] CPC shareholders are the Russian Federation (31%; represented by Transneft with 24% and CPC Company with 7%), Kazakhstan (20.75%; represented by KMG with 19% and Kazakhstan Pipeline Ventures LLC with 1.75%), Chevron Caspian Pipeline Consortium Company (15%), LUKARCO B.V. (12.5%), Mobil Caspian Pipeline Company (7.5%), Rosneft-Shell Caspian Ventures Ltd. (7.5%), BG Overseas Holding Ltd. (2%), Eni International N.A. N.V. (2%), and Oryx Caspian Pipeline LLC (1.75%). KCP is owned 50-50 by KazTransOil and the CNPC subsidiary China National Oil and Gas Exploration and Development Corporation (CNODC). BTC shareholders are: BP (30.1%), SOCAR (25%), Chevron (8.9%), Equinor (8.71%), TPAO (6.53%), ENI (5%), Total (5%), Itochu (3.4%), ExxonMobil (2.5%), INPEX (2.5%), and ONGC Videsh (2.36%).

Figure 3.12. Kazakhstan's crude oil exports outlook by route/destination to 2040



*"Iran" exports (swap volumes) are too small to appear in the chart, and the only years of the chart when such exports occur are 2010 and 2011 (i.e., no resumption of this trade is envisioned during the scenario period in our base case).

Source: IHS Markit (Eurasian Oil Export Outlook)

Caspian Pipeline Consortium pipeline

Kazakh exports via the CPC route rose by 9.6% in 2018 to 54.3 MMt (1.09 MMb/d)—amounting to around 75% of total Kazakh oil exports last year (up from about 71% in 2017). The expansion of CPC infrastructure approved in December 2008 was completed in April 2018, and brought CPC nameplate capacity to 67 MMt/y (1.34 MMb/d) (or 72 MMt/y [1.44 MMb/d] if drag-reducing additives [DRAs] are employed). The CPC consortium plans a further upgrade at a cost of about $600 million with the aim of raising available capacity to 72 MMt/y (or 78 MMt/y with DRAs) by 2023, around the time TCO FGP comes on stream (this CPC project is now in the detailed engineering phase). We expect that CPC's share of total Kazakh oil exports in 2040 will amount to about 65% in the base case.

Atyrau-Samara and connecting Transneft routes

Kazakh shipments via the Atyrau-Samara route and connecting Transneft pipelines—now deliveries to the Ust-Luga terminal on the Baltic Sea and Novorossiysk port on the Black Sea—have accounted for most of the remainder of the Kazakh oil exports recently. Exports via the route to Ust-Luga fell by 1.2% in 2018 to 8.8 MMt (176,000 b/d). Kazakh exports to Novorossiysk (i.e., combined volumes of the Atyrau-Samara and Makhachkala-Novorossiysk routes) were down by 8.3% to 6.9 MMt (138,000 b/d) in 2018. Ust-Luga and Novorossiysk nevertheless both remain important export outlets for Kazakhstan longer term, remaining generally within the same range as seen in recent years.[18]

[18] One key factor tending to keep volumes in the Atyrau-Samara pipeline relatively stable is the extra expense that would be required to upgrade the overall Uzen-Atyrau-Samara pipeline infrastructure before it is technically feasible to reduce total throughput significantly, since this is a "hot" trunk line designed to heat and transport the highly viscous (heavy) oil entering the system in Kazakhstan's Mangistau Oblast at the same time as it transports less viscous crude streams. In other words, the volume of relatively light crude currently injected into the pipeline system at Atyrau must be maintained in order to mitigate the viscosity of Mangistau crude in the pipeline unless significant modernization and expansion of oil heating facilities is undertaken.

Kazakhstan-China pipeline

Total Kazakh shipments via the KCP, not including Russian transit crude (much of it physically swapped for deliveries to the Pavlodar refinery), dropped by 48% in 2018 to only 1.4 MMt (28,000 b/d). Reversal of the existing westward-flowing pipeline between Kenkiyak and Atyrau is now planned by 2020. This will provide Kazakhstan with additional sources of crude to supply the Shymkent refinery in southern Kazakhstan and provide the amount of crude needed for the swap agreement with Rosneft for Pavlodar supplies, and incremental exports. This, in turn, is likely to facilitate a several-fold increase of Kazakh exports via KCP during the 2020s. In our base case, Kazakh volumes exceed the Russian swap volumes of 10 MMt/y (200,000 b/d) in KCP after 2035, and reach a maximum annual level of 13 MMt (about 270,000 b/d) in 2040. The price at the Chinese border for Kazakh oil via KCP nonetheless remains a key factor limiting exports in that direction, because the border price is set too low (at around Brent minus $5.70/bbl) to stimulate a large-scale re-orientation of shipments from western Kazakhstan.

Baku-Tbilisi-Ceyhan pipeline

In November 2018, Kazakh Energy Minister Kanat Bozumbayev announced that Kazakhstan will resume oil exports via BTC in 2019, for the first time since such shipments were last made in the second half of 2015. But the continuing lack of details from official sources on timing and volumes suggests that renewal of Kazakh exports via BTC is likely delayed. The IHS Markit base case is currently for Kazakh crude to reenter BTC after about 2030, largely driven by capacity limitations on other routes (namely CPC). Kazakh volumes in BTC are expected to reach a maximum level of only about 11 MMt (220,000 b/d) in 2035.

3.5.2. Regulation of Pipeline Transportation Tariffs

In keeping with 2015 amendments to Kazakhstan's Law "On Natural Monopolies and Regulated Markets," tariffs for oil transportation (for transit through Kazakhstan and export from Kazakhstan) are determined by the oil pipeline company KazTransOil (KTO) itself, which is a subsidiary of KMG, except in the following cases:

• The CPC tariff is determined by a separate mechanism set internally by the CPC consortium.

• The tariff on the route for Russian transit volumes to China is currently approved by the Kazakh Ministry of Energy.

• Oil pipelines operated by JVs (the Atasu-Alashankou segment of KCP and the Kenkiyak-Atyrau pipeline) have individual tariffs regulated by the Committee for Regulation of Natural Monopolies and Protection of Competition (KREMiZK).

KREMiZK also regulates the oil transportation tariff for domestic shipments via KTO, which are calculated on a "cost-plus basis," where the tariff covers the costs of operating the pipeline and a small profit margin designed to ensure sufficient revenues for business operations.[19]

The general approach to tariff-setting adopted by Kazakhstan has generally provided a fairly stable and transparent structure for many years. But there is significant room for improvement in the implementation of existing regulations. For example, even though KTO was specifically granted the latitude to set its own tariffs for transit and export shipments, rather than being directly regulated, in practice KTO has found itself subject to some questionable fines by KREMiZK for allegedly unjustifiable income.

[19] For background, see The National Energy Report 2015, p. 147 and The National Energy Report 2017, p. 56

3.6. Refining and Refined Product Market Dynamics

Kazakhstan's recently completed refinery modernization program is a signal achievement that has significantly lessened Kazakhstan's traditional reliance on imports of light products from Russia. Existing Kazakh refinery capacity should be sufficient to meet domestic oil product demand through at least 2030. Kazakhstan's current tolling system for remunerating Kazakh refiners serves the purpose of paying for refinery modernization. Under this arrangement, crude suppliers pay refiners a tolling fee to process the crude, and retain title to the resulting refined products for subsequent sale. However, this system does not provide sufficient incentive for upstream producers to deliver crude to the domestic market—particularly given relatively low prices in domestic refined product markets, which remain heavily administered notwithstanding official price liberalization. Crude producers are essentially compelled to supply the domestic market at well below export netback parity values. The low values, in turn, complicate the task of additional upstream investment by Kazakh producers needed to offset the decline of legacy Kazakh fields. Another downside of the tolling system is that it insulates the refiners from market forces, with the result that plants lack incentive to further improve efficiencies following modernization.

3.6.1. Kazakhstan's Evolving Refined Products Balance

Refinery throughput in Kazakhstan rose by 10.2% in 2018 to 16.4 MMt (341,000 b/d). The rise in throughput reflected expanded domestic consumption in conjunction with increased refinery capacity (by around 10% to 17.5 MMt/y (350,000 b/d)) following the completion of the $6 billion modernization program.[20] Apparent domestic product demand was up 11.1% to 14.3 MMt (298,000 b/d) in 2018, while product exports declined by 16.3% in 2018 to 3.3 MMt (69,000 b/d), and product imports fell by 37.9% to 1.2 MMt (25,000 b/d). Altogether, last year Kazakh refineries reportedly accounted for around 93% of gasoline supplies to the domestic market, 91% of diesel, and 62% of jet kerosene (see Table 3.4: Kazakhstan's refined product balance). Kazakhstan now has surplus gasoline available for export.

Kazakhstan's three major refineries—the Atyrau, Pavlodar, and Shymkent plants—accounted for 93.6% of Kazakh refinery throughput in 2018 (see Table 3.5: Product output by Kazakhstan's primary refineries). Outside of the three major plants, 34 mini-refineries reportedly operate in Kazakhstan. Individually, these plants generally produce only small amounts of (low-quality or semi-finished) products, but are important for the provision of low-octane (AI-80) gasoline. Following modernization, the three major refineries ceased production of AI-80. This fuel is primarily used in agriculture, and the price is still regulated. In addition, the Caspi Bitumen mini-refinery in Aktau, built and operated by KMG and China's CITIC Kazakhstan company, is a key producer, accounting for 37% of all road bitumen produced in Kazakhstan in 2018.

[20] For details on the modernization programs at the three plants, see The National Energy Report 2017, pp. 86–90.

Table 3.4
Kazakhstan's refined product balance
(million metric tons)

	2010	2011	2012	2013	2014	2015	2016	2017	2018
Production									
Throughput	13.7	13.7	15.1	15.3	16.4	15.0	14.9	14.9	16.4
Output of products (reported)	12.8	13.4	13.7	13.8	14.5	13.5	12.9	13.0	13.4
Gasoline	2.9	2.8	2.9	2.7	3.0	2.9	3.0	3.1	4.0
Kerosene	0.5	0.4	0.4	0.4	0.4	0.3	0.3	0.3	0.4
Diesel fuel	4.4	4.6	4.1	5.1	5.0	4.6	4.7	4.4	4.7
Mazut	4.5	4.3	3.9	4.0	4.2	4.1	3.2	3.4	3.2
Fleet	-	-	0.3	0.3	0.3	0.3	0.2	0.4	0.3*
Furnace fuel	4.5	4.3	3.6	3.7	3.9	3.8	3.0	3.0	2.9
Lubricants	-	-	-	-	-	-	-	-	-
Other (includes LPGs, VGO, etc.)	0.5	1.3	2.4	1.5	1.8	1.7	1.8	3.8	4.1
Petroleum coke/bitumen/other residual	0.4	0.5	0.5	0.6	0.9	0.8	1.0	1.3	1.5
Apparent consumption									
Total (all refined products)	10.3	10.8	12.3	12.5	13.4	12.0	12.9	12.9	14.3
Gasoline	3.7	3.5	4.0	4.0	4.2	4.3	4.1	4.1	4.3
Diesel fuel	3.2	4.1	3.9	5.5	5.3	4.6	5.1	4.7	4.8
Mazut	1.4	0.7	-0.4	-0.7	-0.6	-0.6	-0.4	-0.4	0.4
Other	2.0	2.4	4.8	3.7	4.5	3.8	4.1	4.5	4.7
Net exports									
Total (all refined products)	-3.3	-3.0	-2.8	-2.7	-3.0	-3.0	-2.1	2.0	2.1
Gasoline	0.8	0.8	1.2	1.3	1.2	1.4	1.1	-1.1	-0.4
Diesel fuel	-1.2	-0.6	-0.2	0.4	0.3	0.0	0.4	-0.3	-0.1
Mazut (including VGO and other "zhidkoye toplivo")	-3.0	-3.5	-4.3	-4.7	-4.8	-4.7	-3.6	3.8	2.8
Other	0.1	0.4	0.5	0.3	0.3	0.3	0.1	-0.4	-0.2
Exports									
Total (all products)**	5.1	4.4	4.8	5.3	5.1	4.9	3.9	4.0	3.3
Gasoline	0.1	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Diesel fuel	1.6	0.8	0.3	0.2	0.2	0.2	0.0	0.1	0.2
Mazut (including VGO and other "zhidkoye toplivo")	3.0	3.6	4.5	5.0	4.8	4.7	3.6	3.8	2.8
Other	0.4	0.0	0.0	0.1	0.0	0.0	0.2	0.1	0.3
Imports									
Total (all products)**	1.8	1.5	2.1	2.5	2.1	1.9	1.8	2.0	1.2
Gasoline	0.9	0.8	1.2	1.3	1.2	1.4	1.1	1.1	0.4
Diesel fuel	0.4	0.2	0.1	0.6	0.5	0.2	0.4	0.5	0.3
Mazut (including VGO and other "zhidkoye toplivo")	0.0	0.1	0.2	0.3	0.0	0.0	0.0	0.0	0.0
Other	0.5	0.4	0.6	0.4	0.4	0.3	0.2	0.4	0.6

*Estimate
**Total exports and imports excludes LPGs; reported exports of heavy liquid fuels ("zhidkoye toplivo") includes a variety of other products, including VGO, so calculated apparent consumption has been negative for most years since 2012.
Source: Statistical Committee of RK; IHS Markit

Table 3.5
Product output by Kazakhstan's main refineries
(thousand metric tons)

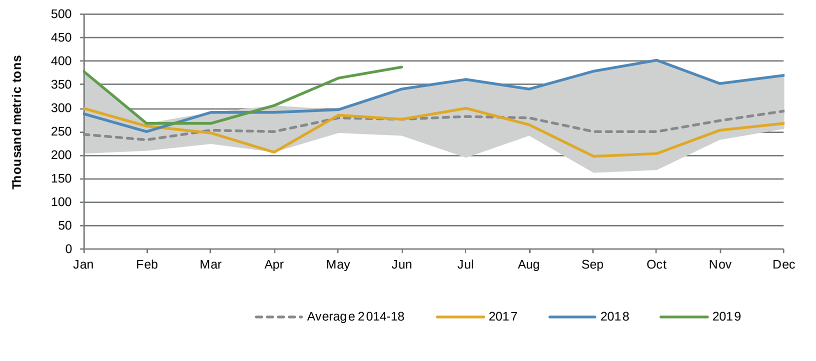
	2012	2013	2014	2015	2016	2017	2018
Atyrau							
Crude throughput	4,423	4,430	4,920	4,868	4,761	4,724	5,268
Motor gasoline	506	505	614	605	643	643	1,191
Diesel fuel	1,218	1,222	1,344	1,207	1,391	1,356	1,459
Jet kerosene	56	38	23	21	20	21	41
Benzene	-	-	-	1	7	8	16
Heating oil	143	124	166	160	68	58	129
Mazut	1,543	1,512	1,510	1,650	1,362	1,495	1,145
Vacuum gas-oil	606	652	779	739	842	741	445
Petroleum coke	75	95	137	111	121	118	131
LPG	14	20	28	29	36	39	166
Sulfur	1	1	2	3	3	2	4
Paraxylene	-	-	-	-	-	-	16
Pavlodar							
Crude throughput	5,037	5,010	4,926	4,810	4,590	4,747	5,340
Motor gasoline	1,332	1,117	1,259	1,249	1,225	1,281	1,430
Diesel fuel	1,514	1,473	1,509	1,457	1,524	1,414	1,734
Jet kerosene	100	133	125	11	-	-	78
Mazut	810	763	668	822	560	600	629
Vacuum gas-oil	123	400	192	123	29	128	84
Petroleum coke	147	146	152	126	224	185	216
LPG	244	215	239	263	244	257	310
Sulfur	24	23	25	30	28	28	41
Bitumen	186	219	244	246	202	245	294
Heating oil							38
Shymkent							
Crude throughput	4,754	4,857	5,065	4,493	4,501	4,686	4,733
Motor gasoline	1,046	1,038	1,126	988	1,032	1,027	1,332
Diesel fuel	1,336	1,376	1,346	1,192	1,203	1,209	1,243
Jet kerosene	275	231	279	254	236	280	270
Mazut	902	968	1,013	889	869	956	826
Vacuum gas-oil	798	827	884	827	811	818	462
Petroleum coke	146	148	142	113			
LPG	-	-	-	-	120	97	170
Sulfur	-	-	-	-	1	1	1

Source: Ministry of Energy of RK

The three key goals of the modernization program have now been largely realized:

• **Increasing the "depth" of refining, thereby boosting the value of the average product barrel.** Refinery depth at the Atyrau plant grew from 64% to 68% during 2017–18, and reached an estimated 85% in early 2019. The Pavlodar plant registered an increase from 77% to 79% over 2017–18, and to an estimated 84% in 2019. Shymkent's refinery depth was unchanged at 74% in 2018 since modernization was only completed in the fourth quarter, but is estimated at 89% in 2019. These changes are reflected in the sharp increase in Kazakh gasoline production (see Figure 3.13: Monthly gasoline production trends in Kazakhstan).

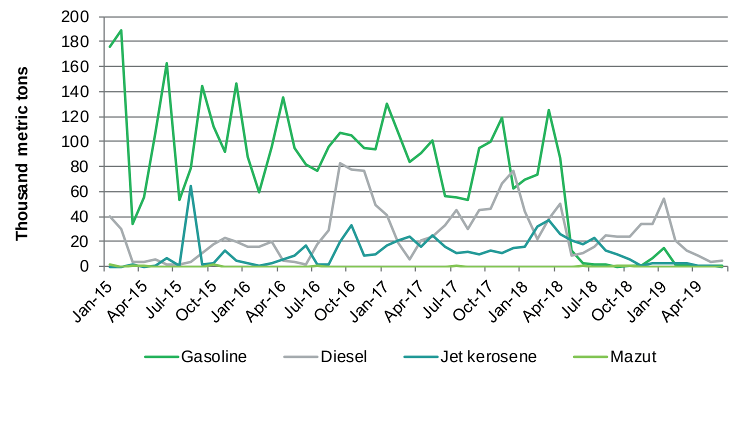
Figure 3.13. Monthly gasoline production trends in Kazakhstan



Source: IHS Markit, Kazakhstan Committee on Statistics, Infotek

● **Eliminating the need for imports of Russian light products.** The modernization program was accompanied by a steady decline in Kazakh imports of gasoline, diesel, and jet kerosene, as Kazakh refineries have increasingly met domestic demand for lighter products (see Figure 3.14: Monthly imports of refined products by Kazakhstan). In December 2018, the Energy Ministry concluded that the modernized refineries should satisfy domestic needs through at least 2030. This corresponds to the current IHS Markit base case, in which modernization negates the need for additional refining capacity until well into the 2030s, assuming a moderate rate of economic growth over the next decade.

Figure 3.14. Monthly imports of refined products by Kazakhstan, 2015-18

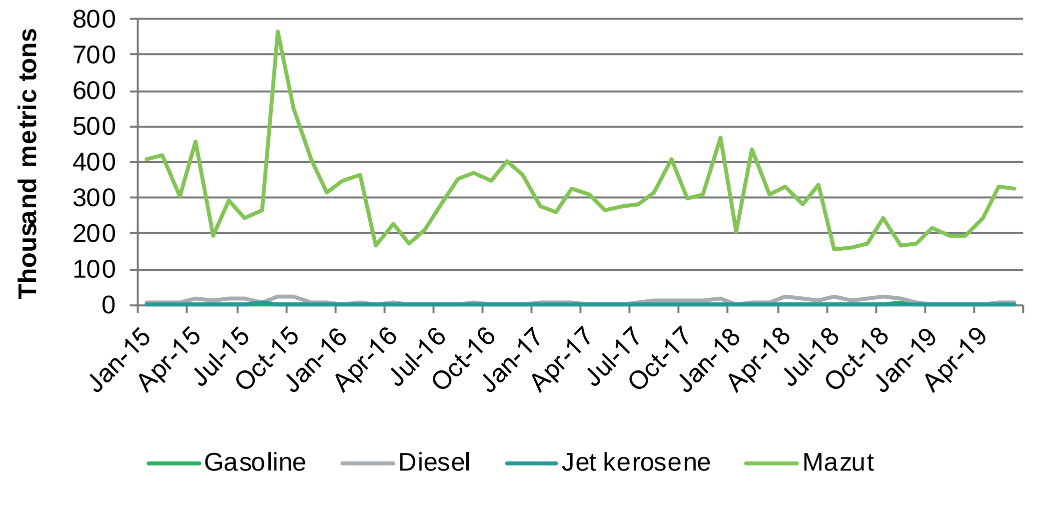


Source: IHS Markit, Kazakhstan Committee on Statistics

● **Reaching EAEU technical specifications for product quality.** All three refineries are now producing K-4 and K-5 grade fuels (similar to Euro-4 and Euro-5), which is the specification agreed for the EAEU.

However, the promise of large-scale light product exports remains elusive, despite higher output and modernized assets. Not surprisingly, fuel oil still accounts for the bulk of Kazakhstan's refined product export mix, but the country's mazut surplus has declined (see Figure 3.15: Monthly exports of refined products by Kazakhstan). Kazakhstan may well have material surpluses now of light products, which can find market niches regionally (e.g., in Kyrgyzstan), but the volumes are likely to remain relatively small. The economics of Kazakhstan's fuel oil exports are likely to be increasingly challenging in the near term as a result of the 2020 enactment of International Maritime Organization (IMO) marine bunker fuel sulfur restrictions—reducing maximum sulfur content from 3.5% to 0.5% on a global basis. The new IMO rules are expected to lead to a significant discount for high-sulfur fuel oil in world markets generally.

Figure 3.15. Monthly exports of refined products by Kazakhstan



Source: IHS Markit, Kazakhstan Committee on Statistics

The Ecology Code will likely require some additional plant upgrades by KMG in order to meet new best available technology (BAT) and/or other targets. Top downstream priorities for KMG include various debottlenecking initiatives (e.g., improvements to storage and loading systems) and increased automation and digitization to improve efficiency.

Key factors in our base case for domestic demand growth include a moderate rate of economic growth (GDP growth averaging 2.8% per annum during 2019–40, roughly comparable to expected average global GDP growth), increasing population, and vehicle fleet expansion. Demand growth will be led by the transportation segment, with greater personal mobility as well as increasing cargo traffic through Kazakhstan, lifting gasoline, diesel, and jet fuel consumption. Kazakh refinery throughput increases by 17.5% to 21 MMt/y (429,000 b/d) during 2019–40 in our base case.[21]

3.6.2. The Economics of Refining in Kazakhstan

The refurbished refineries have improved the national product slate and enhanced the country's self-sufficiency, but continue to operate within a highly regimented market structure. The government still determines most aspects of refinery operations, including aggregate throughput, product output, and the general allocation of refined products. The main refineries now operate commercially on a tolling scheme, and although it guarantees a generous refining margin, it effectively isolates them from market forces. KMG's upstream entities own the bulk of the crude delivered to refineries and the resulting refined products, and neither KMG nor other market players formally influence actual refining activity given the overriding role of state directives. Meanwhile, KREMiZK effectively continues to regulate domestic refined product markets notwithstanding the formal liberalization of nearly all prices; e.g., by monitoring margins and fining gasoline stations for "unsubstantiated" price increases.[22]

Current tolling, domestic pricing, and export-import policies result in market distortions that are increasingly at odds with the EAEU integration dynamic,

[21] See the IHS Markit Strategic Report Eurasian Oil Export Outlook for April 2019, and the IHS Markit Downstream Market Profile, Kazakhstan – Supply & Demand May 2019.

[22] For background on the evolution of Kazakhstan's refined product markets and regulatory framework, see The National Energy Report 2015, pp. 197–216, The National Energy Report 2017, pp. 80–97, and the IHS Markit Insight, Relief in sight for Kazakhstan's recurring problem of refined product shortages? Completion of refinery modernization program will reduce dependence on Russian imports.

while Kazakhstan's refining sector itself may ultimately pay the biggest price for such policies in the form of lost opportunities for development:

- **Although the current crude processing system pays for modernization and ensures high margins for refiners, it complicates the tasks of securing crude supply and additional investment in refining longer term.** Under the crude processing arrangement, a number of large and small tolling (give-and-take) providers work with the refineries: they acquire oil from subsoil users, transport it to the refineries, get it processed, and then sell the resulting products. KMG EP is the largest crude oil supplier to Kazakhstan's refineries, it supplies crude directly and retains title to the resulting refined products for subsequent sale. The processing tariffs are not directly regulated by KREMiZK, but are set by KMG, in consultation with the Ministry of Energy. Kazakh refiners benefit in the short run, since processing tariffs are two to three times higher than refining margins in Europe or Russia (see Table 3.6: Refinery processing fees in Kazakhstan). But the sustainability of such an arrangement is doubtful given the prospects of increased competition from Russian refineries under EAEU terms and difficulties obtaining crude for domestic refineries. Moreover, the tolling system does not incentivize refineries to improve operational efficiencies and respond to supply and demand dynamics; their operations simply respond to Ministry-set plans for output.[23]

Table 3.6
Refinery processing fees in Kazakhstan

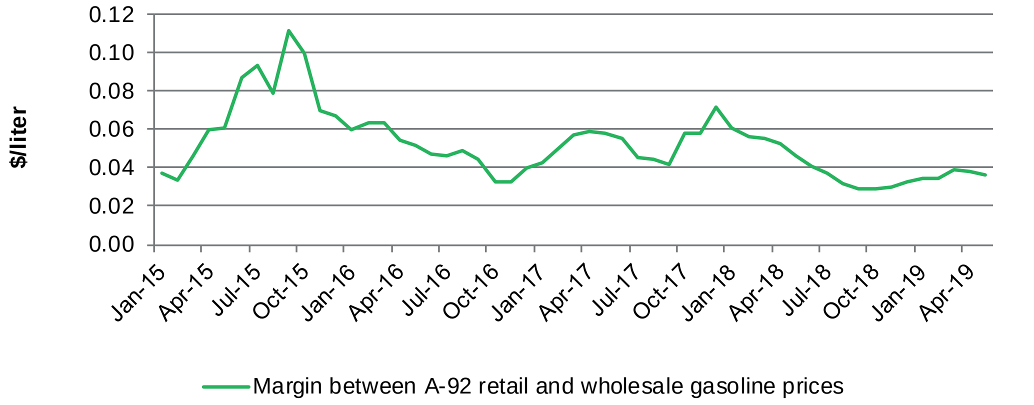
	2015			2016			2017			2018			% change (tenge rate), 2015-16	% change (tenge rate), 2016-17	% change (tenge rate), 2017-18
Refinery	tenge/ton	$/ton	$/bbl	tenge/ton	$/ton	$/bbl	tenge/ton	$/ton	$/bbl	tenge/ton	$/ton	$/bbl			
Atyrau	14 068	63.30	8.33	20 378	59.62	7.85	23 370	71.67	9.43	33 810	98.03	12.90	44.9	14.7	44.7
Pavlodar	10 162	45.72	6.02	14 895	43.58	5.73	15 429	47.32	6.23	17 250	50.01	6.58	46.6	3.6	11.8
Shymkent	11 454	51.54	6.78	11 454	33.51	4.41	12 809	39.28	5.17	19 579	56.77	7.47	0.0	11.8	52.9

Note: The current tolling fees are 37,436 tenge per ton for Atyrau (from 1 August 2018), 19,805 tenge per ton for Pavlodar (from 1 January 2019), and 24,750 tenge per ton for Shymkent (from 1 July 2019). Average annual exchange rates are used to convert tenge to dollar equivalent.
Source: IHS Markit, KazMunayGaz

Despite official price liberalization, retail prices remain heavily monitored, and over-administered (de facto and de jure). Kazakhstan officially liberalized AI-92 and AI-93 gasoline prices in September 2015, and diesel prices in July 2016, and continues to regulate retail prices for AI-80 gasoline (used mostly in the agricultural sector and no longer produced by the three major refineries).[24] But full-scale decontrol of prices remains challenging. As in many former Soviet republics, major political figures and the general public in Kazakhstan largely view motor fuels as a public good that should be abundantly available at low prices, regardless of global and regional market conditions. KREMiZK often fines retail stations for "anti-competitive" pricing practices when they are in fact merely passing along higher acquisition costs to consumers. Effectively, through fines, KREMiZK monitors and regulates product margins, which in turn tends to keep retail prices relatively low, even if this forces private businesses to operate at a loss (see Figure 3.16: Margin between retail and wholesale gasoline in Kazakhstan). Thus even as global oil prices grew in 2018, domestic refined prices stayed relatively flat.[25]

[23] The Ministry of Energy of Kazakhstan believes that the processing tariff reduction is inadvisable at the moment, since the loans for rehabilitation and modernization of the country's refineries (amounting to over $6 billion) are repaid from the processing fee and fixed in foreign currency.
[24] Plans to liberalize AI-80 prices are currently on hold, given the perceived need to ensure ample volumes of the grade to agricultural enterprises.
[25] The tendency of KREMiZK to selectively apply the official formula governing price changes is another complicating factor. In theory, those prices that remain regulated in Kazakhstan should be determined in accordance with an approved formula, but KREMiZK has on occasion tended to disregard the formula when it indicates that a price should be increased, but strictly applies the same formula when it indicates that prices should fall.

Figure 3.16. Margin between retail and wholesale prices for gasoline (A-92) in Kazakhstan



Source: IHS Markit

• **Market intervention by Kazakh authorities is still practiced most directly with respect to product exports and imports.** Kazakh officials continue to impose periodic restrictions on both imports and exports of selected products. Gasoline import bans are designed to ensure priority of Kazakh gasoline production in the domestic market vis-à-vis imports from Russia. In August 2018, for example, Kazakhstan imposed a ban on gasoline imports from Russia by rail for a period of three months, with the aim of allowing Kazakh refineries to ramp up output without having to compete directly with imported Russian gasoline, and in January 2019 announced another three-month ban on the import of Russian gasoline by rail. Meanwhile, a ban on diesel exports to other EAEU states was imposed in the first half of 2019 with the aim of preventing shortages and dampening upward price pressure; specifically, this restriction was triggered by the prospect of major outflows of Kazakh-produced diesel, especially in areas near the border, given the wide differential between prices for diesel in Russia and in Kazakhstan.

3.7. Key Differences in Oil Markets of Selected EAEU Member States

While the further liberalization of Kazakh oil markets makes sense in its own right, the planned creation of a common EAEU oil market heightens the urgency of such reform. At the same time, as the largest player by far among the EAEU member states, the Russian Federation, naturally will have greater influence on the specific terms of EAEU integration. The following sections look in more detail at key differences between selected oil sector regulations of Kazakhstan, the Russian Federation, and Kyrgyzstan—and the challenges associated with integration of regional markets.[26]

3.7.1. Integration with Neighboring EAEU Markets Is Most Critical, but Involves Special Challenges: The example of refined product prices

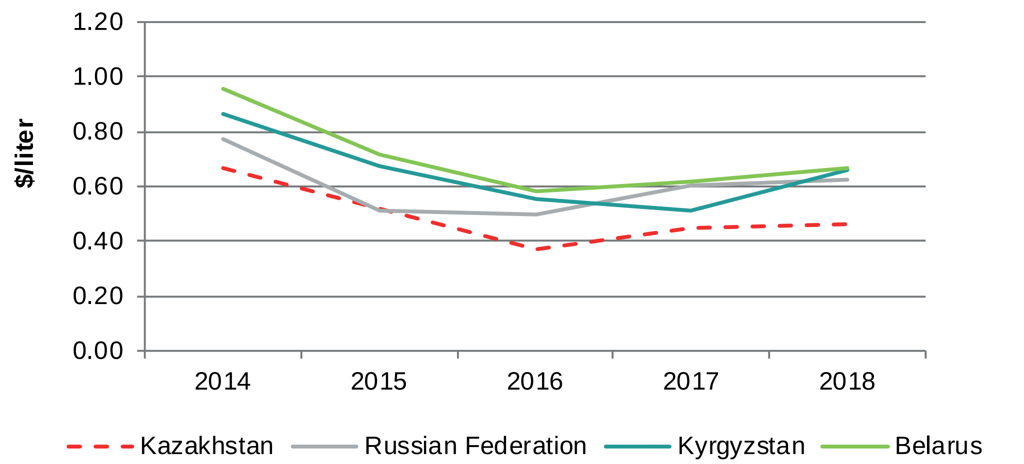
Major differences in the scales of the three countries' oil industries translate into different degrees of influence on the EAEU integration process. As the largest oil producer, consumer, and exporter by far

[26] The oil sectors of the other two EAEU member states, Belarus and Armenia, are of less direct concern here given the historic absence of a significant crude oil or product trade between Kazakhstan and these nations, and in any case Belarusian trends have traditionally tended to be closely linked to the Russian market structure because of the dominance of Russian oil imports in Belarus. Recent Kazakh-Belarus negotiations nevertheless suggest the potential for Kazakh oil exports to Belarus going forward.

within the EAEU, the Russian Federation will undoubtedly wield predominant influence on EAEU oil market policy.

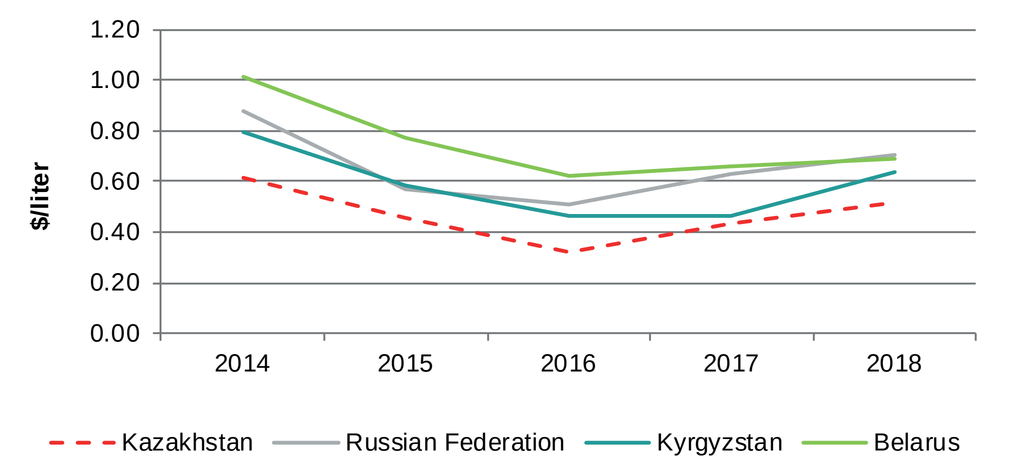
One key area where Russia is likely to have a major impact if and when EAEU oil market integration materializes, is pricing. In such a scenario Kazakhstan would need to change its pricing policies more than other EAEU member states in order to achieve a genuine common market—since Kazakhstan has the lowest retail gasoline and diesel price levels among the five EAEU nations (see Figure 3.17: Average retail prices of A-92 gasoline in selected EAEU countries; and Figure 3.18: Average retail prices of diesel in selected EAEU countries). The difference between retail product price trends in Kazakhstan and adjacent Russian territory (i.e., Omsk Oblast) is particularly striking, and indicative of the relatively heavy price regulation that persists in Kazakhstan in practice—well beyond levels of regulation considered necessary to protect consumer interests in neighboring countries (see Figure 3.19: Retail refined product prices in Kazakhstan and Russia (Omsk Oblast).

Figure 3.17. Average retail prices of A-92 gasoline in selected EAEU countries



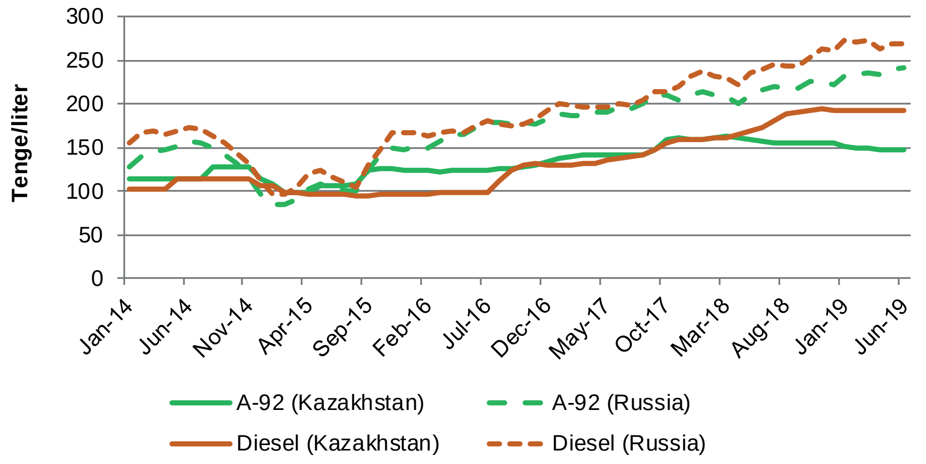
Source: IHS Markit © 2019 IHS Markit

Figure 3.18. Average retail prices of diesel in selected EAEU countries



Source: IHS Markit © 2019 IHS Markit

Figure 3.19. Retail refined product prices in Kazakhstan and Russia (Omsk Oblast)



Source: IHS Markit

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Wide price differences in Kazakh and other EAEU countries are just one indicator of the divergence of oil sector regulations amongst the member states, but merit special attention given the consequences for refined product trade within the territory of the planned common market. In short, these price differentials incentivize the redirection of Kazakh motor fuels to consumers in neighboring states, in a variety of forms:

- **Personal use.** Russian and Kyrgyz motorists regularly drive across the border and fill up on comparatively cheap Kazakh gasoline for personal use.
- **Resale.** Other motorists from neighboring states purchase Kazakh gasoline for resale within their countries, often installing additional gasoline tanks on their vehicles for this purpose.
- **Transit traffic.** Truckers who use Kazakhstan as a transit route (e.g., from China to Europe) typically concentrate their long-haul motor fuel purchases in Kazakhstan.

The net result for Kazakhstan tends to be upward pressure on product prices if not outright shortages of supply, particularly in border regions, in turn prompting Kazakh product export bans. Such actions must be administratively implemented. Kazakh authorities have explored various options in addition to export bans to address this issue, including within the framework of intergovernmental agreements with Russia and Kyrgyzstan governing product trade. For example, Kazakh officials have sought to ban the use on Kazakh territory of vehicles with fuel storage capacity in excess of the vehicle manufacturer's original specifications, and Kazakhstan has recently sought Kyrgyzstan's agreement to a restriction of bilateral product trade to rail routes (circumventing the problem of contraband trade in product by means of motor vehicles altogether). But even if implemented, such ad hoc solutions are likely to have at most limited effect. In contrast, full-scale product retail price liberalization in Kazakhstan would eliminate the reason for the contraband trade in the first place.

3.7.2. Russian Federation

Russian refined product balance trends: Increasing incentive to export gasoline, even as traditional markets become more competitive

Following extensive post-Soviet modernization (still ongoing in various cases) Russian refineries can now turn out a product mix that better corresponds to domestic demand. With respect to product balance dynamics, Russian refinery throughput stabilized in 2017–18, following slight declines in 2015 and 2016 that were triggered by the reduction in subsidies in connection with tax reform (see Table 3.7: Refined product balance for the Russian Federation). Oil refining economics in Russia have come under increased pressure from administrative curbs by Russian authorities on price growth in the domestic market.

Table 3.7
Refined product balance for the Russian Federation
(MMt)

	2014	2015	2016	2017	2018
Refinery throughput (total output)	289.9	282.4	279.7	279.7	287.0
Gasoline	64.5	63.8	65.8	65.6	66.4
Automobile	38.3	38.8	40.0	39.2	39.4
Aviation	0.0	0.0	0.0	0.0	0.0
Other	26.1	24.9	25.8	26.3	26.9
Diesel fuel	77.4	76.1	76.4	76.9	77.5
Kerosene	11.2	9.7	9.7	11.1	12.7
Mazut (total)	81.7	73.5	58.5	52.4	47.8
Furnace	80.9	72.1	57.2	51.1	46.4
Fleet	0.7	1.4	1.3	1.3	1.4
Other	55.2	59.3	69.4	73.7	82.6
Refined product exports	164.8	171.5	156.0	148.4	150.1
Gasoline	21.1	21.5	23.4	22.5	21.9
Automobile	4.2	4.7	5.2	4.3	4.2
Other	16.9	16.8	18.1	18.2	17.6
Kerosene	0.8	1.1	1.1	0.9	1.2
Diesel fuel	47.4	51.0	48.6	50.9	54.8
Mazut (furnace and fleet)	81.0	81.0	65.5	54.2	48.2
Other	14.5	16.9	17.5	19.8	24.0
Refined product imports	2.0	1.3	0.7	0.7	0.5
Gasoline	1.4	0.8	0.2	0.2	0.0
Kerosene	0.0	0.0	0.0	0.0	0.0
Diesel fuel	0.1	0.1	0.1	0.1	0.1
Mazut (furnace and fleet)	0.0	0.0	0.0	0.0	0.0
Other	0.5	0.4	0.4	0.4	0.4
Apparent consumption*	127.0	112.2	124.4	132.2	137.5
Gasoline	44.8	43.0	42.6	43.2	44.6
Automotive	35.6	34.9	34.9	35.1	35.3
Other	9.2	8.2	7.6	8.1	9.3
Kerosene	10.3	8.7	8.6	10.2	11.5
Diesel fuel	30.1	25.2	27.8	26.0	22.7
Mazut (furnace and fleet)	0.7	-7.5	-7.0	-1.8	-0.4
Other	41.2	42.8	52.4	54.6	59.1

*Apparent consumption is calculated as refinery output (throughput less estimated refinery losses and own-use) minus net exports. In some periods for certain products, apparent consumption is negative. This evidently results from exports including all sources whereas production only includes refinery sources and excludes other sources (e.g., petrochemical plants, condensate splitters, field stabilization plants). This also reflects any changes in storage. Actual consumption of individual products during any given period can be quite different.
Source: IHS Energy, Russian Ministry of Energy, Russian Federal State Statistics Service

Russia is now long on gasoline, which drives the overall Russian refined product balance. Russian refiners are keen to increase gasoline exports. But the chief direction of Russian motor gasoline exports traditionally—Central Asian markets and, in particular, Kazakhstan—have become more challenging in the wake of Kazakhstan's refinery modernization and the emergence of surplus Kazakh gasoline supply. Total Russian product exports to the Caspian and Central Asian region fell by around 25% in 2018, to 3.6 MMt (see Table 3.8: Russian exports of refined products to the Central Asian countries). This largely reflects a reduction in Russian gasoline exports to Kazakhstan, which declined by 61.5% (to only about 400,000 tons) in 2018. The position of Russian gasoline is coming under increased pressure by Kazakh gasoline exports. For example, during January–April 2019 Kazakh gasoline exports to Kyrgyzstan increased by over threefold (albeit from a small base), while Russian gasoline exports to Kyrgyzstan during the same period rose by around 24%.

Post-2020, Russian tax policy and additional refinery modernization trends point to further reduction (and lightening) of Russian refinery output. In the IHS Markit base-case scenario, Russian refinery throughput drops by 19.9% overall during 2019–40, to 230.0 MMt (4.60 MMb/d). This contraction is driven mainly by falling product exports—down 33.9% altogether, to 99.2 MMt (1.98 MMb/d), while aggregate domestic consumption of refined products dips 4.5% to 131.3 MMt (2.63 MMb/d).

Table 3.8
Russian exports of refined products to the Central Asian countries
(thousand metric tons)

Country	2017	2018	Percent change 2017-18
Regional total	4,845.9	3,637.4	-24.9
Kazakhstan	2,416.2	1,571.8	-34.9
Kyrgyzstan	1,294.8	1,297.2	0.2
Uzbekistan	866.8	447.3	-48.4
Tajikistan	263.7	317.8	20.5
Turkmenistan	4.4	3.3	-25.0

Source: Argus

Russian oil market: 2019–24 tax reform, driven partly by EAEU integration issues, spells new uncertainties

Since the Russian government eliminated margin caps on domestic crude oil prices in 1995, Russian authorities have had no direct control over the domestic crude oil market, but have not been willing to relinquish control to market forces completely either. As a result, Russian policy has vacillated between more liberal and more statist approaches to markets in the period since. These have included periodic usage of a wide variety of administrative measures, including export taxes on both crude and products—now slated to be phased out under the 2019–24 tax maneuver—and various "agreements" with the leading Russian companies to limit domestic motor fuel price increases (as discussed below).[27]

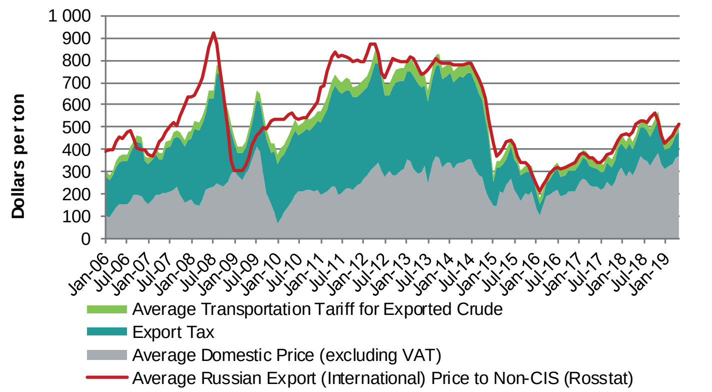
Unlike refiners in Kazakhstan, Russian

[27] See the IHS Markit Insight, Russia's 2019 oil taxation reform: Export duties to be phased out, with major tweaks to all other tax components, August 2018.

refiners function largely as merchant operators who buy crude and sell products, without specific aggregate throughput or product output targets set by the government. Nearly all of the larger Russian refineries—accounting among them for the vast majority of Russian refinery throughput—belong to one or another of the major Russian vertically integrated companies (VICs), but they may and do purchase crude from a variety of sources outside their own VICs, since VIC subsidiary production volumes and refinery capacities typically diverge.

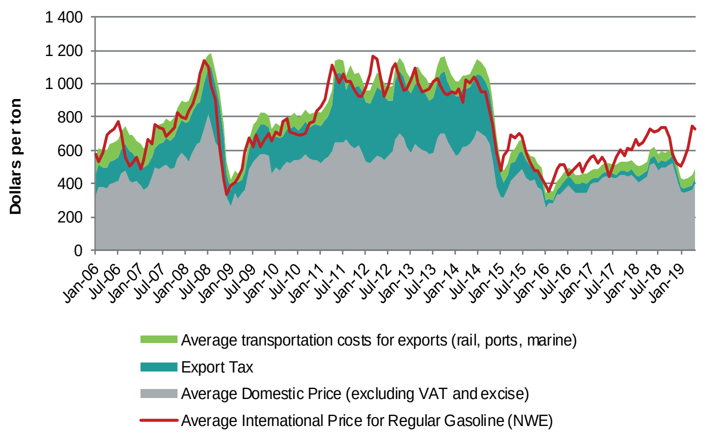
Russia's crude oil and refined product export duties, which are linked to world oil (Urals Blend) export prices, have traditionally played a key role determining domestic Russian crude and refined product prices. For both Russian refineries buying crude and Russian consumers buying refined products, domestic prices have traditionally tended to align with export netbacks, with the export parity price amounting to the international export price minus the export tax and transportation costs. In short, Russia's export tax has thus served as a wedge between international and domestic prices for crude oil and refined products. The crude export duty has been Russia's mechanism for prioritizing crude supplies to its refineries (see Figure 3.20: International versus domestic prices for Russian crude oil). However, the Russian refined product export duty has lately worked less effectively for prioritizing domestic product supplies, at least in the case of gasoline; i.e., domestic gasoline prices have recently diverged from export parity levels (see Figure 3.21: International versus domestic prices for Russian motor gasoline)

Figure 3.20. International and domestic prices for Russian crude oil



Source: IHS Markit

Figure 3.21. International versus domestic prices for Russian motor gasoline



Source: IHS Markit

The diverging paths of crude and gasoline prices in Russia this year partly reflect Russian authorities' still-evolving oil sector tax and pricing policy, and in particular the government's efforts to mitigate the impact on domestic product consumers of an ongoing fiscal regime overhaul—the latest so-called tax maneuver—through a series of ad hoc deals with Russia's leading oil companies to put a lid on the price of motor fuels at the pump.

In 2018, Russian authorities finalized amendments to the Tax Code and customs tariff legislation, setting the stage for a series of interlinked changes to virtually all oil sector taxes during the next five years (i.e., 2019–24). The government has continued to tweak the tax maneuver in 2019 in an effort to balance the many competing interests. Significant "midcourse corrections" in Russian oil tax policy are likely to continue between now and 2025 as various issues inevitably arise, but the broad outlines of the fiscal reform and its general implications for oil markets are already clear enough.

The changes currently underway amount essentially to a continuation of previous reforms involving a simultaneous reduction of export duties and rise in the upstream Mineral Resources Extraction Tax (MRET)—with a few key new twists, including the phased complete elimination of both crude and refined product export duties this time, at least aside from possible exceptional circumstances.[28]

In broad terms, the 2019–24 tax reform is designed to minimize risks associated with EAEU integration, rationalize the downstream Russian oil sector, and generate new revenue streams with which to finance President Vladimir Putin's ambitious new national projects:

- **Minimize the risks of redirection of significant oil flows and accompanying value to other EAEU member states following creation of a common oil market.** The timetable for completion of the Russian tax reform on the eve of the planned 2025 EAEU oil market integration is no mere coincidence. Without the elimination of export duties as envisioned by the tax maneuver, creation of the EAEU common market could result in the redirection of Russian oil export flows from Russian outlets under high export taxes to Belarusian or other EAEU routes with little or no duty.

- **Curb "opportunistic" refining while neutralizing the impact of the reform on sophisticated refineries and Russian motor fuel consumers.** The phasing out of export duties is partly designed to tackle the problem of "opportunistic" export-oriented refining incentivized by differential export duties for crude versus products, which have benefitted from preferential export duty rates. Russian policymakers are counting on the use of negative excise taxes applied to domestic crude oil purchases on the part of selected plants to neutralize the impact of higher domestic crude prices for relatively sophisticated or modernizing refineries. Under the new system, refiners may also claim compensation from the government for some of the difference between export and domestic prices for refined products when domestic prices are lower (after factoring out transportation costs and export duties), but face an additional tax when the reverse holds true.

- **Generate additional revenue to finance President Vladimir Putin's national projects.** Putin's 7 May 2018 decree, formulated after his reelection for a third presidential term during 2019–24, outlined key national goals and objectives designed broadly to transform Russia into one of the top five economies of the world by 2024. By default, the oil sector has emerged as potentially the largest

[28] Specifically, the current marginal crude oil export duty rate of 25% (of the international price) is scheduled to decline by 5 percentage points during each of the next five years, so that the rate falls to zero in 2024. Refined product export duties will be automatically phased out as well, since these are tied to the crude export tax.

single source of financing for the national projects, through means of tax reform (specifically, withdrawal of governmental subsidies from less sophisticated refineries and the MRET hike).

One key uncertainty, however, is the extent to which policymakers may seek to continue to limit the impact of the 2019–24 tax reforms on domestic product prices given the political sensitivities. The planned elimination of export duties will tend to put further upward pressure on Russian retail prices—dampening product demand in turn—especially in the current environment of higher world oil prices combined with elimination of the export tax's role as a "wedge" between export and internal prices. But the government has repeatedly demonstrated its determination to prevent sharp increases in prices at the pump, and further state intervention in domestic product markets is likely in one form or another, though stopping short of systematic price regulation.

Another issue slowing the progress of market liberalization in Russia is the risk posed for the smaller, less sophisticated refineries, many of which are under tremendous economic pressure and struggling to survive, especially following withdrawal of subsidies under the 2019–24 tax maneuver, but often have powerful regional government patrons.[29] Therefore Russia, like Kazakhstan, is concerned about the potential impact that aggressive moves toward liberalization under EAEU auspices might have on its refining sector, and is likely to proceed with caution.

3.7.3. Kyrgyzstan

Kyrgyz oil balance trends: Still heavily dependent on imported gasoline and diesel

Kyrgyzstan does not produce nearly enough crude oil to meet domestic refined product demand, which had reached about 1.5 MMt/y in 2017–18. Kyrgyz crude production was up by 18% in 2018 to around 200,000 tons (4,000 b/d), and crude production is likely to remain small overall. Kyrgyzstan has little prospect of supplying sufficient crude to meet all of its own oil needs longer term, and will either have to import products or crude for its refineries.

The Kyrgyzstan refining sector's underlying problem is a mismatch between available refining capacity and the types of products consumed domestically. Although several small refineries have been built, with enough aggregate capacity to fully cover domestic demand, they remain underutilized because of the difficulties of procuring oil feedstocks to run them; they are also relatively simple, with limited secondary processing capacity, so they do not produce the types of high-quality products needed in the domestic market.[30] As a result, Kyrgyzstan still relies heavily on imported oil products, mainly from Russia so far, to meet domestic demand. Russia has committed to supply 1 MMt of duty-free products to Kyrgyzstan in 2019 (the same level as in 2018), which is enough to fully meet Kyrgyz demand after factoring in domestic refinery operations.

Kyrgyzstan managed to ramp up its gasoline production several-fold during the period 2014 to 2017, when Kyrgyz gasoline output amounted to about 235,000 tons (see Table 3.9: Automobile gasoline balance for Kyrgyzstan). But this still falls far short of domestic market needs.

In 2017, Kyrgyz consumption of automobile gasoline and diesel amounted to around 692,000 tons and 620,000 tons, respectively, while fuel oil demand was about 115,000 tons. Partial data for 2018 indicate nearly the same level of gasoline demand in 2018. Specifically, 2018 gasoline production is estimated at 237,000, while gasoline imports are reported at 426,000 tons—implying total demand on the order of 663,000 tons.

[29] In contrast, Russian mini-refineries located relatively close to export markets have continued to prosper on account of their comparatively low transportation costs.
[30] See the IHS Markit Insight Kyrgyzstan's Refined Product Needs Still Met Mainly with Imports Despite Buildup of Refining Capacity, March 2016.

Table 3.9
Automobile gasoline balance for Kyrgyzstan
(thousand tons)

	2010	2011	2012	2013	2014	2015	2016	2017	2018
Production	15.3	15.5	10.5	9.0	65.2	115.1	171.3	234.8	237.0
Imports	423.8	558.7	908.3	802	618.4	625.3	532.9	468.5	426.0
Domestic consumption	433.2	589.6	872.3	804.5	652.0	689.7	739.0	691.5	663.0
Losses	1.6	1.0	13	0.6	0.8	0.8	0.6	0.6	
Exports	1.8	10.4	4.5	17.0	24.8	31.8	6.8	6.6	
Stocks remaining at the end of the year	62.7	37.3	66.4	55.2	61.2	79.3	37.0	41.6	

Note: Preliminary estimates for 2018.
Source: National Statistical Committee of the Kyrgyz Republic

Kyrgyz oil market: Relatively liberalized

Under the terms of the EAEU, which Kyrgyzstan joined in 2015, export duties on oil products imported from other members do not apply, but currently inter-union trade in oil products still remains strictly bilateral. This favors imports of refined products over crude, although removal of all export duties is slated to occur eventually (but perhaps not before 2025).

For many years Russia did not levy export duty on product deliveries to Kyrgyzstan, in accordance with a bilateral free trade agreement dating from 1992. In May 2010, Russia started charging export duties on its products delivered to Kyrgyzstan (and also to Tajikistan). However, Russia again suspended export duties starting in 2011 as both countries reached several strategic agreements, including on Russian companies' acquiring controlling stakes in the Dastan torpedo factory and in Kyrgyzgaz by Gazprom, as well as on writing off Kyrgyzstan's sovereign debt to Russia.

In Kyrgyzstan, because Russian product imports dominate supply, the refined product market is now much more liberalized than in Kazakhstan, and Kyrgyz prices tend to track Russian price levels. Kyrgyz authorities have contemplated reintroducing price regulations on occasion.

A growing problem recently has been the illegal import of Kazakh refined products into Kyrgyzstan (i.e., bypassing official customs channels). The volume of this trade has lately been estimated at 250,000–300,000 tons per year—amounting to around 20% of the total Kyrgyz market, costing the Kyrgyz government up to 3 billion som per year (over $40 million) in lost revenue. It is unlikely that Kazakh and Kyrgyz authorities will be able to completely stamp out the illicit product trade so long as product prices remain substantially lower in Kazakhstan than in Kyrgyzstan, even if an intergovernmental agreement is finalized.

3.8. Implications of the EAEU Regulatory Framework for the Oil Industries of Kazakhstan and Other Member States

One of the main challenges to integration for Kazakhstan within the EAEU is the lack of strong economic complementarity with Russia, the EAEU's largest economy and most important member. Both Kazakhstan and Russia are major hydrocarbon producers and exporters, dependent on exports of raw materials that go mainly to global markets rather than other EAEU members. In contrast, for example, the economy of Belarus is mainly based on manufacturing, with the output sold mostly to Russia, while it imports raw materials (again from Russia), so its trade structure is oriented more strongly toward the FSU economic space. Similarly, Kyrgyzstan relies heavily on imports of Russian refined products, while its own hydrocarbon production and exports are negligible. Thus, the process of harmonization with Russia will be more onerous for Kazakhstan than for EAEU members who are mainly or entirely energy importers (Armenia, Belarus, Kyrgyzstan), as they already largely operate according to Russia's general acquis.

Creation of the EAEU's common oil and refined products markets was envisioned in three stages in accordance with Article 84 of the EAEU Treaty. The first phase, envisaging development and approval of the EAEU's common oil and refined products markets formation program was completed in December 2018, with the formal approval of this program by the Supreme Eurasian Economic Council (consisting of the leaders of the five EAEU member states).[31] The second phase (to 2023) involves implementation of the steps stipulated in this program, including development of unified rules of access to oil and refined products transportation systems located within the member states. The third phase (to 2024) would finalize formation of the EAEU common oil and refined product markets (to take effect from 1 January 2025).[32]

Basic principles for oil and oil products markets formation include provisions for market pricing; development of fair competition; and removal of technical, administrative, and other obstacles hindering trade in oil and refined products, as well as related equipment, technologies, and services. Additionally, they include ensuring non-discriminatory conditions for the member states' business entities, harmonizing rules and regulations concerning operation of technical and commercial infrastructure, and unifying oil and refined products norms and standards.

Development of the common market for oil and oil products prioritizes cooperation of member states with an emphasis on fair treatment and mutual benefit.

Member states have agreed to provide equal access to infrastructure for transporting oil and oil products to all companies, continuing a system of transit flows that has existed since the collapse of the Soviet Union. One of the stated principles of the EAEU common market for oil and products is to respect the balance of economic interests of the EAEU's entities, including the interests of the natural monopolies that provide transportation services. Transportation of oil and oil products to meet the domestic demand of member states is given priority over export needs. Transportation tariffs are to be set individually by each country, but they cannot be higher for companies of other member states than for domestic companies (they could be lower, however, at the discretion of the member state). Still, conflicts have surfaced between goals and realities, as disagreements have arisen concerning oil pipeline tariffs.[33]

The member states agreed to have no quantitative restrictions or export duties (or other types of customs duties, taxes, and charges) in their mutual trade. Export and customs duties levied on oil and oil products beyond the EAEU are regulated

[31] https://docs.eaeunion.org/docs/ru-ru/01420205/scd_07122018_23
[32] See the IHS Markit Insight, The Eurasian Economic Union and Kazakhstan's Domestic Oil and Gas Markets, March 2018.
[33] The EAEU member states agreed that the principles established for internal oil and refined product markets shall not apply to the legal relationships arising within the framework of intergovernmental agreements concerning cross-border pipelines that already exist. Belarusian refineries currently receive Russian crude duty free, and Belarus collects the export duty when it sells products refined from this crude in international markets. Minsk is demanding compensation for the change, claiming that removal of the duty will cost the country some $11 billion in lost revenues over a six-year period.

by separate agreements.

Mutual trade in oil and refined products among market participants will be conducted either under bilateral contracts or through exchange trading. The oil and oil products common markets concept calls for market-based pricing. However, the concept also stipulates that pricing mechanisms shall take into account the pricing mechanisms existing in the markets of the member states and the formation phases of EAEU common oil and refined product markets. Recent signposts indicate that development of exchange trading infrastructure remains weak and the scale of the trading volumes is small, indicating that for some time bilateral agreements and contracts between individual EAEU states will continue to predominate.

Progress on the program for oil and oil products integration is jeopardized by escalating tensions between Russia and Belarus, resulting from Russia's plan to gradually phase out export duties as part of its tax maneuver, with negative implications for Belarus.[34] The two sides remained deadlocked over a possible compensation mechanism, along with a host of other bilateral trade issues. In one sign of the potential impact of this impasse on EAEU integration, Belarus has recently begun lobbying for a change in the EAEU rules governing decision-making at the EAEU intergovernmental council.

3.9. Recommendations for Kazakh Oil Sector Policies Needed in Connection with EAEU Integration

The timetable for full integration of EAEU oil markets remains highly uncertain, notwithstanding the official plan to put this in place by 2025. Given that the two largest member states (Kazakhstan and Russia) are cautious about rapid integration, the oil products market for the whole of EAEU will likely remain administratively managed for some time thereafter, albeit with elements of openness where mutually agreeable.

The EAEU integration dynamic has nevertheless been set in motion, and this creates considerable challenges—as well as opportunities—for Kazakhstan, where the refining and downstream sector remains highly administered despite nominal liberalization of retail prices on some products (gasoline and diesel). The fact is that reforms needed to achieve a successful EAEU market integration are also typically a precondition for attraction of critical investment and increased oil industry efficiencies, and therefore tend to make sense in their own right.

As shown by the historical example of the European Union, regional integration is most effective when member states liberalize both domestic policies and cross-border arrangements. Therefore, as a member of the EAEU, Kazakhstan (as well as the other members) should introduce market mechanisms and refrain from establishing restrictive administrative mechanisms with regard to refined products production, distribution and transportation, and trade. While such liberalization can involve political challenges in countries where populations have grown accustomed to low-cost energy supplies, the risks inherent in a "business as usual" strategy are much greater.

While Kazakh authorities themselves must naturally decide the specifics of any new reforms, IHS Markit concludes that the following general policies would enable Kazakhstan to gradually harmonize its oil market regulations with those of other EAEU member states in coming

[34] Belarusian refineries currently receive Russian crude duty free, and Belarus collects the export duty when it sells products refined from this crude in international markets. Minsk is demanding compensation for the change, claiming that removal of the duty will cost the country some $11 billion in lost revenues over a six-year period.

years, while simultaneously enhancing oil supply and price security and improving the overall oil sector investment climate:

• **Allowing domestic crude prices to rise to the level of export netback parity.** Importantly, in time, this will provide sufficient incentive for crude producers to supply domestic refineries, as they receive the same revenues for their oil in either market. With Kazakhstan's available export capacity for crude oil, incremental crude production should be able to find a cost-effective export route, allowing the domestic market to clear at export netback parity with international prices (minus transport/insurance/loading charges and export duties).

• **Reduce refinery tolling fees by stages, and phase out the tolling system altogether by the mid-2020s.** Refiners should effectively function as merchant operators who buy crude and sell products and make their business decisions independently, making money on margins like in other countries. One key corollary of this policy is a simultaneous phasing out of the Energy Ministry's role in determining specific output levels among refineries (the three major plants as well as smaller ones manufacturing selected products such as bitumen).

• **Permit full-scale liberalization of domestic refined product prices, so that domestic retail product prices are free to rise to at least the average level among EAEU member states.** This means official decontrol of prices for AI-80 gasoline and an end to the continuing de facto regulation of other prices (e.g., through questionable fines on retail stations for alleged anti-competitive pricing). Motor fuel consumers might be compensated for higher prices at the pump by means of an equivalent reduction of the transportation tax on vehicles.

• **Align excise tax rates with those in Russia as part of the single economic space.** In addition to price harmonization, eventually Kazakhstan will need to harmonize its downstream taxes with those in Russia to minimize the risk of major end-market price differentials and distortions, and the resulting complications noted above.

• **Minimize product import-export restrictions.** To allow domestic market forces to operate effectively, the government needs to ensure that the practice of periodic bans on refined product exports and imports is strictly limited to cases where such prohibitions are vital for national security reasons as spelled out in both Kazakh and EAEU legislation.

Comments by KAZENERGY Association

The KAZENERGY Association, while sharing IHS Markit's general views on long-term sector development prospects (after 2025), regards some recommendations as premature when applied to the current situation:

- **Oil export netback parity**

Currently, there are no regulatory [legislative] restrictions preventing oil prices from reaching export netback parity in the domestic market. However, crude oil is effectively acquired by the refineries at a significant discount, and so are refined products from the refineries, through the operations of the tolling scheme, in order to prevent growth of retail prices for refined products. A full-fledged transition to export parity in the foreseeable future is inevitable, however, and represents a significant step toward fuel and lubricants market liberalization. However, it needs to be implemented gradually, in stages. Presumably, as an initial step in such a transition, the MRET on crude oil supplies to the domestic market should be lifted and the resulting reduced tax should be transferred to a higher MRET that would be levied on export volumes (the estimated amount "at stake" is about KZT60 billion per year, or $154 million).

- **Refinery tolling fee reduction**

It is impossible to reduce refinery tolling fees simultaneously and immediately for all plants. The current tariff was approved as part of the corresponding refinery investment programs, taking into account the loans for modernization. Accordingly, as the debt is paid off, the plan is for the tolling fee to decrease.

- **Refined product prices**

Due to the significant difference in light product prices (especially for AI-92) in Russia and Kyrgyzstan compared to Kazakhstan, the unauthorized outflow of light products is occurring in the regions bordering the two aforementioned countries. For example, the current price difference for AI-92 is about 80 KZT/liter ($0.22/liter). Furthermore, the fuel going from Kazakhstan to Russia becomes part of Russia's consumption and balance, thus increasing the potential volumes of export of Kazakhstan's fuel from Russia with the payment of the corresponding customs duty.[35]

Notwithstanding the domestic refinery modernization and full coverage of Kazakhstan's domestic needs (for gasoline, and eventually for jet kerosene), there is always a risk of a fuel shortage developing in Kazakhstan (the volumes of "gray" exports are estimated at 0.5-1 MMt of fuel per year). The measures taken by the government (such as creation of special customs control posts to prevent unauthorized export of motor fuels, controls at filling stations) are ad hoc (irregular) and cannot change the situation radically. Price parity between Kazakhstan and Russia needs to be achieved by economic measures. However, given the high social sensitivity of the issue, this should be done in a gradual and balanced manner, taking into account the interests of all market participants, primarily households. The most acceptable tools for synchronizing retail prices of fuel and lubricants are fiscal ones – namely, excise taxes – as well as trade liberalization. Currently, in Kazakhstan the wholesale excise tax rate is 10,500 KZT/ton ($27.3/ton) on motor gasoline and the retail excise tax rate is 500 KZT/ton ($1.3/ton), which combined is about sixth to one-seventh that in Russia ($189/ton).[36] In other words, the increase in the retail price of fuel and lubricants in Kazakhstan will be achieved largely through an increase in taxation, without any substantive increase in the underlying

[35] IHS Markit notes that this potential is rather limited. Russia exported 150.1 MMt of refined products in 2018, while Kazakhstan exported only 111,100 tons of refined products to Russia. So, Russia's imports of Kazakhstan's products represented a mere 0.1% of Russian exports.
[36] Converted to liters, Kazakhstan's total excise tax on gasoline is $0.02/liter, while in Russia it is $0.14/liter.

commodity price and margin of the refined product market entities – subsoil users, refiners, traders, distributors, and filling stations. The population (residents) could be compensated for the proposed increase in budget revenues from excise taxes through a reduction of social taxes (in order to increase effective take-home pay) as well as through the elimination of the transport tax.

4. KAZAKHSTAN'S NATURAL GAS MARKET AND FUTURE CHALLENGES TO GASIFICATION

4. Kazakhstan's natural gas market and future challenges to gasification

One of the government of Kazakhstan's key energy goals is widespread gasification, further utilizing a potentially abundant (and relatively clean) domestic natural resource for power generation, in industry, and in the residential sector. However, there are various structural, regulatory, and pricing impediments to rapidly expanding gas penetration in domestic energy consumption. Furthermore, the creation of a common Eurasian Economic Union (EAEU) gas market in 2025 adds an additional layer of complexity and will necessitate that the gas market develops in a way counter to many of Kazakhstan's domestic social policy preferences. This chapter analyzes the current and potential future development of Kazakhstan's natural gas production, consumption, and trade—along with existing regulatory and pricing mechanisms—and generates recommendations that will allow Kazakhstan to integrate more harmoniously into the EAEU common market and realize its own domestic and Paris Climate Agreement priorities to increase the utilization of natural gas in its economy.

4.1. Key Points

- A combination of low prices for producers of associated gas offered by state-owned KazTransGas (KTG) and low end-user prices set by Kazakhstan's State Committee for Regulating Natural Monopolies and Competition Protection (KREMiZK) threatens Kazakhstan's gasification goals, by dis-incentivizing production of commercial gas and also discouraging its efficient use by consumers.
- Kazakhstan's gas balance is expected to become increasingly tight. Over the coming years commercial production is expected to grow very little, while more robust growth is likely in domestic consumption. Because of constrained commercial supplies, Kazakhstan will have to make hard choices between achieving high levels of exports to China (up to 10 Bcm/y during 2019–23) or making more gas available for domestic use. Unless changes are made to current pricing policy, one or both of these goals may suffer: Kazakhstan's gas exports to China could begin to decline in the early 2020s and a deficit in commercial gas supply in the country's southern regions could develop.
- How this plays out will have critical implications for KTG, which in recent years has relied on export revenues to offset financial losses it incurs when providing gas to the domestic market at low prices even as it builds out domestic gas distribution infrastructure.
- Artificially low domestic prices also will impede Kazakhstan's efforts to harmonize its prices with those of Russia in the lead-in to the Eurasian Economic Union's planned single gas market (2025). To harmonize industrial gas prices in western Kazakhstan's producing area (Atyrau Oblast) with those in gas-producing Yamal-Nenets Okrug in Russia would require a 13% increase each year between 2020 and 2025.
- A more gradual staged increase in both producer and end-user prices would alleviate some of this pressure, but it is not clear whether the political will exists to educate consumers about the imperative for higher prices. Because of strongly held convictions that utilities are a right to be ensured for all by the government, Kazakhstan is an outlier country globally in terms of its extremely low energy prices (in most oblasts the

average resident pays only about 3% of their household incomeon gas, electric power and other utilities, a much lower share than in either developed countries and even in analogous lower income developing countries such as Azerbaijan and Turkey).

- Natural gas production costs are much higher than indigenous coal, which means that power market mechanisms need to be adjusted to support gas-fired generation. This may include raising the price of coal for consumers to reflect the cost of carbon emissions through carbon trading or some kind of special feed-in or capacity tariffs for gas-fired plants. Politically this is a difficult move as it could raise costs for Kazakhstan's power consumers significantly, perhaps even undermining the competitiveness of exports of mineral products such as copper, chrome, iron ore, and other metals.
- Still, a more robust policy framework that addresses emissions by coal cannot be ignored much longer going forward. The revised Ecology Code, released for comment in July 2019, and currently being debated, generally still presents a punitive approach towards emissions, including flaring of associated gas (even in emergency situations), aimed particularly at oil and gas companies, even as coal-based emissions receive comparatively light treatment. Gas flaring is also subject to an emissions tax, at a rate that is exponentially higher than the rate for other types of stationary sources, especially when taking into account penalties. This approach essentially ignores the problem of the largest carbon emitters (coal-fired power stations), while excessively penalizing oil and gas operators which have already reduced flaring to minimal levels. This does not help improve Kazakhstan's overall investment attractiveness, increase commercial gas availability, or most importantly, help Kazakhstan to achieve its Paris Agreement goals.
- Greater use of gas instead of coal in power generation is important not only because of environmental considerations, especially quality of air in cities, but also because Kazakhstan's power generation is short on flexible capacity that can quickly respond to changes in power demand. This is a need that is only expected to increase going forward.
- As stated in The KAZENERGY National Energy Report 2017, a substantial transition from coal to gas consumption in the economy, as well as increased energy efficiency, and continued build-out of renewable energy are pathways essential for Kazakhstan to achieve its full 15% unconditional emissions reduction target (below 1990 levels by 2030) under the Paris Agreement. These changes could also bring Kazakhstan halfway to the higher conditional goal of a 25% emissions reduction.

4.2. Production, Consumption, and Trade

4.2.1. Production

Natural gas production (gross extraction) has been increasing rather robustly in recent years, by 4.8% in 2018 after a sizable increase (13.4%) in 2017, boosted mainly by growth in output at Kashagan. Commercial production (gross output minus reinjection) in Kazakhstan has also been on the rise. In 2018, the national total was about 36.4 Bcm, 10% higher than in 2017 (see Table 4.1. Kazakhstan's natural gas balance, 2010–18); Kashagan produced 5.46 Bcm of commercial gas last year, while Tengiz sold 9.2 Bcm of commercial gas, a significant increase from 7.5 Bcm in 2017, and Karachaganak reinjected less gas in 2018, boosting its commercial production to 10.3 Bcm.

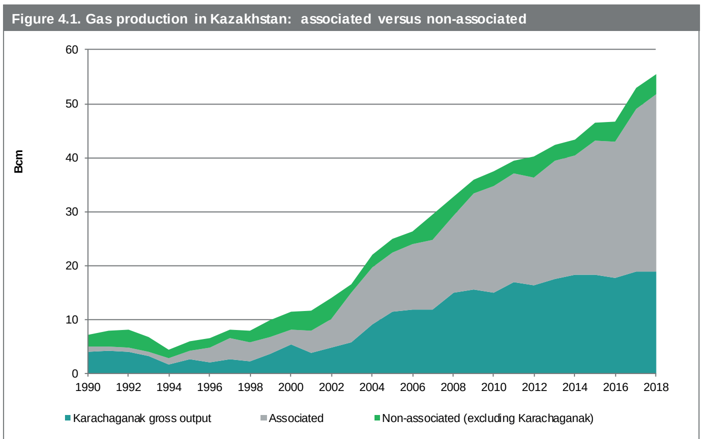
Table 4.1
Kazakhstan's natural gas balance, 2010-18
Bcm

	2010	2011	2012	2013	2014	2015	2016	2017	2018	Percent change 2017–18	Percent change 2016–17
Production (gross)	37.4	39.5	40.3	42.4	43.2	45.3	46.7	52.9	55.5	4.8	13.4
Production (commercial)	24.0	24.6	24.3	24.5	24.6	27.5	28.8	33.1	36.4	10.0	15.0
Imports (operational statistics)	4.5	4.3	2.5	2.7	2.2	3.2	4.9	5.0	6.0	20.2	0.8
Exports (operational statistics)	12.4	11.7	10.9	10.8	10.6	10.9	12.8	16.8	19.4	14.9	31.3
Imports (customs statistics)*	4.0	3.7	4.6	5.2	4.4	5.8	6.9	5.6	7.0	24.2	(17.7)
Exports (customs statistics)*	14.5	22.3	20.5	20.6	20.3	21.5	21.6	24.1	26.5	10.1	11.3
Apparent consumption (commercial gas)	15.6	16.6	18.0	18.9	18.5	22.4	22.8	21.9	24.1	9.9	(4.0)
Reported gas deliveries to consumers**	9.0	10.1	10.5	10.9	12.4	12.0	13.1	14.0	15.1	8.2	6.8

*Exports and imports reported from customs (trade) statistics differ from operational statistics reported by KazTransGas and the Ministry of Energy.
** Amount reported as consumption (end-of-pipe deliveries) by the Ministry of Energy
Source: IHS Markit, Ministry of Energy, Kazakhstan Statistical Agency.

Despite this recent growth, Kazakhstan's gas market has a number of constraints. First,more than half of gross gas production now is associated gas—i.e., gas that is produced alongside oil as part of operations intended primarily to produce oil; much of the remainder is from Karachaganak, where the focus is on extracting natural gas liquids (NGL) as well (see Figure 4.1. Gas production in Kazakhstan: associated versus non-associated). As a result, Kazakhstan's gas production levels are determined in large part by liquids-driven operations, especially at the three major upstream projects (Karachaganak, Kashagan, Tengiz), which account for about 76% of national gross gas output.[1] This heavy dependence on associated gas makes it difficult to scale commercial gas output in response to demand.

Figure 4.1. Gas production in Kazakhstan: associated versus non-associated



Notes: Gross production, including reinjected volumes.
Source: IHS Markit, Kazakhstan statistical agency, Ministry of Energy.

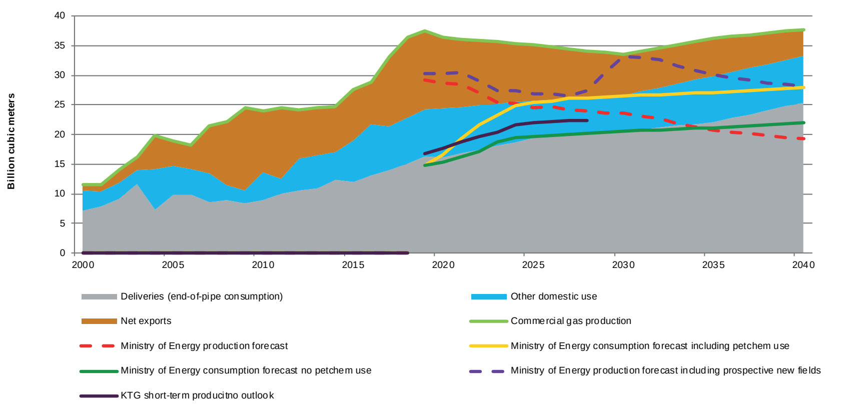
Second, much of the associated gas has a high sulfur content (the Tengiz and Kashagan fields' sulfur content is about 18–19%), which requires expensive processing and demands additional measures to safely store, utilize, and monetize the large amounts of recovered sulfur. At present, low domestic gas prices

[1] Karachaganak is Kazakhstan's largest gas producer, accounting for about 34% of total gross output and 28% of total commercial gas output.

do not provide adequate incentives for producers of this associated gas to make additional commercial volumes available on their own. Some subsoil users indicate that the price they receive for commercial gas is less than the cost of production "by many multiples." Further, for both the three "mega" projects and smaller producers, gas reinjection back into reservoir to maintain pressure provides additional support for liquids production. So far, reinjection has become the preferred solution for both the producers and the government, as greater liquids production generates higher revenues for producers and additional revenues for the government (through taxes and export duties) and avoids operational and financial challenges associated with gas processing. Theoretically, the reinjected gas remains available for re-extraction at a later date, but the reality of high cost of gas processing remains.

Finally, Kazakhstan's gas market is highly regulated, with producer and consumer prices suppressed in some cases below cost. This will make it difficult to adequately supply Kazakhstan's gas market in the medium term as domestic demand grows and export demand remains ever-present. The Ministry of Energy now envisages a domestic gas deficit emerging in the mid-2020s, but that assumes a relatively rapid build-out in methane-based petrochemicals. IHS Markit's gas balance forecast anticipates that Kazakhstan will remain a net gas exporter, while the domestic market will be met with both domestic supply and continued imports through the 2040s (see Figure 4.2. Outlook for Kazakhstan's natural gas balance).The build-out of petrochemicals, particularly methane-based nitrogenous fertilizers and methanol, is likely to be much slower in our view than currently projected by the Ministry.

Figure 4.2. Outlook for Kazakhstan's natural gas balance to 2040

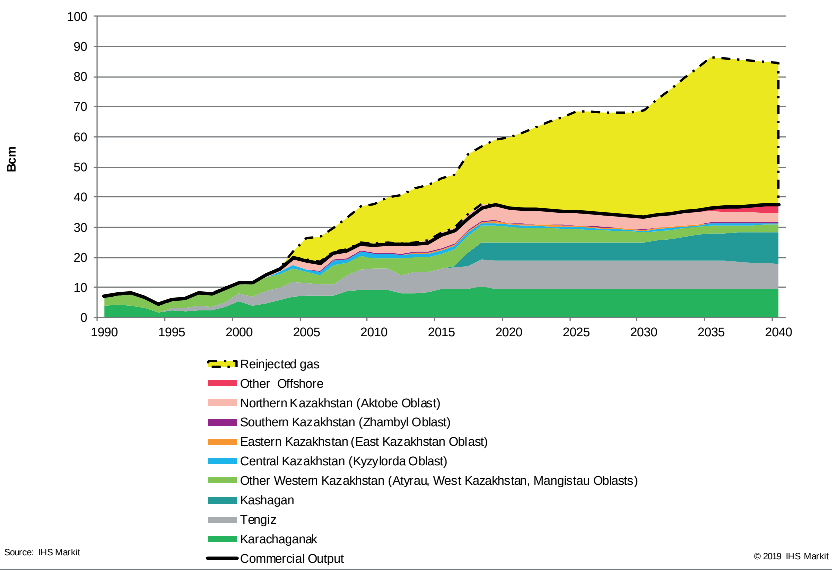


Notes: Other domestic use includes: field use and losses, processing losses, pipeline use, changes in stocks.
Source: IHS Markit

Mainly reflecting the overall growth in Kazakhstan's liquids output, by 2040 IHS Markit projects that gross gas output will grow by 52%, to 84.4 Bcm/y, but commercial volumes will barely increase at all, only by about 3.6% and be on the order of 38 Bcm/y due to sustained high reinjectionneeds and to the challenges to commercial use described in this chapter (see Figure 4.3. Kazakhstan's gas production profile to 2040, base case). Of the total increase in gross gas output between 2018 and 2040, 95% is expected to come from Kashagan, 2% from Tengiz, while the contribution of Karachaganakto gross output is expected to decline slightly (-1%). At the same time, Karachaganak's commercial gas output is expected to generally remain stable through 2040 at about 9.5 Bcm/y, while Tengiz's commercial gas deliveries will remain around 9.5 Bcm/y through 2035 and then decline to 8.5 Bcm/y by 2040. At Kashagan, commercial gas output in the IHS Markit base case is expected to rise to 9 Bcm by 2035 and 10.5 Bcm by

2040, assuming Phase 2 development goes ahead and the Bolashak gas treatment facility's capacity is expanded. The only other source of new potential incremental output growth in our forecast could come from new projects in offshore blocks, although the currently discussed joint development of the Kalamkas-more and Khazar fields is not expected to yield commercial gas. Of course, the adoption of market incentives for dry gas development is possible to attenuate the decline in the mature onshore fields in Aktobe, Kyzylorda, and other regions, as well as to generate some new sources.

Figure 4.3. Kazakhstan's gas production profile to 2040, base case



Source: IHS Markit

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In search for additional volumes of sales gas, KTG is considering building additional gas processing capacity of up to 2 Bcm/y that would use Kashagan gas as feedstock, in close proximity to NCOC's current facilities.

Since passage of the updated Subsoil Code, KMG has also secured a variety of exploration agreements that could yield new gas. In 2018, KMG and LUKOIL signed acontract for exploration of the Zhenis offshore block, and in June 2019, the companies agreed to negotiate mineral rights for the I-P-2 offshore block (located 130 km off Aktau) as a prelude to an exploration contract. In 2019, KMG and ENI Isatay BV inked a joint exploration contract for the offshore Abay oil and gas block roughly 70 km northwest of the Buzachi Peninsula. In May 2019, BP and KMG signed an agreement to share upstream data, and explore potential future cooperation. If exploration results are successful, these fields could provide some incremental volumes of gas.[2]

The signing of these new exploration agreements is, of course, a positive development for Kazakhstan's upstream sector. More is needed. Specifically, the proposed joint field development project between the Kalamkas-more (NCOC) and Khazar (CMOC) fields should be approved by late 2019, to allow the consortia to proceed with Front End Engineering Design (FEED), so they can make the Final Investment Decision (FID) and begin project development by the mid-2020s. This project benefits from experienced operators, and given its smaller size (relative to Kashagan) will serve as a harbinger for the next generation of offshore Caspian oil and

[2] But these new projects are unlikely to come on line in the near term, and their output will not so much boostnear-term output as to provide a buffer against the decline of oil and gas from the currently producing projects longer term.

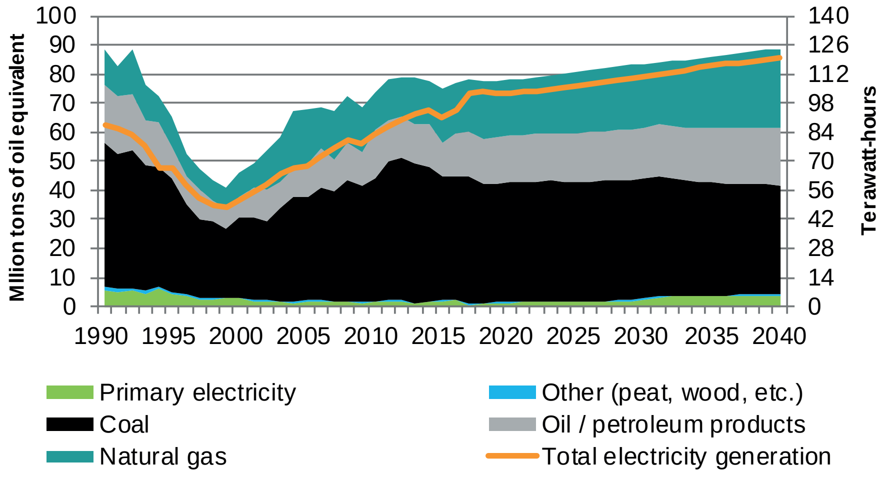
gas projects. Beyond Kalamkas-more and Khazar, the current scale of exploration investment still pales in comparison to that required to sustain future growth in field development and production.There have even been some market exits, with ONGC pulling out of the Satpayev block in 2018. The Ministry of Energy's upstream auctions held in June 2018 only granted 11 onshore blocks to small companies. Kazakhstan's policymakers should not lose sight of the fact that only investors with stability clauses in their contracts thus far have been willing to make the significant investments that have led to the recent trend in production growth.

To summarize production in the context of the current gas balance: Of total (gross) gas production of 55.5 Bcm in 2018, 34% (19.1 Bcm) was reinjected, leaving 36.4 Bcm available for commercial use. Of this, 19.4 Bcm was exported (according to operational data), leaving roughly 17 Bcm for the domestic market. This was augmented by 7.0 Bcm of imports (primarily from Russia and Uzbekistan to the adjacent regions in Kazakhstan), yielding approximately 24 Bcm of apparent domestic consumption[3] (see Table 4.1. Kazakhstan's Natural Gas Balance, 2010-18).

4.2.2. Consumption

Unlike other CIS countries, gas plays a relatively limited role in Kazakhstan's primary energy balance. The country's energy consumption needs are met mainly by coal (59%) with gas accounting for only 21% of primary energy consumption, although its share has been rising; oil accounts for 18%, and primary electricity and other sources 2% (see Figure 4.4. Kazakhstan's primary energy consumption by fuel).

Figure 4.4. Kazakhstan's primary energy consumption by fuel



Source: IHS Markit

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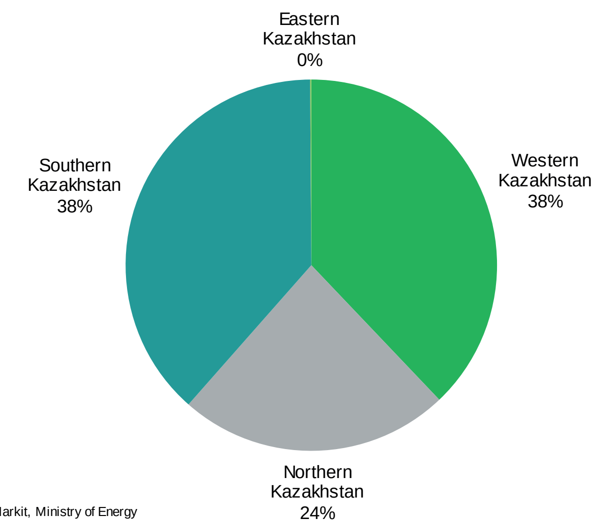
In terms of regional gas consumption, there are three broad regional markets identifiable in Kazakhstan (see Figure 4.5. Regional shares of gas consumption in 2018). The western part of the country (mainly the oil and gas producing regions) is a significant gas consumer, while in the north and the east, economies are run predominantly on coal. This trend is expected to continue. In the south, both coal and gas are used and will compete going forward. There is a potential to increase the use of natural gas in the south in all three consumer categories—

[3] Apparent consumption is commercial production plus imports minus exports and differs from "end-of-pipe deliveries." The apparent consumption figure is an estimate, due to uncertainties in export and import volumes.

the power sector, residential-commercial sector, and the industrial sector—owing to the growth of population and commercialization. Unlike Kazakhstan's other two power zones where gas dominates in the Western Zone and coal dominates in the Northern Zone, thermal plants in Kazakhstan's South have a greater mix of gas- and coal-fired capacity (fuel use in the Southern Zone thermal utility stations in 2018 was 60.6% coal, 36.9% gas, and 2.5% mazut). And despite having access to gas, the region has a surprisingly small amount of gas turbine capacity for flexible power generation.[4]

Figure 4.5. Regional shares of "end-of-pipe" gas consumption in 2018



Source: IHS Markit, Ministry of Energy

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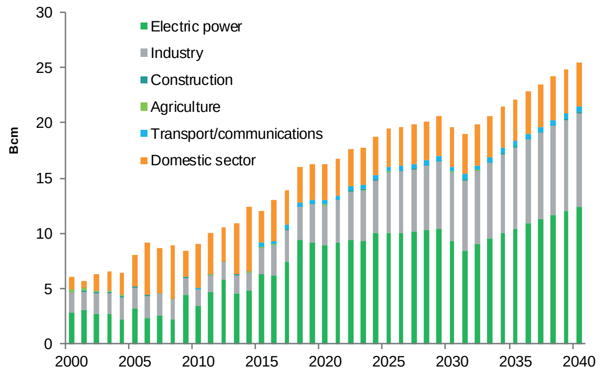
In 2018, Kazakhstan's "end-of-pipeline" consumption reached 15.1 Bcm, 68% higher than the 9 Bcm consumed in 2008 and higher than the 1990 level of 14.4 Bcm achieved at the end of the Soviet period. Most of the gas delivered by pipelines is consumed in power generation (50%), followed by residential-commercial users (domestic sector) (36%), and industry (14%). Significant growth potential exists for use of gas in power both to lessen the power sector's negative impact on the environment and to provide flexible generation for an increasingly pronounced peak profile, stemming from an ongoing structural shift in electricity demand to residential-commercial use from industry. In 2018, gas-fired generation accounted only for 19% of national powerproduction overall. There is also potential for utilization of gas in vehicles (transportation, reducing demand for refined products) and industry, including in Karaganda and Akmola oblasts. In the residential sector, major support for consumption growth is provided by KTG's ongoing build-out of distribution pipeline infrastructure (see below). However, consumption of natural gas by the power sector and industry is impacted by preferences rooted in economics and in ecological regulations favoring coal over gas (see section 4.4.2 below). In summary, there is little incentive for most industrial consumers in Kazakhstan to switch from coal to natural gas. Nonetheless, we expect Kazakhstan's apparent natural gas consumption to grow at about 1.9% per year on average out to 2040.This is to about 33 Bcm, or about 38% above the current level. With commercial gas production expected to remain stagnant, the gap between commercial volumes of gas available and apparent consumption (a gap which is now essentially exported) diminishes appreciably during our forecast period, by roughly almost two-thirds. So, the current tightness in the gas market is a feature that

[4] Hydropower capacity in the South Zone also plays a growing role in flexible power supply, although its future expansion appears limited.

is only expected to intensify in the future.

By 2040, the share of end-of-pipe gas consumption by the electric power sector is expected to remain at about 50%, although it will expand in volume to about 13.5 Bcm, reflecting new generating capacity additions coming onstream. The share of residential-commercial use in gas consumptionwill decrease from a third to about a quarter, while industry's share will grow from 14% to 25%, underlining the greater potential for gas use in industry, including applications of natural gas use in the petrochemical industry (see Figure 4.6. Kazakhstan's natural gas consumption by sector). End-of-pipe consumption is expected to grow by 68% between 2018 and 2040, reaching 25.4 Bcm.

Figure 4.6. Kazakhstan's natural gas consumption by sector



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

One key conclusion from our analysis that there will be competition for available commercial gas volumes between domestic consumption and exports. Although the allocation between the two is essentially a political decision and the Law on Gas and Gas Supply prioritizes domestic deliveries over exports, there are a number of key factors to be considered. We will discuss these further as we consider gas trade and exports in the next section.

Kazakhstan's Evolving Petrochemical Clusters

Atyrau gas-chemical complex

Long-held plans to establish a major gas-based petrochemical industry in western Kazakhstan (and specifically, Atyrau Oblast) appear to now be finally bearing fruit, partly owing to general improvements in the external economic environment. Actual construction is now under way and orders placed for the equipment for Phase 1 of a larger project. Phase 1 includes a propane dehydrogenation (PDH) unit and polypropylene plant as well as associated infrastructure.Total capital expenditures for the Phase 1 facilities are estimated at about $2.3 billion.

Phase 1 of the gas-chemical complex was transferred to the trust management of KMG NC for implementation, from United Chemical Company (UCC), as both are owned 100% by the national sovereign wealth fund Samruk Kazyna. This occurred in June 2018, which facilitated the launch of full-scale construction work (this is now 34% complete compared to only 6% when KMG took over), taking advantage of the experienced project team at KMG that oversaw the completion of the refinery modernization program.

The government has long been promoting plans for a large gas-chemical complex at Karabatan, located about 40 km east of the city of Atyrau. The specialized company UCC was established within Samruk Kazyna to carry out this endeavor, albeit through consortiabetween UCC and other stakeholders (including international partners and investors). This large complex is still planned to produce both ethylene and propylene, and then convert them into polypropylene and polyethylene. Ambitious plans also call for other related chemical products to be added eventually, such as ethyl benzene, ethylene glycol, polyethylene terephthalate (PET), and polyvinyl chloride (PVC). The overall project is still being led by UCC. Phase 1 is being developed by KPII (Kazakhstan Petrochemical Industries Inc.), established in 2008 as a partnership between UCC (owning 51%) and Almex Plus (49%). In 2018, Almex Plus reduced its share to only 1%, leaving 99% held by UCC.

This large project is of strategic importance to Kazakhstan because it will help diversify the hydrocarbons economy from a purely resource extraction position through more "value-added" in petrochemicals. Petrochemical (olefin) production in western Kazakhstan is to be based on feedstock-rich gas—and on the competitiveness of relatively cheap and potentially large volumes of natural gas liquid (NGL)-rich associated gas.

The complex's source of gas is the Tengiz field operated by TCO. TCO (TengizChevrOil) is the largest crude oil producer in Kazakhstan, producing 27-29 MMt (600,000-625,000 b/d) of crude oil per year in recent years, which represented about 32% of Kazakhstan's total crude oil production in 2018.

The complex is planned to process about 7 Bcm/y of gas from TCO. The dry gas would be run through a gas separation unit (GSU) to extract the ethane and propane necessary for the production of olefins, while the methane will be returned to be available for other uses.The sales gas from TCO is expected to contain sufficient quantities of ethane, but also some propane and butane, to allow the GSU to extract over 1 MMt/y of ethane and about 0.4 MMt/y of propane/butane mix (comprised mostly of propane).

The large gas-chemical complex is being developed in two major phases:

- As noted above, Phase 1 involves the construction of a polypropylene production line with a capacity of 550,000 metric tons/y and associated infrastructure and facilities, including a 550,000 ton propane dehydration (PDH) unit. This is being overseen by KPII. The latter will be equipped with CB&I's Catofin technology to convert propane to propylene, while the 500,000 ton/y polypropylene plant will use CB&I's Novolen advanced gas-phase technology. CB&I received notice to proceed with its scope of work in December 2017. Orders for the equipment have been placed. The plan is for Phase 1 (polypropylene production) to be launched in late 2021.

- Phase 2 is planned to include the construction of a polyethylene production line with two 625,000 tons/y trains, as well as associated infrastructure. It also includes a 1.25 MMt/y ethylene steam cracker (pyrolysis unit) (see Figure 4.7). The construction of the ethylene/polyethylene line is now planned to begin in 2021, and launched into operation in 2025; currently, a feasibility study is underway. This is being done under an agreement signed between Borealis, a leading global producer of polyolefins owned jointly by the Mubadala Group and OMV, and UCC in March 2018. Currently, Phase 2 is proceeding as a 50:50 JV (Sileno) between UCC and Borealis.

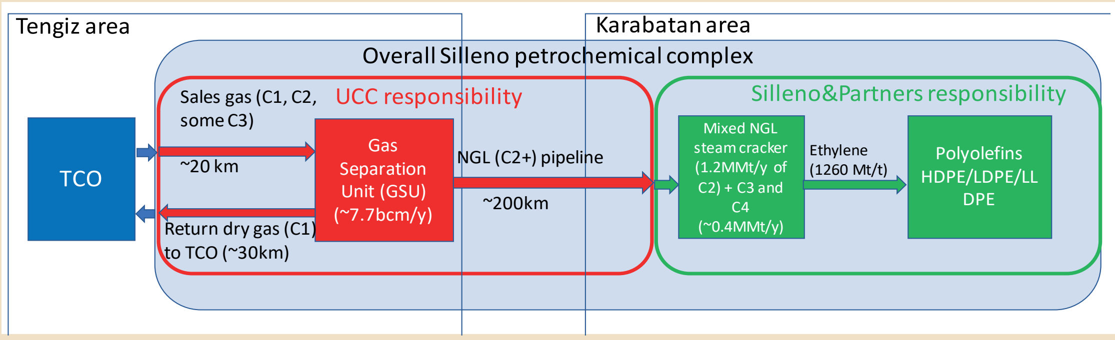


Figure 4.7. Schematic configuration of the UCC petrochemical complex

The petrochemical complex is spread over two locations: at Tengiz and at the town of Karabatan near the city of Atyrau (see Figure 4.8). The facilities at Tengiz are the gas separation unit or gas processing plant (GPZ), an NGL fractioning unit, and associated utilities. The steam cracker, PDH unit, and the downstream polypropylene and polyethylene production units are located at the Karabatan site. The complex will also have its own power plant, of 310 MW, that is planned to be completed in 2020. A 200 km pipeline will transport ethane to Karabatan, while rail transport will be used for the extracted propane.

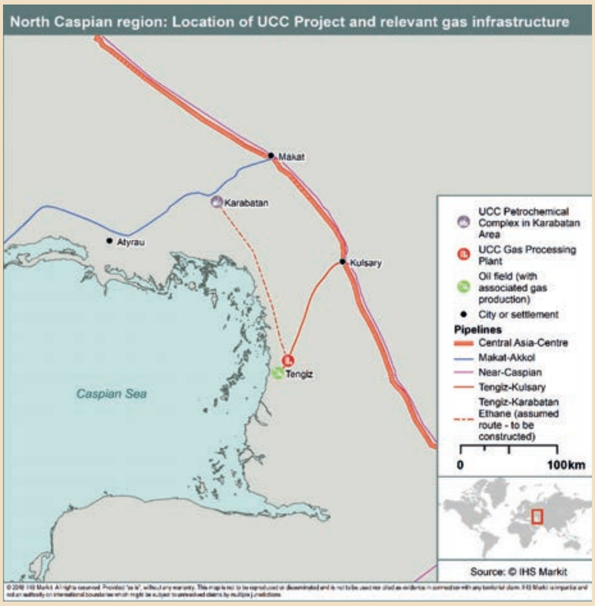


Figure 4.8. Location of UCC Gas-Chemicals Project

Globally, the main element determining costs of integrated polyolefin production and the relative competitiveness of a particular plant is actually the cost of the feedstock (see Chapter 4 of The KAZENERGY National Energy Report 2015). Therefore, the low-cost feedstock available to the Kazakh plants should make them very competitive globally, even on a delivered cost basis (i.e., including transportation costs), either to European markets or to Asian markets; their projected costs of operation are lower than nearly all other producing regions around the world; the exception is ethane-based manufacture in Saudi Arabia.

Therefore, it appears that a major reason for the reluctance of investors to proceed previously in Kazakhstan was the general global business climate and related uncertainties of demand and pricing for petrochemicals, although it must be recognized that major investments are proceeding in other low-cost feedstock locations such as the US Gulf Coast and Middle East.[5] Previously, the main issue for the hesitancy for investment in Kazakhstan's petrochemical development was stated to be the high costs of construction due to the country's remote location, as the equipment costs tend to be very similar between countries. The other issue appears to be the general (and more intangible) regulatory and fiscal risks of doing business in Kazakhstan, particularly for external investors and financial institutions.

Atyrau PET plant

Another petrochemical project under development is a proposed plant to produce polyethylene terephthalate (PET) plastics by Almex. This would be in Atyrau Oblast within the special economic zone (FEZ) of the National Industrial Petrochemical Technopark where the larger UCC facilities are located.[6] PET is the most common thermoplastic polymer resin of the polyester family and is widely used in a variety of applications, including fibers for clothing, containers for liquids and foods, and thermoforming for manufacturing.The logic for the proposed plant is the availability of paraxylene (PX) from the new unit that went into operation at the Atyrau refinery in 2015, that has the capacity to produce up to 496,000 tons/y of PX.[7] Kazakhstan currently has no domestic demand for PX, so instead of being exported, the idea is to use it locally to produce terephthalic acid (PTA), and then PET plastics. Chinese investors are being lined up, and a feasibility study is planned.

Aktobe petrochemical complex

Another petrochemical project that is under development is another large polyolefins complex, but in Aktobe Oblast. The Chinese firm Tianjin Bohai Petrochemical, part of the Tianjin Bohai Chemical Group, signed a cooperation agreement for the project with the government of Aktobe Oblast in January 2018. The plan is to develop two phases, with both phases to be completed by 2021: Phase 1 will be a 1.8 MMt/y methanol plant, with Phase 2 consisting of a 300,000 ton/y olefin plant (steam cracker) and two 300,000 ton/y units for polyethylene and polypropylene, respectively.

The source of feedstock for the facility is not specified, but could be NGLs produced locally by the large gas processing plant (GPZ) at Chinese-owned upstream producer CNPC-Aktobemunaygaz.

Proposed Mangistau petrochemical complex

A joint venture between Kazakhstan's KazAzot (39%) and China's Inner Mongolia Berun Holding Group (61%) announced that it intends to build a gas-chemical complex in Mangistau Oblast (probably in Aktau at the Seaport Special Economic Zone), reportedly worth about 1 trillion tenge ($2.7 billion). The planned production slate includes methanol (400,000 tons/y) and nitrogenous fertilizers (600,000 tons/y) in the first phase, followed by a second tranche of methanol and nitrogenous fertilizers, and then in a third phase involving the production of olefins. Total capacities would be 1 MMt/y of methanol, 1.2 MMt/y of nitrogenous fertilizers, and 600,000 tons/y of olefins.

KazAzot is a domestic producer of ammonia and ammonium nitrate as well as natural gas in Mangistau Oblast. Its hydrocarbon production would likely be the source of feedstock for the proposed petrochemical complex.

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[5] For example, the most recent project to be announced this year is an $8 billion complex, known as the US Gulf Coast II Petrochemical Project, that includes as partners Chevron Phillips Chemical (51%) and Qatar Petroleum (49%). It is slated to include a 2 MMt/y ethylene cracker and two 1 MMt/y high-density polyethylene units. A final investment decision is expected by 2021, with start-up planned for 2024. In fact, it is possible that global oversupply may emerge in particular segments because of the large number of petrochemical projects now underway.

[6] Currently, there are six active projects within the Technopark SEZ, involving 17 different investors. The volume of production within the Technopark was reportedly 10.1 billion tenge (about $27 million) last year.

[7] The aromatics complex (KPA)at the Atyrau refinery entered operation in late 2015. The KPA consists of five major technological installations: a catalytic reformer (1 MMt/y), xylene isomerization, paraxylene production, a heavy aromatics transalkylation unit, and raffinate separation. Axens' ParamaX BTX technology constituted the bulk of new installations, while Foster Wheeler provided a hydrogen unit, and other units were providedby Prosernat, UOP, and Omskneftekhimproyekt. The KPA can operate in one of two modes, either to optimize high-octane gasoline production or to produce aromatics (up to 496,000 tons/y of paraxylene and 133,000 tons/y of benzene), depending on domestic fuel demand. The heavy aromatics transalkylation unit provides this flexibility, as it produces gasoline as a byproduct. Since its commissioning, the KPA has mostly operated in gasoline production mode because ofthe pressing need for gasoline for domestic consumption, but aromatics production commenced in 2018 following the commissioning of the deep refining complex.

4.2.3. Trade

Of Kazakhstan's 19.4 Bcm of "operational" exports[8] in 2018, we calculate that 12.6 Bcm was sent northward to Russia; the bulk of this is raw (unprocessed) gas directed from Karachaganak to the Orenburg GPZ, with the remainder transported northward via the Central Asia–Center and Bukhara–Urals pipelines (see Figure 4.9. Map Kazakhstan's gas sector (selected key elements). According to KTG, the export of commercial gas to Russia amounted to 13.8 Bcm, while Gazprom reported that it received 12.3 Bcm from Kazakhstan in 2018.

In 2018, China emerged as a major destination for Kazakh gas, receiving 5.2 Bcm, pursuant to the one-year agreement for up to 5 Bcm signed between KTG and PetroChina International Company Limited via the Central Asia–China gas pipeline system (CAGP).[9] The increase in Kazakh CAGP deliveries brought CAGP utilization to over 50 Bcm (more than 90% of available 55 Bcm/y capacity). On 12 October 2018, the partners inked a five-year contract for the export of up to 10 Bcm/y of gas via CAGP. Although KTG seeks to export as much as 10 Bcm/y during this period, it does not expect to sustain exports at this level after 2023 because of lack of commercial gas supply. In fact, the IHS Markit base-case scenario does not envisage exports to China exceeding 8 Bcm/y over the forecast period out to 2040.

Figure 4.9. Kazakhstan's gas sector (selected key elements)

Source: IHS Markit/1747250

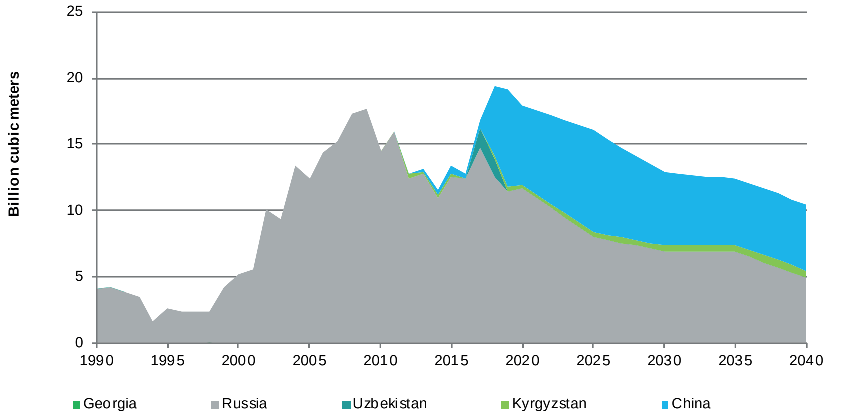
[8] Reporting of Kazakhstan's gas exports remains convoluted. The Statistics Committee of Kazakhstan reports total (invoiced) gas exports as 26.5 Bcm in 2018, an amount almost as large as total commercial volumes available (see Table 4.1). According to "operational" data reported by Kazakhstan's Energy Ministry (based on shipments reported by the pipeline operators), only 19.4 Bcm of gas was physically exported from Kazakhstan. The reason for these sizable discrepancies in reported gas exports stems from the statistical treatment of Karachaganak 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.

[9] See the IHS Markit Insight, Kazakhstan Launches Large-Scale Natural Gas Exports to China via Central Asian Pipeline System. These volumes supplemented the smaller volumes (around 0.5 Bcm/y) sent via the 110km Zaysan-Jeminay pipeline in eastern Kazakhstan.

Competition between domestic demand and exports has important implications for KTG and its overall business operations. Given low regulated domestic gas prices and KTG's mandate to expand domestic gasification, these sales generate financial losses for the company. KTG operations overall have remained in the black, but mainly due to gas exports to China. In 2018, Chinese export revenues jumped to $2.47 billion, up from $1.74 billion in 2017. Thus, the decline in exports to China after 2023 would represent a major financial blow to the company (see below).

Reflecting the tightening domestic gas balance, IHS Markit base-case projections of Kazakhstan's operational exports by 2040 actually decline by almost half relative to current levels, to about 10.5 Bcm/y. Russia and China remain the major export destinations (see Figure 4.10. Outlook for Kazakhstan's natural gas exports by country to 2040). Thus, not only do Kazakhstan's limited commercial volumes place constraints on expansion of domestic gas consumption, but also put a ceiling on exports.

Figure 4.10. Outlook for Kazakhstan's natural gas exports by country to 2040



Notes: Exports allocated according to existing export contracts
Source: IHS Markit

Imports were 7.0 Bcm in 2018 (according to customs statistics) or 6.0 Bcm (according to operational statistics) (and 6.1 Bcm according to KTG) (see Table 4.1). Imports are projected to remain at about this level (~6 Bcm/y) through 2040, as they are quite effective for serving border regions in the south and north, and giving Kazakhstan flexibility in its gas balance. As detailed in the previous National Energy Reports, for geographical and logistical reasons, it makes sense for Kazakhstan to continue importing natural gas in the north from Russia and in the south from Uzbekistan (and longer term from Turkmenistan). Russian gas is used in Kostanay and Aktobe oblasts, while Uzbek imported gas (2.5Bcm in 2018) is used in southern Kazakhstan (Almaty, Taraz, Shymkent [Turkestan] oblasts), although Uzbek gas availability is likely to diminish given limited production growth and its own burgeoning domestic demand. Imports from Turkmenistan for Kazakhstan's domestic use have remained negligible (0.3 Bcm in 2017, or 0.1 Bcm according to KTG), but are likely to increase given that country's almost unlimited resource base. Turkmenistan is expected to essentially supplant Uzbek gas in southern Kazakhstan over time. Kazakhstan is expected to remain a net natural gas exporter through 2040, although the balance becomes increasingly tight.

In December 2018 Intergas Central Asia (ICA) and Uztransgaz signed a contract for the transit of Uzbek gas through the territory of Kazakhstan to

Uzbekistan's capital, Tashkent. Transit deliveries commenced at the end of the year through the Gazli-Shymkent and Bukhara gas region-Tashkent-Bishkek-Almaty (BGR-TBA) pipelines. The contract provides for transit of up to 1 Bcm of Uzbek gas for consumers in the Uzbek capital.

4.3. Key National Gasification Policy Goals

Kazakhstan's long-term policy goals for gasification include the following: (1) expand domestic gas consumption through greater regional gasification, particularly gasification of the capital Nur-Sultan; (2) strive to meet the country's Paris Climate Agreement goals on "greening" the economy by shifting from coal to gas, especially in electric power generation; (3) increase the competitiveness of the economy and industry by increasing fuel efficiency and reducing energy costs; and (4) join the EAEU single market for gas upon its formation in the mid-2020s.

The general scheme for the gasification of the Republic of Kazakhstan for 2015–2030 (hereinafter "the General Scheme") calls for 1,600 population centers, or 56% of Kazakhstan's population, to have access to gas by 2030.[10] Currently, 10 out of Kazakhstan's 14 oblasts and 2 of 3 republic-level cities (Almaty and Shymkent), or 49.7% of Kazakhstan's population, have access to natural gas. By 2030, following the completion of the SaryArka trunk pipeline (and others, including distribution pipelines), 14 of these regions and another republic-level city (Nur-Sultan) will have piped gas available to the population.

4.4. Agenda and Outlook for Domestic Gas Consumption

4.4.1. Pipeline Construction

Historically, the core of Kazakhstan's national pipeline infrastructure dates from the Soviet period, in which Kazakhstan served as a transit country via which Central Asian gas moved north to Russia via the Central Asia–Center and Bukhara–Urals pipeline systems. Since independence, Kazakhstan's goal was to create a unified domestic gas system. This was largely accomplished with the completion of the Beyneu-Bozoy-Shymkent (BBS) pipeline in 2015, which connected the western gas-producing regions of the country to gas-consuming regions in southern Kazakhstan (see Figure 4.9). The commissioning of BBS, together with the construction of additional loops and links, as well as installation of advanced compressor stations, finally created a unified gas pipeline system. Now all the main gas trunklines of Kazakhstan are connected into a single gas transportation system, including the Soyuz, Central Asia–Center, Bukhara-Urals, Tashkent-Bishkek-Almaty, and Gazli- Shymkent, as well as the BBS and CAGP pipelines.

Importantly, the BBS pipeline potentially allows Kazakhstan to lessen its dependence on Uzbek gas imports in southern Kazakhstan; these have proven to be vulnerable in the past, especially in winter, and are handled through a complex gas swap agreement between Uzbekistan (Uzbekneftegaz), Russia (Gazprom), and Kazakhstan (KTG).

Construction of BBS also made large-volume gas exports to China possible, as BBS links to the CAGP at Shymkent. Original capacity of the BBS line was 10 Bcm/y, but capacity was expanded to 15 Bcm/y in late 2018, at its section going from Bozoy to Akbulak, upon completion of two additional compressor stations. In 2018, Kazakh shipments through the BBS pipeline nearly doubled, to 8.35 Bcm.

BBS also provides a gateway for

[10] For further discussion of gasification policy, please see Chapter 5: Natural Gas, in the KAZENERGY National Energy Report 2017.

the gasification of areas in central and northern Kazakhstan currently lacking access to natural gas. More specifically, its Karaozek compressor station, along the middle portion of its route in Kyzylorda Oblast, will serve as the western terminus of the SaryArka pipeline, which will deliver pipeline gas to such cities as Zhezkazgan, Karaganda, Nur-Sultan, Kokshetau, and Petropavlovsk. The key endpoint for Phase 1 of construction, which began late in 2018, is the national capital Nur-Sultan (formerly Astana). The 1081 km long Karaozek–Zhezkazgan–Karaganda–Nur-Sultan segment is expected to become operational in late 2019 or early 2020, at an estimated cost of $743 million.

The initial goal of the project appears to be launching a skeletal network as a foundation upon which incremental future gasification can proceed, as initial capacity of the pipeline to Nur-Sultan is only 3.6 Bcm/y.[11] The first users are to be formerly coal-fired boilers producing heat at the same sites as Nur-Sultan's two combined heat-and-power stations (TETs) as well as 2.7 million residential customers in selected districts in Nur-Sultan, Zhezkazgan, Karaganda, and other settlements along the pipeline route. This approach runs counter to convention, as large industrial users are traditionally the initial targets of regional gasification schemes.

To date, KTG manages more than 19,000 km of trunk gas pipelines and more than 48,000 km of gas distribution networks. In addition to the trunk pipeline build-out, local authorities have invested heavily in gasification, particularly in the residential distribution sector, which has accounted for much of incremental gas demand growth in recent years.[12]

4.4.2. Emissions Trading System and New Ecology Code Send Mixed Signals for Gasification

Another challenge to increasing domestic gas consumption in Kazakhstan involves the uncertainties from changing environmental regulations. In Kazakhstan's carbon dioxide emissions trading system, for example, the benchmarking system for free allowances grants a "weighted intensity coefficient" of tons CO2 per unit of physical production (MWh, ton, gigacalorie, etc.) to power plants and industrial enterprises. This coefficient is then multiplied by the projected amount of production to calculate the amount of free allowance in each year of a trading period. For power plants, the coefficient for generating electricity from coal under the existing Ministry of Energy order is 0.985 tons of CO2 per MWh, while the coefficient for power plants using "other" feedstock sources (grouped together, including both mazut and natural gas) is only0.621 tons of CO2 per MWh. In other words, benchmarks have been designed to give more free allowances to coal-fired plants than gas-fired plants. This weakens any incentive rooted in this trading mechanism for a transition to gas-fired power.

Proposals in the July 2019 Ecology Code draft reinforce this trend.The revised Ecology Code is slated to be passed by parliament in mid-2020 and enter into effect on 1 January 2021, introducing a series of levies and fines on industrial users and power plants for their air, water, and soil emissions. Reforming the Ecology Code was motivated by Kazakhstan's intention to join the ranks of the top 30 developed economies by 2050, articulated by First President of Kazakhstan Nursultan Nazarbayev in the Kazakhstan 2050 strategy presentation on

[11] See the IHS Markit Insight, Construction Is About to Begin on Kazakhstan's SaryArka Gas Pipeline, but Its Promise of Broad Regional Gasification Remains Elusive, October 2018.
[12] The total length of the distribution gas network in Kazakhstan in urban and rural areas (inside the city-gate), reached 27,085 km in 2018, versus 25,253 km in 2016 and 25,525 km in 2014. The bulk of growth occurred in Zhambyl Oblast, where 1,124.1 km of new pipe was installed between 2014 and 2018, and Almaty Oblast (net addition of 806 km of pipe). At the national level, 7,976 km of new pipeline was installed between 2014 and 2018, 1,337.2 km was retired (54% of which occurred in West Kazakhstan Oblast), and 1,289 km of pipes were identified as in need of repair (28% of which was in South Kazakhstan [now Turkestan] Oblast).

14 December 2012. The Paris Agreement accelerated environmental reform.

Energy companies generally embrace ecological improvements, especially international companies with global shareholders that value health, safety, and environment (HSE) performance. But the regulations to achieve this must be properly designed, transparent, and equitable.

Unfortunately, the Ecology Code's current version, released in July 2019, contains a series of measuresthat send mixed signals and actually diminish incentives for gasification.

Currently the Ecology Code effectively presents seven mechanisms to induce efficiency and environmental improvements, including market mechanisms (primarily the trading mechanism mentioned above for regulating CO2 emissions), concessions to enterprises using green bonds from the Astana International Financial Center (AIFC), government financing of projects, and insurance, among others. As before, there remains a series of levies (taxes) on various types of emissions, with rates varying across different categories and industries:

- **Payments (taxes) on air pollutant emissions from stationary sources.** Levied in tenge (KZT)/ton on a quarterly basis, this tax applies to emissions of 16 components, including sulfur dioxide and nitrogenous dioxide, methane, ammonia, phenols, and formaldehyde, among others.
- **Payments (taxes) on atmospheric emissions from gas flaring.** This applies to upstream producers in the oil and gas industry, and covers 8 components, all but one of which (mercaptans) are already covered under stationary sources. But for gas flaring, rates are much higher, from 20 times higher (for SO2, NO2) to 278 times higher (for hydrocarbons).
- **Payments (taxes) on effluent discharge of pollutants to water.** This tax covers 13 components, including nitrites, zinc, ammonium nitrate, oil wastes, and sulfates, among others.
- **Payments (taxes) on industrial and household solid waste.** This tax applies for accumulation (and shipments) of municipal and household solid waste as well as industrial and nuclear waste.
- **Payments (taxes) on stored sulfur that has been produced by oil and gas companies.** This is a blanket tax (KZT/ton) that applies to premium-grade sulfur pastilles awaiting shipment to buyers as a "waste" subject to a fine.This provision effectively punishes upstream projects that process high-sulfur gas into commercial gas volumes.

The methodology for calculating all fivetypes of emission payments is prescribed in the Ecology Code and fixed payment rates are set for individual components within each category (in the Tax Code). The rates are set in units of the monthly calculation index (MCI) (which is adjusted yearly to account for inflation) per amount (ton, cubic meter, kilogram, etc.) emitted. Because their businesses are largely regulated by KREMiZK, "natural monopolies" (e.g., KTG, KEGOC) and power producers are entitled to a "discount," allowing them to multiply the MCI-based payment rates by a coefficient that represents a reduction.

The effect of this discount, and the disparity between emission payment rates for stationary sources versus gas flaring are startling. Karaganda and Pavlodar oblasts are the top two generators of air pollution in Kazakhstan. Their total emissions (mainly from coal-fired power generationandmetallurgy)in2016were3.5 times more than the total emissions of two hydrocarbon-producing areas, Atyrau and Aktobe oblasts. But total environmental payments for those air emissions in Karaganda and Pavlodar were 3.2 times less than for Atyrau and Aktobe.Thus, the currentstructure of emission payments in the Ecology Code is counterproductive to achieving real air emission reductions, especially through greater gasification.

The new draft Ecology Code provides for all emissions tax rates, across the board, to double upon its entry into force (expected on January 1, 2021), doubling again in 2024, and doubling yet again in 2027. However, the draft Ecology Code provides exemptions from these increasing emission taxes that are, in theory, designed to incentivize natural monopolies, power plants, and industry to reduce their emissions. This is through obtaining an Integrated Environmental Permit and adopting Best Available Technology (BAT). Again, the intentions underlying the initiative are laudable, with the European Union Best Available Techniques Reference document (EU BREFs) as a basis. However, the mechanisms the government will ultimately employ in creating a 'localized' version of this, and the criteria used to check BAT compliance and grant tax relief remain unclear. In theory, the money otherwise paid in emission taxes could be re-directed into emission reduction investment, but it appears that the emission tax breaks already provided to the power sector reduce this incentive factor where it is needed most.

Kazakhstan has been successful in greatly reducing routine gas flaring. This has been achieved by taking a firm regulatory stance against approving new field development plans without full gas utilization as well as stringent enforcement of already existing anti-flaring regulations. According to the Ministry of Energy, associated gas flaring in the country amounted to only 729 MMcm in 2018, down from 1,024 MMcm in 2017, and below the 2014 level of 786 MMcm. This miniscule amount represents only 1.3% of the total amount of gas extracted last year. Even though atmospheric emissions from gas flaring are a small fraction of the total for stationary sources, flaring is subject to an emissions tax at a rate that is many times higher than the rate for atmospheric emissions from other stationary sources. Under the new Ecology Code this disparity will greatly increase as existing emission tax rates increase by multiples with its introduction in 2021 (and gas flaring is not allowed the BAT tax break provided to other stationary sources). Furthermore, the draft Ecology Code also proposes doubling of fines for repeat violations, which are incidences that occur more than once during a three-year period. These multipliers could easily lead to potentially tens of millions of dollars in fines for safety flaring events that would be considered normal and acceptable in other jurisdictions.

Such administrative fines seem disproportionate to the environmental issue they aim to address, and the liability involved will likely have a deleterious effect on investment conditions. Relevant ministries and local authorities should explore a more practical approach towards regulation of gas flaring, and one more aligned with global practices. At the time of this publication the policy on gas flaring fines is reportedly being reconsidered, so it remains to be seen what approach is ultimately taken by Kazakhstan in this regard.

4.5. Pricing Policies and Implications

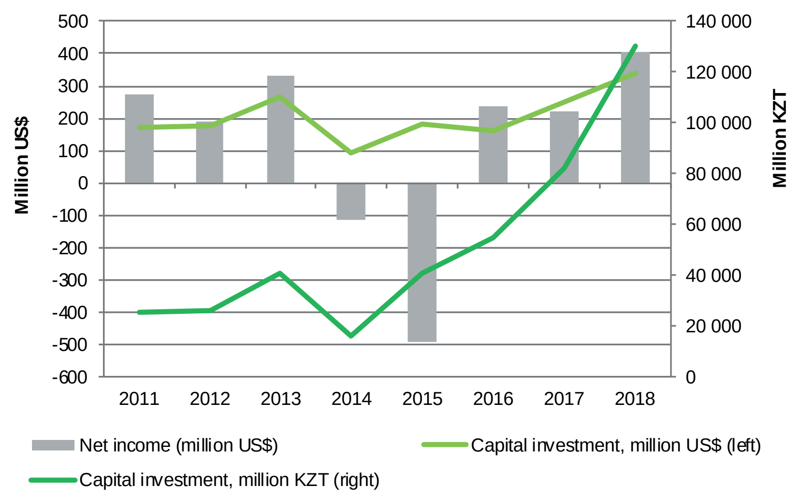
Despite the ongoing pipeline build-out in support of the gasification agenda, the currentregulatory structure, largely determined by social considerations, not only provides inadequate price signals for the development of the domestic gas market but impedes its growth. Producer and end-user prices often do not cover full costs, forcing market participants throughout the gas value chain to cross-subsidize their gas market operations with other activities. At the same time, strongly held convictions that utilities are a right to be readily available for all citizens by the governmentcontinue to be used to justify policies that suppress prices throughout the value chain and keep gas prices artificially low.

Administrative management of domestic energy prices has hidden costs, including inefficient resource use and a chronic supply shortage. As long as prices for gas and other utilities remain artificially low, addressing the looming challenges facing the energy sector, such as investments needed in the power sector and more commercial gas supply, will be pushed into the future.

Maintaining the status quo will have consequences that key industry players already are beginning to signal in their own development plans. For example, KEGOC does not expect anyone to build new gas-fired power generating capacity in southern Kazakhstan; instead, it expects a deficit of power to develop there by 2025–26; it is mooting a concept for construction of another long-distance North–South high-voltage electric transmission line, allowing it to move available coal-fired generation in the north to the south. KMG, in turn, sees a tightening gas balance as something that is already here, with price as the key issue, and a supply deficit at the national level looming in the early 2020s. Pricing disparities already apparent in the domestic market will be exacerbated by EAEU gas market integration, which will necessitate Kazakh domestic gas prices moving upward towards Russian levels (see below).

The challenges of Kazakhstan's gas market are exemplified by the national gas operator, KTG. A cursory look at KTG's finances reveals that the company has been generating a positive net income in the last several years in aggregate (see Figure 4.11. KTG finances). One of the uses of the funds it generates is for capital expenditures to expand the national gas transportation network. However, closer examination reveals that the company loses money on its basic business, selling gas to domestic consumers. KTG reported that between 2014 and 2018, it incurred 200 billion KZT (~$520 million) in losses from domestic market operations. For the first six months of 2019, KTG reported losses of almost 63 billion KZT (about $164 million) on domestic market operations, even as net income for the company's activities overall increased by 100 billion KZT (140% year-on-year increase). Essentially the company's positive margins come from international transportation of natural gas (including third-party transit) as well as gas exports.

Figure 4.11. KTG finances



Notes: Does not include investment by ventures that are jointly controlled (e.g.

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KTG's approach to addressing unprofitable operations in the domestic market is to advocate for increases in the availability of commercial gas so that export levels can be maintained or expanded. This seems a palatable approach to the company's top management (given the social mandate in addition to business goals of the company) and for policymakers. However, this necessitates reforms that would make upstream gas exploration, production, and processing attractive for investors. Instead, it appears that policymakers are being tempted to institute more punitive and/or administrative measures toward existing gas producers.

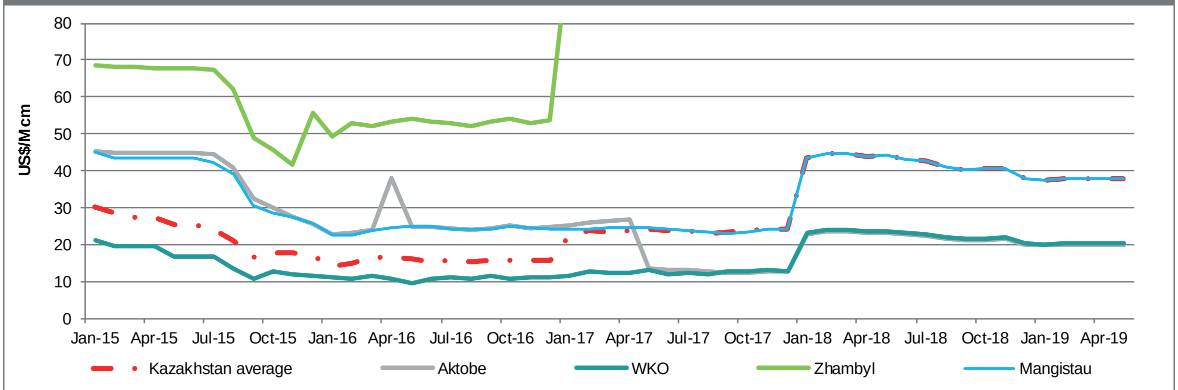
4.5.1.Producer Prices

Producer prices are not administratively regulated, but are individually negotiated between producers and buyers, mainly KTG, the national gas market operator that retains monopoly authority as the single "priority" buyer for associated gas. Theoretically, natural gas producer prices are supposed to be determined by rules given in the Law on Gas and Gas Supply (2012), which includes a "cost-plus" price component, codified in Article 15:

Production cost ($/Mcm) + processing cost ($/Mcm) + transmission tariff to point of sale to KTG ($/Mcm) + profit margin (<10%)

In reality, KTG yields significant power in negotiating gas prices, and because KTG is under financial pressure by low end-user prices, producer prices do not always cover all of the involved costs. In mid-2018, the average gas price received by Kazakhstan's producers was still only 14,556 KZT/Mcm ($43.31/Mcm) (see Figure 4.12. Regional producer prices by oblast). In May 2019 the average national producer gas price was 14,394 KZT/Mcm ($37.87/Mcm). This may be sufficient to cover costs for shallow dry gas, but it is not sufficient to cover the costs associated with recovering associated sour wet gas that must be gathered, processed, and transported to an injection point. Several market participants indicate that the price garnered through sales to the domestic market is less than their own production costs by a "multiple." The theory behind the national operator model used by Kazakhstan is that associated gas is a low-cost byproduct of oil production, but in practice, particularly for new fields and those utilizing gas processing plants, transforming gas at the wellhead to commercial quality gas is an expensive process. The producers of associated gas are liable for upstream tax payments on the extracted gas even as if receive very little value from it.

Figure 4.12. Regional producer prices by oblast



Notes: Average monthly producer prices for Zhambyl Oblast reached about $180/Mcm in 2018, but this trend is totally atypical. The oblast includes only one small producer that is a subsidiary of KTG. It may be considered to be exporting some of its gas pro

4.5.2. End-User Prices

KREMiZK wields the most influence over end-user gas prices, which it regulates by region and customer type (residential versus industrial).Its approach is guided not strictly by energy policy per se, but broader macroeconomic considerations. The government-dictated inflation target is perhaps the major factor guiding KREMiZK's gas pricing approach, as it seeksto keep price appreciation within 20% of the prescribed inflation corridor. In other words, in 2019, the overall inflation rate target is 5.3%, so end-user prices for energy and other utilities (gas, heat, power, railway transportation, and water) should account for no more than 1–2 percentage points of that overall inflation level.

Regional wholesale prices are determined annually and are in effect between July 1 and June 30 of the following year.By law, regulated gas prices in Kazakhstan cannot increase by more than 15% annually.

In May 2018 marginal wholesale prices for commercial gas increased by 7%–10% in the southern regions to reflect higher costs of delivered natural gas (from both domestic sources and imports).[13] However, by November 2018 a decision was made to reduce prices by 11% on average for the first six months of 2019. These price cuts were subsequently extended through 30 June 2020.[14] These changes were instituted to fulfill the First President's mandate expressed at the Security Council on 7 November 2018 to reduce utility prices for the population, which the First President said were too high to bear. According to the Energy Minister Kanat Bozumbayev, reductions in wholesale gas prices would translate into electricity and heat tariff reductions by 6–15% depending on the region. Indeed, in December 2018, the Ministry of Energy reduced marginal (cap) electricity tariffs for energy-producing organizations by 18% on average starting from 1 January 2019.[15]

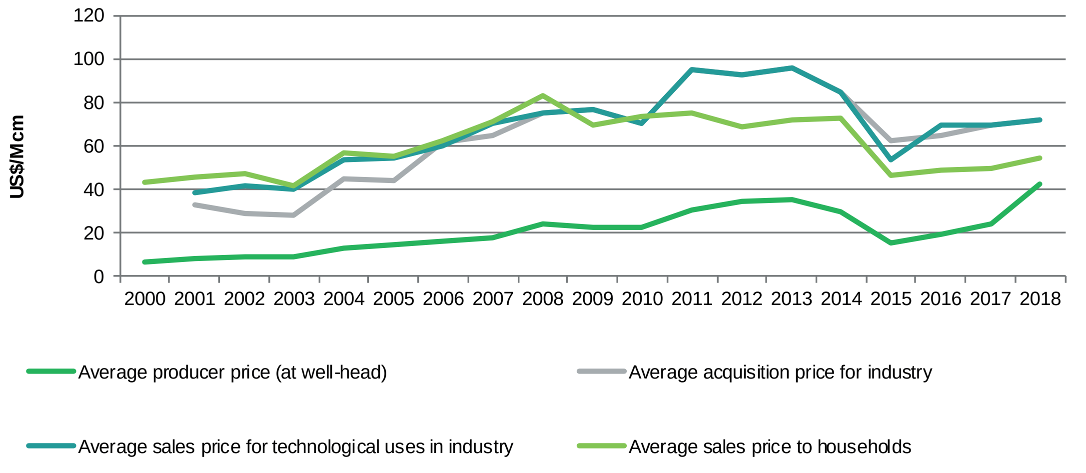
As in the case of producer prices, end-user prices are determined from a "cost-plus" methodology[16]:

Procurement cost (wholesale price) + pipeline transportation cost+ distribution cost (including storage costs) + investment component[17]

However, due to social concerns (keeping prices low for end-users and curtailing inflation), gas prices have not always been adequate to cover KTG's expenses and to generate a surplus to fund new investment (network expansion) and system maintenance. Average end-user prices for industry in Kazakhstan have risen less abruptly than producer prices, from 22,349 KZT/Mcm ($67/Mcm) in January 2017 to 24,345 KZT/Mcm ($75/Mcm) in April 2018. In 2019, average prices for industry actually went down to 20,136 KZT/Mcm ($52.99/Mcm). Prices for residential end-users reached 18,710 KZT/Mcm ($49.24/Mcm) in May 2019 compared to 18,440 KZT/Mcm ($56.17/Mcm) a year earlier. In May 2019, the difference between the average producer price and industrial price, and the producer price and residential price, was $15/Mcm and $11.4/Mcm, respectively, down from $29/Mcm and $11.9/Mcm in January 2018 (see Figure 4.13 Trends in domestic gas prices in Kazakhstan (reported at year-end)).

[13] Southern regions include Almaty city and Almaty Oblast, Shymkent city and Turkestan Oblast, and Zhambyl Oblast.
[14] Price reductions ranged from 3.8% in Turkestan Oblast and the city of Shymkent to 17.5% in the city of Almaty and Almaty Oblast. Price levels were unchanged for Atyrau and East Kazakhstan oblasts.
[15] To comply with the mandate, KEGOC decided to reduce the approved tariffs' caps on electric power transmission by 12%, on technical dispatching of electricity to the grid and consumption in the grid by 23%, and on balancing electricity production and consumption by 10%.
[16] Kazakhstan's Law on Natural Monopolies and supporting rules issued by KREMiZK establish a methodology to calculate an acceptable profit rate for gas transportation companies (KTG and subsidiaries) based on their regulated asset base, which reflects their expenditures and investment programs. In practice, determination of end user prices still follows a "cost plus" approach where an acceptable profit rate is believed to be no more than 10%.
[17] Transportation costs typically incorporate an "acceptable profit margin" in the regulated transportation tariff, and usually the investment component in rolled into the tariff as well. Some regulations have been rewritten for this to incorporate RAB-type approaches for gas pipelines, where the regulated profit margin is to be based on the regulated asset base (RAB), but this new approach does not seem to have been widely implemented.

Figure 4.13. Trends in domestic gas prices in Kazakhstan (reported at year-end)



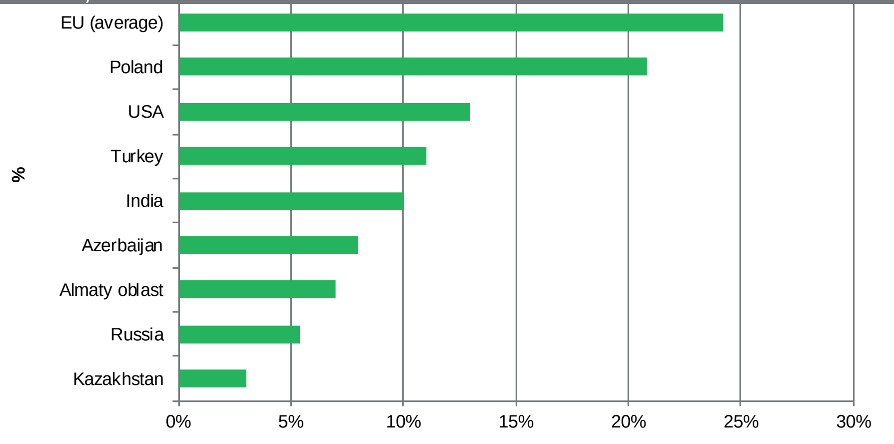
Source: IHS Markit

There are proposals to modify the current gas pricing formula to be cost+0% for power plants, and cost+7% for petrochemical facilities. For both types of enterprises, the cost of feedstock (gas) is one of their key cost components. The rationale for higher prices for petrochemicals (than for power stations) is presumably the export-orientednature of their products, while lowering prices for gas supplied to power plants would lower electricity tariffs for consumers. Still, end-user gas prices already appear to not actually reflect the prescribed cost-plus formula and the contemplated changes are quite small, so instituting these special pricing arrangements would seem to have little practical impact.

Clearly, prices throughout the value chain must rise to incentivize supply and generate funds for additional investment in gas transportation and distribution infrastructure by KTG. The role of prices is fundamental in an economy by shaping the behavior of producers and consumers. For producers, rising prices stimulate production, and for consumers, higher prices communicate the production chain costs, and incentivize energy rationalization and improved efficiency.

Gradually increasing end-user prices will also ease impending harmonization challenges for Kazakhstan when it accedes to the EAEU common gas market in 2025 (see below). Although the potential negative public response to higher prices remains salient in the minds of politicians and regulators alike, who are seeking to shield the public from higher rates out of social concerns, what is not as evident is that Kazakhstan has some of the lowest utility rates (for gas and electric power) in the world (3% of average household income in most oblasts). This is low compared to developed country markets (22–23% in the European Union) and several large BRIC markets (5–8% for Russia,and 10–12% for India). The potential for modest rate hikes in Kazakhstan is evident even in closely analogous markets (Azerbaijan and Turkey, both at 8–10%) (see Figure 4.14. Comparison of spending on energy utilities as share of household income, 2017). For those most susceptible to rising prices, i.e., the nearly 2 million residents who are pensioners on fixed incomes, Kazakhstan should consider developing a special system of rebates/subsidies specifically targeting these users.

Figure 4.14. Comparison of spending on energy utilities as share of household income, 2017



Source: IHS Markit

4.6. EAEU Single Gas Market and Harmonization Challenges

The member states of the Eurasian Economic Union (EAEU)—Armenia, Belarus, Kazakhstan, Kyrgyzstan, Russia—have agreed to establish common markets for (a) natural gas; and (b) oil and oil products by the mid-2020s (2025), following electricity markets integration. This is an ambitious and challenging objective, as currently energy trade among these countries is governed mostly by special bilateral trade agreements that cover volumes and terms, pricing, and other issues, such as export duties.

Under the EAEU Program for gas (approved in early December 2018), member countries are to agree on the key principles for the single market—including mechanisms for trading—by 1 January 2021, and to amend national legislation where needed. A draft intergovernmental agreement on the creation of the single market is planned to be ready a year later. This is to be followed in 2023–24 by active measures to facilitate the trading of gas, such as the creation of exchanges.[18] Major issues remain to be resolved, such as the formation of a mechanism for price deregulation in the single market: i.e., the price will be determined in direct supply contracts between participants in the single market or in exchange trading, without price regulation and with re-exports of volumes acquired in the single market prohibited to third countries. According to the Program, the price benchmark for the single gas market will be a combination of the SPIMEX price and those in the contracts of independent gas producers. Yet each country, including Russia, has yet to decide how and where to register independent gas producers' prices.[19]

4.6.1. Harmonization of gas pricing

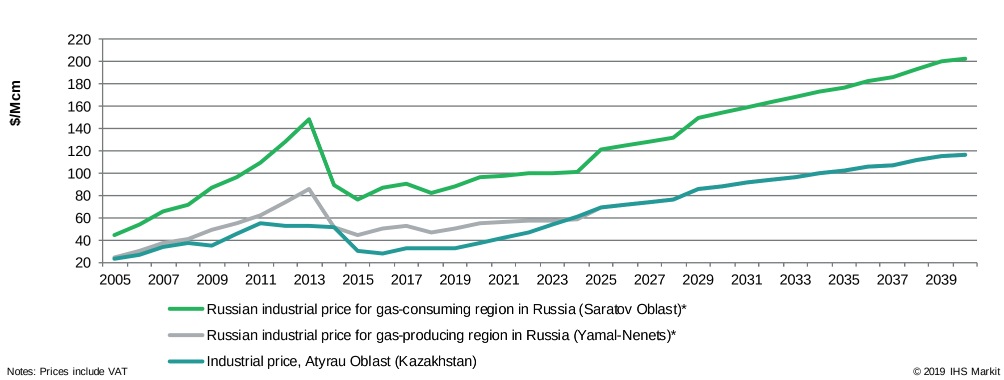
Over the longer term, end-user natural gas prices are planned to be harmonized between Kazakhstan and the Russian Federation as part of a general movement toward integrated open markets. Given that gas production, trade, and the size of the domestic market in Russia are all much larger than in Kazakhstan or any of the other EAEU members, it stands to reason that domestic prices in Kazakhstan will converge with domestic prices inRussia rather than vice versa. However, little has actually happened so far on this issue.

[18] Presently, transactions are limited to the St. Petersburg International Mercantile Exchange (SPIMEX).
[19] For now, the regulated price that the Federal Antimonopoly Service (FAS) establishes for majority-state-owned Gazprom essentially serves as a key benchmark for gas traded on SPIMEX and for gas sold by independents (e.g., NOVATEK, Rosneft, LUKOIL, Surgutneftegaz) under long-term agreements; see IHS Markit Strategic Report Gas Trading on the SPIMEX and Russia's Domestic Gas Pricing Dilemma; and IHS Markit Strategic Report Russian Domestic Gas Prices: How high can they go?

Russian (as well as Kazakh) domestic gas prices vary by region. A key question for Kazakhstan's policymakersis with which Russian pricing zone should Kazakhstan's domestic prices be harmonized (especially in gas-producing western Kazakhstan)? At the end of 2018, the gas price for industrial consumers in the key Russian gas-producing region of West Siberia (Yamal-Nenets Okrug) was about 58% of the price in a gas-consuming province in European Russia that neighbors Kazakhstan on the northwest (Saratov Oblast). Such regional disparities around the average price within Russia are expected to continue going forward. In the gas-producing areas in western Kazakhstan, domestic Kazakh prices paid by industrial consumers were approximately equivalent to prices paid by industrial consumers in the gas-producing Russian price zones in 2014, but now are about 30% less (see Figure 4.15. Price outlook for natural gas consumed by industry in western Kazakhstan (Atyrau Oblast): Harmonized with Russia's Yamal-Nenets Okrug in 2025)

Kazakhstan plans to harmonize its prices with the lower industrial prices found in gas-producing zones in West Siberia and not with the higher prices in European Russia's consuming regions. 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, to harmonize with Yamal-Nenets Okrug in Russia by 2025 (as planned within the EAEU), prices in western Kazakhstan would need to rise by 13% annually on average, between 2020 and 2025, with prices then moving upward basically at the rate of domestic (Russian) inflation after 2026.

Figure 4.15. Price Outlook for Natural Gas Consumed by Industry in Western Kazakhstan (Atyrau Oblast): Harmonized with Russia's Yamal-Nenets Okrug in 2025



Notes: Prices include VAT

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4.6.2. Similarities and differences in gas markets

In assessing harmonization challenges, it is also worth reviewing the general situation of the gas markets in EAEU member countries. Russia is the largest natural gas market, producing 725 Bcm in 2018, accounting for 93% of gas production in the EAEU in 2018 (see Table 4.2. Natural gas balance of EAEU member countries). Apparent consumption was 476.5 Bcm, or 91% of EAEU consumption and 31 times that of Kazakhstan's end-of-pipe consumption. Gas production in Kyrgyzstan and Belarus are each less than 0.3 Bcm/y, and Armenia does not produce gas at all. Russia's national gas network operator and largest producer, Gazprom, owns the gas transmission systems in Belarus, Armenia, and Kyrgyzstan, and provides gas to these countries on relatively favorable pricing terms (higher than domestic prices, but lower than what it receives from European exports). In this respect, Russia's, specifically Gazprom's, interests will inevitably dominate EAEU gas market policy.

Table 4.2
Natural gas balances for EAEU member countries
(Bcm)

	2010	2011	2012	2013	2014	2015	2016	2017	2018
Total EAEU gas production (commercial))	675.0	695.4	679.6	693.1	665.3	663.5	669.3	724.5	761.6
Total EAEU gas consumption (commercial)	505.8	503.5	514.6	508.4	501.2	487.2	475.9	512.4	523.8
Armenia									
Production	-	-	-	-	-	-	-	-	-
Imports	1.9	2.0	2.5	2.4	2.5	2.3	2.3	2.4	2.4
From Russia	1.4	1.6	2.0	2.0	2.1	1.9	1.9	2.0	2.0
From Iran	0.4	0.4	0.5	0.4	0.4	0.4	0.4	0.4	0.4
Exports	-	-	-	-	-	-	-	-	-
Apparent consumption	1.9	2.0	2.5	2.4	2.5	2.3	2.3	2.4	2.4
Kazakhstan									
Production (gross)	37.1	39.5	40.1	42.4	43.2	45.3	46.4	52.9	55.5
Production (commercial)	24.1	24.7	24.4	24.6	24.8	27.7	28.8	33.1	36.4
Imports (trade statistics)	4.0	3.7	4.6	5.2	4.4	5.8	6.9	5.6	7.0
Exports (operational statistics)	12.4	11.7	10.9	10.8	10.6	10.9	12.8	16.8	19.4
Apparent consumption (commercial)	15.7	16.7	18.1	19.0	18.7	22.6	22.8	21.9	24.1
Reported gas deliveries to consumers*	9.0	10.1	10.5	10.9	12.4	12.0	13.1	14.0	15.1
Kyrgyzstan									
Production	0.02	0.03	0.03	0.03	0.03	0.03	0.03	0.03	0.03
Imports	0.27	0.31	0.40	0.27	0.24	0.24	0.26	0.28	0.28
Exports	-	-	-	-	-	-	-	-	-
Apparent consumption	0.29	0.33	0.42	0.31	0.27	0.28	0.29	0.30	0.30
Russia									
Production (gross)	650.7	670.5	655.0	668.2	640.2	635.5	640.2	691.1	725.0
Imports	36.2	33.7	36.4	31.7	25.7	19.2	16.7	18.9	16.4
Exports	220.7	240.0	218.2	233.6	206.5	211.7	225.3	241.5	264.8
Apparent consumption (commercial)	466.2	464.2	473.2	466.3	459.5	443.0	431.7	468.5	476.5
Belarus									
Production (gross)	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2
Imports	21.6	20.0	20.3	20.3	20.1	18.8	18.6	19.0	20.3
Net exports	-21.4	-19.8	-20.0	-20.0	-19.8	-18.6	-18.4	-18.8	-20.1
Apparent consumption (commercial)	21.8	20.2	20.5	20.5	20.3	19.0	18.8	19.2	20.5

* Amount reported as consumption (end-of-pipe deliveries) by the Ministry of Gas/Gazprom or Kazakh statistical sources.
Source: National statistics for the individual countries; CIS Statistical Service

There are significant differences between gas operations in Russia and Kazakhstan, and both countries are confronted with the need for substantial reforms (see Table 4.3. Comparison of gas market regulations in Russia and Kazakhstan). The markets are similar in that both contain a national company overseeing gas transmission and distribution, and transportation tariffs are regulated by a state body. But the underlying operations are quite different.

Table 4.3
Comparison of gas market regulations in Russia and Kazakhstan

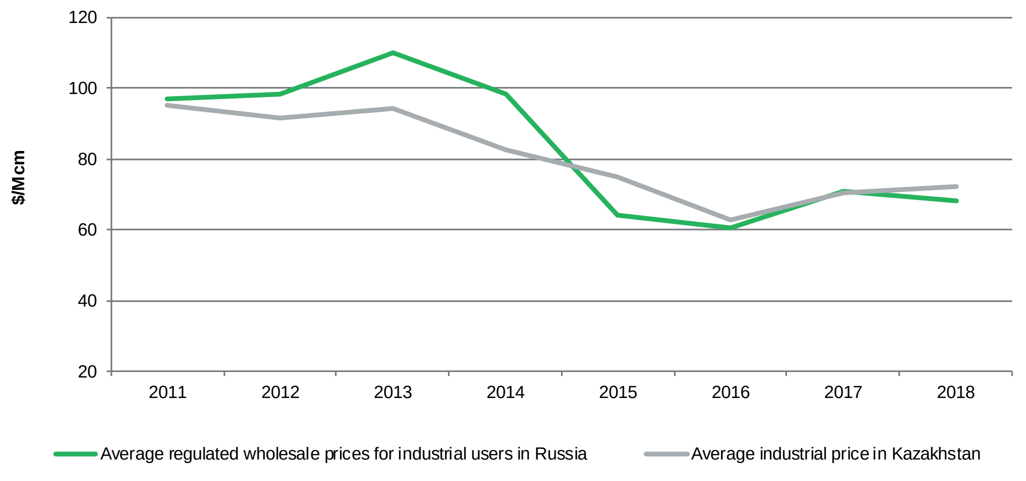
	Russia	Kazakhstan
National gas system operator	PAO JSC Gazprom	AO KazTransGaz
Government regulatory authorities	Federal Antimonopoly Service (FAS)	State Committee for Regulating Natural Monopolies and Competition Protection (KREMiZK)
Gasified territory	85 provinces (of which 60 are in UGSS); 172,600 km of trunk pipelines	10 oblasts; 48,000 km of trunk pipelnes
Number of gas consuming groups	Seven customer groups, distinguished by level of gas consumption and customer type, with regional variation	Six customer groups, distinguished by socio-economic activity, with regional variation
Upstream		
Mineral Resource Extraction Tax (MRET)	Three MRET formulas for fuel equivalent, condensate, and gas, respectively, with varying coefficients, while maintaining a linkage to international oil prices, and gas export netback value	MRET for associated gas changes with international oil price, at conversion ratio of .857
MRET exemptions	MRET generally 0-8%, although changes yearly; exemptions and reductions granted by region for selected, strategic projects (for example, 0% MRET for gas production in Irkutsk and Yakutia to improve economics of Power of Siberia pipeline)	MRET exemptions and reductions granted for offshore and deepwater fields, as well as fields that are high cost and contain hard to recover resources
Producer acquisition pricing	Not regulated, as Gazprom bilaterally negotiates prices with independent producers and with its upstream subsidiaries	Associated gas price determined by cost-plus price formula: production cost (US$/Mcm) + processing cost (US$/Mcm) + transmission tariff to point of sale to KTG (US$/Mcm) + profit margin (< 10%)
Policy towards flaring	Flaring threshold set at 5% of APG extraction, with fines levied at coefficient of 1.04 if flaring exceeds 5%	Rigid penalties levied on all gas flaring, including safety flaring
Midstream		
Transportation tariff formation along major trunklines	Tarriff determined and regulated by FAS for independent producers, with regional variation and two-tier system that includes entry-exit and distance	Tarriff determined and regulated by KREMiZIK for ICA network, AGP and BBS
Transportation tariff rates in 2018	For export markets: 82 rubles/Mcm/100 km ($1.30/Mcm/100 km)*	2212.7 tenge/Mcm ($5.98/Mcm)** along ICA system
	For domestic market: 65 rubles/Mcm/100 km ($1.03/Mcm/100 km)	18,050 tenge/Mcm ($48.78/Mcm) along BBS BBS
	Average tariff: 65 rubles/Mcm/100 km ($1.03/Mcm/100 km)	$3.58/Mcm/100 km along AGP
Application of transportation tariff	Applies to "independent" (non-Gazprom) producers	Applies to all subsoil users in Kazakhstan using KTG network
VAT rate	20%	12%
Downstream		
Local transmission and distribution tariffs	Determined locally, based on volume of gas consumption by individual consumers, and are set to compensate local gas distributer for upkeep	Determined and set by KREMiZiK for KTG-Aimak, based on oblast-level investment program and set margins
Wholesale price formation	Regulated by FAS, distinguished by oblast and consumer type, although regulated prices apply only to gas produced and sold by Gazprom	Regulated by KREMiZik by oblast and consumer type, with regulations applying to all gas in KTG system
	Prices generally correspond to the distance from main gas-producing region in Yamal-Nenets Okrug in West Siberia	Regulated wholesale prices generally correspond to the distance from main gas-producing region in western Kazakhstan, but less so in recent years
Export duty	Pipeline exports subject to 30% of gas customs value, while LNG exports exempt	0%; however IGA levies a tariff on transportation of natural gas exported of $5/Mcm/100 km

* Assumes 1 USD = 63 rubles
** Excludes VAT, assumes 1 USD = 370 KZT
Sources: IHS Markit, Gazprom, Intergas Central Asia
Source: Compiled by IHS Markit

In particular, KREMiZK favors the administrative suppression of gas prices, while in Russia, the Federal Anti-Monopoly Service (FAS) seeks lower gas prices for consumers as well, but through liberalization and transition towards market-based price formation principles. Over the past decade, Russian gas prices were raised significantly, to support a new generation of supply development and to curb excessive consumption growth.[20] Industrial users do have access to lower priced gas through securing separate supply contracts with independent producers that are eager to cut into Gazprom's market share (see Figure 4.16. Average industrial consumers prices for natural gas in Russia and Kazakhstan). For residential consumers, however, the regulated minimum rates, while regionally varied, are consistently higher than those in Kazakhstan.

One of the core tenets of the EAEU approach to an integrated gas market includes unification of gas transportation tariffs. As of February 2019, EAEU members were debating three proposals on this important issue.[21] The first proposal stipulates that transit tariffs fall under the jurisdiction of national governments, and any gas transit requires bilateral agreements between respective states that specifies the applicable tariff. The second idea is to stipulate an EAEU-wide gas transit tariff rate, with the proviso that it cannot exceed the transportation tariff applicable for domestic shipments in each country. The third option is for a supra-national methodology to be developed that will be used to determine gas transit tariff rates. Currently, none of these proposals appear to have secured full support.

Figure 4.16. Average industrial consumer prices for natural gas in Russia and Kazakhstan



Source: IHS Markit

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4.6.3. Summary

Aspirationally, the EAEU single market for gas is expected to create conditions for efficient, non-discriminatory trade; ensure sharing of information about consumption, production, transportation, and delivery of natural gas; and increase transparency in pricing. Additional goals include: ensuring duty-free shipment of gas acquired under direct contracts or through an exchange; maintaining market prices that ensure commercial profitability of gas sales across the common market; and for the member countries to make a coordinated decision on a transition to netback prices for gas on the territory of member states. Establishing common EAEU energy markets will require: (a) harmonization of regulations, prices,

[20] See IHS Markit Strategic Report Russian Domestic Gas Prices: How high can they go?
[21] https://ria.ru/20190201/1550266436.html

tariffs, and downstream taxes among member states; and (b) uniform, non-discriminatory access to markets and infrastructure in member states.

The reality is that creating a single gas market, such as has been the goal for many years in the European Union, will require significant liberalization and alignment of policies. Harmonization will thus pose considerable challenges for Kazakhstan, whose domestic gas prices and domestic market are heavily regulated. IHS Markit continues to recommend that end-user prices in Kazakhstan be harmonized with those in Russia's gas-producing regions in West Siberia (e.g., Yamal-Nenets Okrug). This will allow industry in western Kazakhstan to remain competitive within the broader EAEU economic space, as well as ease the overall adjustment by Kazakh consumers to the higher level of prices.

4.7. Recommendations

• In order to stimulate new gas production and incentivize producers to supply gas to the domestic market, upstream procurement prices must at least be high enough to fully cover the costs involved in producing, processing, and delivering commercial gas into the national gas network. For the most part, these higher producer prices should be passed on to consumers through higher end-user prices. Higher end-user prices will motivate consumers to use natural gas more efficiently and are in concert with the objective of harmonizing Kazakhstan's prices with those in Russia as part of the general movement toward the common gas market of the EAEU. 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 and the general resistance among both politicians and the public to sizable hikes in gas (and electricity) prices. Already, consumers in EAEU member states with lower GDP per capita than Kazakhstan (i.e., Armenia, Kyrgyzstan) are paying higher gas prices than are consumers in Kazakhstan.

• Kazakhstan should encourage exploration for additional gas resources, including unconventional gas.

• 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 western Kazakhstan should be set on a trajectory that will approachthose in Russian gas-producing regions (e.g., Yamal-Nenets Okrug) rather than in that country's neighboring gas-consuming regions (Saratov Oblast); this will help ensure the competitiveness of Kazakhstan's gas in the common economic space.

• The experience of amending the new Ecology Code exemplifies the insufficient legislative review and commentary period for many Kazakh legislative initiatives. The period for review and comment by enterprises on new laws should be increased from the existing 10 days to 45–270 days, to allow companies and other stakeholders sufficient time to analyze the effects of new legislative proposals.

• The methodology used to establish benchmarks for best available practice under the Ecology Code needs to be clarified, as well as the guidelines for distinguishing between routine flaring and safety flaring of gas. In order to reach Kazakhstan's obligations under the Paris Agreement, the government should consider reducing or eliminating the disparities in the coefficients applied to power plants compared to oil and gas producers for atmospheric emissions.

5. ELECTRIC POWER INDUSTRY

5.1. Key Points

5.2. General Description of Kazakhstan's Electric Power Industry

5.3. Capacity Market Formation and Clean Generation Stimulation Opportunities

5.4. Evolution of RES Support Mechanisms in Kazakhstan

5.5. Transition to Incentive Tariff Regulation in the Electric Power Industry

5.6. Heat Energy Market Regulation

5. Electric power industry

The rise in oil production that started in 2016, a ramp up in mining and metallurgical activity and implementation of several major power projects increased electricity consumption in Kazakhstan by 11.7% between 2016 and 2018. The power consumption has exceeded NER 2017 forecast by about 5 billion kWh, or 4.7%. Despite more robust growth in power consumption in the past two years, IHS Markit's outlook is for a moderate annual consumption growth in the years to come driven by the underlying assumption of Kazakhstan's average annual GDP growth of 3.3% per year to 2040 (which is still fairly robust by international standards, though less than the official government forecast) and global markets' outlooks. Given current network expansion and a regular increase in the available capacity of existing power plants, there is no urgent need for new generating capacity. However, the Government of Kazakhstan has set ambitious goals for transition to a green economy, where the main highlight is development of renewable energy sources.

In addition to renewable energy development programs, the country is planning to adopt regulations for the introduction of the best available technologies (BAT) at coal-fired power plants and large boiler houses, and adopt emissions standards and regulations in line with those present in OSCE markets. Given that coal-fired power dominates electricity generation, and many of these plants are technically outdated (turbine equipment depreciation at thermal power plants is over 70%), upgrading such facilities by introducing new technologies is essential to underpin future power generation and meet Kazakhstan's ecological goals. Realizing such technological improvements requires efficient market mechanisms and an investment-friendly regulatory structure.

5.1. Key Points

In order to implement its energy strategy, the Government of Kazakhstan will have to adopt a multi-pronged approach that combines achieving "green" targets with the introduction of efficient mechanisms. In this respect, the following issues require particular attention:

• The segment lacks a strategic planning document outlining the power sector's long-term development path that would account for Kazakhstan's new socio-economic realities, the situation and interests of related industries, the opportunities for technological and innovative power sector development, as well as environmental policy and energy security goals. It is essential for the policymakers and power sector regulators to have a realistic and sound medium to long-term sector's development program.

• The capacity remuneration mechanism (capacity market) targets require harmonization with the principals of the energy strategy. In addition to insuring the adequacy (sufficient availability) of generating resources (commissioning new and modernizing existing generating assets) the capacity market should also play a role in improving efficiency of exiting generation and implementing the environmental policy (stimulating transition to new environmental standards). Capacity market prices must be adequate and sufficient to cover power plants' fixed costs.

• Electricity market liberalization must be accompanied by an effective pricing policy; the marginal tariffs set for power plants should not make their operation unprofitable.

• The mandate of traditional generation to finance the development of renewable energy sources in the context of the policy of "frozen" and reduced tariffs, as well as other price caps, fails to increase confidence in the ability to recoup investments in renewables. Instead of burdening traditional energy sources, the government and/or end-users should pay for renewable energy investments.

• The power companies' transition to an incentive tariff regulation should be accompanied by the clear obligations of the latter to improve costs efficiency and enhance the quality of power transmission and distribution services.

• There is an urgent need to adopt the heat energy supply law, the absence of which prevents this segment from efficient operation and regulation. The heat energy market regulator's practice of administratively reducing heat energy producers and suppliers' profits negatively affects the segment's investment attractiveness. The absence of incentive tariff regulation prevents the heat energy companies from improving their efficiency and does not incentivize rational use of the heat energy by consumers.

• Lack of open access to regular information and statistical data on all aspects of the power market operation affects its investment attractiveness and increases Kazakhstan's investment risk.

5.2. General Description of Kazakhstan's Electric Power Industry

Kazakhstan's electric power sector is the third largest in the region (after Russia and Ukraine) with the total installed generating capacity reaching 21.9 GW and available capacity reaching 18.9 GW by the end of 2018.

Kazakhstan's power sector enjoys a number of benefits, notably the low cost of generation due to the availability, proximity, and cost of fuel resources. Substantial coal reserves in Ekibastuz and Karaganda have underpinned the predominance of coal generation in the North and in the East of the country.[1] Meanwhile, associated gas production has promoted the development of gas-fired generation in the West of the country. Coal's dominance in the power mix in eastern and northern Kazakhstan is further bolstered by the high transportation costs required to deliver energy resources (particularly natural gas) across the country's vast territory. The costs of delivering natural gas to eastern, northern and even some parts of southern Kazakhstan (particularly Almaty oblast) is prohibitively high for power producers at existing tariff levels, and ultimately makes gas uncompetitive with coal.[2]

The power grid infrastructure and the power production and consumption dynamics have predetermined the composition of Kazakhstan's energy system which is split into three energy zones:

- The North energy zone: 13.6 GW of available generation capacity, 14.8 billion kWh generation surplus, 9.6 GW peak load
- The South energy zone: 2.8 GW of available generation capacity, 11.1 billion kWh generation deficit, 3.6 GW peak load
- The West energy zone: 2.5 GW of available generation capacity, 0.1 billion kWh generation deficit covered by the Urals Unified Power System (UPS), 1.9 GW peak load

The North and South energy zones are connected by two North-South transmission lines and a third North-East-South 500 kV line with a total carrying capacity of 2 GW. They often considered together and collectively referred to as the North-South energy zone. The West energy zone is not connected with the North-South and is balanced by the Urals Integrated Energy System (IES) of Russia's UES.

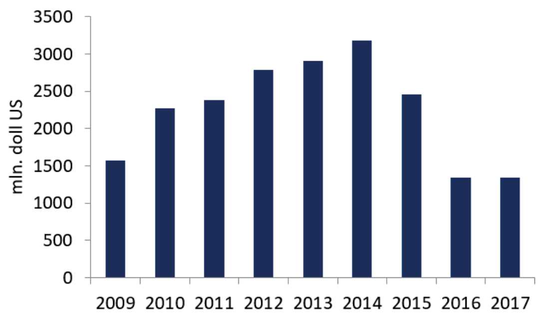
The expansion of Kazakhstan's own

[1] The cost of Ekibastuz coal is $5.9/ton, among the lowest in the world
[2] For example, transitioning Almaty available generation capacity, 0.1 billion kWh generation deficit covered by the Urals Unified Power System (UPS), 1.9 GW peak load TETs-2 (510 MW) to natural gas would result in a 2.4-fold increase in the cost of electricity.

Fig. 5.1. Kazakhstan service areas.

generating capacity, as well as the extensive construction and modernization of its inter-regional power network infrastructure enabled the country to overcome its dependence on electricity imports from Russia and Central Asia that in 1991 amounted to 15 billion kWh per year (over 15% of total consumption). At present, Kazakhstan is a net exporter of electricity.[3]

Since 2004, investments in the electric power industry have grown, especially between 2009—2015, when marginal tariffs were in place (a program coined as "tariff for investment"). During that time, fixed assets were substantially renovated, yet even these upgrades proved to be insufficient to keep pace with Kazakhstan's burgeoning power demand. The depreciation rate exceeds 75% at nearly one-third (36%) of turbine equipment at existing thermal power plants, and ageing technology at these facilities limits available capacity (up to 1.2 GW).



Source: Source: Statistics committee

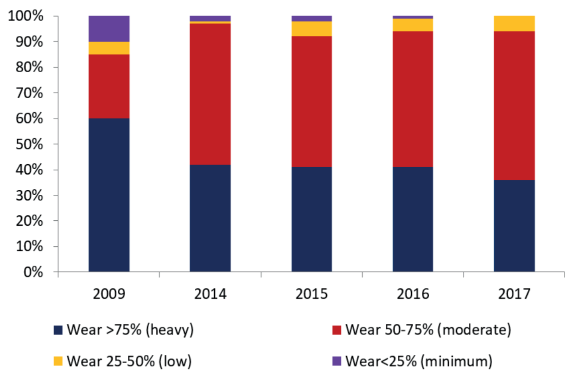


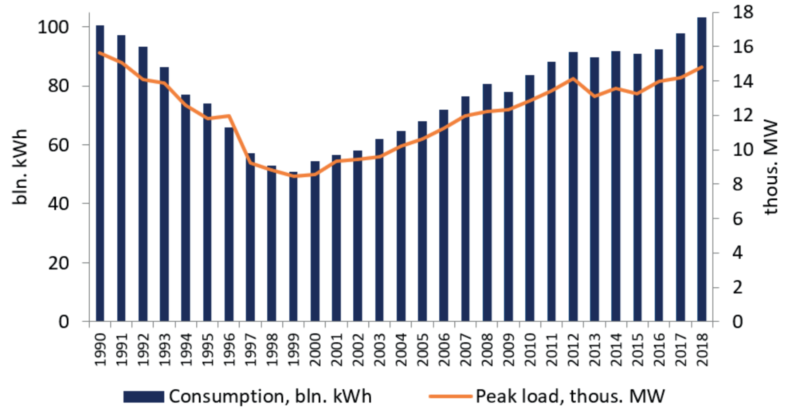
Fig. 5.2. Depreciation of turbine equipment at thermal power plants (left) and investments in 2009–17 (right, in mln. tenge).

Between 2009 and 2018, the installed capacity of Kazakhstan's power plants increased by 2.7 GW, having closed the gap between installed and available capacity from 4.3 to 3 GW, primarily due to a reduction in technical constraints. Over the same period, the share of heavily worn turbine equipment at thermal power plants fell from 60% to 36%, while the share of moderately worn turbine equipment increased from 25% to 58%. Marginal tariffs facilitated the

[3] In 2018, net electricity exports from Kazakhstan amounted to 3.6 billion kWh—0.9 billion kWh less than in 2017 (decrease in exports to Russia).

partial modernization and reconstruction of turbine and boiler-house equipment at district TPPs (abbreviated in Russian as GRES) and CHPPs (abbreviated in Russian as TETs).

For industry, modernization of power assets during the period of marginal tariffs (2009–15) enabled an increase in electricity production that covered burgeoning consumption.



Source: KEGOC

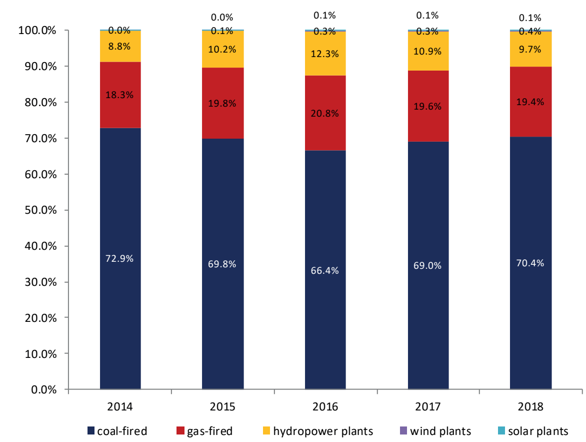
Fig. 5.3. Electricity generation and peak load (GW), 1990–2018.

To enable the continued upgrade of the energy system and commissioning of new generating capacity, the government has approved the introduction of the capacity market that was launched in January 2019. Nevertheless, the limited target-setting, unsustainable price setting for the existing generation, and nonmarket mechanisms for the implementation of investment projects limit the ability of the capacity market to attract new technologies to ensure security and reliability of power supply, to implement the objectives of the Ecology Code and climate policy, as well as to implement technological updates of the existing thermal generation fleet (see chapter 5.3).

5.2.1. Production of electric power

According to the system operator («KEGOC») the power production in Kazakhstan in 2018 reached 106 797.1 mln. kWh, an increase of 4.3% when compared to 2017. The North and West energy zones have been the main growth areas (with 5% and 8% respectively), while the power production in the South energy zone fell by 4.7%.

The current structure of electricity production is dominated by coal-fired generation (70.4%), followed by gas-fired plants (19.4%), hydropower plants (9.7%), and wind and solar plants (0.4% and 0.1%, respectively).



Source: KEGOC

Fig. 5.4 The structure of power production.

Despite a small share in electricity production, installed capacity of renewable energy sources (RES) has significantly increased over the past five years due to active legislative support for this segment.

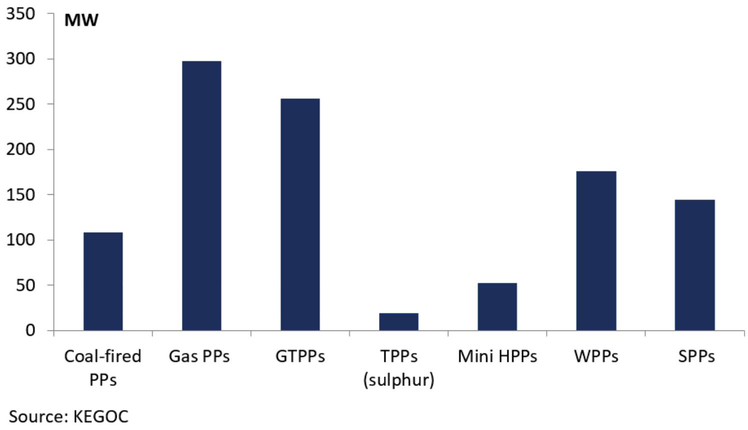


Fig. 5.5. Changes in the power plants' installed capacity between 2014–18, MW.

A handful of large companies dominate power generation in Kazakhstan. The state holding company Samruk-Energy generates 37% of total power, while mining and metallurgical heavyweight, Eurasian Resources Group (ERG), produces 17% of the country's power on the power plants that make up the group. The TETs owned by the Central Asian Electric Power Corporation (CAEPCO) produce 7% of power, while Kazakhmys Energy and Kazakhstan Utility Systems account for 6%, each. [4]

Is a special support mechanism needed for gas-fired generation in Kazakhstan? (IHS Markit)

As discussed above, the expansion of gas-fired generation in Kazakhstan is important for several reasons. One is that it has been identified as a critical pathway for Kazakhstan to meet its international commitments to reduce GHG emissions by substituting for coal in thermal generation. Another is to meet the growing need for more flexible generation, both because of underlying structural shifts in the load curve and the need for frequency support, but also because of the expansion of intermittent renewable generation.

But a key obstacle is that coal is very inexpensive in Kazakhstan, as the country is endowed with large reserves of coal that can be mined at very low cost. Gas is more expensive in Kazakhstan, but still quite low-cost in global perspective. But end-user electricity tariffs are largely geared to low-cost coal-fired generation in much of the country, making it difficult for generators to switch to gas and remain competitive. For example, in the discussions relating to regional gasification of the capital city, Nur-Sultan, with the arrival of the SaryArka pipeline, it was deliberately decided not to convert the city's power plants from coal to gas. The use of gas would require much higher electricity prices for the generators to cover the additional costs. Energy Minister

[4] This refers to the power generation part of the Kazakhmys Corporation, the major copper producer in Kazakhstan.
[5] See the IHS Markit Insight Construction is about to begin on Kazakhstan's SaryArka gas pipeline, but its promise of broad regional gasification remains elusive, 12 October 2018.
[6] The calorific value for hard coal varies significantly because of differences in coal quality mined at different deposits. The Ministry internally uses a conversion of 0.626 per ton of hard coal, representing an average calorific value of 4,382 kcal/kg. This seems reasonable, as Ekibastuz coal, a sub-bituminous coal, dominates steam coal deliveries to power plants in Kazakhstan. It averages about 4,000 kcal/kg, which would represent a conversion coefficient to standard fuel of 0.600.

Kanat Bozumbayev stated that switching Astana's combined heat-and-power plants (TETs) from coal to gas would raise the cost of generating electricity by about 50%.[5]

For example, the average acquisition price paid by industrial users (such as power plants) in Kazakhstan for hard steam coal in December 2018 was only 6,819 tenge/ton ($18.34/ton), whereas the average acquisition price paid by industrial users for natural gas was 25,485 tenge/thousand cubic meters (Mcm) ($68.54/Mcm). Converted to tons of standard fuel equivalent (7,000 kcal/kg), this works out to about $29.3 per ton of standard fuel (tsf) for a ton of hard coal versus $58.6/tsf for natural gas, a twofold difference.[6] As indicated in the gas chapter, the need for gas-fired generation is becoming more immediate in the southern part of Kazakhstan. Western Kazakhstan is 100% gas-fired already, and the north-central part of the country (including Pavlodar and Karaganda oblasts) is predominantly coal-fired (96.8% for utility stations in 2018) (See Table 5.1a: Fuel use by utility thermal electric power stations in Kazakhstan); it is in the southern part where the generation mix is less concentrated (60.6% coal, 36.9% gas, and 2.5% mazut in 2018).

Table 5.1a
Fuel use by Utility Thermal Electric Power Stations in Kazakhstan
2018

	Total	Coal	Mazut	Gas
Total (utility plants)				
In percent:	100.0	86.1	0.8	13.1
thousand tons of standard fuel	42230.7	36351.2	357.7	5521.8
natural fuel used in utility plants*		58069.0	259.4	4719.5
Northern Zone (utility plants)				
In percent:	100.0	96.8	0.7	2.5
thousand tons of standard fuel	35085.2	33954.6	259.0	871.7
natural fuel used in utility plants		54240.5	187.8	745.0
Southern Zone (utility plants)				
In percent:	100.0	60.6	2.5	36.9
thousand tons of standard fuel	3956.2	2396.6	98.7	1460.9
natural fuel used in utility plants*		3828.5	71.6	1248.6
Western Zone (utility plants)				
In percent:	100.0	0.0	0.0	100.0
thousand tons of standard fuel	3189.3	0.0	0.0	3189.3
natural fuel used in utility plants*		0	0	2725.9

* thousand metric tons for coal and mazut, MMcm for gas.
Note: Utility plants include those connected to the national grid, and producing some merchant power. Excluded are power stations used for own use.
Source: KEGOC

But mainly for environmental reasons (to improve local air quality), Almaty's combined heat-and-power stations (TETs) are being converted to gas from coal. This has already occurred for the most part at Almaty TETs-1 (145 MW), with Almaty TETs-2 is expected to follow later. Preliminary calculations indicate that the cost of producing electricity at the Almaty TETs-2 plant (510 MW) will more than double as a result.

Of course, Almaty has the highest end-user prices for gas in the entire country, as the gas must be either imported (mainly from Uzbekistan) or transported a long distance from the main gas-producing area in western Kazakhstan (see the gas chapter). In Almaty, the average industrial acquisition price for natural gas in December 2018 was 33,455 tenge/Mcm ($90/Mcm). At that time, regional industrial acquisition prices for coal in Almaty were near the national average. So fuel acquisition costs for Almaty TETS-2 would be 2.6 times higher with gas than before the switch: $76.9/tsf for gas versus about $29.5/tsf for coal. Given the plant's average heat rate (fuel use per kWh generated) when operating on gas of about 414 grams of standard fuel, the fuel cost per kWh would be about $0.0318/kWh ($31.8/MWh). In comparison, the average producer price for electricity (received by electricity generators) in Kazakhstan, which must cover all of the generator's costs, was only about $22.4/MWh in December 2018.[7]

The overall situation seems to have parallels with renewable power generation, which also faced problems of competing with conventional generation and has been an object of state support for some time. However, more recently, it should be recognized that globally the general policy thrust is to increasingly "mainstream" renewable generation by reducing the overall level of policy support that it receives and curtaining its privileged position in terms of dispatch, connection, and transmission.

Shymkent power plant development

One mechanism moving forward in Kazakhstan to promote gas-fired generation is to provide gas to particular power plants at special prices, based on a defined formula. This is designed specifically to support power sector development, especially in the southern part of the country. Essentially, this proposal requires KTG to sell gas at discounted (or "subsidized") prices, apparently while trying to make up the difference by charging higher prices to other gas consumers, for example in feedstock use.

The initial example of this particular approach is the special pricing conditions that are being created for the development of a new power plant in Shymkent. The Eurasian Resources Group (ERG), a diversified mining and industrial company, is planning to develop a new gas-fired plant at the site of its existing Shymkent TETs-3 plant (160 MW) to provide power for its ongoing industrial activities. The plan is to install a combined-cycle gas turbine (CCGT) plant with a capacity of up to 550 MW, to start up in 2023.

In Turkestan (formerly Shymkent) Oblast, the average industrial acquisition price for gas in December 2018 was 28,920 tenge/Mcm ($77.8/Mcm), slightly lower than in Almaty, but still among the highest in Kazakhstan. According to ERG's calculations, the acquisition price of gas can be no higher than $60/Mcm for the new plant to produce competitively priced electricity. As a result, the parliament is considering legislation that would allow KTG to sell gas to ERG for the plant at a discounted price of $60/Mcm.

While the intent of the policy is laudable, this type of measure is ad hoc and non-transparent, and cannot be employed with any degree of scale on a sustained basis. A more durable and transparent mechanism needs to be established.

Recommendations.

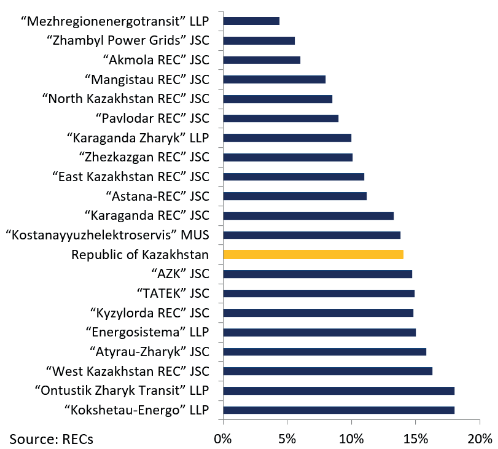
Develop a specific program to foster and expand flexible generation. Policymakers should determine how much flexible capacity is needed in Kazakhstan, where it is needed, and what type of characteristics it must have (i.e., speed of load ramp-up and downturn). The competitive bidding for flexible capacity construction projects could be worked into the capacity market mechanism launched in 2019. Or, policymakers could conduct a tender for specific capacities similar to what is being done for renewables, including setting specific construction start and commissioning dates. Potential investors/providers (who must meet certain technical threshold conditions to be included, such as financial and technical capabilities) should then be invited to submit bids. The winners of the projects would be determined by the lowest bid price. But from the start, such a mechanism should include the resulting higher-cost electricity (and capacity) that is made available by this process into a blended price for end-users. The end-users are the ones who benefit from the flexible capacity, and they should be the ones who pay for it.

5.2.2. Power transmission

The power grid infrastructure of Kazakhstan is comprised of a 500-220 kV grid network operated by KEGOC, the national power grid and system operator, as well as 196 energy transmission organizations (ETOs), 20 regional electricity grid companies (RECs), and 301 energy supply organizations (ESOs).[8] Electricity is transmitted from producers to wholesale end-users (power distribution companies and large consumers) connected to the national power grid.

Tab. 5.1. The grid infrastructure lengths of KEGOC and major RECs, in km.

Voltage	KEGOC	REC
1,150 (in 500 kV mode)	1,421.2	
500 kV	8,288.0	
330 kV (in the mode of 220 kV)	1,864.1	
220 kV	14,694.0	1,428.2
110 kV	352.8	17,062.8
35 kV	44	21,372.3
10 kV	92	51,315.9
6-0.4 kV	18.7	40,586.4



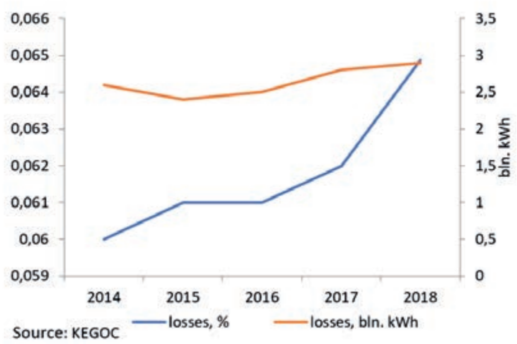


Fig. 5.6. Normative losses among RECs and the national power grid, %

[7] Within Kazakhstan, producer prices for electricity vary more by type of plant than they do by region (see the section on evolution of support mechanisms for renewables above).
[8] KEGOC combines the functions of the national grid and system operator. Through its subsidiary, and FSC, it also acts as a purchaser of power from traditional power plants and renewable energy facilities, and as the wholesale power market operator.

Despite recent influx of investment and development of power network infrastructure, the following challenges remain unresolved:

No direct 500 kV connection between all three oblasts in the South energy zone (Kyzylorda, Turkestan, Zhambyl) and the UES

No direct connection between the West energy zone and the UES, forcing parallel operation through the Russian power grid

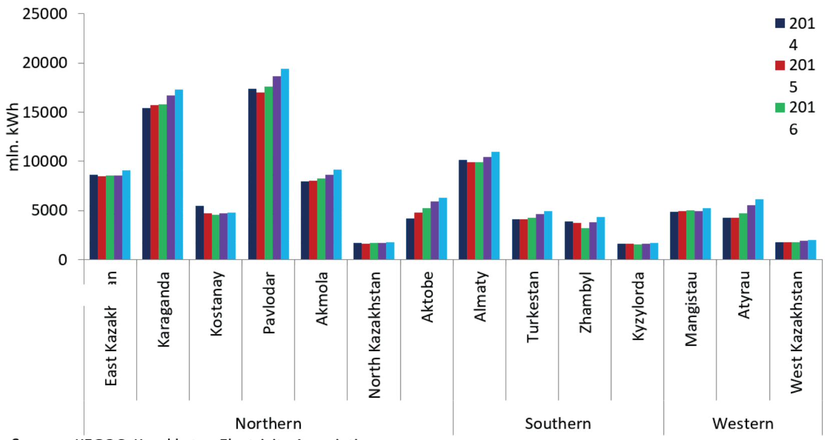
High degree of depreciation of basic equipment at ETOs

A significant number of ownerless power grid assets (1,300 km of power lines and hundreds of substations)

Given the considerable deficit of generating capacity in the South energy zone along with the forecasts for growing power consumption there, the national power grid operator is considering new projects designed to increase the carrying capacity and reliability of North-South transit.[9]

5.2.3. Power consumption

According to the system operator, electricity consumption in Kazakhstan in 2018 amounted to 103 228.3 million kWh, which is 5% higher than consumption in 2017. Consumption growth was recorded in all energy zone and it was 5% in North energy zone, 7% in South energy zone and 8% in Western energy zone, due to increase in industrial production by 4.1% in 14 regions of Kazakhstan. In 2014–18, the greatest increase in electric power consumption was registered in the North energy zone (6.99 billion kWh).



Source: KEGOC. Kazakhstan Electricity Association

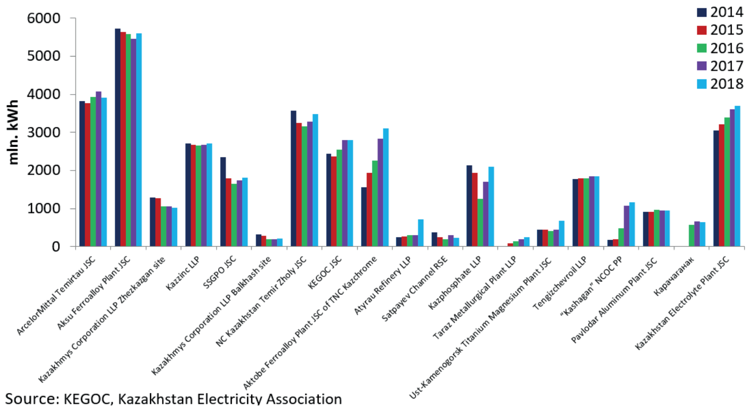
Fig. 5.7. Electricity consumption dynamics in 2014–18.

In recent years, industrial activity has been the largest driver of power demand; the industrial enterprises identified in figure 5.7 account for approximately one-third of the country's total electricity consumption. Between 2014 and 2018, power consumption decreased only in Kostanay Oblast, as the Sokolov-Sarbai Mining Production Organization (SSGPO) cut consumption by 541.1 million kWh on the back of depressed activity. SSGP experienced a 25–29% drop in the extraction and concentration of iron ore, along with the production of final products.[10] The decline in production and exports of iron ore, in turn, is due to a reduction in construction activities in Western China, which was a key market for SSGPO products.

The largest increase in power consumption occurred in Aktobe and Atyrau oblasts (2014 - 2018); Kazchrome's Aktobe Ferroalloy Plant JSC increased power demand by 1558 million kWh, and NCOC's power needs grew by 976 million kWh as Kashagan ramped up production.

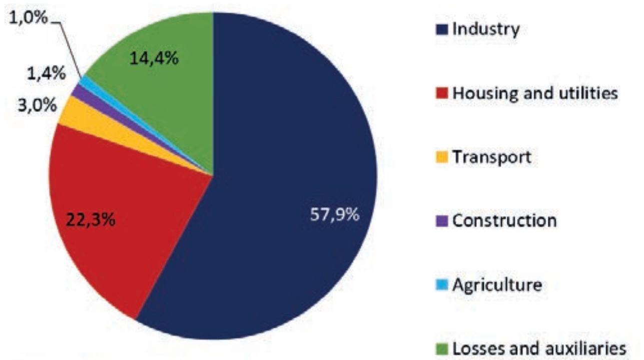
The increase in the price and demand for chromium in the considered period, as well as the high quality of chromium ore mined in the country, led to an increase in the production of JSC AFP (Aktobe Ferroalloy plant) (Aktobe) "TNK Kazchrom", and, as a consequence, doubled power consumption.[11]

Similarly, an uptick in the output of aluminum and other metallurgical products resulted in power consumption growth in Pavlodar and Karaganda oblasts.



Source: KEGOC, Kazakhstan Electricity Association

Fig. 5.8. Dynamics of electricity consumption by major consumers in 2014–18, billion kWh



Source: Ministry of Energy

Fig. 5.9. Structure of Kazakhstan's electricity consumption 2018, %

Industry's predominance in Kazakhstan's electricity balance suggests that projecting future electricity consumption is intimately correlated with developments in international commodity markets, particularly for metals and crude oil. In contrast, electricity demand in the residential sector (housing and utilities), is likely to grow at a slowing rate, despite population growth, as the market is fairly saturated. Furthermore, future improvements in energy-efficiency are expected to cancel out any increases in demand resulting from population growth. Electricity transmission losses can be minimized to a certain minimum technologically level (compatible to Kazakhstan's conditions) through grid equipment optimization and modernization.[12]

[9] The need to construct a North-South DC transmission line was declared in 2018.
[10] There are two iron ore producers in Kazakhstan: SSGPO and ArcelorMittal. SSGPO is the only exporter, as all of ArcelorMittal's production is consumed domestically at the Temirtau plant.
[11] 95% of chromium volumes are used in stainless steel production.
[12] In 2014–18, the actual average energy losses in REC grids dropped from 11.7% to 10.3%.

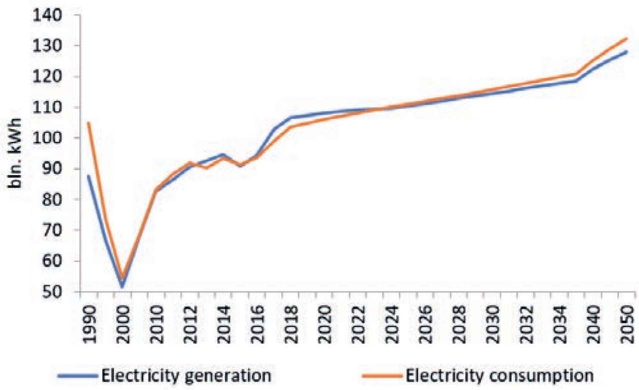


Fig. 5.10. Electricity production and consumption outlook for 1990–2050, billion kWh.

According to the IHS Markit base-case electricity consumption outlook, there will be no need for any significant increase in baseload capacity until 2030. However, the planned commissioning of up to 2.5 GW of wind and solar power capacity necessitates additional flexible generation capacity.

5.2.4. Industry regulation

Regulation of electricity in Kazakhstan is simultaneously carried out by several agencies and structures responsible for specific aspects of the sector. The illustration below outlines authority and responsibilities of key entities:

<table>
<tr><td>Ministry of Energy</td><td>Ministry of National Economy</td><td colspan="2">Ministry of Industry and Infrastructure Development</td></tr>
<tr><td rowspan="2">Implementation of state policy in the field of:
– electric power industry
– heat supply (TETs, distribution companies)
– nuclear power utilization
– Renewable energy source (RES) development
– environment protection
Approval of:
– electricity and EM forecast balances
marginal electricity and capacity tariffs</td><td>Committee on Regulation of Natural Monopolies and Protection of Competition (KREMiZK)</td><td colspan="2">Committee on Construction, Housing and Utilities</td></tr>
<tr><td>Approval of tariffs
Natural monopoly entities: electricity transmission, heat generation, transmission, distribution and marketing
Public interest market entities:
electricity retail sales</td><td>Implementation of state policy in the field of:
– heat supply (boiler houses, heating networks);
– water supply
Development of justification of investments in heat supply systems modernization and development
Financial operator of the “Nurly Zhol” program</td><td>Comprehensive extra-departmental expert evaluation of projects</td></tr>
<tr><td>SWF Samruk-Kazyna JSC</td><td></td><td></td><td>Akimats</td></tr>
<tr><td>KEGOC JSC</td><td>KOREM JSC</td><td>Market Council</td><td></td></tr>
<tr><td>Kazakhstan UPS operator
FSC for RES LLP</td><td>Kazakhstan electricity and capacity market operator</td><td>Reviews modernization investment programs, controls construction and reconstruction of energy producers</td><td>Municipal energy and utility departments
In charge of energy, utilities, industrial safety in a city/ town</td></tr>
</table>

Fig. 5.11 - The scheme of regulation of the industry.

With seeming separation of functions and areas of responsibility, some of the agencies are simultaneously involved in regulating activities of the same market participants. For example, the regulation of electricity and capacity tariffs for thermal power plants (TETs), which are limited by maximum values is carried out by the Ministry of Energy, while the tariffs for heat supply are regulated by the Committee on Regulation of Natural Monopolies and Protection of Competition (KREMiZK) under the Ministry of national economy. In view of the social significance of ensuring heat supply, KREMiZK implements a policy of restraining tariff increases for end consumers, resulting in unreasonably suppressed tariffs for thermal energy.

5.2.5 Electricity and capacity markets in Kazakhstan Kazakhstan's electric power market is divided into two segments – wholesale and retail – each of which is subject to its own regulatory nomenclature. The wholesale market structure is illustrated schematically in Figure 5.12.

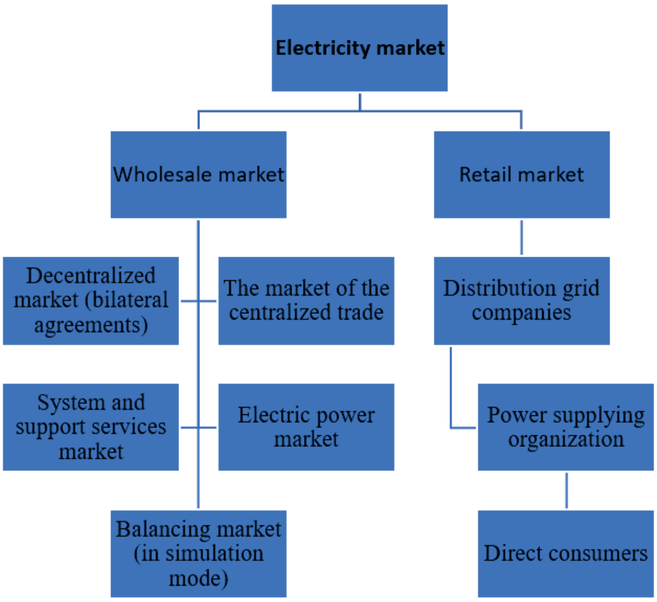


Fig. 5.12. The wholesale electric power market structure.

The entities of the wholesale electricity market are:

energy producing companies, who supply to the wholesale market electricity in the amount of no less than 1 MW of daily average power;

energy-producing organizations using RES, supplying the wholesale market of electricity in the amount of at least 1 MW of average annual capacity;

electricity consumers, purchasing electricity on the wholesale market in the amount of no less than 1 MW of average power;

power transmission organizations;

supply organizations, which do not have their own electrical networks and buy on the wholesale market of electricity for resale in the amount of no less than 1 MW of average daily (basic) power;

the system operator (JSC "KEGOC");

the operator of centralized electricity trade (JSC "KOREM")

On the wholesale electricity market, the power generating organizations sell electricity to power supplying organizations and wholesale consumers. Since 2019, Kazakhstan has a capacity market, thus, electricity and capacity are sold in the wholesale market.[13]

In the retail electricity market, energy producing and energy supplying organizations sell electricity to retail consumers, capacity is not sold on retail level (capacity costs are included in the price of electricity).

In addition to electric power, heat energy is also supplied and sold in Kazakhstan. In contrast to the electricity sector, the heat industry includes three sub-sectors:[14]

Heat energy generation (38 TETs, 63 large and 2,200 small boiler houses), whereby 62% of central heating is supplied by TETs

Heat energy transmission, distribution, and marketing along the main and district heating networks (>12,000 km)

Heat energy consumption by industrial consumers, public and private entities and the population

In contrast to the electricity market, the heat energy market operates only at the retail level. Retail consumers, for their part, are not able to select suppliers.

5.2.6. Volume of electricity and capacity markets

In Kazakhstan the electric power is traded both centrally (with the market price settling at the end of the trading session) and through the bilateral agreements (signed between the power plants and the wholesale consumers) at prices that cannot exceed the price cap. Prior to the launch of capacity market in 2019 bilateral agreements constituted 70-80% of all electricity sales. From 2019, similar to the electricity market, the capacity is sold both centrally and through bilateral agreements.

In 2018, 15,770 transactions were concluded as a result of centralized electricity trading, totaling 21.26 billion kWh (20%) worth 151.4 billion tengeexcluding VAT. The average price of electricity traded amounted to 7.12 tenge per kWh (ex. VAT). The volume of trade transactions in 2018 decreased by 27% (28.96 billion kWh). The remaining volume (80%) of produced electricity was supplied under bilateral agreements, details of which are confidential. A share of electricity (particularly within industrial groups) is sold at prices below price caps.

In general, the electricity market value in 2018 can be estimated at 800 billion tenge. This amount does not include electricity generated at in-house power plants at oil and gas fields (Kashagan, Tengiz, Karachaganak, Kumkol, etc.), although charges for electricity generated from renewable energy sources are included in the costs of traditional power plants.

Based on the 2019 capacity market trading results with the total volume amounting to KZT35 billion (or only 4% of the electricity market volume in 2018), and taking into account the marginal tariff reduction, we forecast an overall decrease in the electricity and capacity market volume of KZT200 billion (or 25%) as compared to 2018.

There are special conditions, created for the sale of electricity, generated by RES. Sale and purchase of renewable energy is carried out centrally through a Single buyer (Financial Settlement Center of RE [FSC] to support renewable energy). Volumes and expenses of electricity purchase from RES are distributed in proportion to the share of electricity production of traditional power plants in the total output. Payment for renewable energy is included in the marginal tariff of traditional power plants regardless of the energy zone, less the production of its own renewable energy sources. As per our estimates power plants' costs associated with the purchase of renewable output (excluding fuel cost increases) are expected to rise by 50 billion tenge relative to 2018. As a result, not only will power plant profits fall, but there will also be pressure to reduce costs. In practice, the simplest way to cut costs over the

[13] As far as the capacity market is concerned, a number of large industrial enterprises contain their own power plants and consumers.
[14] According to the definition given in the current legislation, the electric power industry includes electricity and heat generation, transmission, distribution, and consumption.

short term is to reduce payroll (personnel downsizing, elimination of bonuses, etc.), since reducing repair costs requires a decrease in the tariff by the Regulator.

All of these factors have placed the power industry in a tricky situation. On the one hand, power producers should strive to introduce new technologies to enhance energy efficiency and reduce emissions. On the other hand, the increase in individual plants' costs effectively forces plants to contemplate extreme measures, such as scaling back personnel, to ensure profitability. Given these dynamics, the government should assess and revise the electric power industry development goals, market structure and tariff policy in order to create a cogent regulatory framework conducive to economic and sectoral growth.

5.2.7 Pricing for electricity, power and heat energy

The Ministry of Energy of the Republic of Kazakhstan sets the maximum level of electricity tariffs for the relevant group of energy-producing organizations. In 2019, tariff limits were fixed for the period 2019-2025, and the number of groups from 16 was increased to 43, actually corresponding to the number of large power plants in Kazakhstan. The criteria for setting individual marginal tariff for power plants are their type, installed capacity, fuel type and location (energy zone). The price of electricity may not exceed the tariff cap, except for electricity sold on a centralized platform. Thus, the price of electricity at a centralized auction may exceed the limit set for the power plant, but the volume of electricity sold at such a price may not exceed 10% of the volume of electricity generated by this station.

In support of RES development, the marginal tariff is reduced by the cost of electricity purchased from RES.

The Ministry of Energy also regulates capacity tariffs for existing power plants, the upper limit of which is set for a 7-year period. Realization of investment projects within the capacity market is carried out under individual conditions with the approval of individual tariffs on a long-term basis.

As mentioned above, in addition to the Ministry of energy, TETs tariffs are regulated by KREMiZK for production of thermal energy (heat). KREMiZK is also the main body that sets tariffs for the transmission and distribution of electricity and heat.

5.3. Capacity Market Formation and Clean Generation Stimulation Opportunities

5.3.1. General information on capacity market and first trading results

Kazakhstan's capacity market has been functioning since 1 January 2019. According to the Law on Electric Power Industry, the capacity market was introduced to "attract investments to support the operation of existing capacities and commissioning of new generation to meet the demand for electric power."[15] Despite a slight change in the 2012 wording (when the capacity market was to prevent the generating capacity deficit), the main goal of its introduction remained unchanged, which is to ensure the reliable operation of Kazakhstan's UPS.

Indeed, the underlying rationale for various capacity remuneration mechanisms around the world is the inability of electricity markets to attract and cover the cost of new investments into generating capacity thus presenting a long-term threat to the reliability and security of power supply.[16] The advantage of such mechanisms for investors is that the power plants selected for the capacity supply receive income from capacity payments regardless of demand (supply). This implies long-term guarantees and a high level of financial stability for the power plants' operators.

[15] Law of the Republic of Kazakhstan on Electric Power Industry No. 588-II dated July 9, 2004 (as amended and supplemented on April 19, 2019).
[16] The capacity market is only one of the capacity remuneration mechanisms.

In 2009–15, the long-term security of power supply in Kazakhstan (given the high depreciation rate of fixed assets and projected rapid growth in consumption) was achieved by the electricity market. Marginal tariffs set for the power plants in 2009 in accordance with the "Tariff for Investment" program included an investment premium. They enabled to raise around 1 trillion tenge of investments into modernization and expansion of existing generating assets, and increased their available capacity by 4.2 GW by 2018.

Nevertheless, according to the capacity balance forecast by the Ministry of Energy the surplus of generating capacity (accounting for the required reserve) in 2019 will constitute 332 MW only (without planned commissioning).[17]

The power reserve sufficiency situation varies in different service areas:

In the isolated West energy zone, a deficit of 43 MW is already registered in 2019. Its projected growth by 2025 (accounting for the required reserve) is 920 MW.

In the South energy zone (the deficit of which is traditionally met by transfer from the North energy zone) the deficit is expected at 1,456 MW in 2019 (accounting for the necessary reserve). By 2025, it is expected to increase to 2,297 MW.

Despite capacity surplus in the North energy zone through to 2023 (accounting for the reserve requirement for the South energy zone) the system operator anticipates its gradual decline from 1,831 MW in 2019 to 158 MW in 2025. By 2025 the North energy zone is expected to register a deficit of 726 MW (accounting for the required reserve).

Ensuring sufficiency of generating capacity is one of the ways to secure the power supply and the approach pursued by Kazakhstan.[18] According to the Ministry of Energy between 2019–25 Kazakhstan plans to commission up to 7.3 GW of new capacity, 1.7 GW of which in 2019 (see table below).

Tab. 5.2. Planned commissioning of new capacity, MW.

Service area	2019	2020	2021	2022	2023	2024	2025
North	946	1193	1911	2213	2278	3363	4034
South	523	1106	1257	1341	1368	1369	1495
West	260	688	974	1702	1712	1773	1796
Total	1729	2987	4141	5255	5358	6505	7325

Source: Electric capacity forecast balance for Kazakhstan UPS for 2019–25, Ministry of Energy of the Republic of Kazakhstan.

Nevertheless by the end of 2018 three years after "Tariff for Investment" program termination the electric power market was incapable of creating adequate economic incentives for investment into either overhaul of generating assets (that have been put into operation 30–40 years prior), or let alone construction of new power plants (despite the shortage of flexible generating capacity). Namely:

The Tariff for Investment" program was replaced by new price caps and accompanied by the cancellation of plants' investment commitments.

Insufficient liberalization of the wholesale electricity market—about

[17] "Forecast Balance of Electric Power Capacity per Hour of Coincident Maximum of Electric Loads in the Unified Power System of Kazakhstan for 2019–25," Order No. 10 of the Minister of Energy dated January 14, 2019.

[18] Decisions on measures designed to eliminate the threat to security of electricity supply depend on its nature. The threat to the security of power supply can be related to fuel shortage (limited access to a specific type of fuel), generation-related (insufficient generating capacities due to disposal and obsolescence),or associated with insufficiency of balancing capacities and resources (generation, demand side management, energy storage systems) and grid constraints (high grid depreciation rate and limited capability to integrate new technologies). The approach to addressing the threat to power supply reliability is selected upon analysis of technical and economic causes of the threat and any factors that can improve the situation with power supply.

75% of electricity was sold under direct contracts between energy producers and wholesale consumers.

Under the prevailing pricing policy, the power plants' tariff covered only current repairs and limited modernization, reconstruction, and expansion for short-term operation.

The electricity price made it impossible to attract investment into overhaul of existing power plants and/or construction of new generation as it could not cover the cost of new construction making new construction uncompetitive when compared to the costs of running the existing power plants

Nevertheless, no attempts have been made to complete the electric power market reforms and improve the price setting and the electricity trading mechanisms.[19] The experts' arguments that the introduction of a capacity remuneration mechanism would not help to solve the electric power market issue accumulated over the years were disregarded, and the decision to introduce the capacity market, postponed since 2017, was finally made in 2018 with the launch of capacity market in 2019.[20]

5.3.2. Kazakhstan's capacity market model

The capacity market in Kazakhstan is a service market where the Single Buyer represented by the KEGOC Financial Settlement Center (FSC) selects generating capacity,[21] including those selected through the auction, and sells the selected capacity (inclusive of the cost of its services) at a single price to the wholesale buyers—large consumers and electric grid companies. According to the procedure, the FSC selects in the order of priority, thermal (TETs) power plants, then modernized and new power plants, and only after that the existing power plants. Notably, the price competition is envisaged only for the price offers of existing power plants.

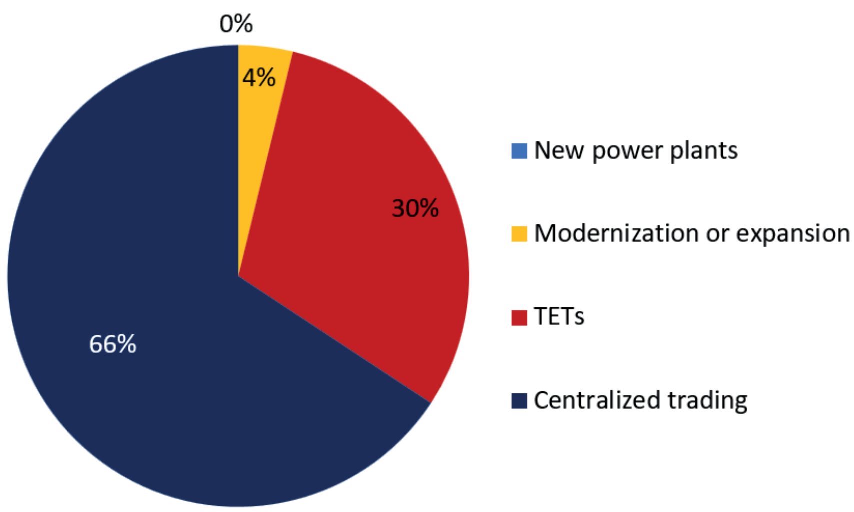
Thus, the capacity price for the wholesale buyers is made up of the cost of:

New power plants' capacity

Modernized and expanded power plants' capacity

TETs capacity in the volume meeting the heat energy output

Capacity selected during annual centralized auction



Source: FSC for RES

Fig. 5.13. Volumes of capacity purchase by the Single Buyer, MW.

[19] Kazakhstan lacks a fully functioning wholesale power market, a balancing market, and a system services market.
[20] According to the proposal of the European Union of May 2019 on electric power markets regulation [COM (2016) 861], introduction of capacity mechanisms (markets) should be considered as a last resort, provided their reasons and goals are clearly substantiated.
[21] The service of ensuring the availability of electric capacity, the capacity tariff, is measured in tenge per MW per month, hereinafter simply "capacity" as a matter of convenience.

As a result, the cost of new generation, expansion, and modernization of power plants are evenly distributed among all consumers.

Notably, there are no market mechanisms for the selection of capacity or setting the price for power plants undergoing modernization or expansion. For example, during modernization of the Sevkazenergo TETs, the price for capacity amounted to 1,376,000 tenge/MW per month, and in case of Karaganda Energy Center TETs—5,233,000 tenge/MW per month.

Shortcomings of the adopted form of capacity market

Target-setting

International experience shows that the difference between the initial capacity remuneration mechanisms of nearly 20 years ago and modern ones is the diversity of goals they are charged with. In addition to ensuring security of power supply the power market mechanisms are employed to:

Advance technical and technological efficiency, facilitate climate policy, and promote economic efficiency

Attract new technologies and resources for meeting the capacity demand, such as demand response, distributed generation, renewables (within the "reliable" load, see below), and battery storage. Accounting for new technologies in the capacity balance reduces the need in new launches and/or delays their commissioning.

Thus, the capacity remuneration mechanisms have undergone significant changes when it comes to detailing their goals and objectives. Since the start of discussions on capacity mechanism in Kazakhstan the vision of the country's sustainable development has changed, and more ambitious goals have been set for economic, industrial, and social development. The legal framework of the country's power sector has been supplemented with policies and commitments concerning transition to a "green" economy, digitalization, and achievement of technological, economic, and operating performance targets in its industrial development. However, none of these changes have been reflected in the goals and mechanisms of the capacity market launched in Kazakhstan in 2019.

This partly explains why the capacity market mechanism in Kazakhstan does not envisage the large power consumers (with a capacity estimated at 200 MW) meeting capacity demand by providing price sensitive demand response services. Demand response would have enabled to reduce energy consumption, greenhouse gas emissions, and postpone commissioning of new generating capacity.

Changes to capacity market target-setting and detailing of its goals would make it possible to link the goals of the capacity market with those of the power sector's, tasks outline in the Environmental Code (inclusive of BAT goals),_enable maximum utilization of available resources, create conditions for new participants and technologies, as well as implement a gradual transformation of the current rigid sector architecture.[21] If the current goals and associated mechanisms of Kazakhstan's capacity market remain unchanged, Kazakhstan risks entrenching the current structure of the sector and the paradigm of relations thus impeding progressive (innovative) development of the country's electric power industry.

Technologies approved for the capacity market selection

In accordance with the Rules of capacity market organization and functioning in Kazakhstan, existing power-producing companies whose generating unit electrical capacity has been certified by the system operator can participate in the market.[22]

[21] The current wording "attract investments in maintenance of existing capacities and introduction of new electrical capacities to meet the demand for electric power" could be changed to a more specific "ensure long-term reliability of power supply through the Unified Power System of Kazakhstan with the use of all available technologies (both for electricity consumption and generation, and storage and digital solutions), and higher technical and technological efficiency, environmental friendliness and flexibility of the power system, while respecting the quality-to-price ratio for final consumers."

[22] See the Rules of capacity market organization and functioning, Annex to Order No. 439 of the Minister of Energy of the Republic of Kazakhstan dated November 7, 2018. Approved by Order No. 152 of the Minister of Energy of the Republic of Kazakhstan dated February 27, 2015.

Essentially, this means identifying capacity available for delivery, through verification of electrical load rates and compliance of declared generating unit parameters with actual values. This approach is in line with the current capacity market goal-setting process and ensures access of a maximum number of existing power plants to the capacity market.

By applying no technical requirements towards the existing power plants' (for example, steam pressure level, the year of main equipment production, flexibility and speed of load increase and decrease, type of fuel, turbine technologies, performance indicators, and adherence with environmental criteria) the system operator fails to leverage the capacity market mechanism for systemic improvement of the sector's efficiency, flexibility, accelerated modernization, and decarbonization.[23] The fact that such requirements are set only for investment projects for reconstruction, expansion, or modernization of existing power plants decelerates technological upgrading and innovative development of the sector.[24]

For reference, according to the European Parliament resolution of April 2019 and updates to previously adopted documents regarding Electricity and Capacity Markets functioning in the European Union (EU) (between 2009 and 2016), starting from 1 January 2020, capacity market mechanisms will be introduced as a last resort, subject to clear justification for the purpose of its implementation.

Those regulatory and procedural changes were adopted in order to create the electricity market signals that could stimulate greater flexibility, decarbonization and innovation of power plants in support of EU climate and energy policy targets. In particular, in the EU countries where capacity remuneration mechanisms are present (whether individual mechanisms or capacity markets) the power plants that have not previously participated in capacity selection (with emissions of over 550 g of CO_2/kWh) will not be eligible to take part in the selection or receive capacity remuneration from 1 January 2020. The power plants that have already been selected for capacity delivery for the next four years, and emitting over 550 g of CO_2/kWh, will be banned from participation in capacity remuneration schemes starting from 2025.[25] Equal conditions of access to capacity selection are recommended for all types of technologies, both on consumption and production sides.

Thus, Kazakhstan offers certified generating companies no other incentives (besides compliance with system-wide technical parameters of generating equipment) to participate in the capacity market. All that is required is successful submission of a price offer within the established limit.

In Kazakhstan the power plants' capacity selection only represents the risk of excessive capacity selection and a greater than necessary financial burden on consumers. At the same time, Kazakhstan still has an unused resource of industrial groups' capacity in terms of price-responsive load management (demand response), which could be taken into account when electrical capacity demand is projected.

[23] For reference, in Russia, generating facilities featuring generating equipment with fresh steam pressure of 9 MPa or less, consisting of a turbine unit with a steam turbine (turbines) and its main parts produced before 1967, are not allowed to participate in competitive capacity outtake, except when the utilization rate of installed capacity of such turbine unit was more than 8% in the year preceding the outtake year.

[24] "Investment agreements for modernization, expansion, reconstruction and/or upgrading set the following target indicators for each year: specific reference fuel consumption in electric and/or thermal energy supply; available electrical capacity; service life of capital generating equipment; degree of depreciation of capital generating equipment; environmental performance." See the Law of the Republic of Kazakhstan on Electric Power Industry No. 588-II dated July 9, 2004 (as amended and supplemented on April 19, 2019), Article 15-4, paragraph 6.

[25] See EU Directive on Common Rules for the Internal Market in Electricity [COM(2016)864], Proposal for a Regulation on the Internal Market for Electricity [COM(2016)861], Proposal for a Revised Regulation on the European Agency for the Cooperation of Energy Regulators [COM(2016)863], Proposal for a New Regulation on Risk Preparedness in the Electricity Sector [COM(2016)862], Proposal for a Revised Renewable Energy Directive [COM(2016)767], Evaluation of the Electricity Market Design and Security of Supply [SWD(2016)413], Report on the Sector Inquiry on Capacity Mechanisms [COM(2016)752], and Report on Energy Prices and Costs in Europe [COM(2016)769]; The European Commission's sector inquiry on capacity mechanisms analyzes capacity mechanisms in the EU and offers conclusions about the design principles to ensure their effectiveness.

Demand-side management is the mechanism most frequently used globally in capacity remuneration, due to consumers' ability to quickly reduce peak consumption for a long period of time, with the lowest cost for the system. Demand-side management delays the need for investment in new generating assets.

The US PJM market is an example of active development of demand-side management within the capacity market mechanism, where controlled-load consumers participate in the capacity market along with generation. Of the total capacity selected on the market, the share of controlled-load (demand side) is 10% (peak demand in PJM is about 160 GW)—it significantly reduces the financial burden on end users and eliminates the need for investment in generation that would only be loaded intermittently.[26]

The UK system operator is already using demand-side management to balance the system. Peak demand in the UK is about 60 GW, with half of it coming from industrial consumers and commercial centers. The system operator has a goal—to balance the system with the help of controlled-load consumers by 30% before 2020.

In the next seven years Kazakhstan has planned to commission 2.6 GW of renewable capacity within the framework of Kazakhstan's renewables support and development program (see table below).

Tab. 5.3. RES-based capacities planned for Kazakhstan, 2019–25, MW.

	2019	2020	2021	2022	2023	2024	2025
Area 1 (North-South)							
HPPs	90.9	116.7	152.1	193.8	219.8	219.8	219.8
WPPs	371.5	582.0	966.9	1148.7	1148.7	1148.7	1148.7
SPPs	439.9	872.1	1119.1	1119.1	1119.1	1119.1	1119.1
Biofuel power plants	1.1	6.1	15.8	15.8	15.8	15.8	15.8
Total	**903.3**	**1576.9**	**2253.9**	**2477.4**	**2503.4**	**2503.4**	**2503.4**
Area 2 (Western service area)							
WPPs	95.8	95.8	110.8	110.8	110.8	110.8	110.8
SPPs	2	2	2	2	2	2	2
Total	**97.8**	**97.8**	**112.8**	**112.8**	**112.8**	**112.8**	**112.8**
Total in Kazakhstan	**1001.1**	**1674.7**	**2366.7**	**2590.2**	**2616.2**	**2616.2**	**2616.2**

Note: HPPs = small hydro power plants; WPPs = wind power plants; SPPs = solar power plants; BioCPPs = Biogas heat and power plants.
Source: KEGOC FSC

Of the planned 2.6 GW, over 90% comes from solar (SPPs) and wind (WPPs), whose capacity, according to the accepted methodology of electrical capacity balance forecasting is assumed to be 0. Indeed, due to the nature of their generation, WPPs and SPPs cannot guarantee availability of power during the hours of maximum load. However, if renewable energy sources do not participate in the capacity selection but supply power to meet the demand, the capacity of pre-selected thermal power plants will be reduced by the amount delivered by renewable energy facilities. In countries where capacity remuneration is paid upon physical delivery, the revenue from thermal generation will be reduced. In countries where selected traditional

[26] The second most important demand-side response market of the capacity remuneration mechanism in the United States is ISO New England (ISO-NE). Selected efficiency improvement programs can also participate in the capacity market, but only within a fixed timeframe during a capacity supply year.

capacity remuneration is paid for operational readiness, as it is expected to be in Kazakhstan, capacity of such plants will be paid as if delivered, maintaining the financial burden on consumers.

In order to balance the privileged position of renewable energy sources and with due regard to consumers' interests, Kazakhstan may consider taking renewable capacity into account in the capacity demand projections within its "reliable" output, which would be a more systemic approach to capacity planning and market outlook.[27]

Capacity selection principles and capacity market pricing

Existing plants with no plans for modernization, expansion, or reconstruction.

New and old capacity are often selected separately, and in that respect Kazakhstan's approach does not contrast much with models adopted around the world and in neighboring Russia. Indeed, on the one hand, in auctions with a single price for all participants, the price quoted by new facilities can create higher incomes for existing (old) generation. This applies especially to Kazakhstan, where no requirements for technological efficiency and innovation are specified in the rules on access to selection of existing generation, that would have otherwise stimulated displacement of technologically outdated capacities. However, different capacity price-setting terms for existing, modernized or newly commissioned generation, make it impossible for the existing power plants to execute meaningful upgrade of their fixed assets.

According to the rules, the existing power plants are selected within a short-term capacity market one year before the capacity supply. If selected, during the first seven years, power plants receive a single rate per MW per month, administratively approved for all participants (calculated as the ratio of total net profit of existing power plants as of 2015 to their maximum possible electrical power output).

The capacity price covers fixed costs and net profit. Notably, net profit and depreciation deductions are the most common sources of investment in Kazakhstan. The main source of investments into existing generating assets is net profit (notably, short-term capacity selection and terms of implementation of investments, as well as restrictions on tariff growth make borrowing difficult). Limiting investment to one year shifts the power plants' focus to ongoing repair. Capacity tariff policy for the existing power plants limits costs optimization opportunities, and could result in staff and related development programs reductions mainly.

The rules provide for the possibility of upgrading existing power plants (subject to approval of a respective investment project), but omit competitive conditions for displacing technologically outdated facilities based on price (provided that their heat and power generation could be replaced by other sources). Thus, Kazakhstan has created conditions that preserve the existing technological structure of the market.

Power plants planning modernization, reconstruction, or expansion.

As of 2019, the depreciation rate of 36% of the turbine equipment at Kazakhstan's TETs exceeds 75%. During the period of marginal tariffs application (2009–17), the share of heavy-wear turbine equipment at TETs decreased from 60%

[27] A "reliable generation" assessment shall be based on historical data on generation at SPPs and WPPs, and represent an average value to be accounted for in capacity balances and during capacity selection (this methodology is used in the PJM and NI markets in the United States). Even if generation at WPPs and SPPs is taken into account in the balance and during selection, it is still possible to reliably predict the capacity available for delivery only one day ahead. As RES installed capacity and generation (WPPs and SPPs) are growing, such an approach is being tested in Europe.

to 36%, but in case of moderate wear it increased from 25% to 58%. This means that, in combination with the pricing model adopted on the short-term capacity market for existing capacity, fixed assets can be upgraded only through implementation of investment projects for asset modernization, where capacity prices and terms are agreed on a case by case basis.

According to the capacity market rules modernization, reconstruction, or expansion projects as well as projects for the commissioning of the new are selected within the framework of a long-term capacity market on individually agreed price and payment terms.
Simultaneously, the Law on Electric Power Industry (the Law) makes provision for the capacity that has completed modernization in 2009–15. Payment for such capacity also shall be made at individual rates for an individual payback period.[28] These include:

- Power plants that implemented large-scale investment programs in 2009—2015 during the marginal tariffs period, whose costs, in addition to the investment component of the marginal tariff, also included significant additional external financing, as well as the funds received for refinancing and repayment of the principal debt under earlier project obligations
- Power plants commissioned in 2009—2015, where debt financing was attracted for construction before 2015, including for refinancing and repayment of the principal debt under earlier obligations, and the financing target was the power plant construction

The Law and the rules, however, set no limitations to the number of modernization projects selected each year that would be necessary to constrain the end users' power price growth. Taking into account the current capacity surplus, the priority selection of modernized projects (in compliance with the Law and the rules) implies non-selection of existing power plants within the short-term market, and an increase in the average end users' capacity price.

Commissioning of new plants.
According to the Law, commissioning of new capacity shall be envisaged if the electricity and capacity balance forecast approved for a seven-year period projects a capacity shortage of over 100 MW in the Kazakhstan's UES or in one of its energy zones during the first five years of forecast.[29] Such an approach is in line with the current capacity market target-setting making no allowances for any changes in the capacity structure or taking into account the shortage of flexible capacity.

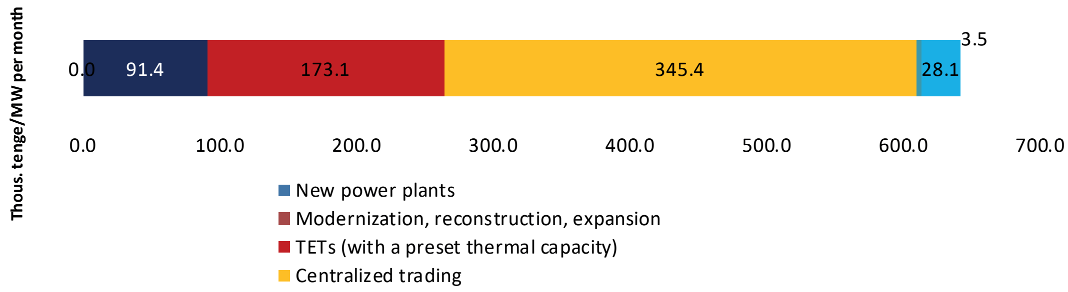
Projects designed to cover this deficit will be selected through individual tenders; the relevant parameters will be approved by decision of an authorized body; and after that an individual tariff will be established for an individual payback period with the project's capacity to be selected on a priority basis.

Given the actual shortage of flexible capacity and the need to balance increasing WPP and SPP generation, the current capacity market mechanism fails to stimulate construction of flexible sources due to lack of a projected capacity shortage.

Capacity market pricing

According to the results of the first capacity selection for 2019, the average capacity sale price is 613,410 tenge/MW per month.

[28] Law of the Republic of Kazakhstan on Electric Power Industry No. 588-II dated July 9, 2004 (as amended and supplemented on April 19, 2019), Articles 9 and 9-1.
[29] Law of the Republic of Kazakhstan on Electric Power Industry No. 588-II dated July 9, 2004 (as amended and supplemented on April 19, 2019).

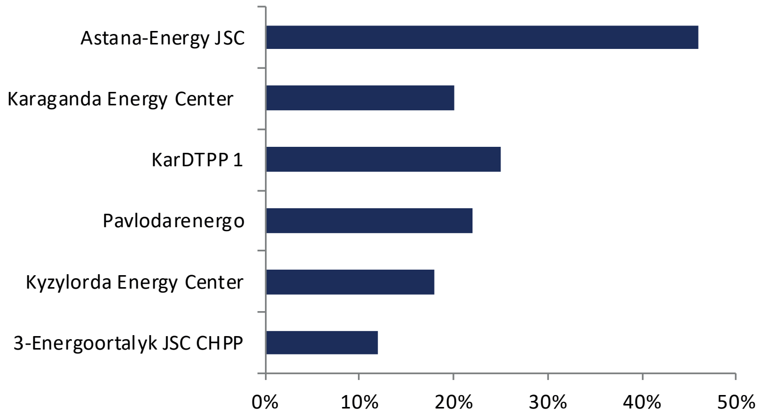


Source: FSC for RES

Fig. 5.14. Structure of a single capacity price in 2019 following the trading results.

The capacity tariff—intended to cover fixed costs, including wages, repairs, depreciation, and investment—was set at the marginal level of 700,000 tenge/MW per month.

However, already in late November 2018, before the capacity purchase took place, the marginal tariff was decreased by 15.7% in a statutory procedure, and in December of the same year the marginal tariffs for electricity were reduced. Taking into account the separate pricing procedure for power plants under modernization (expansion) and new power plants, the first competitive capacity trading resulted in a relatively insignificant price reduction—by an average of 7.4%. The capacity tariff reduction resulted in a decrease in power plants' income by 10 billion tenge (under comparable trading conditions).



Source: power plant data

Fig. 5.15. Share of fixed costs covered by the capacity market.

A cost analysis of power plants proves that the currently established marginal capacity tariff does not cover the plants' fixed costs let alone create opportunities for sustainable development of the power sector.

5.3.4. Recommendations

Goal-setting. The lack of specific technological, technical, and climatic requirements applied to the capacity selection and to the resources ensuring its operation risks freezing the established sector architecture that hinders its innovative development. Kazakhstan needs to harmonize capacity market goals with the country's long-term development programs, e.g., transition to new environmental standards. The capacity market has to cover the costs associated with introduction of environmentally friendly and best available technologies during the power plants' modernization.

Technologically neutral selection and capacity demand forecast. Technologically neutral selection in Kazakhstan implies not only selection of fossil-fuel power plants, as it is formalized now, but also involvement of industrial consumers in price-responsive demand-side management. Later, conditions have to be created for the participation of demand aggregators in the provision of similar services on the retail market.[30] The number of resources available for participation in the capacity market may be expanded in the future to include renewables. With due regard to Kazakhstan's plans to increase the share of renewable energy (dominated by WPPs and SPPs) up to 30% by 2050, the statistics accumulated by that time and further technological improvements will enable a more accurate estimation of "reliable" output for WPPs and SPPs, so that they can be accounted for in the capacity balance.

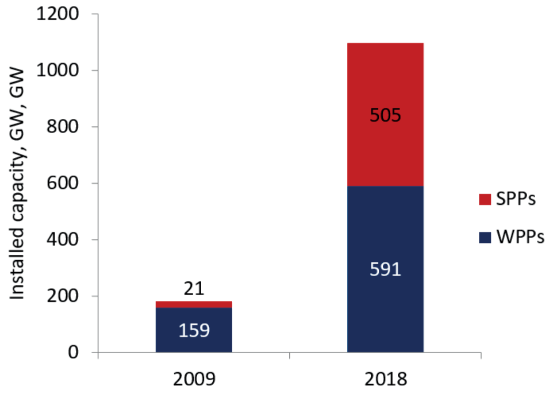
Capacity pricing. Kazakhstan has chosen administrative capacity pricing for upgrades and commissioning of new capacities. This means that investment projects that will have the right to participate in the market in the future are selected outside a competitive process, and their capacity price is set by the authorized body through bilateral negotiations. Project approval and tariff setting on a case-by-case basis is subjective. Competitive selection of modernization and new construction projects should be more transparent and objective.

Selection of operating power plants. The capacity market has no mechanism for displacing technologically outdated capacities or assets whose operation does not comply with the policy of transition to a "green" economy. It is recommended to set capacity market access criteria for existing generation (load factor, equipment operation parameters, environmental performance indicators) and participation conditions (reliability of power supply, penalties for non-delivery (short delivery), decommissioning terms and conditions, conditions for must-run participation (implying terms of short term operation with subsequent replacement by other heat energy and electric power generating sources).

Pricing. The current marginal capacity tariff does not cover the actual fixed costs and profits of existing power plants. Reductions in marginal tariffs for electricity and an increase in power plants' costs, including support for renewable energy, pose a significant risk to financial stability of the sector. In addition to the above, there is not market mechanism for the capacity price-setting for the power plants planning modernization or expansion.

5.4. Evolution of RES Support Mechanisms in Kazakhstan

A shift in the global energy development paradigm towards renewable energy sources (RES; mainly wind and solar generation) has been led, above all, by the international climate agenda. Countries experiencing no shortage of fuel resources still pursue active development of renewable energy primarily to replace coal generation, which is the greatest source of greenhouse gas emissions. For example, wind and solar power plants accounted for 88% of total new electric generation capacity commissioned in the EU-28 in 2018.[30] Over the past 10 years, the total installed capacity of solar power plants (SPPs) operating around the world has increased more than 24-fold, and of wind power plants (WPPs)—3.7-fold. The total installed capacity of wind and solar power plants exceeded 1,000 GW in 2018, which is approximately 15.5% of the total installed capacity of all power plants operating around the world.



Source: REN21 Global Status Report 2019

Fig. 5.16. Increase in the total installed capacity of wind and solar power plants around the world, GW.

While renewable energy generation was growing, the relative capital investment rates for wind and solar power plants have fallen by 15% and 20%, respectively, pointing the way toward a decrease in the cost of electricity generation from renewable energy sources. According to the forecasts made by the International Renewable Energy Agency (IRENA), capital and operating expenditures will continue to move along this trendline, decreasing by 12% for WPPs and by 57% for SPPs by 2025.

Kazakhstan's contribution to global greenhouse gas (GHG) emissions does not exceed 1%, allthough it is one of the top 10 nations with the highest carbon intensity of GDP. In order to comply with the country's international commitments and achieve its own targets in terms of transitioning to green economy, renewable energy development was chosen to be the main instrument of the country's climate policy.

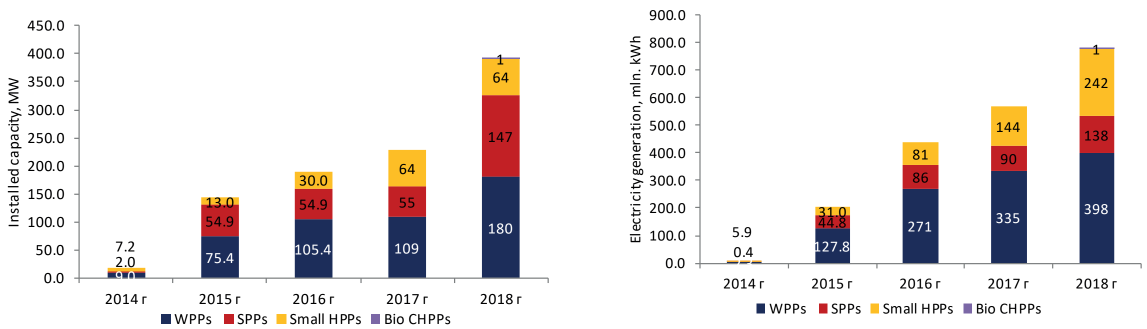


Figure 5.17. Electricity generation and installed capacity of renewable energy facilities delivering electricity through the FSC, 2014-18

Over the last five years, Kazakhstan's renewable energy has been developing at an impressive pace. Electricity generation at new solar, wind and small hydropower plants has increased by 155 times (from a small base), while their total installed capacity (without large HPPs) has reached 632 MW,[32] or about 2.4% of the total installed capacity of all power plants operating in the country.

As elsewhere in the world, wind and solar energy development has largely been supported by the state, since without any government support mechanisms such power plants are uncompetitive com-

[30] In Russia, price-responsive demand management on the wholesale capacity market has been in place since 2016. The concept of demand-side response (DSR) aggregators on the retail market was developed by the Russian System Operator in 2018 and approved by the government in Q1 2019. Results of the pilot program of participation of DSR aggregators (consumer groups, distributed generation, and electricity storage facilities) in the retail electricity market should be evaluated by 1 September 2020.
[31] Wind Energy in Europe in 2018. Trends and Statistics.
[32] All power plants using RES are accounted for, not just those included in the FSC's list.

pared to the conventional generation. In Kazakhstan too, renewable energy has benefited from a high level of government support. The Law on Support for the Use of Renewable Energy Sources[33] was adopted in 2009. Later, in 2013, the government support mechanism for the renewable energy sector was launched.

It is based on centralized guaranteed purchase of all electric energy produced from renewable energy sources at fixed tariffs through the Financial Settlement Center of Renewable Energy (FSC). However, in contrast to the traditional approach where end users directly pay for generation from RES, in Kazakhstan, responsibility for successful implementation and support of renewable energy is placed on traditional power plants. In other words, conditional consumers that include traditional power plants and electricity importers are now obliged by law to buy electricity from the FSC pro rata their share in total electricity generation.

The legal framework established in Kazakhstan to support renewable energy provides for a most favorable level of regulated stability and predictability for investors.

The main renewable energy support mechanisms are:

- Tariff stability guarantees—tariffs are approved for a period of 15 years and are subject to annual indexation depending on inflation. Tariff indexation with regard to difference in exchange rates is possible in projects financed with foreign currency loans.
- Guaranteed purchase of the whole generated electricity volume
- Guaranteed connection and access to the network: grid operators are obliged to connect renewable energy facilities on a priority basis.
- Exemption from service fees for electricity transmission

Relatively high tariffs were fixed in Kazakhstan, several times higher than the threshold set for traditional power plants, to attract investors' attention.

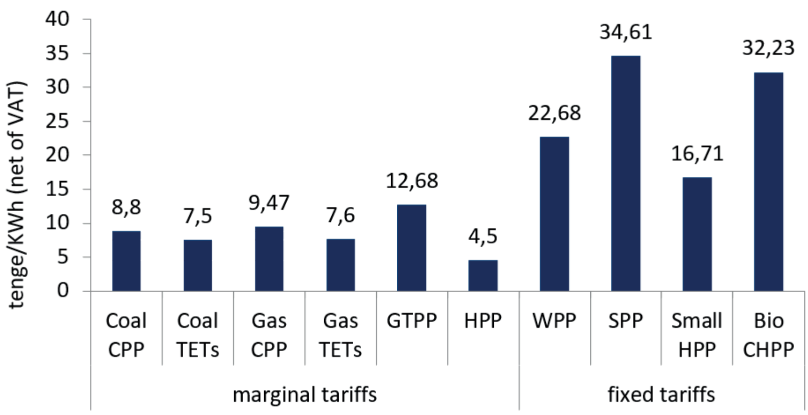


Figure 5.18. Marginal and fixed tariffs, 2018 Source

As a result of the above measures, as of 2015, applications had been filed for construction of renewable energy facilities with a total capacity of about 7 GW, while the total installed capacity of Kazakhstan's power system is 21 GW. Since it is impossible to integrate so much renewable energy capacity into the power grid, and due to the unstable nature of

[33] According to current Kazakhstan legislation, renewable energy includes energy produced by wind power plants (WPPs), solar power plants (SPPs), small hydropower plants (HPPs) with a capacity up to 35 MW, and biogas power plants.

energy generation at solar and wind power plants and lack of balancing capacities, the need soon arose to limit introduction of renewable energy sources. In 2016, legislation was amended to provide for gradual commissioning of renewable energy capacities and approved targets.

Table 5.4. Renewable energy sector development targets until 2020, MW.

Renewable energy facilities	2020 (approved)	2025 (projected)
Wind power plants	933	1,200
Photovoltaic power plants	467	1,100
Small hydropower plants	290	219
Biogas units	10	15
Total capacity	1,700	2,615

Approval of the targets implied that given intense interest in implementation of renewable energy projects and a significant number of construction applications, transparent selection criteria must be set. Taking into account proposals of the KAZENERGY Association, the auction was designated as the preferred mechanism for project selection. In 2017, amendments were introduced in the Law on Support for the Use of Renewable Energy Sources, providing for the organization of reverse auctions for new renewable energy projects (this mechanism does not apply to existing facilities or projects under construction already using fixed tariffs).
The first auction held in 2018 proved to be an efficient and transparent selection mechanism, and resulted in a significant reduction in the cost of renewables support. The average reduction in the cost of a kWh of electricity at solar power plants was 34%, and about 13% at WPPs and small HPPs.

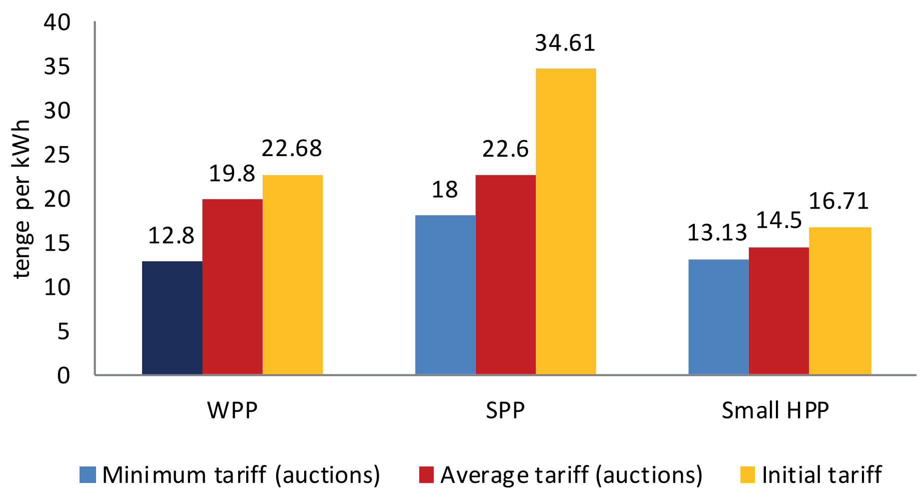


Fig. 5.19. Tariff reduction as a result of auctions held in 2018.

A total of 113 companies from 9 countries participated in the auctions; 36 projects with a total capacity of 857.9 MW were selected. The greatest demand was registered in construction of solar power plants.

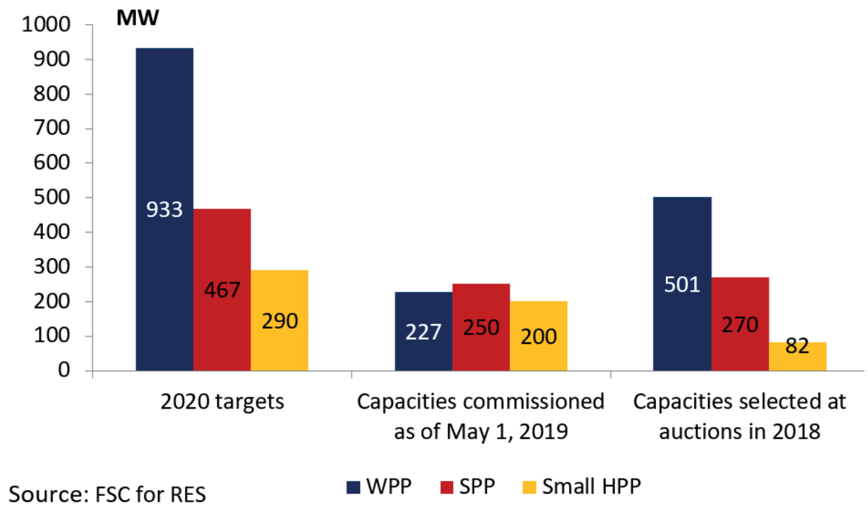


Fig.5.20. Targets and commissioned renewable energy capacities, 2018 auction results.t

Holding auctions to select renewable energy projects is a global trend. According to IRENA, over 67 countries have already introduced the auction/tender mechanism for selection of renewable energy projects. However, the principles for project selection vary.

The essence of the mechanism introduced in Kazakhstan is holding an electronic reverse auction among investors. The investor who offers the lowest cost of electricity wins the auction. The winner and the FSC enter into an agreement for purchase of all electricity produced after a power plant is commissioned at a price set during the auction. Investors undertake to start construction and commission the facilities within the timeframe established by law. Auction winners provide collateral in the amount of 10,000 tenge (26 $US) per kW of their project capacity. Failure to meet the deadlines for construction commencement or plant commissioning entails a penalty of 30% or 70% of the collateralv

Changes in the RES support policy of the OECD

Privileges and non-market support used to be a standard practice of renewable energy promotion in OECD countries. Growth in generation from renewable energy sources in combination with a continued loss of money when the wholesale price of electricity does not cover all the production costs led to price decreases for producers and the need for early decommissioning of combined heat and power plants. At the same time, the need for thermal generation remained, in order to balance the volatile generation from renewable energy sources, which is dependent on weather conditions.

•This led many countries and the European Federation of Energy Traders to call for the cancellation or reduction in support for renewables. The major changes in the support mechanism and new requirements for renewables include the following:

•Responsibility for balancing has to be borne by all types of generation, including renewables.

•The practice of priority dispatching and grid access should be discontinued.

•Dispatching has to be based on the cost of electricity, rather than on obligations to pay preferential fixed tariffs.

•The procedure and cost of grid connection has to be the same for renewables and traditional power plants.

•Final prices for renewables must include electricity transmission costs.

•Preferential fixed tariffs have to be phased out.

•The wholesale price of electricity has to be cleared of any influence of renewables support mechanisms and climate policies, environmental taxes, and charges that have to flow into the national budget.

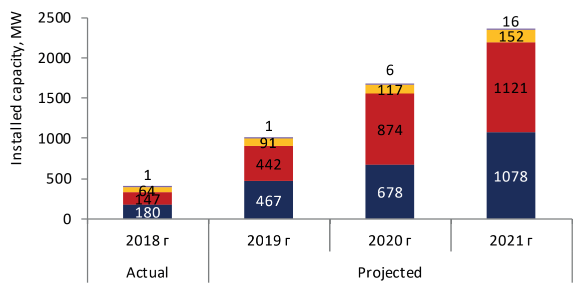
As the share of generation from RES (especially at WPPs and SPPs) is growing, the wholesale electricity price is becoming increasingly capable of responding to changes in the supply and demand balance and to the need for investment (in energy storage systems, demand management, balancing generation). The United States, Canada, and Europe have faced an urgent need to revoke operational privileges and preferential connection of renewable energy facilities to the grid.

amount, respectively, and agreement termination.

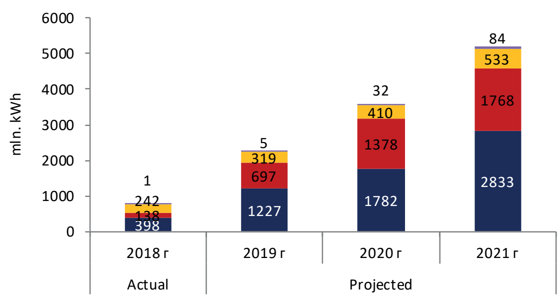
Despite a significant increase in the capacity of renewable energy sources and an effective reduction in the cost of their support in Kazakhstan, there are long-term development risks associated with the increased financial burden on traditional power plants.

Revenues of conventional power plants, which are obliged to buy the entire amount of electricity generated from RES through the FSC, are limited by marginal tariffs for electricity and capacity. According to the latest changes in legislation, the marginal tariffs for electricity and capacity were reduced by an average of 20–25% for traditional power plants and will remain unchanged until 2025 (see the section on electricity and capacity markets).

Generation from RES in turn could increase by as much as 5.6 billion kWh by 2021, and become seven times higher than as in 2018. Thus, expenditures of traditional power plants on the purchase of electricity from RES will increase significantly, while their incomes will remain the same.v



Source: FSC for RES ■WPP ■SPP ■Small HPP ■Bio CHPP



Source: FSC for RES ■WPP ■SPP ■Small HPP ■Bio CHPP

Fig. 5.21. Projections of installed capacity and electricity generation from RES supplied through the FSC, 2019–21.

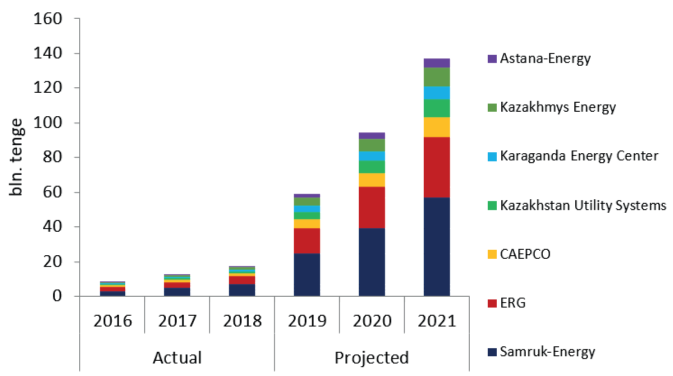


Fig. 5.22. Expenditures on purchase of electricity from RES, 2019–21.

At present, expenditures by traditional power plants on the purchase of electricity generated from renewable energy sources (through the FSC) do not exceed 2–4.5% of the overall cost structure. By 2021, however, they will rise to 15–30% of total expenditures, provided RES generation targets are achieved. Yet, as was already noted above, the marginal tariffs for electricity and capacity will remain at the same level until 2025[34]. This, combined with rising fuel costs and other expenses, could put the traditional energy sector in a critical financial situation. Increasing payment arrears from the purchase of electricity from RES will affect the overall financial stability of the electric power sector.

Thus, the current model of renewable energy implementation and financing in Kazakhstan and the tariff policy for traditional power plants pose a significant risk to sustainable development of both renewable energy and traditional generation.

5.4.1. Recommendations:

- Taking into account the decrease in the cost of construction of wind and solar power plants projected by IRENA that will be possible after 2025, Kazakhstan should delay some renewable energy development (e.g., as specified in the targets in Table 5.4) until after that date.
- The current renewable energy support mechanism (which penalizes traditional generation) should be replaced with internationally recognized non-discriminatory mechanisms. If the present mechanism remains in use, a surcharge must be introduced to the marginal tariffs for traditional power plants (in place until 2025) that will take into account their increasing expenditures on renewable energy purchases.
- Changes in the tariff regulation of electric grid companies that stimulate grid and service development (which are needed to accommodate an increasing share of RES-generated electricity) must be planned and introduced.
- After 2025, a transition to market-based mechanisms of payment for electricity generated from renewable energy sources should be completed, and such generation has to be transferred to the wholesale market at a price reflecting the true costs of production.
- By 2025, payment for electricity transmission service has to be introduced for power plants using renewable energy sources.

5.5. Transition to Incentive Tariff Regulation in the Electric Power Industry

5.5.1. Incentive regulation in international practice

For electricity transmission and distribution companies, ensuring the power sector's sustainable development has meant creating conditions that would minimize the power sector's impact on the environment, including incentivizing and integrating distributed generation (renewable energy sources, storage systems) and consumer participation (demand response, electric vehicles, prosumers, battery storage). Given the high degree of assets' depreciation, the challenge for the electric grid companies has been in keeping end-consumer tariffs at a level set by regulators while at the same time making capital investments and funding technological upgrades.

Limitations of the cost-plus tariff

[34] Order of the Minister of Energy of the Republic of Kazakhstan dated December 14, 2018 No. 514 " On approval of marginal tariffs for electric energy"

[35] In Kazakhstan, according to the Law on Natural Monopolies, electric grid companies can use only 50% of their savings at their own discretion. They are obliged "to allocate at least fifty percent of underutilized tariff funds (accumulated as a result of cost savings) to energy-saving and energy efficiency measures, creation of new, expansion, rehabilitation, maintenance, reconstruction, and technical re-equipment of existing assets."

methodology (either targeting profit or revenue control)—namely the short-term nature of the price-control period; lack of incentives stimulating efficient planning and spending, optimization of expenses, and remunerating efficient operation—led to its gradual rejection. Since the mid-1990s, it has been replaced by tariff regulation based on long-term cost planning, the possibility of long-term investments, long-term price-control periods, and financial incentives to outperform the price-control period targets. The latter has translated into setting qualitative and quantitative performance indicators for the companies, as well as requirements improving the overall power market and the sector's efficiency, realization of climate policy as well as power-sector research and development activity.

The major incentives for the electric grid companies are the long-term tariff regulation, return on capital investments, and the right to use cost savings (as a rule operational) at their own discretion until the end of the long-term price-control period (five to eight years, depending on the country). Priorities for the Regulator are the reliability of power supply and the control over the end-consumer price growth, which is managed by setting the allowed revenue, and its likely subsequent downward revision with a start of a new price-control period. In addition, the companies' performance is measured and remunerated by linking performance targets (on reliability of supply and quality of customer service) to the companies' allowed revenue.

Efficiency incentives and targets therefore mimic "pseudo-competitive" market mechanisms that are not usually present in the electric grid segment. As of 2019, incentive tariff regulation for the electric grid companies is practiced in 19 out of 25 European countries, as well as in the United States (New York, California, New England, etc.), Canada, Australia, New Zealand, Russia, and Ukraine. Kazakhstan too has made several attempts to introduce incentive regulation for the electric grid companies.

Regulated asset base (RAB) tariff regulation Regulated asset base tariff regulation was first introduced in the United Kingdom in 1995, and later spread around the world. It has been popular for the following reasons:

- Better predictability of electric grid companies' operation due to long-term tariff-setting
- Cheaper financing of capital-intensive projects compared to project financing
- Transparency of tariff calculation process and methodology
- Stimulation of investments (through identification of a realistic rate of return and subsequent inclusion of invested capital in the asset base, thus accruing to the company's profits)
- Incentives to reduce operating expenditures by allowing companies to retain savings for the entire price-control period and thus gaining additional profit[35] Stimulation of more effective cost planning and control over end-user tariff growth by shifting to a non-discriminatory principle of total (operating and capital) cost assessment (TOTEX)
- Ability to control end-user tariff growth by setting limits to either price or revenue growth, or an acceptable level of the rate of return
- Correlation between revenue and the quality and efficiency of provided services as well as achievement of companies' targets, inclusive of fines for the failure to achieve targets

The core principle of RAB methodology is the Regulator's ex-ante approach to tariff-setting based on the valuation of assets committed to service provision, gross revenues covering the companies' operation and assets' renewal, and companies' remuneration. Thus, the method estimates the value of realized investments (capital base), operational expenditures related to maintenance and development, as well as a profit from asset management and on new investments (in the form of a regulated profit).

Revenue = operating expenditures (controlled and uncontrolled) + depreciation + profit + taxes

Profit = committed assets * rate of return

The structure of individual components included in the asset base committed to service provision may vary from country to country, and include, in addition to fixed assets (transmission lines, buildings, structures, land, office furniture, machinery, equipment, vehicles, etc.), working capital and assets under construction.[36]

Valuation of the asset base also depends on the country, and various valuation methods can be used (historical cost, indexed historical cost, replacement cost, market value [when assets are sold or privatized], or a combination of historical and replacement cost).

The fundamental feature of RAB methodology is a correlation between the company's profit and the value of committed assets, with due allowance for operational quality and effectiveness (regardless of the volume of services provided). This stimulates investments (i.e., increase in the asset base) and ensures their stable return.

As a rule, the following categories are subject to negotiation between the company and a Regulator when itemizing the allowed gross revenue:

- New (capital) investments (leading to an increase in the value of the asset base)
- Depreciation (leading to a decline in the value of the asset base)
- Production expenses (maintenance and operation of assets committed to service provision)
- Financial expenses (cost of borrowed capital, cost of equity financing, allowed profit)
- Taxes

At the same time, the Regulator needs to have a clear idea about the necessity (priority), quality, and most importantly, efficiency of expenses. Electric grid companies tend to prioritize capital expenditures (over operational expenditures), since the former increase the asset base value and, subsequently, the companies' profits, while operating expenditures simply get refunded through the tariff.

With a view toward stimulating alternative ways of achieving the grid companies' targets, first in the UK, then in Italy, and now in Australia, the methodology's focus has shifted from incentivizing capital expenditure toward stimulation of total expenditure (called TOTEX), i.e., choosing the best combination of operating and capital expenditures and applying the efficiency factor to TOTEX.[37] This enables the Regulator to control spending and its efficiency (reduction in unnecessary capital investments), control the asset base value growth, and as a consequence the company's profit.

Growing decentralization of power production, the need to integrate new sources of electricity generation and consumption, digitization of the sector, climate policy, and the growing role of consumers have forced regulators not only to revise the targets and develop new incentives for the grid companies' operation and investment, but also to shift to a new interpretation of the RAB formula. As a result, a part of operating expenditures on equipment repair can be

[36] In 60% of the cases, rented assets (involved in direct service provision) are included in operating expenditures, while connection fees and any benefits (subsidies, grants, and payments) are excluded from the base, since they are not directly funded by the grid company.
[37] According to the TOTEX method, the regulator does not approve operating (OPEX, e.g., grid maintenance and repair) and capital expenditures (CAPEX, e.g., replacement, expansion, construction, and commissioning of new power grid assets) separately. The regulator approves a single authorized volume of expenditures with a predetermined capitalization rate (i.e., what amount of total expenditures will be included in the regulated asset base). Such an approach makes it possible to move away from approval of specific operating and capital project expenditures and shift the focus to innovation and efficiency (i.e., obtaining the best benefits in terms of both the life cycle of an asset and consumers' expectations, including future ones).

included, in line with the TOTEX method, in the committed assets base. Such an approach motivates companies to choose between repair and new equipment.

Such an interpretation of the revenue formula is driven by the long-term objective to create a more intelligent (smart), change-resistant grid infrastructure ensuring reliable power supply, achievement of low-carbon policy targets, and long-term material benefits for the power consumers.

Based on the segment objectives above and the anticipated outputs, the Regulator defines (prior to the start of a price-control period) the anticipated results of companies' activities, identifies terms and incentives that would contribute to their achievement, and measures the effectiveness of their achievement at the end of the price-control period. The outputs include such parameters as customer satisfaction, reliability and quality of power supply, information availability and publicity, safety, terms and speed of grid connection, environmental impact of electric grid companies' operation and services, and ways of supporting the low-income population.

Responsibility that is thus imposed on a regulator—when it comes to coordinating the segment objectives with those of the sector and the economy, setting the outputs and incentives for the grid companies, and deeply understanding the nature and efficiency of expenditure (inclusive of capital)—calls for the establishment of a completely independent regulator, funded by the sector, and operating exclusively in the interests of sustainable development of the power industry.

5.5.2. Transition to incentive regulation for the electric grid companies in Kazakhstan

Between 1 January 2013 and extending through 2015, Kazakhstan had been in transition from the "cost-plus" to the "benchmarking" methodology of tariff calculation, where the regional electric grid companies' (RECs) performance parameters were set individually on the basis of their comparison to each other. To stimulate efficient spending, the efficiency factor (X factor) was applied to expenditures.[38]

Nevertheless, after a trial period of using the benchmarking methodology, the tariff regulation for distribution companies and the National Operator (KEGOC) has been amended and shifted to an "incentive" methodology, where the profit, similar to the RAB methodology, depends on the asset base value and the relevant rate of return,[39] while tariffs are set for a five-year period. However, no connection between revenues and the quality of service or losses reduction have been made.

Upon adoption of a new Law on Natural Monopolies[40] in 2018, incentive tariff regulation has been approved for a number of electric grid companies, while the majority of them still use the cost-plus methodology for tariff calculation.

When the Regulator sets the rate of return (as a rule calculated as a weighted average cost of capital [WACC]) that is applied to estimate the companies' profits (the rate of return multiplied by the asset base value) it is essential that it is set correctly, because if understated it could result in lower profits and underinvestment. At that, the level of the rate of return is usually a subject of negotiation between a grid company and the Regulator. In Kazakhstan, according to the Instruction on the profit rate calculation, a two-level method of the weighted average cost of capital is used, where capital (investments) is divided into equity and borrowed funds.[41]

[38] Order No. 152-OD of the Chairman of the Agency of the Republic of Kazakhstan on Regulation of Natural Monopolies dated June 27, 2012.
[39] Order No. 17-OD of the Chairman of the Agency of the Republic of Kazakhstan on Regulation of Natural Monopolies and Competition Protection dated January 27, 2003.
[40] Law of the Republic of Kazakhstan on Natural Monopolies No. 204-VI dated December 27, 2018.

The profit rate equals the sum of the rate of return on equity and the interest rate on borrowed funds, and the total amount depends on the leverage (debt-equity ratio). It is important to note that the rate of return on equity in Kazakhstan depends on the industry-specific Beta ratio equal to either 0.89 or 1.3 (the latter only for companies participating in the People's IPO program). In this way, the rate of return on the committed asset base depends more on a company's leverage than on any parameters related to actual risk of investment.

According to the Instruction on profit rate calculation, the allowed profit for Kazakhstan's electric grid companies should "reflect effective functioning and improvement of service quality." However, the profit rate calculation methodology lacks parameters linking the profit rate with electric grid companies' performance.

The Law on Natural Monopolies refers to introduction of service quality and reliability indicators as well as performance indicators that the electric grid companies have to comply with for the duration of the tariff (five years or more). At the same time, the Law provides for tariff reduction only in case of failure to fulfil the investment program or deviation from approved expenditures.

Based on the power sector and the segment objectives the Regulator and network companies should agree on specific quantitative or qualitative outputs that the companies should achieve by the end of the price control period (on average five years). The subsequent evaluation of companies' performance should be based on achievement of every target (efficient use of funds for the outputs, and the effective transformation of the companies' activities to meet the changing sector environment).

In 2017, Kazakhstan adopted the natural monopolies' quality of service assessment methodology, which introduces a number of parameters that measure the electricity transmission and distribution companies' service quality. Namely,

- The time it takes to process consumers' requests
- Duration of off-schedule interruptions in power transmission
- Time it takes to reply to consumers' complaints about late issuance of connection requirements
- System Average Interruption Duration Index (SAIDI)
- System Average Interruption Frequency Index (SAIFI)

Despite the requirement to account for the service quality ratio in the tariff, this procedure is defined neither in the tariff-setting methodology, nor in calculation of the profit rate on the committed asset base. At the same time, poor service quality is not a reason for tariff reduction. Although there has been a gradual improvement in the electric grid companies' activities over the last five years (see Figures 5.24 and 5.25 below), the lack of clear principles of energy efficiency stimulation and service quality improvement in the tariff calculation methodology makes Kazakhstan's incentive tariff regulation significantly different from the RAB methodology and global practices.vvt

[41] Order No. 17-OD of the Chairman of the Agency of the Republic of Kazakhstan on Regulation of Natural Monopolies and Competition Protection dated January 27, 2003.

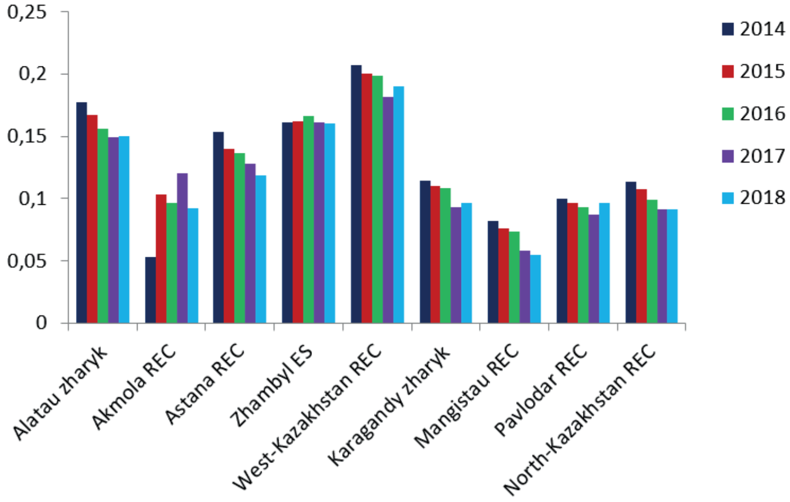
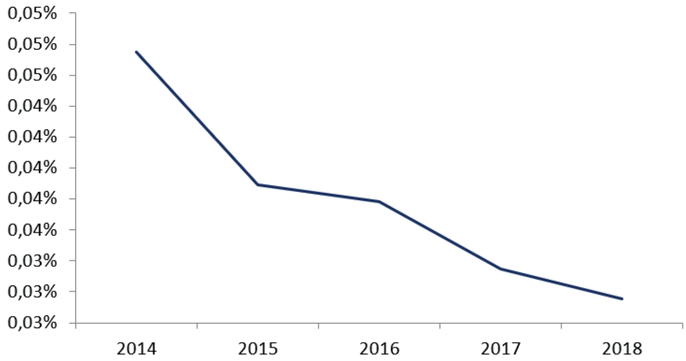


Fig. 5.23. Reduction in actual electricity losses during transmission through REC grids

In 2014–18, the average electricity losses in the selected RECs decreased from 11.5% to 10.2%.



Source: RECs

Fig. 5.24. Reduction in the number of failures and undersupply of electricity. [Data being processed]

5.5.3. Recommendations:

- Establishment of an independent segment regulator. Independence of the Regulator can be ensured if a special mark-up for its financing is included in the tariffs.
- The Regulator should set clear mid- and long-term goals for the development of the power transmission and distribution sector in Kazakhstan and harmonize these goals with those of the power sector, economic and technological development programs, as well as the climate policy.
- The incentive tariff regulation and profit rate calculation methodology must account for efficiency requirements and service quality improvements set by the Regulator.
- Incentive tariff regulation has to be expanded to include all RECs.
- The TOTEX methodology should be introduced by 2025 to stimulate and optimize capital (investment) and operating expenditures.

5.6. Heat Energy Market Regulation

Kazakhstan's heat supply systems are a combination of heat sources (boilers and CHP), that provide hot water or water vapor heating to a necessary temperature and pressure, as well as heat networks, that ensure hot water/vapor transportation and distribution in accordance with customer demand.

In the structure of heat energy supply TETs account for over 62% , although the share of TETs during 2014—2018 has declined by 4%. In the structure of heat consumption, over 50% is by the population and only 27% is industrial consumption; this is reflected in both the social significance ascribed to heat production and nature of industry regulation.

The country's heating networks are 11,500 km long, and the share of trunk heating networks is 16%. High transmission losses amounting to 30% (17%, according to official statistics) and the low efficiency of heat sources are typical of the heat supply sector. The most problematic issue is the deterioration of the heating networks: although the share of heating networks in need of replacement has decreased from 68% to 59% over the past five years, the volumes of their replacement remain insufficient.[42]

Centralized heat energy supply systems in cities of Kazakhstan supply heat to 70% of the country's population. Despite significant transmission losses, central heating with a high proportion of TETs is much more efficient from an energy point of view than non-centralized municipal heating systems. First and foremost, the efficiency of TETs is based on the cogeneration cycle—generation of both electricity and heat (see the figure below).

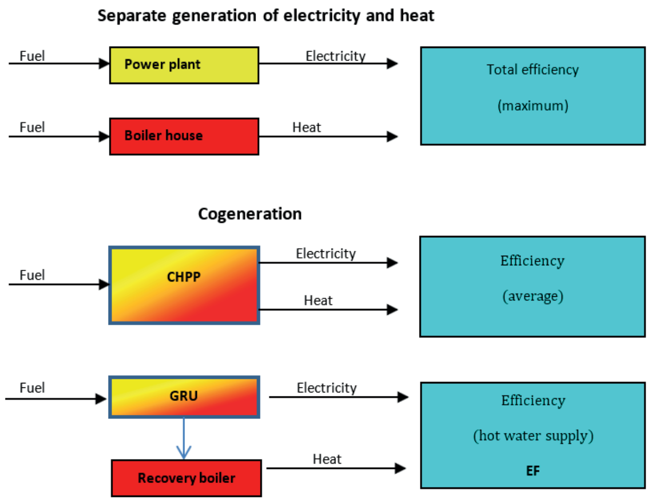


Fig. 5.25. Comparison of cogeneration and separate generation efficiency Source

Note: GRU = gas reciprocating unit with exhaust gas heat recovery cycle (GRU efficiency is higher than that of gas turbine units); EF = efficiency factor.

In general, fuel savings in cogeneration versus separate generation of electricity and heat amount to 25–30% depending on cogeneration type and separate generation options. TETs' efficiency in terms of reduction in fuel consumption and emissions is widely discussed and encouraged in the energy sector development programs of the European Union (EU) and Nordic countries. The future structure of heat supply systems is considered in the context of climate policy implementation and the role the electricity sector should play in the long-term and

[42] According to the statistics, around 1,700 km of heat distribution lines were replaced in 2014–18.

reliable supply of clean electricity and heat energy at the most affordable consumer prices. The latter is the key factor for consumers who prefer the lowest price as they choose their heat energy supplier. This implies their capability of substituting a central heating source (for example, a TETs) with an alternative one. The substitution principle adopted in the Nordic countries, Scotland, Germany, and Russia is the basis for price competition between distributed and centralized heat energy supply sources, between TETs, boiler houses, heat pumps, and electric heating appliances.

Generic requirements for TETs and decentralized heat energy supply sources in terms of heat energy supply quality and compliance with low-carbon policy standards (against the backdrop of price competition) necessitate improvement of business processes by the heat energy supply companies, market models, introduction of new operating standards and solutions (e.g., lower return temperature), and adjustment of price regulation for heat supply systems.

Kazakhstan's strategy of transitioning to a "green" economy does not clearly define the role of TETs. Moreover, according to the capacity forecast balance of the Ministry of Energy, the composition of capacities and the share of TETs, accordingly, will remain virtually unchanged until 2025. According to the new capacity market rules, TETs shall be given priority in capacity offtake. However, out of 38 TETs, 25 are coal-fired power plants producing high emissions of greenhouse gases and other pollutants. The transition of some coal-fired TETs (especially the Astana TETs) to natural gas is very unlikely; therefore, given an unchanged share of coal in the fuel balance and a goal of promoting Kazakhstan's transition to a "green" economy, TETs and boiler houses will be forced to implement modernization programs including introduction of flue gas cleaning and ash recovery technologies. Taking into account the future requirements of the Environmental Code regarding implementation of the best available technologies (BAT), achievement of the set targets will depend on the availability of incentives through effective tariff regulation of the industry to improve efficiency, flexibility, eco-friendliness, and quality of heat energy supply services, on the one hand, and rational heat energy use and repair of living quarters by consumers, on the other.

5.6.1. Tariff regulation of heat supply

International practice offers two major approaches to tariff-setting in district (centralized) heat energy supply: the cost method (tariff coverage of costs plus allowed profit) and the marginal cost method.

Despite simplicity of the "cost-plus-profit" method in terms of accrual and regulatory administration, lack of incentives for competition between heat energy supply organizations limits its use to regulated markets.

The marginal cost method, which involves covering variable costs associated with production of an incremental unit of heat energy, is more typical of markets that have been reformed to a certain extent. However, when tariffs are set on the basis of a generated heat energy unit, heat supply companies run the risk of not covering fixed costs associated with equipment and network maintenance, repairs, and investments. Thus, inclusion of fixed costs in the tariff—for example, the cost of maintaining a consumer's connection to the heating networks, keeping heating networks in working condition, and their readiness to cover heat energy loads in the agreed volume—is more important for companies, as it ensures a constant cash flow and covers investment costs and repairs. For comparison, neither households nor industrial enterprises pay for the service of being connected to the heat energy network. More over, a number of large heat consumers have their own heat supply sources and are connected to heating networks to ensure security of heat energy supply, while hardly consuming any heat energy from centralized heat supply systems. This means that their payment for centralized heat energy consumption is minimal, whereas heating networks and sources incur significant costs due to losses and the need to keep the heating capacities ready to cover maximum anticipated load.

For Kazakhstan's consumers (as it is for any heat energy consumers globally) the variable costs are of greater importance, as they are associated with the consumer's ability to lower the tariff through the rational use of heat energy and price competition under the substitution principle. Additional incentives only increase the value of variable costs for consumers. For example, when the tariff is differentiated by season (the highest tariff for the four coldest months of the year, the lowest for the four warmest months of the year, and the average for the remaining four months), consumers reduce heat consumption during the most expensive season.

Thus, the ratio of variable to fixed costs becomes essential for creation of conditions whereby a consumer is motivated to consume heat energy in a rational manner and make reasonable investments in housing repair to save heat, while a heat energy supply company is stimulated to manage the system more efficiently, plan investments, and improve the quality of service.[43]

In Kazakhstan, heat energy supply is still regulated by the Law on Electric Power Industry. Lack of a legal framework for heat energy supply not only implies inconsistency in law enforcement practices, but also inhibits attraction of investments in the industry and impedes development in heat energy supply systems development and their upgrade rate. A separate draft Law on the Heat Energy Supply is being developed at the moment, which, according to draft specifications, will be aimed at "creation of an integrated system of legal regulation of relations in the field of heat energy supply."

Prices in the industry are regulated by the Law on Natural Monopolies. According to the law, marginal tariffs are set for a five-year period for heat energy generation and the combined service of heat energy transmission, distribution, and marketing.

Marginal tariffs for heat energy generation and supply are calculated according to a methodology whereby costs are regulated, and the profit rate depends on the asset base committed to service provision.

Income = Costs + Asset base * Rate of return => Tariff = Income/Q

where Q is the volume of heat generation or transmission.

The approach to the profit rate calculation is regulated by the same methodology as is used by electric grid companies.[44] The rate calculation with the use of this method is unambiguous and depends on the rate of return on equity and borrowed funds, while the size of the debt risk premium can be determined in various ways.

Valuation of assets committed to heat energy generation and supply is a rather controversial aspect of the methodology. Thus, in case of heating networks, due to high depreciation of fixed assets, it is not clear how the cost of heating network equipment should be assessed if the

[43] For fully depreciated grid companies, the level of long-term marginal costs is usually set above the average cost level, but lower than the cost of an alternative source (with full coverage of variable costs). The level of fixed costs in the tariff is about 30% of all costs and can be set either on the basis of the area of residence, or on the basis of annual consumption by a consumer (differentiated by the size of the consumer).

[44] Order No. 17-OD of the Chairman of the Agency of the Republic of Kazakhstan on Regulation of Natural Monopolies and Competition Protection dated January 27, 2003.

depreciation period has expired, but the equipment is still in operation. Besides, for a number of private companies owning heating networks it is difficult to value assets, because part of the heating system is on the balance sheets of city authorities.

Despite the approved marginal tariff-setting methodologies, the social factor has the greatest influence on heating tariff regulation in Kazakhstan. The Regulator (KREMiZK) seeks to reduce the tariff and the final cost for the consumer and reserves the right to lower the rate of return essentially reverting the methodology back to cost plus. This affects the capability of the entities to repair and replace equipment of boiler houses, TETs, and heating networks.

While in the case of heating networks the asset base valuation is complicated by the need to assess the value of heavily worn objects and issues associated with the balance inventory, in case of TETs it is impossible to determine precisely what assets of a power plant are involved in the heat energy production. Therefore, the value of the TETs asset base is specified in full, but only a certain percentage of it is accounted for when the heating tariff is calculated, according to the approved methodology.[45]

The TETs tariff calculation is associated with a complicated process of correct distribution of costs (variable and fixed) between heat and electricity generation. Other sectors enjoy the freedom to distribute their costs between the types of final products, depending on market conditions, but this is limited in the heat and power industry. Due to the sector's monopolistic nature, prices are directly regulated by the state. Heat supply regulation and marginal electricity and capacity tariff setting by the Ministry of Energy prevent TETs from freely distributing costs between heat and electricity generation.

A number of methodologies have been developed around the world to separate variable (mainly fuel) and fixed (wages, depreciation, etc.) costs at TETs:

- thermodynamic methods (energy method and exergy method)
- alternative electricity supply methods
- alternative heat supply method
- benefit distribution method

Weighted average cost of capital (WACC)

The rate of return on a regulated asset base is the weighted average cost of capital (WACC). WACC calculation is based on determination of shares of borrowed and equity capital and calculation of profit rates/cost of equity and borrowed capital. There are many ways to calculate those rates.

Table 5.5. Profit rates for WACC calculation in various regulated sectors in Kazakhstan

Profit rate/cost	Energy sector	Gas supply	Oil transportation (export)
	Depends on:		
Borrowed capital	-Refinancing rate -Debt risk premium for the company	Weighted average rate on borrowed capital	-Rate on borrowed funds
Equity capital	-Refinancing rate -β industry coefficient	-Profitability of shares of proxy group companies	-Risk-free rate -Country risk -β industry coefficient -Specific risks

[45] No efficiency or quality improvement incentives have been developed in regulation, while depreciation charges and profits cover TETs expenditures on equipment repair and replacement.

Note:

Proxy group – a selected group of pipeline companies Risk-free rate – profitability of the 20-year US Treasury Bond

Country risk is determined based on the country's credit rating.

Within the framework of the CAMP (capital asset pricing model), the β industry coefficient is defined as the ratio of covariance between sector returns and stock market returns to squared standard deviation of stock market returns. In Kazakhstan's methodology of profit rate calculation for the energy sector, the β industry coefficient can be one of the two values: generic 0.89 or 1.3 for companies participating in the People's IPO program (these values are not calculated).

In the gas sector, the equity cost and the rate of return depend on the selection of companies in the proxy group. The profit rate can be increased if this or that company is selected.

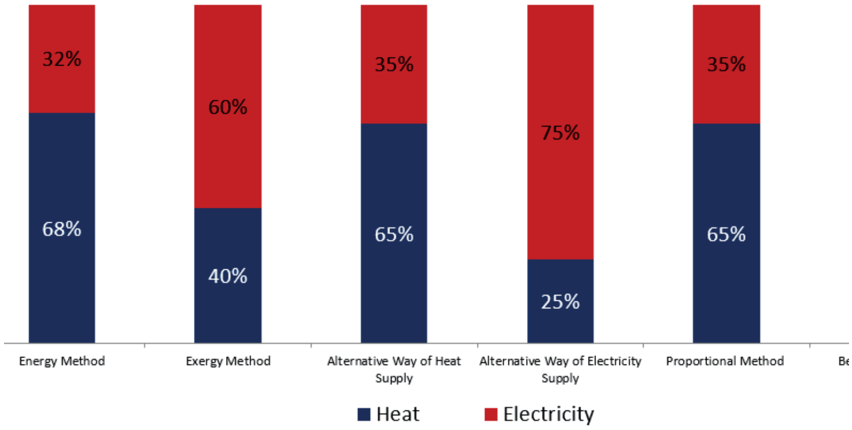


Fig. 5.26. Benefits distribution in various methodologies of TETs cost distribution

Source:

Only thermodynamic methods—physical and exergy—are used for heat generation cost distribution in Kazakhstan. The physical method distributes costs pro rata to electricity and heat generation. This is a simple method used by most TETs in Kazakhstan. However, it is associated with a higher cost of heat. Compared with high-efficiency boiler houses, TETs turn out to have higher heat generation costs. This facilitates replacement of TETs with boiler houses on the market.

The exergy method considers cost distribution from the point of view of distribution of exergy fluxes[46] between generation of heat and electricity. The method's practical application is complicated by the need to take many parameters into account (it was used only at the Almaty and Astana TETs); however, this method is deemed to most fairly distribute cogeneration benefits between electricity and heat from the point of view of thermodynamics. Utilization of the exergy method results in a lower cost of heat generation compared to the most efficient boiler houses.

Use of the physical method at the majority of TETs in Kazakhstan does not imply cross-subsidization of heat by electricity. However, the heat cost restrictions imposed by the Regulator, and electricity and capacity tariffs reduction by the Ministry of Energy result in significant underfunding of TETs.

End-user heating tariffs are differentiated by consumer groups (population, budget organizations, and others), and depend on availability of a heat meter. Taking into account the social orientation of the heat energy tariff policy, Kazakhstan might consider increasing the heat production and heating networks tariffs by the means of a more pronounced price differentiation.[47] In practice this approach will mean that the major financial burden will be borne by industrial consumers and state and municipal enterprises, with no significant effect on the population. Nevertheless, such approach will create a precedent for cross-subsidy between the consumer groups and decrease price transparency. In its turn, an increased financial burden on industrial consumers, that will be taking on higher environmental costs in accordance with the new Ecology Code in addition to supporting renewable generation (in the absence of own renewable sources of energy) could result in an negative multiplier effect, and impede competitiveness, particularly noticeable forexport-oriented industries.

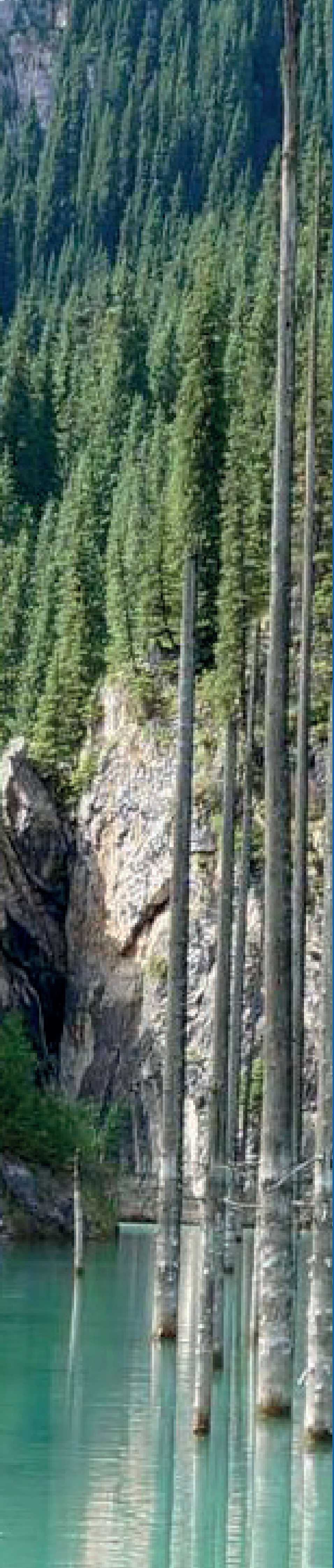
5.6.2. Recommendations on industry regulation

- Lack of a program document setting out the heat energy supply operation and regulation guidelines creates obstacles to the effective functioning of the segment. When the draft Law on the Heat Energy Supply is finalized, heat energy supply sector priorities will need to be harmonized with the long-term plans of the electric power sector, the functioning of the capacity market (when it comes to the nature of TETs investment projects), and Kazakhstan's "green" economy targets.
- Policymakers should formulate their position toward cogeneration from the perspective of creating and maintaining the most efficient sources of heat energy supply.
- In order to develop a more dynamic tariff-setting methodology for the heat energy producers and heat energy supply companies, it is recommended to
  - o analyze the total costs of heat energy production and delivery in Kazakhstan (taking into account capital costs, the cost of maintaining equipment and heating network, cost of heat production and transmission)
  - o determine the correct ratio of fixed and variable costs in the tariff, stimulating both heat energy consumers and suppliers to increase efficiency of heat energy production, transmission, and consumption.
- In order to create incentives for economically viable investments in the segment and use the already implemented tariff regulation method based on the regulated asset base, it is necessary to

  -provide for transition to incentive regulation based on service efficiency and quality targets and coefficients

  -provide for regulated companies' right to retain the economic benefits generated from more efficient planning of operating expenditures for the regulatory period.
- There should be direct interaction between the Regulator and the Ministry of Energy,[49] so that they could implement a better coordinated policy towards cogeneration and marginal tariffs' setting at such a level that both products could be cost-effective and remain competitive in their respective markets.
- Allow for other cost distribution methodologies for TETs owners to increase flexibility in the costs distribution between heat and electricity generation.
- Ensure open access and regular publication of information, data, and statistics on the heat energy sector activities available on the Kazakhstan Energy Association website (kea.kz) and /or on the website of a professional heat energy association, when it is established in Kazakhstan.

[46] The thermodynamic process exergy is a function of enthalpy and entropy.
[47] This approach is called third-degree price discrimination.
[48] The best option would be to transfer the marginal tariffs approval function from the Ministry of Energy to KREMiZK.



6. ENVIRONMENT AND CLIMATE PROTECTION

6. ENVIRONMENT AND CLIMATE PROTECTION

The concept for Kazakhstan's transition to a "green" economy sets very ambitious targets, and their achievement now depends on whether the country can succeed in creating conditions for attraction and return on investments needed to improve overall environment performance (such as reducing greenhouse gas emissions) without compromising economic growth.

6.1 Key Points

- One of the most consequential events for the energy sector since the publication of NER 2017 is development of the new Ecology Code. The project is being implemented by the Ministry of Ecology, Geology, and Natural Resources (established in 2019) and involves significant changes in terms of both an increase in the financial burden on the industrial sector as a whole (continuing the existing concept of "polluters pay for pollution"), and general principles and approaches to environmental protection. The OECD environmental legislation principles that served as the basis for the new code are planned to be implemented before 2030. At the same time, the sources of cost recovery for the introduction of "green" technologies[1] have not yet been determined.
- The climate policy set out in the draft Ecology Code has not been changed in any considerable way from the previous approach. It will still be based on an allowance allocation and the domestic carbon market, whose efficiency as an incremental mechanism for stimulating investment in low-carbon projects is largely undermined by the volatility of carbon prices and lack of their regulation.
- In our opinion, the energy-saving and energy efficiency aspects of legislation do not imply any important changes either. First and foremost, the legislation is supposed to stimulate energy-saving by companies[2] involved in electricity, heat, and gas transmission (as they account for the largest share of losses) through inclusion of energy-saving project costs in their investment programs.
- In general, the country's priority to reduce environmental impacts and improve environmental quality has to be linked and coordinated with state social and economic policy. Adding more financial pressure on specific industrial sectors (e.g., electric power generation, gas extraction) with no change in overall energy pricing policy may actually result in a negative multiplier effect. Therefore, the actions and plans of government bodies in the environmental, social, and economic domains have to be combined and coordinated.
- We recommend development of a Kazakhstan Sustainable Development Strategy[3] that would formalize interlinked and coordinated goals and objectives of the country's environmental, social, and economic development.

[1] According to a preliminary, "bottom-up" assessment, best-available-technology (BAT) introduction costs will amount to 4 bln tenge or 6,7 % of Kazakhstan's GDP; however, they most likely will end up being even higher.
[2] These companies are regulated natural monopoly entities.
[3] Sustainable development should mean

6.2 Environmental Protection

Many of Kazakhstan's environmental problems are directly connected with the history of the country's economic development, in particular, of the USSR's military-industrial complex. Due to its extensive territory and low population density, in Soviet times Kazakhstan was the site of numerous nuclear tests and the location of countless radioactive and hazardous waste storage facilities. Intensive water withdrawal from the Amu Darya and the Syr Darya rivers for irrigation purposes and water supply to the Soviet republics in Central Asia especially for cotton production, resulted in the massive shrinkage of the Aral Sea, and problems stemming from this, such as land desiccation and sand storms on the former sea bottom, concentration of pollution and irrigation run-off in the remaining water flow, and death of the local fisheries industry.

In fact, the most important development for the country's environment would be the elimination of historic waste dumps, although intensive mining development since 1991 has also created considerable environmental problems.

In 2015, Kazakhstan ratified the so-called 2030 Agenda,[4] aimed at achieving 17 sustainable development goals, 5 of which refer to environmental protection:

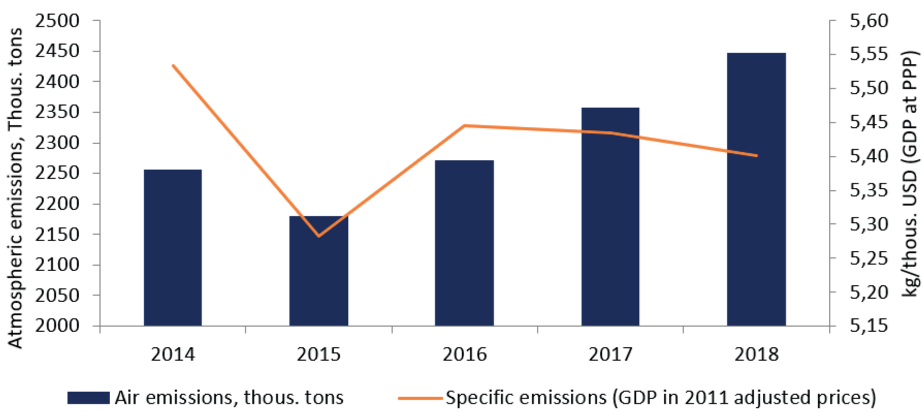
- Clean water and sanitation (Goal 6)
- Responsible consumption and production (Goal 12)
- Climate action (Goal 13)
- Life below water (Goal 14)
- Life on land (Goal 15)

Despite the voluntary nature of commitments involving the sustainable development goals, Kazakhstan should adopt specific quantitative targets to be achieved in the field of sustainable development.

6.2.1 Air quality

Kazakhstan has adopted air quality standards for all major atmospheric pollutants. According to official statistics, environmental indicators are simultaneously improving around the country in several respects.

Emissions of major pollutants are currently below the levels recorded in 2000, with the exception of nitrogen oxides and carbon monoxide emissions, which have risen by 64% and 26%, respectively. This is despite the twofold increase in the volume of electricity generation and aggregate energy production during this period. More recently, between 2014 and 2018 emissions (of all major types) also grew in absolute terms, while emissions per unit of GDP declined.



Source: Statistics committee

[4] Resolution of the United Nations General Assembly on Sustainable Development until 2030.

Fig. 6.1. Air emissions of harmful substances in 2014–18

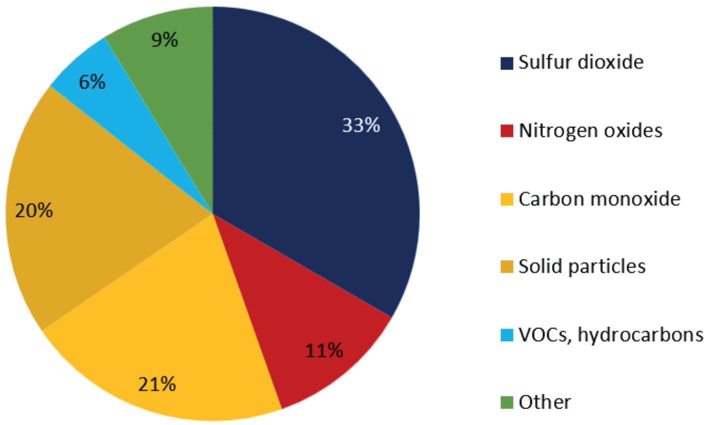
It is important to note that in Kazakhstan stationary sources account for over 87% of air emissions. Therefore, they are the primary target for air emissions regulations.

Of all stationary sources, thermal power plants make the largest contribution, accounting for around 40% of major emissions. Despite compliance with applicable emission standards by most power plants in Kazakhstan, the total annual emissions amount to:

solid particles (particulates) – over 119 thousand tons;

nitrogen oxides – 120 thousand tons;

sulfur oxides – 319 thousand tons.



Source: Statistics committee

Fig. 6.2. Structure of harmful substance emissions from stationary sources

The structure of emissions from stationary sources highlights priority areas for further reduction of air emissions:

- Introduction of high-performance double-flow electrostatic precipitators collecting up to 99.6% of fly ash and reducing ash concentration in processed gas to less than 100 mg/nm^3
- Introduction of combustion optimization systems with fuel-air ratio control,[5] which decreases Q_2 losses (i.e., with flue gas heat) and reduces nitrogen oxides and carbon monoxide emissions
- Introduction of sulfur oxide control systems, e.g. lime scrubbing of flue gases to produce plaster ($CaSO_4 \cdot 2H_2O$)

Kazakhstan's enterprises do not significantly exceed the country' current emission standards, which, however, are less stringent than those of OECD countries and China. For example, permissible emissions of solid particles by coal-fired power plants in Kazakhstan are several times higher than the limits set in the EU.v

Tab. 6.1. Emission standards for coal-fired power plants, mg/m^3

	Kazakhstan (current)	China (new)	USA	EU
Nitrogen oxides	450	100	135	200
Sulfur oxides	780	200	185	200
Solid particles	200	30	19	20

[5] Higher fuel-air ratios raise nitrogen oxide emissions.

Gradual transition to tighter requirements for air pollution emissions is inevitable. To that end, it is necessary to determine not only technologies that will enable such transition of enterprises to new standards over time, but also the potential to locate manufacturing facilities producing elements of these technologies in Kazakhstan.[6]

In international practice, capacity payment mechanisms cover the cost of modernization associated with the transition to new environmental standards. However, in Kazakhstan the new capacity market's main purpose is to only facilitate the replacement of outdated power equipment as part of general modernization..

Reduction of emissions from coal-fired power plants in China

In the 1990s, China increased its electric power capacity from 17 GW to 227 GW, mainly with the help of new small coal-fired power units of simple design ("subcritical" steam cycle, efficiency factor 32–33%). Air emissions were not controlled; this resulted in massive air pollution, smog in cities, and acid rain.

In late 1990s, the escalation of air pollution prompted the Chinese government to issue a regulation banning construction of power units with a capacity of less than 25 MW and forcing the shutdown of inefficient coal-fired power plants up to 50 MW.

In 2004, new requirements for the planning and construction of coal-fired power plants were introduced—all new coal-fired generating facilities with a capacity of over 600 MW have to be equipped with installations for dust removal (solid particles) and flue gas desulfurization.

In 2007, flue gas desulfurization became mandatory for all power plants with a capacity of more than 135 MW. In 2012, emission standards were tightened even more, leading to installation of electrostatic precipitators and selective catalytic reduction (SCR) in over 80% of facilities. All these stringent measures forced decommissioning of small coal generation facilities with a total capacity of 95 GW in the period from 2005 to 2014. In 2014, China adopted technical standards for new and existing coal-fired power plants, which will enter into full force in 2020 (in 2017 – in eastern China and in 2018 – in central China). The new standards are even more stringent than those of the European Union and the United States.

With the targeted policy of the Chinese leadership to tighten emission standards in coal-fired generation, as well as promotion and support for more general high-performance technologies, today China operates at least 69 power plants with ultra supercritical pressure technology, vis-à-vis one such power plant in the United States.

6.2.2 Water resources

Kazakhstan with its continental climate has sharp seasonal temperature fluctuations (from -50°C to +49°C) and general aridity, making availability of water (both in terms of quality and quantity) a major environmental problem.

Despite its large territory, Kazakhstan's water resources depend heavily on transboundary rivers. The biggest challenge is now associated with lack of proper regulation of water withdrawal by China from the upper Irtysh and the Ili. Intensive development of the arid Xinjiang Uyghur Autonomous Region and the country's plans for a 1.5–2.0 fold increase in water withdrawal from these basins can create downstream issues for Kazakhstan, both for the overall environmental aspect for these watersheds, but also for hydropower generation. China is not a party to the Convention on the Law of the Non-Naviga-

[6] For example, combustion optimization systems of domestic origin have been installed at a number of enterprises and power plants.

tional Uses of International Watercourses (1997) or the Convention on the Protection and Use of Transboundary Watercourses and International Lakes (1992). Therefore, any resolution with China on the use of shared transboundary river resources for Kazakhstan has been slow in coming. However, unlike other countries bordering China,[7] which have similar problems with transboundary rivers, Kazakhstan is the main land route for Chinese energy supplies. Partly for that reason, China has made some concessions in negotiations on sharing transboundary river resources with Kazakhstan.

Another problem associated with the use of water resources is wastewater treatment and prevention of water pollution. For example, when the Nura River was treated for mercury pollution[8] and the contaminated territory reclaimed, the wastewater effluent of the Temirtau Electrometallurgical Plant were not cleaned and remain a continuing source of pollution of the river with mercury-containing substances.

This points to the fact that wastewater treatment remains an unresolved issue across much of Kazakhstan. Thus, the proportion of wastewater discharged without treatment, despite the downward trend, remains significant, at 27–30%.

For the oil and gas industry, the problem of wastewater is connected with the need to treat and dispose of high volumes of wastewater. As the water used at the fields often has a high salt concentration exceeding the set requirements, wastewater disposal, even its reinjection, is associated with high desalination costs.

6.2.3 Solid waste management

Since NER 2017 was published, progress has been made in the country in terms of solid waste management. The share of solid municipal waste that is treated has increased from 3% to 14.8%, and of industrial waste – from 24% to 32%. The Concept for Transition to a Green Economy has set targets to increase industrial waste treatment further, to 40% by 2030, and to 50% by 2050.

The mining industry dominates in the waste structure (i.e., including extraction of all natural resources), accounting for over two-thirds of the total.

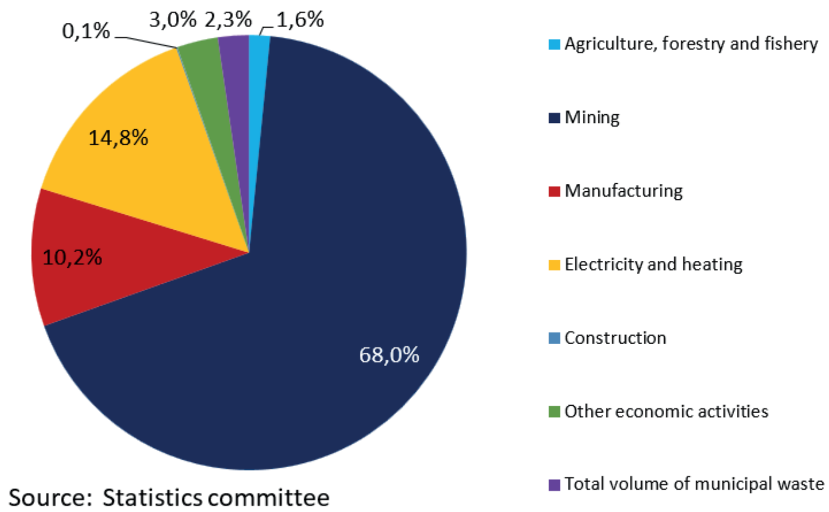


Fig. 6.3. Annual waste structure

Despite the fact that waste volumes are growing in absolute terms, they are decreasing per unit of GDP.

[7] China shares over 40 transboundary rivers with its neighbors, and half of Chinese river systems are transboundary.
[8] The project of the Nura purification and cleanup of contaminated territories from mercury cost a total of $104 million.

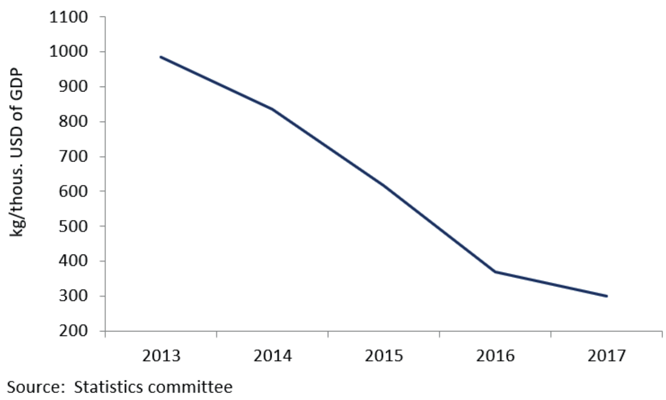


Fig. 6.4. Decrease in specific waste indicator to GDP

The share of municipal waste processing has grown significantly since 2010—from 1.9% to 14.8% in 2017, but remains rather small compared to the level of processing in EU countries, for example.

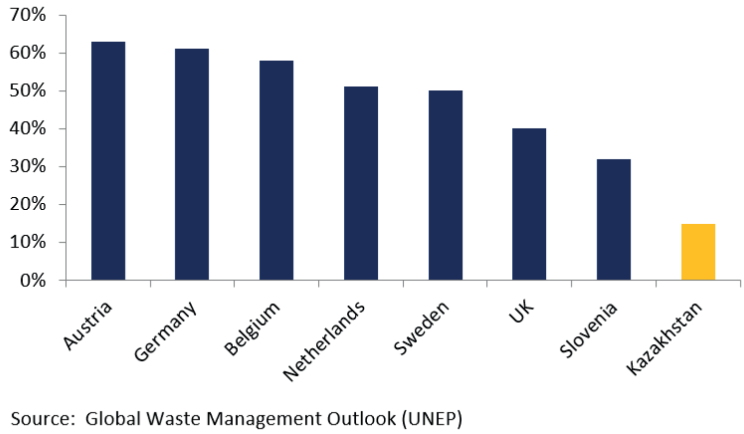


Fig.6.5. – Municipal solid waste processing in the EU and Kazakhstan

Issues connected with solid waste landfills include the inadequate state of landfills and a significant number of unauthorized landfills; in 2018 alone, 9,600 waste disposal facilities were identified, of which 90% were illegal.

An integrated approach needs to be developed to increase the share of processing and disposal of municipal and industrial waste, supported at a legislative level. Policymakers should consider creating waste incineration plants producing heat with a special tariff, similar in function to the special tariffs available for renewable energy sources.

Mining-industry waste includes "man-made" deposits[9] where certain types of resources can still be extracted. According to the Geology Committee, 1,406 man-made mineral formations with a total volume of 47.4 billion tons are registered in the country, about 250 of which are state-owned. There are historical reasons for the existence of waste rock and tailing dumps, mostly due to the fact that waste processing in earlier years was an unprofitable undertaking in comparison with ore mining and processing.

Man-made mineral formations also include ash and slag waste from coal-fired power plants; its accumulated volume exceeds 580 million tons, while processing

[9] Man-made mineral formations include overburden, stored oxidized rock, mined raw ore, tailings, and slag dumps.

is limited—about 8% annually. According to the Geology Committee, high-ash coal of the Ekibastuz Basin contains elevated concentrations of Ti, Zr, Ge, Co, Ni, and rare-earth elements. Therefore, ash and slag waste of this coal can be a valuable source for rare and rare-earth metals extraction.

In addition to rising prices and demand for metals (especially rare-earth metals), processing of man-made mineral formations is driven by technological development in such areas as grinding, reagents, and technological equipment, making it possible to increase the recovery ratio in comparison with operations 20 years ago. However, modern technologies and equipment enabling processing of man-made mineral formations require significant investments. Therefore, preferences for their implementation have to be granted to companies involved in such processing (such as the abolition of the mineral extraction tax on mining from man-made mineral formations, etc.).

6.3. Climate Policy

Despite the fact that Kazakhstan's contribution to global greenhouse gas emissions[10] does not exceed 1%, the country is in the top 10 economies with the highest carbon intensity of GDP.

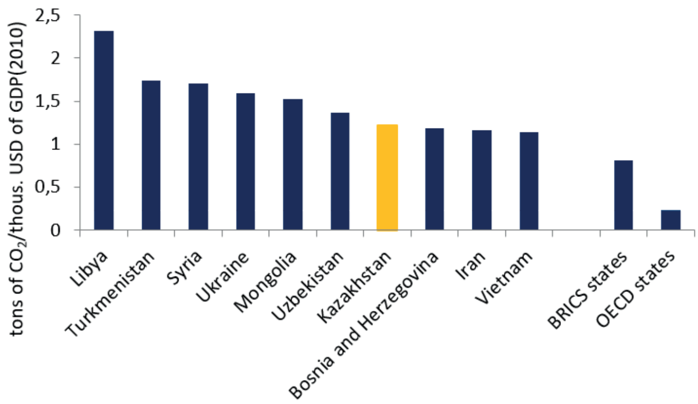


Fig. 6.6. Economies ranked by carbon intensity of GDP.

Kazakhstan is a party to a number of international treaties on climate. In 2009, it ratified the Kyoto Protocol to the UNFCCC, and in 2016—the Paris Agreement providing for quantitative commitments to reduce greenhouse gas emissions by 2030 by 15% compared to the 1990 level.

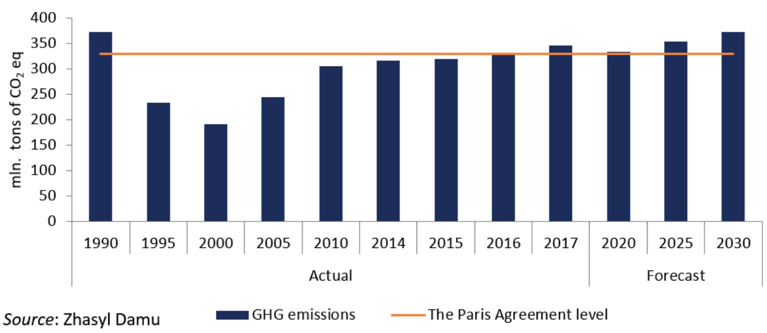
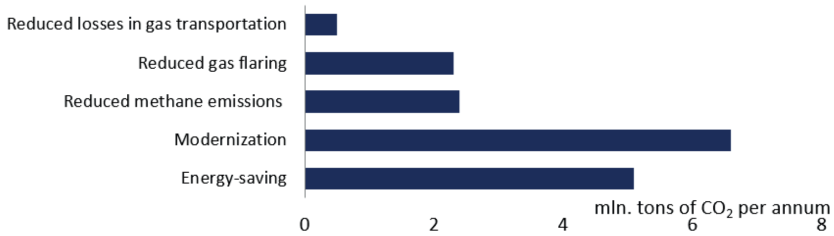


Fig. 6.7. Kazakhstan's greenhouse gas emissions (actual and forecast) and commitments under the Paris Agreement

[10] Greenhouse gases (GHGs) include carbon dioxide (CO_2), methane (CH_4), nitrogen oxide (N_2O), hydrofluorocarbons (HFCs), perfluorocarbons (PFCs), and sulfur hexafluoride (SF_6). The measurement unit is a ton of CO_2 equivalent. Greenhouse gas emissions are converted into the given unit with the relevant factors.

The forecast out to 2030 shows that even if policy measures are taken to reduce greenhouse gas emissions, in order to achieve its target set in the Paris Agreement, Kazakhstan will have to invest additional efforts to reduce GHG emissions by 30-40 million tons of CO_2 equivalent per year.

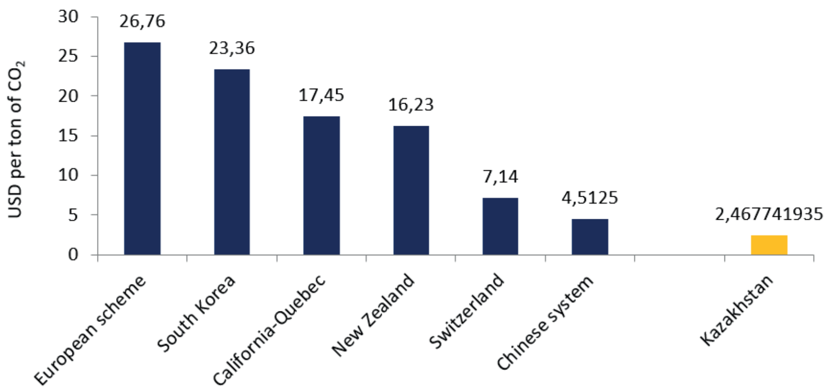
Taking into account Kazakhstan's current state of industrial development, an efficient market-based emissions regulation mechanism creates additional incentives to invest in environmental projects and domestic manufacturing. The volume of domestic low-carbon projects (excluding development of renewable energy sources) is estimated at 17 million tons of CO_2 (annual GHG emissions reduction). However, their implementation requires introduction of additional incentive mechanisms.



Source: Electric Power Industry Development Outlook to 2050. AMME, 2017.

Fig. 6.8. Potential GHG emissions reduction upon implementation of green projects

In 2013, Kazakhstan became the first country in Asia to introduce a national greenhouse gas regulation system, and in 2014 it launched an emission trading system. In 2014–15, emissions trading was done on the "Caspian" Commodity Exchange, but was suspended in 2016. Emission trading revealed a number of flaws with the scheme, with high price volatility (10-fold or higher fluctuations) and confirmation that the allowances being sold resulted from a real reduction in emissions, and not from a decrease in production volumes.

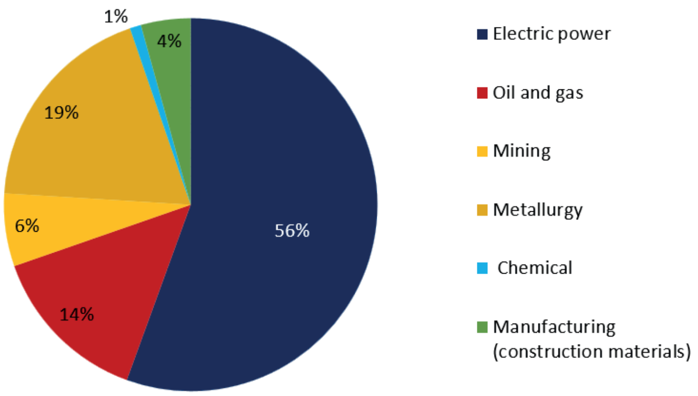


Source: State and Trends of Carbon Pricing, World bank 2019

Fig. 6.9. Carbon prices around the world, $US per ton of CO_2

The emission trading system (permits for CO_2 emissions) enables enterprises operating in regulated sectors to sell "spare" allowances resulting from GHG emissions reductions, or they can buy them in the case their emissions increase and they face an allowance deficit. They can also convert low-carbon project results into carbon units for trading.

Regulation covers enterprises with GHG emissions of over 20,000 tons of CO_2 per year in the approved economic sectors. They are granted emission allowances for a certain period of time,[11] and if they exceed the granted volume, the difference must be bought on the market.



Source: National GHG Allowance Allocation Plan for 2018-2020

Fig. 6.10. Allowance allocation to regulated industries for 2018–20, million tons of CO_2

The new draft Ecology Code incorporates some measures that address the shortcomings of the first trading period (2014-16), including participation of the state in sale of additional allowances at special auctions outside exchange trading. However, the price level achieved on the domestic carbon market (in 2015) is insufficient for any substantial investment support for low-carbon projects. Currently, the issue of pricing in the domestic carbon market remains unresolved.

The level and stability of allowance prices (per ton of CO_2) is extremely important for both enterprises experiencing an allowance deficit and investors in low-carbon projects. High carbon prices significantly increase the financial burden on operating enterprises, especially power plants, but low prices fail to stimulate investment.

6.4. Planned Changes in Environmental Legislation

The main innovations of the draft Ecology Code are set out in its Concept:

1. **Environmental standards** – phased transition from simple sanitary specifications to broader **environmental standards** adopted and applied in the EU and OECD, based on a balance between what is desirable from an environmental point of view and what is feasible from a technical and economic point of view.
2. **Integrated environmental permits (IEP) and best available technologies (BAT)** – emission standards are set on the basis of BAT to be implemented (for some of the operating category 1 facilities), subject to formulation of clear individual environmental requirements, by a production facility during its life cycle and with due regard to Environmental Impact Assessment (EIA) results.
3. **Integrated approach to EIA,** where it is seen as an integrated procedure (rather than a document). Simultaneous introduction of screening procedures (preliminary review of design solutions with risk assessment). A full-scale EIA will be mandatory only for large environmentally hazardous enterprises (category 1 facilities), while a simplified EIA will be carried out for medium-sized

[11] The National Allowance Allocation Plan.

projects.

4. Transition to **targeted collection of environmental payments**[12] and their collection only when it is appropriate in affecting the behavior of polluters towards the environment, as well as elimination of a differentiated approach to emission fee rates by region.
5. Transition to **mandatory automated emission monitoring** for category 1 facilities, with potential deductions of an enterprise's capital expenditures on the installation of automated monitoring systems from any emission fees that are owed.
6. **Environmental damage prevention and elimination** – priority of in-kind damage compensation, and only for direct damage that requires evidence of the fact and extent of environmental damage.
7. **Transition to basic waste management principles based on EU legislation**, with introduction of:
   - The "circular economy" principle: a hierarchical approach to reduction, reuse, recycling, processing, and disposal of waste
   - Economic incentives and government support for activities aimed at waste prevention, reduction, and management
   - Waste classification based on the same classifier adopted in the EU states
   - The status of secondary raw materials, by-products, with criteria and procedures for their classification either as waste or non-waste
8. Implementation of a **Strategic Environmental Assessment** (SEA) at the stage of planning and state documents development and a **system of environmental quality targets** for local executive bodies.

The planned changes in environmental legislation will be most tangible for category 1 enterprises in terms of obligations to introduce BAT and automated emission monitoring systems (AMS).

It should be noted that according to preliminary assessments only, BAT introduction will require $10–40 billion of investment, and the requirement to introduce AMS will increase the financial burden on enterprises even more. Further, not all emission data can be collected in an automated mode.

As the financial burden on enterprises increases, social factors must also be taken into account. For example, some of the oil fields in western Kazakhstan[13] are unprofitable and are developed and worked out of a need to maintain employment levels and social stability in the region. Any disproportionate financial burden from new environmental legislation on socially significant enterprises (low-margin deposits, combined heat-and-power plants, etc.) may have strong negative social and economic consequences.

[12] In Kazakhstan, collection of emission fees and recovery of damage to the environment are not specifically targeted and spent on addressing environmental problems. Further, there are no clear criteria for decisions to increase the rate of environmental payments, or single emission fee rates.

[13] Old fields under development for over 50 years and water cut above 80%.

As for greenhouse gas regulation, the major changes are shown in Figure 6.11.

	2014-2015	2018-2020	
	Previous Ecology Code	Current Ecology Code	New Ecology Code (draft)
Regulated industries	Electric power industry, oil and gas, mining, metallurgy, chemical industry	The same + manufacturing (construction materials)	The same + manufacturing (construction materials)
Free allowance allocation	From the base year level	From the base year level On the basis of specific coefficients	On the basis of specific coefficients
Regulated entities	166	129	>129
Carbon market	Commodity exchange	Commodity exchange	Auction: sale by the operator Commodity exchange
The state creates	Demand	Demand and supply	Demand and supply
Trading	Allowances, carbon units of domestic projects and international	Allowances, carbon units of domestic projects	Allowances, carbon offsets international carbon units
Ban on sale of allowances appearing from production cutback	+	-	+
Mechanism of allowance origin verification	-	-	+
Operator involvement in trading	-	+	+
Price regulation	-	-	-

Fig. 6.11. Evolution of GHG regulation in Kazakhstan

As noted earlier, the domestic carbon market needs confidence in allowance unit pricing that will enable enterprises to plan emission reduction actions and give price signals to investors for project implementation.[14] Low price volatility in the carbon market cannot be achieved without involvement of the Regulator (Zhasyl Damu) due to the limited number of participants and the speculative nature of exchange trading.

6.5 General recommendations on the draft Ecology Code

I. In the course of transition to integrated environmental permits **(**IEP), category 1 (large environmentally hazardous) enterprises must be granted:
- The opportunity to delay IEP introduction at low-income, socially significant enterprises
- Subsidies for the cost of BAT introduction, which should be accounted for in tariffs for natural monopoly entities
- Tax preferences for the BAT payback period (up to 10 years), such as: exemption from emission fees, land tax, customs duties on equipment imports, accelerated depreciation or 100% deduction for BAT with adjustment of taxable income in the amount of 50% of BAT, etc.
- The opportunity to directly purchase technologies without heavily bureaucratized procurement procedures

II. Implementation of automated monitoring systems:
- Determine clear criteria for the need to install monitoring systems on stationary emission sources.
- Formulate terms and conditions of monitoring systems implementation.

[14] The EU General Court confirmed that "the inability to predict how the exchange market is developing is an element inalienable and inseparable from the economic mechanism of emission trading scheme" (EU Environmental Law and the Internal Market, Oxford 2014).

III. In order to increase the level of processing of solid waste and man-made mineral deposits, it is necessary to provide:

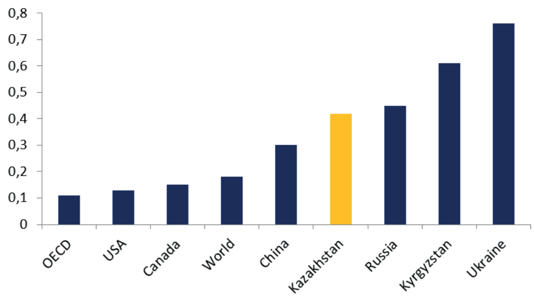
- Tax preferences: This could include complete exemption from the mineral resource extraction tax for man-made (secondary) mineral deposits
- Incentives for establishment of incineration plants (municipal waste) via special tariffs for the heat they generate

In addition, the following issues have to be resolved:

- Wastewater treatment: the concentration of pollutants in wastewater pumped into underground aquifers and not intended for further use must not exceed the existing level of pollutants in those same aquifers.
- Carbon market: it is necessary to provide for the Regulator's involvement in operation of the domestic carbon market as a market maker, in order to maintain a certain price range for carbon that would be optimal in terms of balancing the goals of investment stimulation and keeping enterprise expenses on the purchase of additional allowances at an economically sustainable level.

6.6 Energy savings and energy efficiency

Energy savings and energy efficiency are key elements of climate policy and improving the competitiveness of the economy. Despite the fact that Kazakhstan's economy has one of the highest energy intensities of GDP in the world, the country has a significant potential to reduce energy consumption.



Source: Key world energy statistics, IEA 2018

Fig. 6.12 - Energy intensity of countries.

According to the IEA's database for 2016, Kazakhstan ranks 119th of 143 countries in terms of energy intensity of GDP. At the same time, the Concept on Transition towards a Green Economy aims to reduce the energy intensity of GDP (from the 2008 level) by 25% before 2020 and by 30% before 2030. Despite a reduction in energy intensity of about 27% between 2008 and 2018, the economy of Kazakhstan is still quite energy intensive.

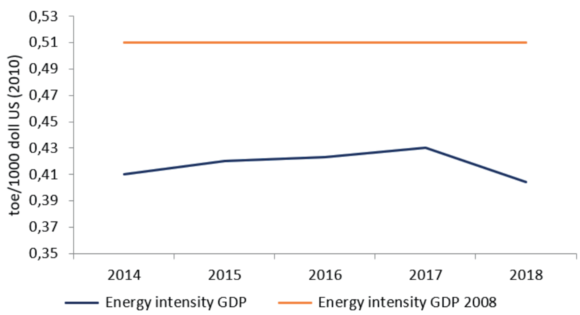


Fig. 6.13 - Dynamics of energy intensity of GDP 2014–18

To achieve the goals of reducing energy intensity, in 2012 Kazakhstan adopted the law "On Energy Saving and Energy Efficiency," which implemented a number of mandatory requirements:

- five-year moratorium on production and sale of incandescent lamps (for lighting purposes)[15]
- mandatory energy audits every five years for enterprises consuming more than 1.5 thousand tons of standard fuel (tsf) per year
- compliance with energy consumption standards and normative values of capacity coefficients in power grid networks;
- review of new construction projects for energy efficiency and energy savings.

As a result of the Law there was a noticeable decrease in the use of incandescent lamps, and energy audits were conducted at large enterprises. Based on the results of the audits, large enterprises were required to establish energy savings action plans, the execution of which is overseen by the operator of the State energy register.

However, the procedures for conducting energy audits and monitoring their results have not been fully developed. Foremost, fines or other penalties for failure to execute energy saving programs were not established, as required by law, limiting the scope of their execution.

6.6.1 Energy savings potential

According to Kazakhstan's Electric Power and Energy Saving Development Institute, the country's total energy savings potential resulting from the energy audits of large enterprises is about 4.9 million tsf (total potential for the country is estimated at approximately 17.2 million tsf). At the same time, the estimated savings potential for electric power is more than 5 billion kWh.

Reduction of losses and consumption of electricity

In terms of its energy resources, Kazakhstan has the most developed commercial and technical accounting for the consumption of electricity: thus, the implementation of measures to save it could be more formalized with more accurate measurements of the effect.

For a number of industrial groups of companies, the electricity saving potential, according to the results of energy audits, has been estimated:

- among the enterprises of the Eurasian Resources Group – 323.3 million kWh / y (2.5 % of total consumption);
- Kazakhmys Corporation LLP – 103.7 million kWh / y;
- «Kazzinc» – 58.8 million kWh/y;
- for the enterprises of JSC KazMunayGas – 134.4 million kWh/y.

Among the large industrial electricity consumers overall, the electricity saving potential is no less than 1.5 billion kWh.

The energy saving potential in the housing and residential sector, in the scope of water and thermal energy transportation systems, could be achieved through the modernization and replacement of pumping and compressor equipment. It is estimated at 1 billion kWh – by implementation of soft-start devices and frequency controls, which allow for significant energy savings (20–30%).

It is also necessary to note the transition to energy-efficient lighting. According to the United Nations Development Programme (UNDP), from 2012 to 2016, the share of incandescent lamps in Kazakhstan decreased from 74% to 18% of the market, while the share of LED lamps increased from 9% to 61%. The resulting reduction in electricity consumption is estimated at 3 billion kWh , due to the transition to energy-efficient lighting during this period . With a certain degree of confidence, it can be said that

[15] Despite the current prohibition, it is still possible to import and sell them under the name of radiant thermal devices.

the picture concerning the reduction in the share of incandescent lamps is overly optimistic.[16] For example, according to the State Statistics Committee, the share of incandescent lamps in households remains at 60% (27 million incandescent lamps). As a result, it is too early to talk about the complete abandonment of incandescent lamps, despite the five-year term of the legislative ban (above). Therefore, in terms of lighting there is a significant reserve for reducing electricity consumption, which, taking households into account, can be estimated at **2 billion kWh**.

Significant energy savings potential is also evident in the electricity transmission sector. Actual losses of electricity in the network of the national power operator (KEGOC) in 2018 amounted to 2.9 billion kWh, or 6.5% of the electricity supply to the network. Average losses in the networks of the regional electric companies (RECs) in 2018 are estimated at 14%. A technically and economically achievable level of reduction of the total standard losses in power grids can be estimated at 10% (of the total losses), i.e., up to **1 billion kWh**.

As a result, due to the implementation of energy saving measures, the possibility of reducing electricity consumption can be generally estimated at more than 5 billion kWh per year.

Reduction of fuel consumption in power plants

The energy efficiency of large coal-fired power plants directly depends on the load and on operation within the parameters of the thermodynamic cycle, which are largely determined by the technical condition of the equipment. Operation at a reduced load, deviations from the design scheme, and reduction of steam parameters lead to a significant increase in per unit consumption of standard fuel in relation to normative values.

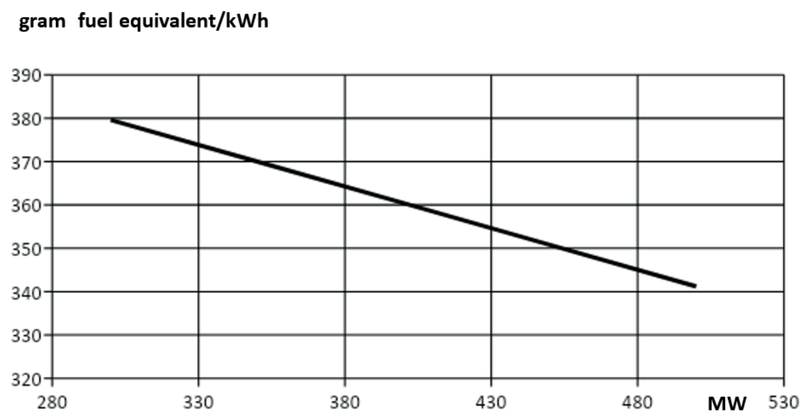


Fig. 6.14 – Relationship between per unit fuel consumption and the load of a 500 MW coal power plant.

As can be seen from the figure, when the load falls to the level of 350 MW, per unit consumption of fuel increases by more than 20 g.t./kWh, compared to the nominal load.

Bringing steam and water parameters to designed levels also makes it possible to increase the efficiency of power generation at thermal power plants. The table below presents calculated effects of steam and water parameters on the efficiency of steam turbine plants.

[16] Lighting Market Research Report in the Republic of Kazakhstan, UNDP, Astana 2017

Tab 6.2 - Influence of steam and water parameters on efficiency.

Action	Relative increase in efficiency
Increase in temperature of the fresh steam	0.02 % /1 °C
Increased pressure of fresh steam	0.1 %/1 МПа
Increase in temperature of the reheated steam	0.015 %/1 °C
Use of second intermediate steam overheating	1.2 %
Reducing the pressure in the condenser	1 % /1 кПа
Increasing the temperature of feed water	0.02 % /1 °C

As can be seen from the above, the modernization of energy blocks and their optimal loading can reduce specific fuel consumption by as much as 10%; i.e., for coal-fired condensing power plants (KES) the fuel savings will be about 2.7 million tons (MMt) of coal.

In terms of coal-fired TETs, the efficiency of which is largely determined by thermal loads, it is not quite correct to compare directly the specific fuel consumption for KES and TETs.

TETs remain a key source of heat supply and are physically more efficient, taking into account that the fuel utilization rates at TETs are higher than at KES and boiler houses. However, in practice, due to a number of factors (see section 5.6), TETs may be inferior in terms of profitability to KES plants and boilers. As a result of the general economic downturn, which began in the early 1990s following the disintegration of the USSR, the consumption of heat (steam) by industry has sharply decreased. Subsequently, the main consumers of heat generated by TETs became the enterprises of the government (all levels) sphere and the housing stock, which led to a significant reduction in the heat load and, as a consequence, in the efficiency of the TETs. At the same time those TETs that supply industrial consumers demonstrate acceptable economic indicators.

Due to the decrease in thermal loads, during the heating period TETs also generate electricity working in the condensation mode, which leads to an increase in per unit fuel consumption for electricity supply. If overproduction of electricity in the condensation cycle is not more than 25–30%, per unit fuel consumption is below 300 g at.t./kWh. However, if overproduction of electricity in condensing mode rises to 60%, per unit fuel consumption is in the range of 300–400 g at.t./kWh. Of course, the efficiency of turbine and boiler equipment has an impact on the efficiency of a TETs, but to a lesser extent than a KES.

As a result, optimization of the thermal load of a TETs allows a reduction in fuel consumption of up to 15% and a reduction in coal consumption by 2.9 MMt. For gas-fired power plants, fuel savings can amount to up to 5% of total consumption, i.e. 230 million m^3 (MMcm).

A systemic approach to implementation of the above measures aimed at energy saving and energy efficiency improvement will allow reducing the national greenhouse gas emissions by 7 MMt of carbon [CO_2] equivalent. The actions that would facilitate this reduction include the following:

- transition to incentive tariff regulation including target setting for reducing grid losses
- modernization of thermal power plants in order to increase energy efficiency within the capacity market
- for natural monopolies, in terms of heat [thermal power] transmission and water supply: inclusion of energy saving measures (modernization of pumping units, introduction of frequency controls and soft-start systems) in the investment programs
- for all natural monopolies: maintaining the cost cutting by means of energy saving without tariff reduction

6.6.2 Energy service contracts

Energy saving measures provide energy savings and cost cutting, but the investment payback period is usually over three years. Overall, the transition to energy-saving technologies is gradually taking place within modernization initiatives, although in order to accelerate this process, some incentives are required.

In order to boost energy savings at enterprises, two factors are necessary: qualified companies implementing energy-saving technologies and preferential loan schemes for energy saving and energy efficiency projects.

The qualified companies may be both energy-saving equipment manufacturers and energy service companies operating under an arrangement whereby they receive income from energy savings at the customer's facility.[17]

Introduction of the energy service contract is a priority for Kazakhstan, which has been pointed out in the Address of the First President (Kazakhstan 2050 strategy, Step 59). Despite legislative amendments designed to improve energy service contracts, their implementation remains very limited: for example, during the period 2015–18 only eight energy service contracts were concluded. By way of comparison, in Russia more than 700 energy service contracts were implemented in 2016 alone. The reason for such limited use of energy service schemes is the complicated return-on-investment procedure for energy service companies (ESCOs), which often rely on loans for initial capital but are repaid according to sometimes imprecise energy saving monetization formulae.[18]

Currently, the draft law "On Amendments to Certain Legislative Acts of the Republic of Kazakhstan Relating to Energy Saving and Energy Efficiency" includes provisions stipulating:

- reimbursement of part of the ESCO's costs incurred as a result of implementation of energy saving and energy efficiency projects;
- preferential loans with a government guarantee provision for some part of the loan;
- tax preferences: exemption from VAT on importing equipment and spare parts, reduction of the total annual income for corporate income tax calculation purposes by the amount of actual savings.

It should be reiterated that the owners of the saved energy amounts under energy service contracts are the energy service companies, which allows them to receive offsets of carbon units, which they can then sell in the carbon trading market.

[17] An energy service company invests in implementation of energy-saving technologies at a customer's facility, and receives income in the amount of the difference between the facility's energy costs (payments for energy) before and after the launch of the energy-saving technology. In Kazakhstan, both the form of the energy service contracts and the procedure for inclusion into the register of energy service companies have now been approved.

[18] Instead of generating income from the sale of products, energy service companies obtain their income from energy savings, which may not always be determined precisely.