KAZENERGY

2015

THE NATIONAL ENERGY REPORT

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Dear Ladies and Gentlemen!

Since publication of the "KazEnergy National Energy Report 2013," the world has experienced considerable geopolitical and economic changes. These are currently having a significant impact on Kazakhstan's economy and its energy sector. A collapse in world oil prices caused primarily by oversupply, in the opinion of leading experts, marked the completion of the high-price period of the 2000s.

All over the world implementation of new oil and gas projects has been suspended, and investment in field exploration and development has been reduced (mostly high-cost conventional oil production projects as well deep-water, Arctic, and other hard-to-recover oil production projects). The issue of when and how the world can return to the previous economic growth trajectory and associated energy demand growth has acquired particular relevance. Of high importance is also the ability of the existing (including unconventional) production capacities to adapt to the new conditions, to optimize costs and to meet global demand for the long run.

These factors will determine the duration of the current low oil price period which brings new challenges for Kazakhstan.

The main challenge, in the opinion of KazEnergy, is the sharp increase in competition among energy supplying countries for both consumer markets and foreign investments.

In the previous National Energy Report, the KazEnergy Association brought forward a number of proposals for improving the business climate and investment attractiveness of the country's energy sector, some of which were subsequently implemented by the state. As part of the 100 concrete steps to implement the five institutional reforms proposed by President Nursultan Nazarbayev, an entire set of measures aimed at improving Kazakhstan's competitivenes in the current context has been establishend and is being implemented.

At the same time, in the current situation where the cost of incorrect decisions can be extremely high, it is of key importance to get an independent external opinion with regard to the prospects of development for world energy markets, the role of Kazakhstan's energy sector in such markets, as well as the actions and policies needed to improve its overall competitiveness and effectiveness. Of equal relevance for the energy sector and the overall country's economy is an objective forecast of domestic energy consumption, which is required, first of all, in order to prevent inefficient spending through excess capacity construction.

Therefore, the KazEnergy Association with support of its members and the special contribution from ExxonMobil Kazakhstan Inc. and Samruk-Energy JSC, decided to involve one of the leading international petroleum and energy consultants, IHS Energy, in the preparation of the "KazEnergy National Energy Report 2015."

I hope that the research carried out by IHS Energy, with the support of specialists from Kazakhstan, will become a significant event for the whole expert community of the Republic, and the findings and recommendations contained in the research will be found to be useful by the government and the business community in guiding their important and difficult decisions.

Timur Kulibayev
Chairman of the "KAZENERGY" ALE

Dear Readers!

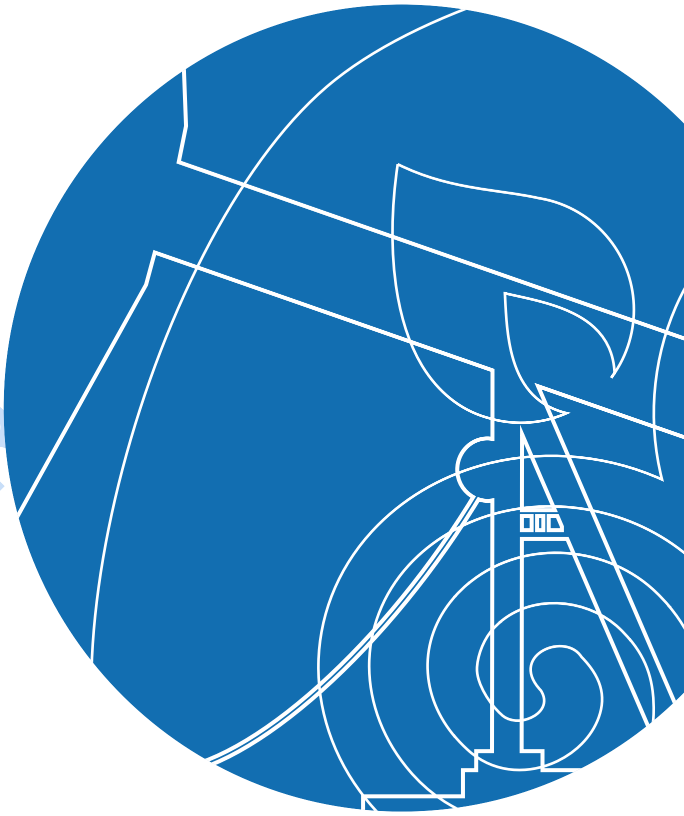
We greatly appreciate the opportunity for IHS to be invited to work on such an important project as the National Energy Report for Kazakhstan and to develop an outlook for its energy future. While Kazakhstan's economy has experienced historic development and some diversification in the two and a half decades since independence, hydrocarbons and other energy resources remain central in the national economy and will for some time to come. The development of the oil and gas industry has served Kazakhstan very well, generating revenues that have been crucial since 1991 to 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. Kazakhstan faces strikingly different challenges than when the first Report was done. From 1993 onward, global commodity markets were dominated by the "commodity supercycle" of strong demand and high prices, driven by the emerging market nations and China, in particular, which greatly benefitted Kazakhstan as a natural resource producer. For many commodities, the supercycle ended a couple of years ago. Oil's supercycle, however, continued until very recently, as increases in oil production in some parts of the world were offset by disruptions that reduced production elsewhere. But now the oil market, too, has been turned upside down. Instead of strong demand and tight supply, it is dominated by weaker demand and oversupply. Prices in international markets are now hovering at levels less than half of what they were a year ago. A number of factors have contributed to this shift, but three are most notable: the slowing of the Chinese economy; the almost doubling of US supply as a result of the emergence of shale oil; and the historic decision of OPEC not to cut output to support price, but rather to seek market share.

The result is sending shockwaves throughout the oil-producing world, putting great pressure on the budgets of producer countries. It is also changing the orientation of the international industry. As the CEO of one company put it, companies "are no longer seeking barrels, but rather efficiency." The aim is to rein-in costs, while capital expenditures are being dramatically cut, with hundreds of billions of dollars of planned investment now being postponed or even cancelled in the new low-price environment. Companies will still compete for new opportunities, but they can be much more selective, and countries will now also have to compete more vigorously for available investment. As a result, we expect more flexibility to emerge in fiscal terms and on local content requirements from host countries. There will also be more emphasis on timeliness and predictability in decision-making by countries.

All this provides the context for the work we have done in this Report. Based upon analyses of above-ground and below-ground factors, we are presenting a baseline outlook for Kazakhstan's long-term energy future that draws upon the variety of drivers, developments, and conditions that we identify and explore in the Report. Yet we recognize that the outcome is as likely to be as determined as much (if not more so) by Kazakhstan's policy responses and decisions as by the country's underlying resource base and international market developments.

We hope that this Report will contribute to that process of decision-making and policy that will contribute to Kazakhstan's continued benefit, in this new context, from what has been achieved since 1991.



Dr. Daniel Yergin
Vice-Chairman IHS

Appreciation

The National Energy Report 2015 was prepared for KazEnergy by IHS Energy, with special contributions from ExxonMobil Kazakhstan Inc., and Samruk-Energy JSC, as well as KazEnergy's members. The contributions to the Report by a number of Kazakhstan-based and foreign experts representing KazEnergy members, state authorities of the Republic of Kazakhstan, companies of the sector, as well as research, development, design and engineering entities also are gratefully acknowledged.

Ruslan Mukhamedov, Deputy Director at the Center for Monitoring and Marketing Expertise at the National Chamber of Entrepreneurs of Kazakhstan "Atameken," and **Oleg Arkhipkin** of the Kazakh Institute of Oil & Gas (KING) took part in the preparation and provided valuable reviews of the entire report on a regular basis, setting its overall direction and focus. A UK-based team from ExxonMobil (**Ursula Hartley, Matthieu Liesch,** and **Suhel Mistry**) similarly actively reviewed the entire report, offering many constructive recommendations. A great many specialists in Kazakhstan and elsewhere also reviewed individual chapters of the report corresponding to their individual areas of expertise. We are grateful to all reviewers for suggestions and revisions that have greatly improved the report.

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On a final note, during the preparation of this report we have been blessed to have met so many wonderful people from different walks of life in Kazakhstan. This year Kazakhstan celebrated its 550th anniversary of Kazakh statehood for which, during our journey, we have sampled its rich culture and have been profoundly moved by the Kazakh's warm embrace. To sum up, it has been an honor to play our role in mapping out Kazakhstan's energy sector development, which is so central to the country's economy. On behalf of IHS, the authors of this report wish Kazakhstan the greatest success for the future.

In Appreciation,

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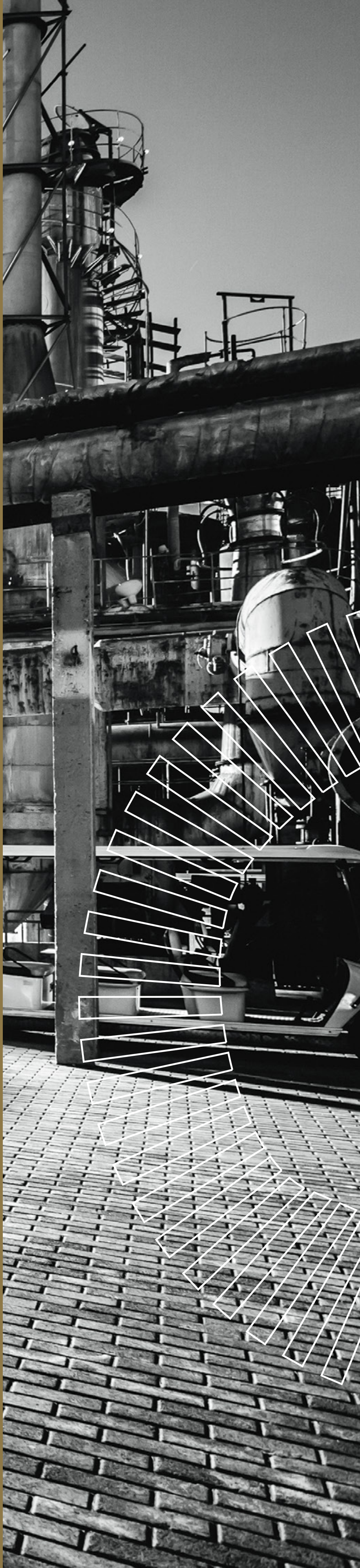
INTRODUCTION AND EXECUTIVE SUMMARY



1. Introduction and Executive Summary

1.1. Introduction

Kazakhstan is a country richly endowed with resources, most notably energy. In the quarter century since independence, Kazakhstan's energy sector has made great strides. Oil production has tripled, and the country now has firmly established connections to the world market. This achievement has contributed enormously to the country's economic and social development.

But Kazakhstan faces challenges for its energy sector that require fresh perspectives and approaches. One challenge is execution—ensuring the timely and efficient delivery of projects and new developments. A second is a challenge shared with the energy industry around the world—the rising costs of projects. The third arises from the oil price collapse and the rebalancing of the oil market at a lower price level, and the pressures that puts on Kazakhstan's energy sector and the national budget.

The fourth follows from the third. The world energy industry has entered a different era—one characterized by a new investment framework and a new investment mentality on the part of international companies. The frenetic search for barrels that characterized the decade-long period of the "commodity supercycle" that began in 2004 is over. Companies are now postponing or cancelling major projects. "Fiscal discipline" and "time," rather than "expansion at almost any cost," are now the focus of managements, who are under pressure from their own shareholders. As the CEO of one company put it, "We are no longer chasing barrels; we're now chasing efficiency." Companies will be more cautious in new investments, more focused on the fiscal system, the local content requirements, and the operating environments than in the past. This will create a more competitive environment among countries. It will be very important for Kazakhstan to understand this new environment and position itself for competitive advantage in order to facilitate the further development of its energy industry.

With a land area of over 2.7 million square kilometers (km^2), Kazakhstan is the ninth largest landlocked (having no access to the world's oceans) country in the world by land area. This large territory spans a great diversity of natural environments and geological conditions. Shaped by a variety of geological processes, including folding, faulting, accumulation of sediments, and metamorphism, Kazakhstan contains an almost unparalleled variety and abundance of mineral resources. Kazakhstan's mineral resource base is unique. Of the 118 elements of the periodic table of chemical elements, 99 have been discovered in the country's subsoil, 70 have been explored (with potential for commercial production), and more than 60 are involved in production.

On the global stage, Kazakhstan is particularly prominent as an energy producer. Ranking 20th in the world in 2014, Kazakhstan accounts for 1.1% of global primary energy production. Its proven reserves of oil, coal, and uranium all rank among the top dozen or so countries in the world, and natural gas in the top 20. Further, Kazakhstan leads the world in production of uranium, and annually ranks among the top 10 producing countries for coal and top 20 for oil. Over the past two decades, it has nearly quadrupled its oil output[1] and is emerging as a new global oil-producing "heavyweight"; most of the incremental oil production growth within the Commonwealth of Independent States (CIS) over the next two decades is expected to come from Kazakhstan.

Challenges and Opportunities

Despite this endowment and muscular energy production profile, however, Kazakhstan's landlocked location in the heart of Eurasia poses challenges to the full realization of its natural wealth. In particular, the issue of transportation to markets assumes outsized importance in the country's energy development decisions, as not all of the country's energy resources are equally transportable. Fortunately, hydrocarbon fuels (mainly oil) have a high value relative to their transportation costs, paving the way for their development and export (the national market is relatively small). Yet counterpoised against the challenge posed to Kazakhstan's energy development by distance and the country's interior location is an enormous opportunity: Kazakhstan shares a 1,783 km border with the world's largest energy market, China. That country plays a key role in Kazakhstan's efforts to develop a "multi-vectoral" energy strategy that emphasizes diversification in export markets and sources of foreign investment.

A similar juxtaposition of opportunity and challenge is evident when considering specific energy resources. For instance, Kazakhstan's Tengiz (onshore) and Kashagan (offshore) oil fields are two of the largest finds in the world over the past 40 years, and have attracted the participation not only of the state oil and gas company KazMunayGaz but also the largest and most important international oil majors. Their oil is light and sweet[2]—two attributes that increase its attractiveness for export—but lies at great depth, under high pressures, and with associated gas that has a high sulfur content. Further,

[1] In 1994 Kazakhstan's national oil and gas condensate production was 20.3 million metric tons (MMt) compared to 80.8 MMt in 2014; meanwhile at independence in 1991, national output amounted to 26.6 MMt.

[2] Both Tengiz and Kashagan are considered to be light sweet crudes. Tengiz crude has a density of 789 (kg/m^3) or an API gravity of 46.8°. Its sulfur content (by weight) is 0.5% as assayed. Similarly, Kashagan crude has a density of 45–46° API and a low sulfur content (0.1%). Despite the low sulfur content of Tengiz and Kashagan crudes, both contain relatively high levels of mercaptans, a type of sulfur compound. Both Tengiz and Kashagan employ field-processing units to remove the bulk of the mercaptans in the field. And unlike the case with crude, the associated gas at Tengiz and Kashagan is quite sour (sulfurous; 18–19% sulfur content) and requires special processing to remove sulfur and other impurities; this is one of the considerations underlying the high (existing or planned) rates of gas reinjection in these fields.

because of the shallow water and cold climate at Kashagan, conventional offshore drilling and production technologies (e.g., fixed or floating platforms) cannot be utilized; instead artificial islands must be constructed to protect drilling and extraction equipment from pack ice. Thus, although supply is abundant and the quality of the resource is high at these major fields, unique and costly technological solutions and infrastructure are required for its extraction and processing, far from engineering and construction centers and with difficult supply logistics for equipment and other materials. Over time, however, the experience gained in working these fields should lead to increasing efficiencies and reduced operating costs, as well as valuable research, development, and engineering experience [know-how] that can be transferred to the development of future deposits with similar operating environments and geological conditions (deep pre-salt reservoirs)—both in Kazakhstan and elsewhere in the world.

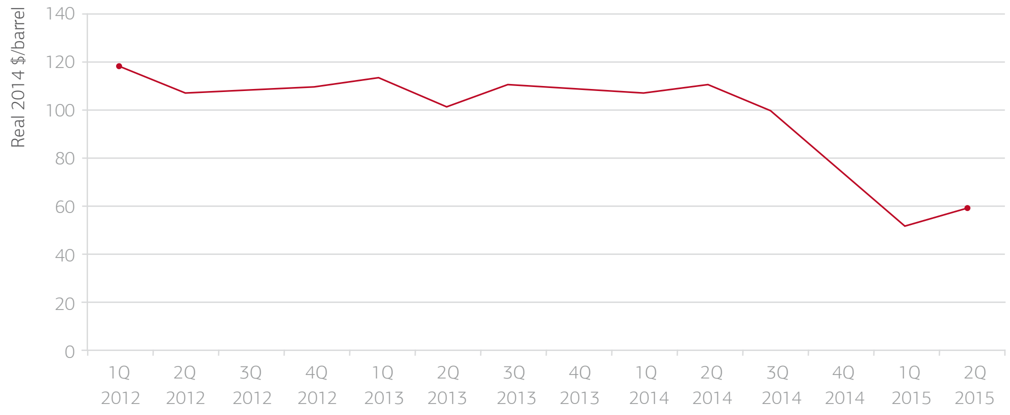
Kazakhstan holds significant natural gas reserves, two-thirds of which are in the form of associated gas that occurs in the same productive horizons as oil. Thus, it is usually not possible to make decisions regarding the extraction of this gas independently from those concerning oil. Consequently, the rapid acceleration of oil production in Kazakhstan has been accompanied by questions of how to manage increasing volumes of byproduct gas—whether to re-inject it into oil-bearing strata to maintain reservoir pressure, use it in the domestic economy, or find markets for its export. Over time, progress along each of these pathways of gas utilization should yield benefits for Kazakhstan, although the economic feasibility of the solution should give preference to one method over another. For example, expanding gas exports substantially is likely to be challenging given the abundance of low-cost gas found in neighboring Russia and Turkmenistan, as well as the ample supply of gas globally.

Another opportunity is presented by thick seams of coal in north-central Kazakhstan that lie near the surface. A well-known example of this is the Ekibastuz Basin. The costs of mining this coal via surface methods are among the lowest in the world (about $6-7 per ton). However, the coal from the Ekibastuz Basin has a high moisture content and relatively low heating value, as well as high ash and sulfur content. This, plus the great distance to potential export markets for a relatively bulky commodity, presently limits coal's use primarily to electric power generation domestically and in the nearby Urals region of Russia. The further development of "clean coal" utilization and processing technologies may make it possible to more fully unleash the potential of Kazakhstan's coal reserves and resources in the future.

Finally, the costs of mining Kazakhstan's uranium resources are relatively low, as almost all current production is from sedimentary deposits that can be exploited using the relatively low-cost and environmentally friendly in-situ leaching (ISL) method. Together with a demand surge in China as that country builds out its nuclear capacity, this has presented an opportunity for Kazakhstan to grow its exports as rapidly as it can increase production. Roughly three quarters of China's uranium imports since 2010 have been devoted to building inventory, however, raising questions about the continued sustainability of past high levels of these imports once China's inventory build-up is completed. But even if Chinese imports were to moderate, world uranium demand is projected to increase through 2035; this should mean that new markets, albeit in the form of a limited number of largely state-owned or state-regulated consumer companies, will be available for future Kazakh uranium exports.

The Changing Global Environment

In addition to this particular set of opportunities and challenges, which can be considered relatively durable over the near to medium term, major new uncertainties have arisen since publication of The National Energy Report 2013, a result of major shifts in the global and regional business environments. Foremost among these are the changing supply and demand fundamentals in the world oil market. More specifically, a stalemate in place for several years between two countervailing forces—rapid non-OPEC production growth (led by the United States) and political instability focused in the Middle East and North Africa—has now been broken, creating a situation of sizable over-supply in global markets. Non-OPEC supply in 2014 registered the largest gain (1.95 million barrels per day [MMb/d]) since 1978, triple the growth in world oil demand (0.6 MMb/d). The shattering of this stalemate due to additional crude output from Libya and Iraq, and the key decision by OPEC not to cut production in response, was followed by a plunge in oil prices (see Figure 1.1). In 2015, in the half year after the price collapse, an additional two million barrels per day came to the world market from increased production the United States, Saudi Arabia, and Iraq. Aggregate OPEC supply might also eventually increase substantially given an agreement reached on 14 July 2015 between Iran and the five permanent members of the United Nations Security Council (plus Germany) resulting in the lifting of the wide-ranging economic, financial, and trade sanctions that have restricted Iran's oil exports.



Source: IHS Energy

Figure 1.1 Dramatic collapse of the Brent price in the second half of 2014

The lower oil price—and heightened prospects for price volatility—add an element of economic unpredictability to the political uncertainty already encountered in many oil-producing regions. By reducing their revenues, it also shrinks the pool of cash international majors and state oil companies have available for investment in new field development, which has led them across-the-board to re-evaluate projects. The international companies are postponing or cancelling major projects and are reducing their work forces. "Capital discipline" has become the new mantra in the senior managements of these companies.

This new situation is creating a different investment framework and a different investment state of mind than existed in the period 2004–2014. A key implication of the combination of rising non-OPEC oil production—particularly from North America—the shifting demand picture and global trade flows, and anticipated downward price pressure (that will continue to slow recovery in prices) is that terms and conditions for energy resource development in some producing countries around the world, including Kazakhstan, may need to be re-evaluated to determine whether they remain competitive for attracting international investment.

A second major uncertainty surrounds the economic impacts of sanctions imposed by the EU, US, and other states on Russia, in connection with the ongoing crisis in Ukraine. Initially imposed as a travel ban and a freezing of the assets of a select few wealthy businessmen and banks with direct ties to the Kremlin in March 2014, the sanctions later were expanded to key sectors of the Russian economy—finance, the defense industry, and oil production. In the latter sector, a ban was placed on the transfer of technology and equipment used in the development of offshore deepwater, Arctic offshore, and onshore unconventional oil fields and several oil companies (e.g., Rosneft, Transneft, Gazprom Neft, LUKOIL, and Surgutneftegaz) were specifically targeted for financial sanctions.

Although Kazakhstan and other states with close economic ties to Russia are not targeted directly by the sanctions, the measures are nonetheless having an effect. Thus far, the most discernible sign of reverberations in Kazakhstan is mounting pressure on its currency, the tenge, against the ruble, euro, and dollar.[3] Further devaluation of the tenge would, of course, boost the competitiveness of Kazakhstan's exports. Oil exports, however, are a special case in this regard. Because oil export revenues are denominated in dollars and oil production costs in local currencies, a depreciating currency cushions to some extent the blow to Kazakhstan's producers from losses in revenue from falling world oil prices.

However, due to Kazakhstan's growing imports in recent years, any currency depreciation would put increasing pressure on its current account balance by making these imports more expensive. Whereas import substitution is feasible in some sectors, this is not the case throughout the entire economy. Many high-value products and services for the oil and gas sector cannot be supplied at present by local Kazakh suppliers—regardless of the exchange rate. Moreover, oil and gas sector projects whose output is not primarily destined for export will see their costs rise. Kazakhstan's refineries, for example, are being upgraded; while investments in expensive equipment are undertaken in foreign currency, almost all of the light products (the yields of which will increase) will be sold domestically in tenge. But a depreciation of the national currency will primarily affect the living standards of the population.

One of the major unknowns in the near term will be the future course of these economic sanctions. For example, the EU's sectoral sanctions on Russia's oil industry, financial sector, and defense industry were set to expire at the end of July 2015; their extension required unanimous approval of the 28 member states. But so far the EU has been able to maintain a unified front on the issue and in March 2015 effectively extended the sanctions to the end of 2015. The US measures, initially implemented by executive order so that they could be quickly reversed if warranted by progress on the diplomatic front, now appear to be more durable. On 18 December 2014, US President Barack Obama signed bipartisan legislation passed by the US Congress that further cordons off large Russian firms from Western financing and technology. The fact that previous sanctions are now codified into US law makes them much more difficult to fine-tune in the future

[3] In February 2014, Kazakhstan's central bank devalued the tenge (it fell 19% against the US dollar) in an effort to bring its currency into greater alignment with that of Russia, its Customs Union (and later Eurasian Economic Union) partner. The ruble's fall, which accelerated after the imposition of sanctions, makes Kazakhstan's exports to Russia more expensive and less competitive.

or to later rescind, as Congressional approval is required.[4] Thus Western (US, if not also EU) sanctions on financing, technology transfer, and goods and services exports will be at least a medium-term feature of Russia's oil and gas landscape, with ripple effects for other countries with close economic ties to Russia.

A final dimension of uncertainty involves how energy trade relations will evolve within the framework of the new Eurasian Economic Union (EEU), which came into existence on 1 January 2015. The EEU supplants the former Customs Union (from January 2010), which eliminated customs duties on trade between its three original member states (Belarus, Kazakhstan, and Russia), but largely excluded most trade in energy commodities from its general trade rules. Rather, energy trade among Customs Union members was governed largely by special bilateral trade agreements. This situation is planned to be gradually rectified under the EEU framework, when a single market for energy is to be forged by 2025. Russia is the dominant partner in the EEU, if for no other reason than the size of its market (146.3 million population), which dwarfs that of the other four member countries (Armenia, Belarus, Kazakhstan, and Kyrgyzstan) combined (35.5 million). This suggests that harmonization of energy policy, to the extent that it occurs, will entail that other EEU member states make policy adjustments that gravitate toward conditions in place in Russia.

Given both the enduring set of challenges and opportunities as well as the new uncertainties described above, it is especially critical for government decision makers and business leaders in Kazakhstan, existing and potential investors in Kazakhstan's energy sector, public opinion leaders, and the interested public to have access to a timely fact-based assessment of key issues, problems, and opportunities in each sector of Kazakhstan's energy industry. In this report, IHS Energy, through the sponsorship of KAZENERGY Association, its members, and other experts in Kazakhstan, will seek to identify best world practices and their application to energy production and resource management in Kazakhstan, highlight areas for policy intervention and reform, and provide insights essential in charting key directions for Kazakhstan's future energy policy. The approach used in this report will be both expositionary—describing the current situation, the interrelations of its components, and the direction in which developments are trending—and analytical—comparing positives and negatives, identifying and analyzing key issues, and providing IHS assessment of general costs and benefits of particular developments in the country's energy sector.

The National Energy Report 2015

The report will retain a strong continuity with The National Energy Report 2013, providing comprehensive coverage of all sectors across the energy industry and within each sector. In addition to a sector-by-sector treatment of Kazakhstan's multi-faceted energy industry, this report will also present an integrated view of the industry that will emphasize interconnections among sectors and the importance of a comprehensive, cross-sector management perspective. We believe it is important during this time of turbulence and transition in the energy industry, which has called into question some of the fundamental assumptions underlying long-term planning and investment, to bring new perspectives to bear on major questions that can be used to forge strategies for navigating the current economic cycle.

The report begins with an assessment of the importance of the energy sector to Kazakhstan's economy (Chapter 2) and a description of the role of government and regulatory institutions (Chapter 3). Chapter 4 outlines key global trends in energy production and consumption and their relevance to Kazakhstan. Chapters 5 and 6 introduce new themes not covered in The National Energy Report 2013, examining, respectively, (a) Kazakhstan's attractiveness as a destination for oil and gas investment and (b) the strategic role of China in Kazakhstan's energy industry as a development partner and export market. This is followed in Chapter 7 by a comprehensive review of Kazakhstan's hydrocarbon-producing sectors, encompassing petroleum exploration and geology; crude oil and gas condensate production; natural gas production, consumption, and transport; liquefied petroleum gas; petroleum refining; and the system of hydrocarbon taxation. The coal, uranium, and electric power sectors (including renewable energy) are analyzed in Chapters 8–10, respectively. Chapter 11 reviews the current energy intensity of Kazakhstan's economy and explores the potential for energy efficiency improvements and resource saving, both in the energy sector and the broader economy. Chapter 12 is devoted to the key issues of further developing the domestic oil services industry and provides an overview and future direction of local content requirements in Kazakhstan's upstream development. Chapter 13 examines environmental issues in Kazakhstan (with an emphasis on those tied to energy development and consumption) and the evolving international policy framework on climate change. Each chapter begins with "key points" relating to the sector and concludes with "key recommendations" for the future development of that segment.

One of the key themes highlighted in the report is Kazakhstan's present comparative advantage as an energy producer. Although economic diversification remains a mantra for all commodity-exporting states, including Kazakhstan, husbanding hydrocarbon resources by delaying their development is a strategy that yields an uncertain result. This is because possible advances in energy use and production technologies ultimately make the future value of hydrocarbon resources difficult to predict. Thus, postponing development now in the expectation of a more favorable price environment in the future runs the risk of being like setting aside a typewriter in the 1960s for a future grandchild who will instead end up using an iPhone in 2015. Possible appearance in the next decade of the first commercial prototypes of quantum batteries (electric power accumulators) may lead to a revolution in the global energy balance, significantly reducing the need for oil[5] due to rapid growth of the share of electric transport. A major breakthrough is also possible in the nuclear power sector through development of fast breeder reactors (producing fissile elements) using high-density nitride uranium-plutonium fuel (e.g., the new BN-800 reactor at Russia's Beloyarsk

[4] One need only recall the persistence as late as 2012 of the 1974 Jackson-Vanek Amendment (enacted by the US Congress in response to the USSR's efforts to curb the emigration of Soviet Jews) to understand the effort that would be required to reverse them.

[5] Transport accounts for 59% of oil consumption globally. "Oil Demand by Sector," World Oil Outlook OPEC 2014.

nuclear plant) and subsequent transition to a closed nuclear fuel cycle through which the efficiency of nuclear fuel utilization increases tenfold.

Moreover, the energy sector itself may provide a beneficial platform from which to launch economic diversification initiatives. Efforts already underway to "deepen" the processing of energy resources being produced in Kazakhstan—e.g., refinery upgrades to obtain a higher share of light fractions; extended uranium cycle; the launch of new petrochemical plants—represent a promising foundation that may lead to further economic diversification.

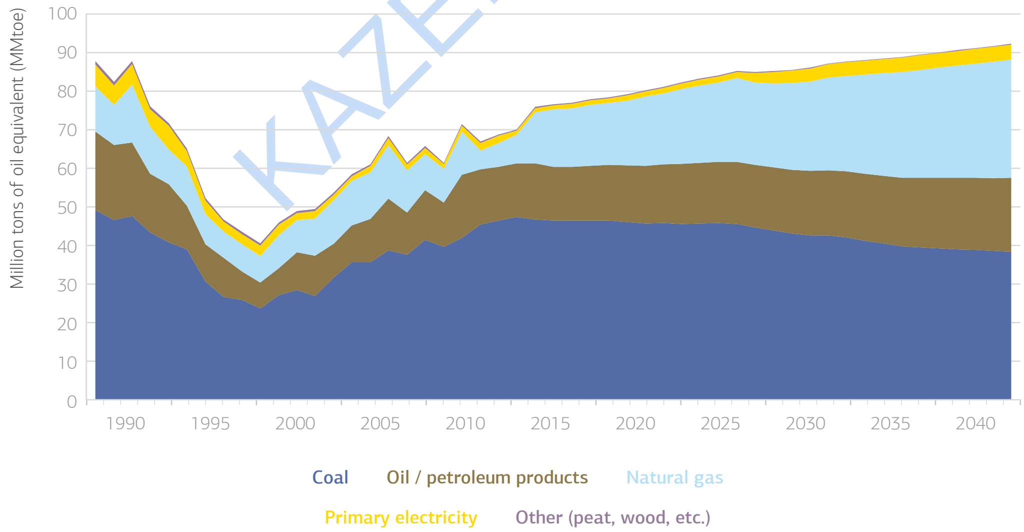
1.2. Executive Summary

Key Points

- Kazakhstan's traditional position as a world-class oil producer and exporter, the very cornerstone of its economy, is being challenged by the unconventional hydrocarbon revolution in North America. Rapid growth of unconventional hydrocarbon production in North America was a major factor in the decline in global oil prices in 2014, and the ample resource available there in a relatively benign investment environment has undermined much of the rationale for companies to "chase reserves" internationally. Investment conditions in many host countries around the world, including Kazakhstan, are no longer competitive to attract a diversified mix of investment. To restore its competitiveness for international investors, Kazakhstan needs to review its fiscal terms and conditions and improve the quality of its decision-making.

1.2.1. Energy's importance to the economy of Kazakhstan

Kazakhstan's economy is based largely upon extraction of natural resources, led by energy resources. This reflects its relative resource endowment, as the country possesses substantial reserves of oil, gas, coal, and uranium. The country's total primary energy reserves (including oil, gas, coal, primary electricity, and uranium) are estimated at roughly 32 billion tons of oil equivalent (toe), representing about 3.6% of total world proved primary energy reserves.[6] The country's total primary energy production has been increasing at an annual rate of 5.5% since 2000, while primary energy consumption over the same period increased by 4.3% annually (see Figure 1.2).



Source: IHS Energy

Figure 1.2 Kazakhstan's primary energy consumption

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[6] By convention, primary energy production does not include mined uranium, but only its contribution to electricity production in a nuclear power plant based upon the amount of electricity generated. But at the resource level, one ton of natural uranium is considered to be capable of producing more than 46 million kilowatt-hours of electricity, which is equivalent to burning 20,000 tons of hard coal or about 12 thousand tons of oil. Energy content of 1 ton of enriched uranium fuel (3.5%) is equal to 93,000 tons of crude oil.

Kazakhstan is a net energy exporter, consuming less than half of its total primary energy production. The energy sector is of great importance for the country's economy, accounting for about 22% of the country's GDP, two-thirds of total export earnings, and 50% of state budget revenues.[7] At the same time, Kazakhstan's economy is highly energy intensive: it takes 314 tons of oil equivalent to produce one million dollars of GDP (in 2014 constant dollars), making Kazakhstan one of the world's more energy intensive economies. The high energy intensity is primarily explained by the country's economic structure, which is dominated by heavy industry and mineral extraction, by Kazakhstan's high-latitude location and distinctly continental climate (increasing heating costs), large land area and relatively low population density (increasing energy transport and distribution costs), and dominance of coal (which has a lower conversion efficiency than many other sources of energy) in primary energy consumption. The high energy intensity is also due to a relatively low efficiency in energy use in industry, the energy sector, and the housing/municipal sector. Overall though, Kazakhstan's aggregate energy intensity has been improving steadily: it has fallen by more than half since 1995.

Not surprisingly, given the strategic importance of energy to Kazakhstan's overall economy, the state exercises a high degree of influence over the energy sector. The President is empowered by Kazakhstan's constitution to determine the strategic directions of energy policy, although the key institution in everyday policymaking is the Ministry of Energy (MOE), formed in August 2014. The MOE is envisioned as the primary body in charge of the entire energy sector, and consolidates the responsibilities previously exercised by the now defunct Ministry of Oil and Gas as well as certain duties of two other liquidated ministries (Ministry of Industry and New Technologies and Ministry of Environment and Water Resources). Kazakhstan's parliament also has a role to play, reviewing policies developed and proposed by the MOE and other government bodies and enacting relevant legislation.

Government bodies, especially the MOE, exercise regulatory and control functions in the energy sector, although operation and investment decisions are carried out by corporate entities and companies (both privately and state-owned).[8] The national oil and gas company KazMunayGaz (KMG) represents the state's interest in Kazakhstan's oil and gas industry, and holds equity interests in all major as well as many smaller production projects. Kazakhstan's Law on Subsoil Use governs activities in the oil and gas industry (and other extractive sectors) and includes provisions that establish local content requirements for oil and gas contracts as well as the state's right to preempt any sale of oil and gas assets that are deemed to have strategic significance. Although the government restructuring carried out in August 2014 resulted in improvements in energy policy and regulation, there is still room for streamlining the distribution of authority over the energy sector among government bodies.

The international market in which Kazakhstan's energy producers operate has been profoundly shaped by a number of key trends. First, in oil, strong conventional and unconventional production growth in North America, Brazil, and the Middle East/North Africa (Libya, Iraq) has resulted in stronger-than-expected global supply growth; in 2014 non-OPEC supply growth by itself was triple the increase in global demand. This has resulted in a substantial near-term decline (by roughly 50% since mid-2014) in global oil prices. A period of readjustment will be required for production to reach a new equilibrium with demand, during which downward pressure on prices is expected to remain a strong feature. During this period, new upstream investment will be curtailed, and higher marginal cost producers—including unconventional producers in North America and offshore producers in some regions (e.g., North Sea)—will face pressure to restrain production. Moreover, OPEC appears to have decided that it will not intervene in the oil market and has left market forces alone to balance supply and demand.

For natural gas, the assessment of the size of the global resource base is shifting to the upside. The industry has traditionally thought of natural gas supply as sufficient to support 60 years of current consumption, but potentially recoverable global reserves of unconventional gas—including both shale gas and coal bed methane (CBM)—are now estimated at 250 years of current consumption. The United States has emerged as a leader in unconventional gas production, reflecting a favorable combination of geology, legislation, openness to technological innovation, and investment capital. However, whether unconventional gas truly will become a "game-changer" in the supply picture outside North America is not completely certain. It is unclear whether the factors leading to the successful North American experience will be replicated elsewhere, and over the near term the picture is clouded by the low oil price environment.

The enhanced supply potential and low production costs in North America have energized gas export plans based on liquefied natural gas (LNG). The first of these projects are about to come on stream, changing global LNG markets from supply-constrained to loose. It is possible that, early in the next decade, the United States will become the largest exporter of LNG. While increasing amounts of uncontracted (and perhaps distressed) LNG will be directed into the stagnant European gas market, especially in the near term—and with consequences for Russian gas exports to Europe—this actually has relatively little impact upon Kazakhstan or Kazakhstan's gas development, which is seen to be primarily domestic.

Renewable energy also appears to have reached a turning point. As a result of the global scale of operations (with large state support for renewable energy) and production cost reductions achieved in recent years—as well as implementation of the policy aimed at reducing carbon emissions—renewable energy is expected to continue to become an important source of new energy for global power generation. However, the recent accelerated growth and investment in renewable energy capacity occurred during a period of historically high oil prices. The current lower price environment for oil and

[7] The share of oil and gas alone in Kazakhstan's GDP was officially calculated as 20.3% in 2014, including all activities—extraction, processing, transportation, and related services. This was down slightly from 21.6% in 2013. The share of the other energy extraction sectors—coal mining, uranium mining—and the electric power sector accounted for 8.3% of the gross value of industrial output, while the contribution of industry to GDP was 27.9% in 2014, so the contribution to GDP of these other parts of the energy sector would be less than 2.3% because much of the gross value of electric power is comprised of the cost of fuel inputs (mainly coal) from extraction.

[8] Production tends to be highly concentrated. For example, in the oil industry 80 companies currently have operations in Kazakhstan, but the five largest oil producers account for 72% of total output.

gas, which further decreases the overall competiveness of renewables, will undoubtedly slow, but not halt, the renewable industry's development and growth over the near term. However, for renewables to play a greater role in the energy mix going forward, costs need to continue to come down and deeply embedded structural constraints to the competitiveness of renewable energy and the challenges of integrating onto existing grids must be surmounted.

A key implication of rising non-OPEC oil production and downward price pressure going forward is that terms and conditions for resource development in some host countries are no longer competitive for attracting international investment. Whereas in the past oil companies "chased reserves" globally and host countries took advantage of this need by enhancing the government "take," today an uncertain price environment is leading oil companies to cut back capital spending plans and generally take a very cautious approach to new projects. This complicates the efforts of host governments around the world (including Kazakhstan) to attract upstream investment.

One of the major considerations in energy-sector investment decisions is the host-country tax regime on hydrocarbons. Kazakhstan's Tax Code (introduced in January 2009) includes multiple tax instruments as opposed to just one or two; this combination has the potential to provide a greater balance of interests between the producers and the government over the life of a project. Major taxes that apply in the fiscal regime include corporate income tax, rent tax on exports, bonuses, a mineral extraction tax, excess profit tax, and an export duty. This regular fiscal regime is in force for almost all existing subsurface users, with the exceptions being those few contracts with stability clauses that came into effect prior to January 2009.

Kazakhstan's overall tax take for upstream projects is relatively high compared to other major oil producers. Moreover, the tax instruments are structured to ensure early revenue for the government before profitability has been assured for the producer. It is also problematic that the regime employs two different taxes or duties on exports, which are essentially redundant. In the emerging more competitive environment for attracting investment, it may be productive for Kazakhstan to streamline its taxation system while reducing tax rates overall. Further, although new PSAs are no longer allowed under the new Tax Code, offering a versatile, stable, long-term legal framework for subsoil use can be attractive to both the contractor and government since it can be adjusted to suit particular project circumstances without changing the overall fiscal framework for the country. Kazakhstan may benefit from a more differentiated approach to subsoil contracts, especially for large, high-risk projects with long gestation periods for investment; otherwise investors would be unwilling to take on such high-risk and high-cost projects.

As a preliminary measure of Kazakhstan's overall attractiveness as a destination for upstream oil and gas investment, this report employs a proprietary IHS index that provides consistent comparison and ranking of government take, rate of return, profit-to-investment ratio, and progressivity/regressivity of international fiscal systems together with other factors such as risk of return and flexibility and stability of the fiscal systems. Just comparing 12 peer group jurisdictions, Kazakhstan's composite score was the second worst from an investor perspective, better only than Russia's. This suggests that measures to further improve the investment environment in Kazakhstan could increase the country's attractiveness to potential new investors. In summary, high government take, the significant frontloading of revenue accruing to the government over the life of a project, and relatively frequent changes in fiscal terms are the major detractors to Kazakhstan's current overall ranking.

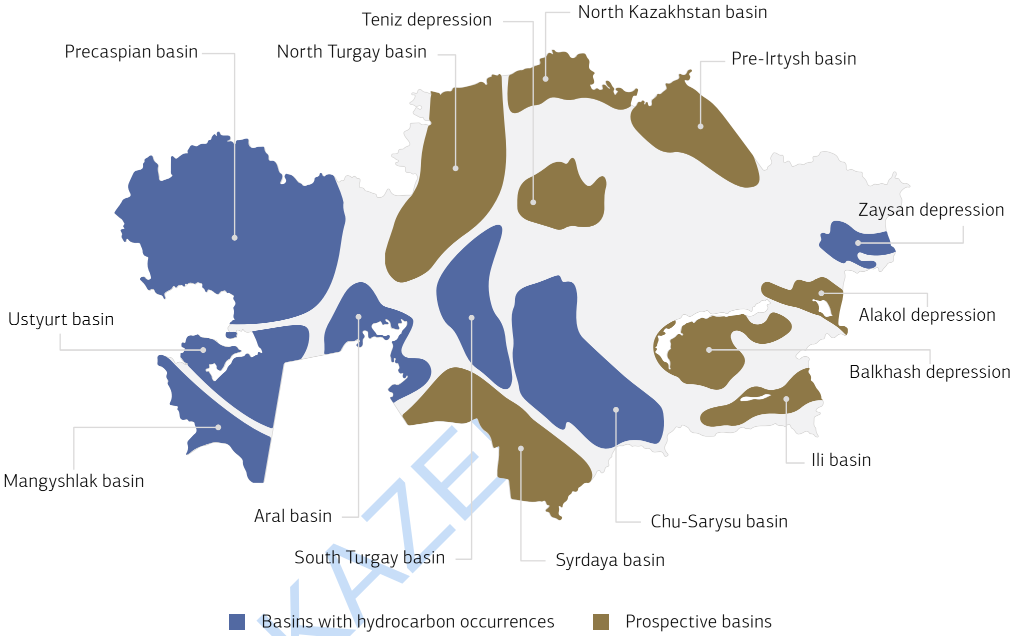
Nonetheless, to date Kazakhstan has attracted substantial outside investment for its hydrocarbon projects. In addition to the international oil majors involved in the three mega-projects, Chinese companies have invested sizeable sums—often in projects that had not attracted other investors—and have become one of Kazakhstan's key strategic partners in the process. A major goal for Chinese investors in Kazakhstan is to secure sources of energy for China that diversify supply and can be delivered overland via non-traditional routes. This means that Chinese investors are not as focused on purely economic aspects of the projects, such as rates of return and market netbacks. A substantial number of Chinese companies, both state-owned and private, are involved in Kazakhstan's energy development, in activities mainly focused on hydrocarbons, including upstream development and pipeline construction, as well as domestic oil refining and gas processing. As energy-sector cooperation between the two countries gained momentum after 2000, the Chinese equity share in Kazakhstan's oil production increased rapidly, reaching about 24% 2009. Because China's upstream assets in Kazakhstan mostly involve mature fields, the potential for production growth is limited; in fact, aggregate output from these assets has been declining in recent years. However, this may change following the acquisition by the China National Petroleum Corporation (CNPC) of an ownership stake in the Kashagan field, particularly if the field's Phase 2 development is sanctioned.

Kazakhstan's interest in energy-sector cooperation with China also includes accessing China's market for energy exports. Since Kazakhstan's independence, the country has pursued a "multi-vectoral" approach in its energy development strategy, seeking diversity not only in sources of investment for upstream development and pipeline construction but also in markets for its energy exports. Although oil and gas exports from early major projects involving Russian, Kazakh, and international oil company investors reached outside markets via pipelines largely traversing Russia, over time Kazakhstan's geographic proximity and economic complementarity with China (Kazakhstan as a major producer; China as a major consumer) have meant that oil and gas pipelines to China can serve as logical alternatives for diversifying the country's exports. The Atasu-Alashankou segment of the China-Kazakhstan oil pipeline currently delivers almost 12 million metric tons (MMt) of oil from Kazakhstan to China, and its planned westward extension to fields in western Kazakhstan could increase annual export flows up to the pipeline's current capacity of 20 MMt per year. "Beyneu-Shymkent Gas Pipeline" LLP, a joint venture between KMG subsidiary KazTransGaz and CNPC subsidiary Trans-Asia Gas Pipeline, is building the Beyneu-Bozoy-Shymkent pipeline to deliver natural gas from areas of production in western Kazakhstan to demand centers in southern Kazakhstan. The pipeline will link with Line C of the Central Asia–China natural gas pipeline network, setting the stage for annual exports of up to 5 billion cubic meters (Bcm) of Kazakh gas to China at some future date.

However, the notion that escalating Chinese demand will continue to support rapidly rising imports of a wide range of energy commodities now requires recalibration. This will have major implications for commodity exporters worldwide, including Kazakhstan. The new Chinese government appears committed to a momentous shift in the country's macroeconomic policy priority, away from an investment-led growth strategy based on exports of manufactured goods toward one focused more on increased domestic consumption and expanded tertiary- and quaternary-sector activity. This will have a major effect on rates of national GDP growth and energy consumption; these are expected to moderate as a consequence. Technological advances in ultrahigh-voltage (UHV) transmission of electricity within China also could contribute to decelerating growth in China's energy imports by utilizing previously stranded coal, hydro, and other energy sources in the country's interior to generate power for demand centers in coastal provinces. Nonetheless, for the most part existing energy supply arrangements between China and international trade partners should continue, reflecting China's commercial and strategic interests as well as a desire for supply diversification.

1.2.2. Hydrocarbons

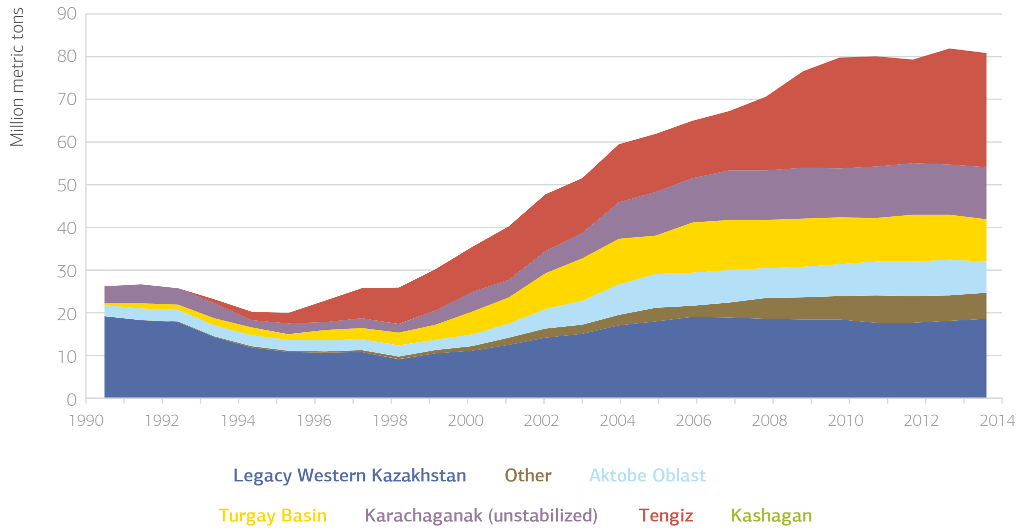
Kazakhstan ranks twelfth in the world in total liquids (oil and gas condensate) reserves. It has a number of petroleum basins with proven hydrocarbon occurrences, among which the Precaspian (North Caspian) Basin stands out as by far the most prolific, with both the largest proven and probable (2P) reserves: the basin's initial 2P oil and gas reserves account for 79% of the country's total. Kazakhstan also most probably is endowed with unconventional hydrocarbon plays, although no systematic analysis has thus far been conducted (see Figure 1.3). A lack of consensus exists at present on whether the time has come to examine this potential or not.



Source: IHS Energy, KazEnergy

Figure 1.3 Kazakhstan's sedimentary basins

Kazakhstan is the second largest oil producer among the Soviet successor states after Russia. Among the countries of the world, Kazakhstan currently ranks 17th in oil production (up considerably from 26th in 1997), accounting for about 2.0% of the world total in 2014. Kazakhstan's crude production has nearly quadrupled since the mid-1990s from 20.3 MMt (or 405,000 barrels per day) in 1994 to 80.8 MMt (or 1.7 million barrels per day [MMb/d]) in 2014 (see Figure 1.4). Much of the expansion of oil production in Kazakhstan over the past decade has been driven by two large projects, Tengiz and Karachaganak, being developed by consortia that include major international oil companies as well as the national oil company KMG. This is a trend that will clearly continue into the next decade with the launch of the first-phase development of another mega-project—the mammoth Kashagan field, fifth largest in the world in reserves—slated to re-start by 2017.



Source: IHS Energy, EOEO

Figure 1.4 Kazakhstan's oil production by producer category since 1990

But Kazakhstan's national production growth has faltered since 2011, largely due to delays at these major projects. Output actually declined by 1% in 2012, mainly the result of a fall in output at the TengizChevroil (TCO) project (Tengiz field), connected with a major capital overhaul of field facilities. National output declined again slightly in 2014, as Kashagan output remained shut-in and TCO underwent another round of regular maintenance.

The sensitivity of Kazakhstan's national output to delays at the mega-projects is mitigated somewhat by significant production growth from smaller producers, who now account for about 10 MMt of output or 12.4% of the national total (up from only 1.2 MMt or a mere 3.5% in 2000).[9] Properly incentivized, small producers can help to even out the overall oil production profile year on year. Due to their relatively larger number—70 small companies registered oil production in 2014—delays at any one project are less likely to affect the national total. They can also play an important role by reworking mature fields more intensively and by creatively developing new resource plays that then may become available to the large companies.

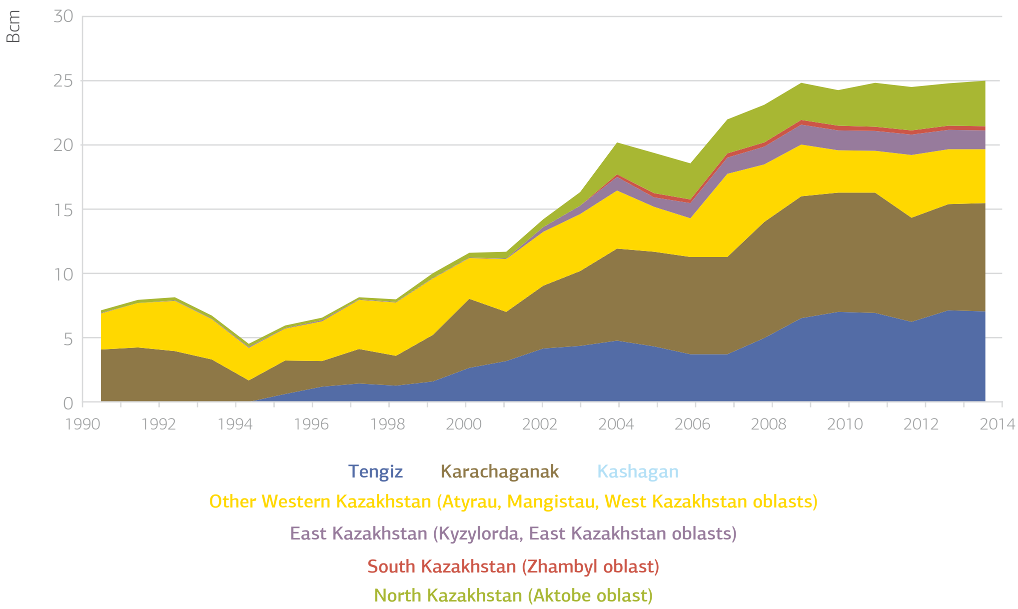
Kazakhstan has always exported the bulk of its crude production (over 80%). Its total crude exports have increased from 20.3 MMt (425,000 b/d) in 1992 to 62.9 MMt (1.32 Mb/d) in 2014 (excluding 7 MMt of Russian transit crude), a more than threefold increase. For the oil consumed in the domestic economy, a major program is underway to reconfigure the mix of products from the country's refineries to more closely meet the needs of its modern economy. Kazakhstan's three main refineries were built during the Soviet period, and have seen very limited modernization since independence. Because of a lack of refining depth, the country's refineries still turn out a significant amount of residual fuel oil (mazut), while demand has shifted decisively toward light products—gasoline, diesel fuel, and jet kerosene—with the ongoing modernization of its economy.

As a result, Kazakhstan ends up exporting a large portion of its own refined products output (primarily mazut for further processing), while it must import light products, mostly from Russia, to meet domestic demand. In aggregate, Kazakhstan's refineries cover only about 78% of domestic product consumption, with imports covering about 22%. To address this imbalance and reduce the volume of products imports, Kazakhstan has launched a major refinery modernization program which should significantly alter the product slate toward light products. Another major downstream project is the planned construction of a fourth major refinery in Kazakhstan, aimed at eliminating the need for imports. Because the future growth in aggregate consumption of light products in Kazakhstan is expected to be relatively modest, however, the construction of a fourth major refinery would result in significant excess capacity for domestic needs. There also are only fairly limited possibilities for refined product exports given the country's inland location.

While Kazakhstan's emphasis in the hydrocarbons sector remains first and foremost on oil production, it also has substantial 2P gas reserves (3.9 Tcm), almost all of which are located in the western part of the country. The bulk of Kazakhstan's gas is produced in association with oil (either as associated gas or condensate-related gas) at the two operating oil mega-projects. Commercial volumes remain secondary to the need to maximize oil production.[10] Reinjection is also an important form of gas utilization. Kazakhstan reinjects about 40% of its associated gas output (18.4 Bcm of 43.2 Bcm of gross output in 2014) to maintain reservoir pressure and realizes only about 60% of its gross gas output as commercial volumes, including own use (see Figure 1.5).

[9] These are defined as companies producing less than 1 MMt (20,000 b/d) per year.

[10] For the purposes of this report, commercial gas volumes are defined as gross gas production minus reinjection volumes, so they include upstream losses and shrinkage, use and losses in the pipeline system, and any changes in stocks.



Source: IHS Energy, EOEO

Figure 1.5 Kazakhstan's gross gas production by producing category

Nonetheless, gas is likely to become increasingly important for domestic consumption; currently gas consumption remains relatively small—accounting for only about 17.5% of the country's primary energy balance—but it is expected to grow robustly going forward. Gas consumption still remains below Soviet-era levels but is expected to about double over the next two decades, albeit from a relatively small base. A major initiative toward the gasification of the economy is construction of the Beyneu-Bozoy-Shymkent pipeline, and perhaps over the longer term a pipeline linking Astana with Russian gas or with domestic supplies at Karachaganak. Pipeline gas is presently available in only 10 of Kazakhstan's 14 oblasts; in the other four (in the northern and central parts of the country) bottled liquefied petroleum gas (LPG) is used.

To promote domestic gas consumption, the government of Kazakhstan has placed the domestic gas market within the responsibility of KazTransGaz (KTG), as the designated "national operator" for the county's single-buyer model. KTG, already the monopoly operator of most trunk gas pipelines in the country, has preemptive rights to purchase associated gas from producers, sell gas on the local market, and export gas. Kazakhstan's single gas buyer model relies on availability of associated by-product gas rather than development of dry gas, which longer term could delay domestic market development.

1.2.3. Coal and uranium

Kazakhstan is a significant producer and consumer of coal. It has the world's eighth largest proved reserves of coal (balance sheet [recoverable] reserves are 34.2 billion tons), almost 4% of the world's total and sufficient to support current rates of production for 250 years. It annually ranks among the top 10 countries in the world in coal production (108.7 MMt in 2014). However, most coal deposits have high moisture content and relatively low heating value, as well as high ash and sulfur content. These characteristics, as well as high levels of methane in most deposits, mean that the production and consumption of coal in Kazakhstan has a heavier environmental impact than in many other parts of the world, despite the fact that some deposits (e.g., Ekibastuz) are economically very competitive due to their very low extraction costs. Typically, some 25-30% of total output is exported (chiefly to Russia), although the country faces a difficult environment for boosting exports, given challenges to the competitiveness of Kazakhstan's coal in international markets.

Coal is also the fuel that drives Kazakhstan's economy, currently accounting for over 60% of the country's primary energy consumption. Although coal's relative share is expected to decline gradually over the longer term, coal will continue to dominate the country's energy mix over the forecast period. Analysis of consumption by economic sector reveals that coal's future in Kazakhstan is closely linked to electric power generation. The projected share of coal consumption attributable to demand from the power sector remains remarkably steady over time, maintaining its current three-fifths share over the next 25 years.

In uranium, as with coal, Kazakhstan possesses an abundant resource that can be mined at a relatively low economic cost. Kazakhstan ranks fourth[11] in the world according to reasonably assured resources of uranium, and is the world's largest producer of natural uranium, accounting for more than one-third of global production. All of this output presently is exported, primarily to China, but also to the EU, South Korea,

[11] If considering only resources that cost less than $80 per kilogram (kg) of uranium to produce (which is an equivalent of $31 per pound of U_3O_8), Kazakhstan has the world's second largest reserves, at 0.2 MMt (16.5% of the world's total), lagging behind only Canada.

and the United States. Kazakhstan's competitive advantage is that most of the reasonably assured and inferred resources of uranium are held in sandstone deposits that are developed through the in-situ leaching production method, which is more cost-effective and less environmentally harmful than traditional (hard-rock) production methods.

Kazakhstan to date has found ready markets for its uranium, expanding exports as rapidly as it can grow production. Further, global demand for uranium is expected to increase to 2035 under virtually any economic scenario, reflecting increased nuclear generation of electricity. However, Kazakhstan's recent export growth has coincided with a rapid demand surge in its major customer China, which accounts for over half of Kazakhstan's exports. China expects to significantly increase its nuclear generation longer term, and has been building up its stocks. However, Chinese demand could moderate once the build-up of its uranium inventories is completed.

Kazakhstan is not presently represented in all stages of the nuclear fuel cycle. It currently undertakes mining and primary processing of uranium. Some processed uranium is sent to Russia for conversion and enrichment (in joint ventures between the state-owned nuclear holding company KazAtomProm and Russian partners), before being returned to Kazakhstan where it is used in the production of fuel pellets at the Ulba Metallurgic Plant (UMP). Current fuel pellet production capacity utilization at UMP is only 1-2% of the design capacity, since in 2008 Russia ceased pellet imports in favor of purchases from domestic producers. Several joint initiatives are being undertaken to develop facilities in Kazakhstan for conversion and reactor fuel assembly production, in order to increase the value-added component in uranium products exports and fuel assembly production. The country is also actively planning for the construction of one or more nuclear power plants.

1.2.4. Electric power

Kazakhstan is in the midst of a sustained effort to upgrade its aging power system. Because almost 20% of the country's existing power capacity entered service prior to the 1970s, Kazakhstan also has the opportunity, where practical and economically expedient, to shift from its dominant coal-fueled generation (around 70% of the total) to a more diversified mix with more gas, nuclear, and renewables.

Gas will provide a considerable amount of future incremental electric power generation. Several new pipeline projects are expected to expand internal gas availability and aid in developing gas-powered generation in selected areas in the western and southern regions of the country. In addition, oil and gas field development creates an opportunity for expanding "own-use" power generation using associated gas. However, gas's share of generation will be limited mainly by infrastructural restrictions. Many important power-producing provinces, especially in the north-central part of the country, remain isolated from gas infrastructure, and for generators in these areas future options will likely lead to new or refitted coal-fired plants, with more efficient and cleaner technologies.

And while policymakers remain interested in Kazakhstan's renewables potential, their combined impact will likely remain relatively small in the medium term, and well below earlier targets of 30% (for renewable, hydropower, and nuclear combined) set for 2030. Experience from elsewhere in the world highlights the current costs and challenges of integrating relatively high amounts of renewables into the grid. Renewables are still in the introductory stages in Kazakhstan and face similar challenges. Therefore, with Kazakhstan's abundance of low-cost coal and its established fleet of large coal-fired power plants, the country will continue to rely heavily on coal for the next two decades, although coal's share of total generation will contract over time.

Nuclear power is the major unknown variable in Kazakhstan's capacity mix. Several locations are now being evaluated as potential sites for one or more projects based on units with up to 1150 megawatts (MW) capacity, with approval(s) possible as early as 2015. The re-launch of nuclear generation in the country (the older Aktau reactor was shut down in 1999) could considerably alter the future character of overall generation capacity, potentially displacing any growth in coal-fired power production.

Notwithstanding the many capacity permutations available to Kazakhstan's policymakers, a robust transmission network remains central to reinforcing the country's energy independence and overall energy security. Along with general modernization of the existing power lines, several new and important transmission lines have recently been added to the national grid. This grid development trend is set to continue and will do much to improve Kazakh power plants' access to demand centers, and in particular help meet southern Kazakhstan's rapidly expanding power consumption (as well as, in the future, western Kazakhstan).

To bolster funding for Kazakhstan's power sector, from 2016, policymakers are modifying the power market, and are developing new supporting financial mechanisms. Most notably, it is planned to launch a capacity market. In return, asset owners will be expected to invest into asset reliability, and if minimum technical standards are applied, improved efficiencies.

1.2.5. Energy efficiency and low-carbon development

In addition to its importance to the economy, the electric power sector also figures prominently in efforts to achieve another important goal—increasing efficiency. The electric power sector accounts for a significant part of energy consumption (approximately one-third of total primary energy consumption), so the potential savings from efficiency improvements here are proportionately large. In the housing sector, energy efficiency improvements are focused on a key problem that drives energy consumption well above levels in countries with similarly cold winter climates—the disrepair and low level of heat insulation of the housing stock. Roughly 70% of the buildings constructed between 1950 and 1980 do not meet modern requirements for insulation and energy use, and as a result an estimated 30% of heat delivered to these structures is effectively lost.

In the industrial sector, a common problem confronting efforts to increase energy efficiency in individual enterprises is a high level of asset depreciation, reliance on outdated technologies, and the failure to monitor energy consumption at various phases of the production cycle. Individual consumption standards developed for each enterprise on the basis of energy audits[12] and specific operational characteristics will produce more tangible energy savings than the mechanistic application of an averaged standard (energy consumption level) for all companies in a particular industry.

State policy intended to increase efficiency across the entire economy is directed toward modernizing various energy-consuming sectors of the economy, introducing audits and energy accounting systems at major enterprises, improving management quality, increasing public awareness of the importance of energy efficiency, and encouraging investment in energy-saving technologies. In addition to legislation, government can support energy efficiency initiatives through investment, research and development, as well as its power to set energy prices.

Increasing the energy efficiency of Kazakhstan's economy also yields benefits for the environment. Given that 90% of global anthropogenic emissions of carbon dioxide (CO_2) (the most abundant greenhouse gas) is the result of fossil fuel combustion, one way of consuming less fossil fuel energy without sacrificing economic growth is to lower the energy intensity of the economy by increasing energy use efficiency.

Kazakhstan's CO_2 emissions profile closely reflects the country's primary energy consumption pattern, which in turn is shaped by its energy-intensive economic structure. Despite the dominance of coal in Kazakhstan's primary energy consumption, greenhouse gas (GHG) emissions associated with energy use[13] over the past two decades have been considerably lower than at the end of the Soviet period. The increase since the mid-2000s in the annual level of these GHG emissions (from 198 MMt to 252 MMt, or 27% growth from 2005 to 2014) has been substantially less than the corresponding rate of GDP growth (69% from 2005 to 2014). This appears to be due to a combination of structural economic change, incipient energy efficiency improvements, and gradual shifts in the energy mix (e.g., away from the use of fuel oil in the industrial and residential/municipal sectors).

The electric power sector should be a major focus of attention, in that it accounts for over 80% of the country's total GHG emissions. A combination of measures for increasing fuel efficiency in thermal (coal-fired) power generation, as well as initiatives designed to reduce electricity demand through efficiency improvements focused on the commercial/residential and industrial sectors, could yield meaningful GHG reductions over the near term even without a comprehensive overhaul of the electric power sector. Longer term, incremental growth in natural gas, renewable, and perhaps even nuclear power generation capacity could accelerate the decline in GHG emissions per unit of gross domestic product already evident in the economy.

As a full member of the United Nations Framework Convention on Climate Change (UNFCCC), Kazakhstan ratified the Kyoto Protocol in 2009, and in December 2012 formally committed to reduce its GHG emissions by 5% in 2020 relative to the level of 1990.[14] In addition to this formal obligation, in 2010 Kazakhstan also voluntarily set the goal of reducing GHG emissions by 15% relative to the 1992 level by 2020 and by 25% of that level by 2050.

Kazakhstan now has an opportunity to recalibrate these commitments, as a successor framework to the Kyoto Protocol is to be negotiated by the parties to the UNFCCC in late 2015 in Paris. An agreement between China and the United States in November 2014 to voluntarily reduce their GHG emissions now puts nearly half of world GHG emissions "on the table" for the first time, opening the possibility that a fundamentally new framework will be finalized in Paris. Mandatory global reduction targets are to be eliminated: individual countries will enact their own plans and set their own goals for emissions reduction. This new framework should allow Kazakhstan to reaffirm its commitment to emissions reduction in a way that is commensurate with its historical development trajectory and status as a major energy-producing state.

[12] Initial energy audits are to take place at all enterprises with energy consumption exceeding 1,500 tons of fuel equivalent per year.

[13] Quoted emissions are calculated by IHS for the energy sector only, thus allowing for consistent historical comparison. Total GHG emissions for the country are somewhat larger, as they include emissions from all economic sectors and activities. Total GHG emissions by Kazakhstan increased from 241 MMt in 2004 to 315 MMt in 2014 according to AO "Zhasyl Damy".

[14] Paragraph 3.7-ter of the "Doha Amendment" establishes the 2008–2010 average emission level as the limit for greenhouse gas emissions in Kazakhstan in 2013–2020.

THE ENERGY SECTOR'S IMPORTANCE IN KAZAKHSTAN'S NATIONAL ECONOMY

2. The Energy Sector's Importance in Kazakhstan's National Economy

2.1. Key Points

- Kazakhstan's economy is based largely on the extraction of natural resources, led by energy resources; this reflects its relative resource endowment, as the country possesses sizable reserves of oil, gas, coal, and uranium as well as renewable energy potential in hydroelectricity, wind, and solar resources.[1]

- Kazakhstan accounts for about 3.6% of the world's total proven reserves of primary energy (including oil, gas, coal, primary electricity, and mined uranium), at roughly 32 billion tons of oil equivalent (toe).[2] Kazakhstan is a net energy exporter, consuming less than half of its total primary energy production. Its net exports have been rising in recent years: the country's total primary energy production (excluding uranium) increased at an annual rate of 5.5% since 2000, while primary energy consumption over the same period increased by only 4.3% annually.

- The energy sector, especially oil, is of paramount importance for the country's economy, accounting for about 22% of the country's GDP in 2014, two-thirds of total export earnings, and 50% of state budget revenues. It has also been the primary destination of foreign direct investment (FDI) within Kazakhstan.

- Kazakhstan has established a national fund to manage its oil wealth and to buffer the economy from the volatility of the global oil market. It receives oil revenues that are excess of immediate budget needs when prices are high, and the fund can be drawn upon when prices are low and revenues are insufficient to support current spending plans. The fund's counter-cyclical operation has already proven its effectiveness, keeping the economy from overheating by "sterilizing" the influx of funds during much of the period since its founding, while at the same time helping to stabilize budget spending during the economic downturns of 2008–2009 and again in 2015–2016.

- Kazakhstan's economy is also highly energy intensive: it takes 314 tons of oil equivalent to produce a million dollars of GDP (in 2014 dollars, with GDP measured at the market exchange rate), which makes Kazakhstan one of the world's most energy intensive economies. The high energy intensity is primarily explained by the country's economic structure, but also reflects the relatively low efficiency of energy use. Nonetheless, energy intensity has declined substantially in the past several years, and further progress is likely.

- The Eurasian Economic Union framework, launched in January 2015 to facilitate trade and allow the free movement of goods, capital, and people across its member states (Armenia, Belarus, Kazakhstan, Russia, and Kyrgyzstan), does not presently extend to trade in most energy products; these continue to be governed under bilateral agreements. Work toward establishment of a single market for the various energy products is ongoing, and is expected to be articulated in two types of documents—Concepts and Programs—for each particular product and market.

2.2. Kazakhstan's Primary Energy Resources

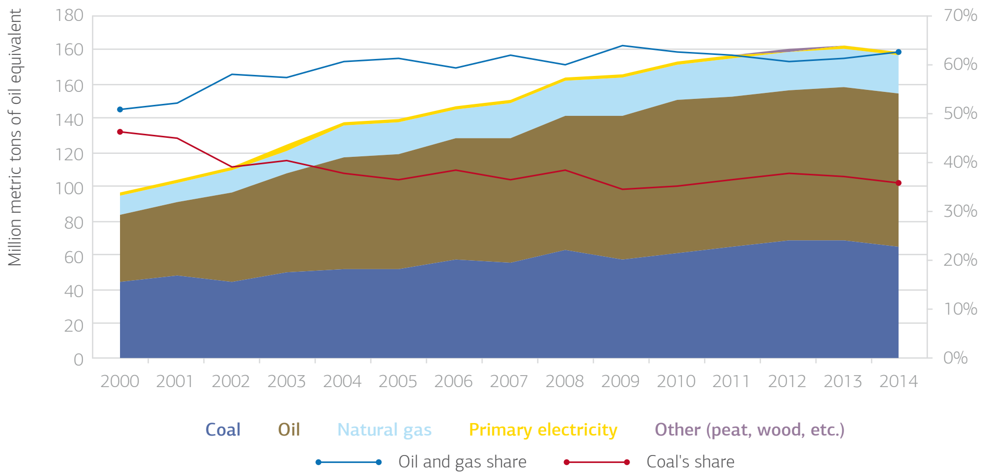
Kazakhstan's energy sector encompasses five major segments—oil, gas, coal, power generation, and nuclear (uranium extraction). According to the BP Statistical Review of World Energy, as of June 2015 Kazakhstan's total proved primary energy reserves, including oil, gas, and coal, amounted to 21 billion tons of oil equivalent (toe). Kazakhstan's proven reserves of uranium, which are also substantial, are estimated at the energy equivalent of over 10 billion toe, bringing total primary energy resources available to be produced to 32 billion toe. This represents about 3.6% of the world's total.

Production of primary energy in Kazakhstan, which includes oil, gas, coal, and primary electricity generation (but not mined uranium), increased by an average of 5.5% annually, from 73 million metric tons of oil equivalent (MMtoe) at the beginning of 2000 to 161 MMtoe in 2014. Oil and gas accounted for about 77% of this increase, and coal about 24%.[3] The share of oil and gas in Kazakhstan's total output of primary energy increased from 51% (45 MMtoe) in 2000 to 63% (101 MMtoe) in 2014, while the share of coal decreased from 46% (41 MMtoe) to 36% (59 MMtoe) in the same period (see Figure 2.1). Although primary electricity generation (hydroelectricity) remained steady at about 2 MMtoe, its share in total production essentially halved, falling from 2.2% to 1.1%.

[1] In terms of minerals, the Republic of Kazakhstan ranks first in the world in discovered reserves of zinc, tungsten, and barite, second – in reserves of silver, lead, and chromites, third – in copper and fluorite, fourth – in molybdenum, and sixth – in gold.

[2] By convention, primary energy production does not include mined uranium, but only its contribution to electricity production in a nuclear power plant based upon the amount of electricity generated. But one ton of natural uranium is considered to be capable of producing more than 40 million kilowatt-hours of electricity, which is equivalent to burning 16,000 tons of coal or 80,000 barrels of oil.

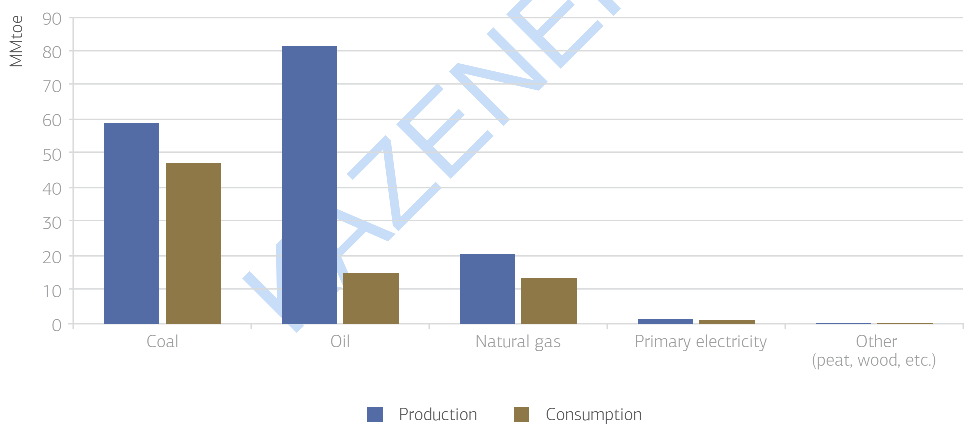
[3] Hydroelectric generation, which fell during the period, accounted for a negative 1% share.



Source: IHS Energy

Figure 2.1 Kazakhstan's primary energy production, 2000-2014

The country is a net exporter of primary energy—it consumes only about 43% of total output (see Figure 2.2). Total apparent consumption grew from 41 MMtoe at the beginning of 2000 to 76.3 MMtoe in 2014, growing at an average annual rate of 4.3%. The sectoral composition of primary energy consumption has changed very little over time. Power generation is the largest consumer of primary energy—its takes 55% of primary energy. The difference between the primary and final energy consumption accounts for the removal of all the intermediary steps of converting, delivering, and processing energy from its original state to a usable state. Final energy demand increased from 33.0 MMtoe in 2000 to 63.6 MMtoe in 2014. The industrial sector accounted for about 30.5% of final energy demand in 2014, transport 10%, and residential-commercial 35%.



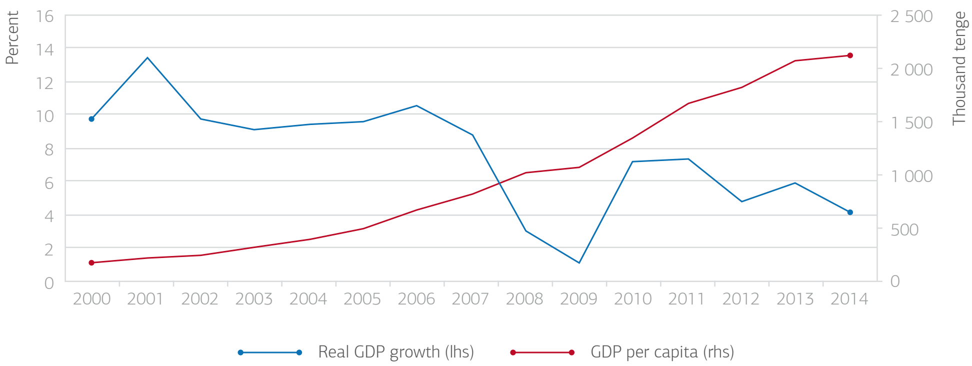
Source: IHS Energy

Figure 2.2 Kazakhstan's primary energy balance in 2014

Changes in production and consumption patterns have impacted export trends: net exports of primary energy increased from 42 MMtoe in 2000 to 85 MMtoe in 2014. The share of oil and gas in net exports—the major primary energy export commodities—increased from 70% (29 MMtoe) in 2000 to 86% (73.1 MMtoe). At the same time, while exports of coal remained about the same in absolute terms, at about 12-13 MMtoe, its share in total primary energy exports decreased from 32% to 14%.

2.3. Importance of the Energy Sector in the National Economy

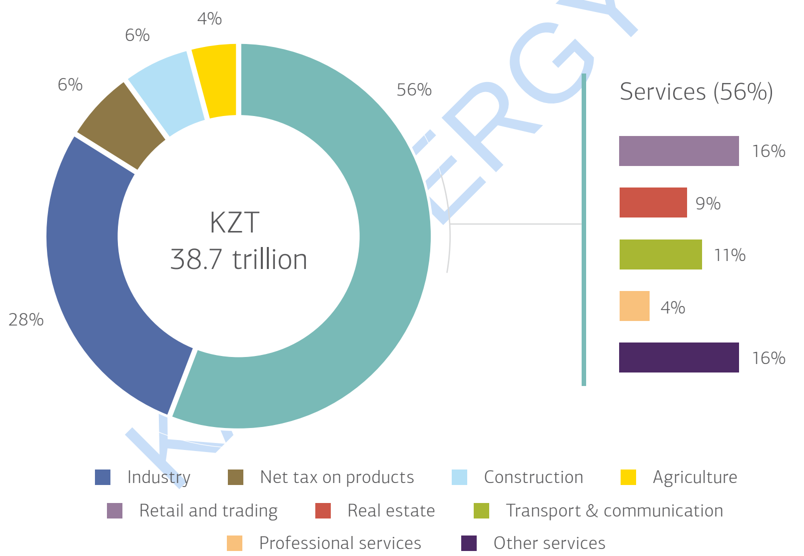
After enjoying robust real GDP growth, averaging 10% annually between 2000 and 2007, Kazakhstan's growth rate suffered as a result of the global economic recession in 2008-2009, but still remained in positive territory at 1% growth in 2009 (see Figure 2.3). Subsequent recovery led to a 6% average annual expansion between 2010 and 2013. Growth slowed in 2014, however, due to a number of factors, including a drop in oil prices in the second part of the year and the general slowdown in the Russian economy (Kazakhstan's major trade partner), partly due to international sanctions. These difficulties led to a 19% tenge devaluation in February 2014.



Source: IHS Energy, Kazakhstan Statistics Committee

Figure 2.3 Kazakhstan's real annual GDP growth

Industry (including the mining sector) is the largest segment of the economy, comprising 27.8% of 2014 GDP (see Figure 2.4). Services, which include the retail, trading, transport, communications, and real estate sectors, account for 55.7% of GDP.

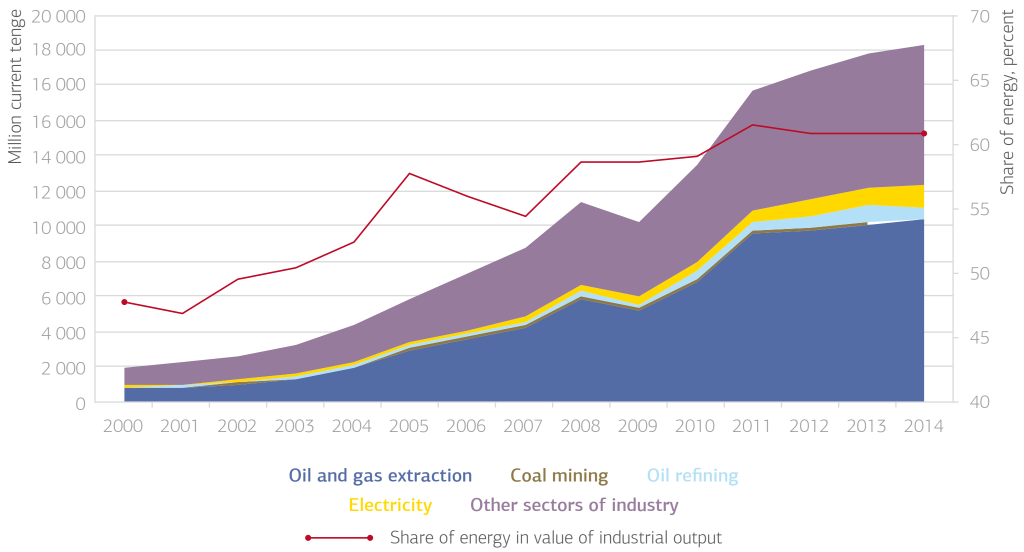


Source: IHS Energy, Kazakhstan Statistics Committee

Figure 2.4 Kazakhstan's GDP in 2014 by sector (in percent)

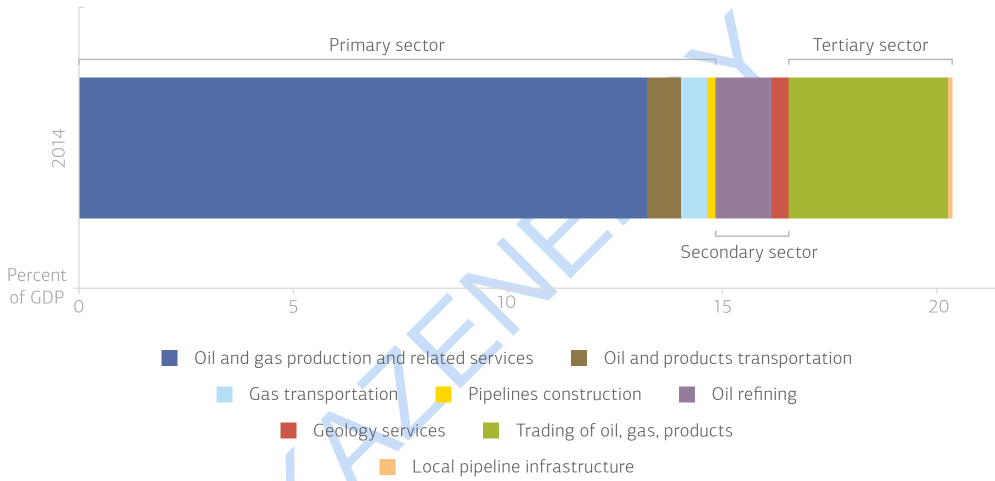
The energy sector is the key driver of the economy, considering its share in both total industrial production and GDP. Industries related to energy extraction and processing, including oil and gas extraction, oil refining, coal mining, and electricity, account for over 60% of total industrial output. Oil and gas extraction alone provides over half of the total value of industrial output (see Figure 2.5). The oil and gas industry also has the largest impact in terms of value-added to the economy: together with related services (e.g., oil and gas transportation, upstream construction, and geology); the activity contributed about 20% to the country's GDP directly in 2014 (see Figure 2.6).[4] Such overwhelming reliance on the energy sector means that global trends, such as commodity price declines, have a broad effect in Kazakhstan, impacting the performance of industries not only in the energy sector itself, but other industries related to energy production, including transportation, construction, trade, and professional services.

[4] The share of oil and gas alone in Kazakhstan's GDP was officially calculated as 20.3% in 2014, including all activities—extraction, processing, transportation, and related services. This was down slightly from 21.6% in 2013. The share of the other energy extraction sectors—coal mining, uranium mining—and the electric power sector accounted for 8.3% of the gross value of industrial output, while the contribution of industry to GDP was 27.9% in 2014, so the contribution to GDP of these other parts of the energy sector would be less than 2.3% because much of the gross value of electric power is comprised of the cost of fuel inputs (mainly coal) from extraction.



Source: IHS Energy, Kazakhstan Statistics Committee

Figure 2.5 Energy's contribution to Kazakhstan's industrial production



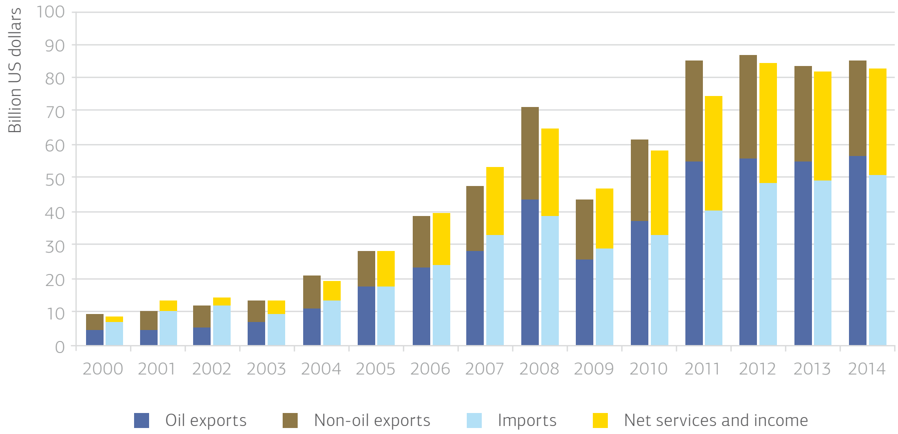
Source: IHS Energy, Kazakhstan Statistics Committee

Figure 2.6 Contribution of Kazakhstan's oil and gas industry to GDP

Oil exports (including gas condensate) account for 66% of Kazakhstan's total export earnings. But its current account balance shows high imports of services, reflecting Kazakhstan's procurement of external services to develop key projects, including the upstream oil and gas sector (see Figure 2.7). Sizable inflows of oil export revenues have enabled Kazakhstan to build a substantial reserves cushion that can be used to weather economic downturns: the combined reserves of the National Bank and National Fund reached nearly $118 billion at the end of 2014—higher than the country's total external debt of $84 billion (including about $6 billion of public and $79 billion of private debt) (see Figure 2.8). National Bank reserves of $28 billion are sufficient to cover about five months of imports—more than the three-month level suggested by the traditional reserve adequacy indicator.[5]

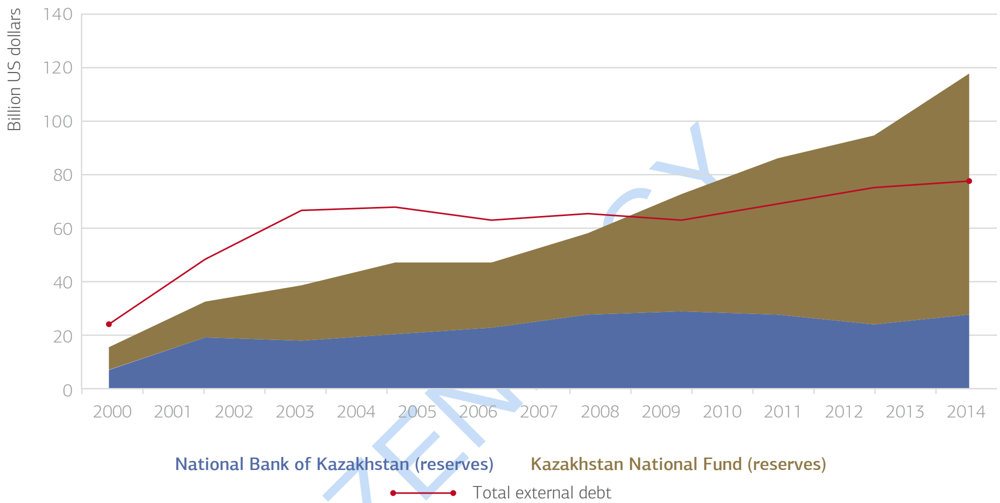
....

[5] The traditional reserve adequacy indicator, also known as the ratio of reserves to imports, or import cover, is a widely used metric of a country's capacity to sustain imports should all inflows (e.g., export revenues or external financing) cease. It has been employed by leading global financial institutions such as the IMF since the late 1950s. A reserve-to-import ratio of between 30% and 50% is considered adequate. A traditional rule of thumb, proposed by the famous US economist Robert Triffin, suggests a minimum threshold of three to four months of imports for a country.



Source: IHS Energy, IMF

Figure 2.7 Kazakhstan's current account in international trade

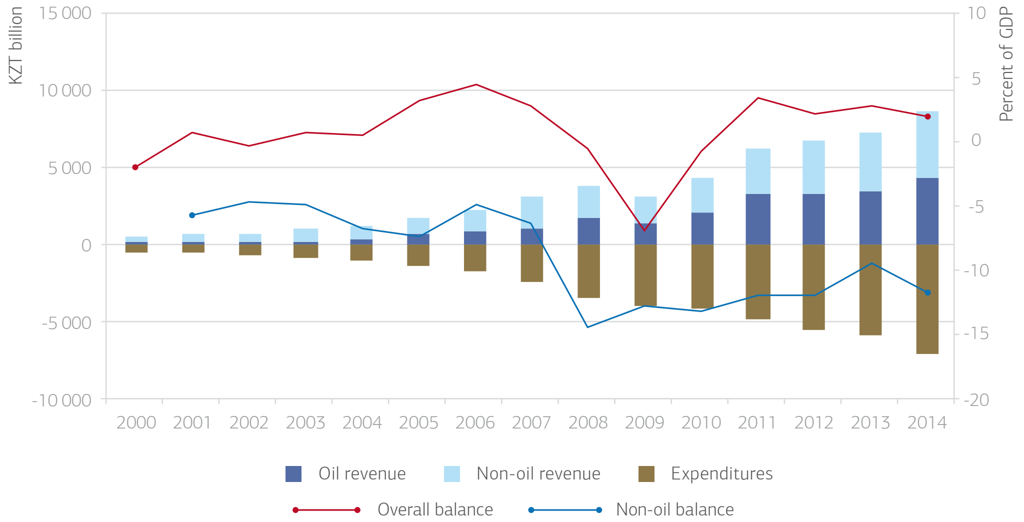


Note: Total external debt excludes intracompany debt.
Source: IHS Energy, IMF

Figure 2.8 Kazakhstan's international reserves position vs. external debt

Kazakhstan has effectively sterilized inflows of commodity earnings from the domestic economy via the National Fund. The Fund, which grew almost threefold between 2009 and 2014, reaching about $90.4 billion, serves two important goals. First, it keeps export earnings from freely flowing into the economy, thus avoiding domestic inflation and tenge appreciation which would undermine local producers' competitiveness—the classic case of so-called "Dutch disease." Second, it provides protection for the state budget from adverse economic conditions. It was toward the latter goal that President Nazarbayev announced in November 2014 that the government would spend $3 billion annually from the Fund during 2015–2017 on infrastructure investments in an effort to stimulate the economy in a global economic environment characterized by falling oil prices and sluggish economic growth.

Kazakhstan's budget revenues depend on the energy sector and, in particular, on oil export revenues. Oil revenues account for about half of total government revenues, including the national budget and those of the oblasts and municipalities (see Figure 2.9).

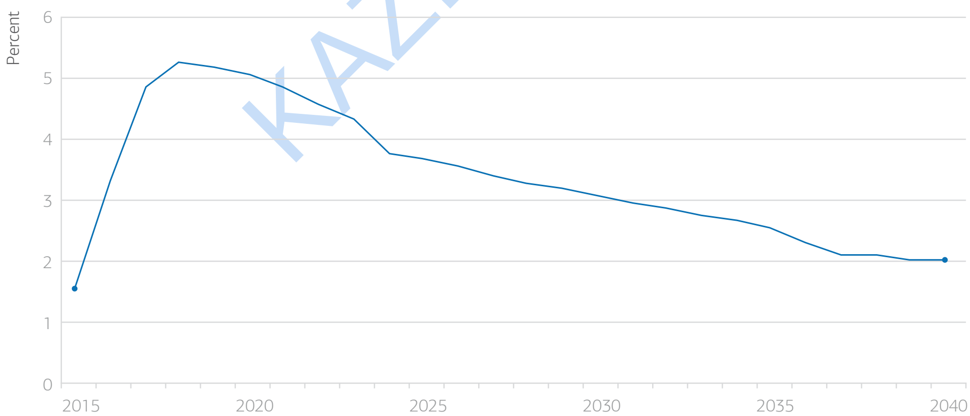


Source: IHS Energy, IMF

Figure 2.9 Kazakhstan's general government fiscal balance

In the regular tax regime, several revenue streams, including the Mineral Resource Extraction Tax (MRET) and the Rent Tax on Exports, are specifically accumulated in the National Fund (to be further invested in various financial instruments). The central government budget then receives transfers from the National Fund annually to finance expenditures.

Because of the importance of the energy sector, and particularly oil production and exports, to the overall economy, the dramatic decline in oil prices in international markets will have a profound impact on economic performance. GDP growth is expected to fall to only 2% in 2015. It is then expected to rebound together with international oil prices (and rising domestic oil production) in the period 2016–2020, during which time Kazakh GDP growth is projected to average 4.7% per year. Longer term, after this initial rebound, economic growth is expected to naturally gradually slow over time, as the economy becomes larger. Thus annual GDP growth rates are projected to ease to about 3.5% in the late 2020s and 2.5% in the 2030s, with the average annual growth rate being 3.3% over the entire period 2015–2040 (see Figure 2.10).

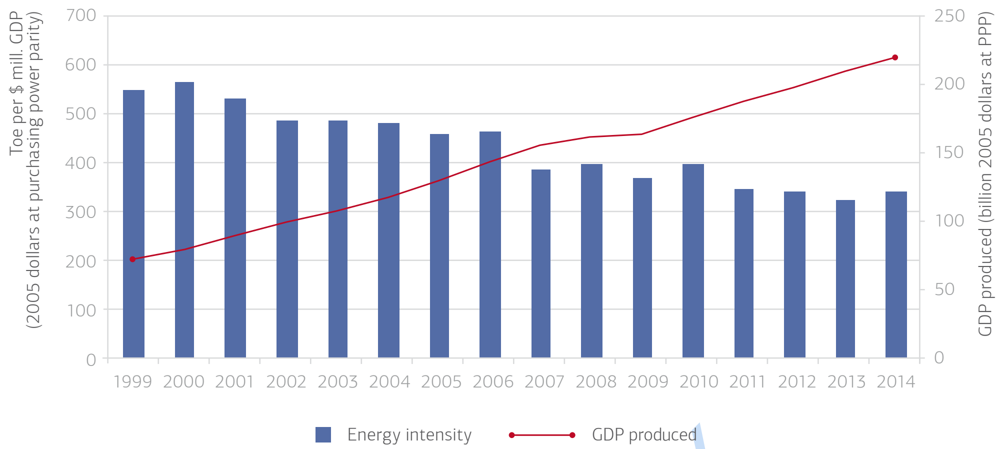


Source: IHS Energy

Figure 2.10 Forecast for Kazakhstan's real annual GDP growth

2.4. Energy Intensity of Kazakhstan's Economy

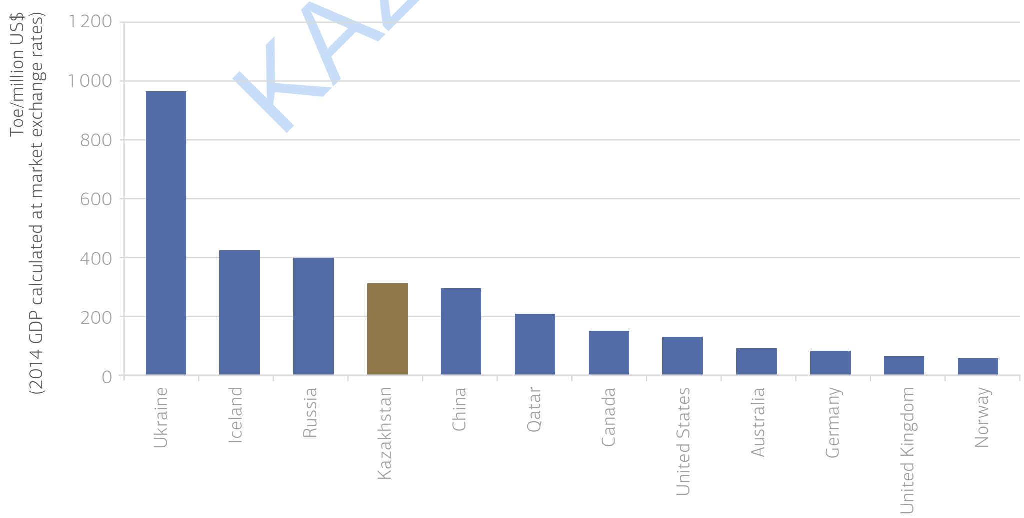
Kazakhstan's economy has grown at an average annual rate of 7.7% since 2000. At the same time, consumption of primary energy increased at a slower pace of only 4.3% annually over the same period. Thus, the energy intensity of Kazakhstan's economy—tons of oil equivalent (toe) consumed to produce a million dollars of GDP (in real 2005 dollars)—decreased by about 38%, from 555 toe in the beginning of 2000 to 343 toe in 2014 (see Figure 2.11)[6] Aggregate energy intensity (the ratio between GDP and primary energy consumption) decreased at an average annual pace of 3.2% during this period.



Source: IHS Energy, World Bank

Figure 2.11 Kazakhstan's aggregate energy intensity

Kazakhstan, however, still displays relatively high energy intensity levels in global comparison. Measured in toe per million 2014 dollars of GDP (measured at market exchange rates), in 2014, Kazakhstan was the world's 28th most energy intensive economy, consuming 314 toe to produce one million dollars of GDP.[7] Compared with other former republics of the Soviet Union, Kazakhstan expends less energy than Turkmenistan (473 toe), Uzbekistan (751 toe), Russia (400 toe), and Ukraine (971 toe) per unit of GDP. It has roughly the same energy intensity as Egypt, but it is higher than China (298 toe), Indonesia (263 toe), or the average for all OECD countries (126 toe) (see Figure 2.12).



Source: IHS Energy, World Bank

Figure 2.12 Energy intensity in 2014: Kazakhstan vs other countries

[6] GDP expressed in terms of purchasing power parity (PPP) in constant 2005 US dollars.

[7] Calculations according to IHS 2014 data. According to IEA calculations for 2012, Kazakhstan is ranked 25th among the countries of the world by energy intensity for its economy. See Chapter 11 for more details.

A key explanation for Kazakhstan's relatively high energy intensity is the structure of the economy: Kazakhstan's industrial sector, which produces almost 30% of total GDP, includes such energy-intensive industries as mining and nonferrous metallurgy. Kazakhstan also has a relatively cold climate, and its large areal extent means that transportation needs are high per unit of GDP. But relatively low levels of implementation of energy-efficient practices are also a key part of the overall explanation (see Chapter 11).

2.5. Kazakhstan's Energy Sector and International Organizations

2.5.1. Former Soviet territory

From the beginning Kazakhstan has played a key role in economic integration within the former Soviet Union space. It was a founding member of the Commonwealth of Independent States (CIS), a political and economic affiliation that was formed among the successor states of the USSR in December 1991. In 1994, President Nursultan Nazarbayev was an early advocate of creating a Eurasian economic union among the former Soviet republics, and in 2000, Kazakhstan, Russia, Belarus, Kyrgyzstan, and Tajikistan founded the Eurasian Economic Community (EurAsEC). EurAsEC goals were to establish a common free-trade space, a Customs Union, and a Common Economic Space (CES). Under the EurAsEC framework, Kazakhstan, Russia, and Belarus agreed to create a Customs Union in 2006, which came into effect in January 2010. Key features of the agreement included the removal of customs clearance and border controls, uniform duty rates, no customs duties on trade between the member states, and a single value-added tax (VAT) assessed at the border of the Customs Union. In December 2010, the three countries established the CES to further broaden economic integration, aimed at allowing the free movement of goods, capital, and people across the member countries. The signatory countries concluded 17 different agreements on key economic issues, including the coordination of macro-economic policy, free movement of capital, and others. The CES came into effect in January 2012. In November 2011, the three countries agreed on a further phase of integration—the Eurasian Economic Union (EEU)—which went into effect in January 2015 and added two new members—Armenia (joined on 2 January 2015) and Kyrgyzstan (on 21 May 2015)—while Tajikistan has shown a sustained interest in joining. The legal agreement establishing the EEU was signed in May 2014.

Trade in most energy products (including crude oil, natural gas, and oil products), however, was specifically excluded from regulation by the general trade rules of the Union, despite its large share of total trade turnover between the member states. This is due to the specific circumstances that prevail within these countries (regulated prices and markets), and their overall importance to the countries' fiscal budgets from the export duties they generate. Instead, trade in these products among the member states remains governed by bilateral inter-governmental agreements that cover volumes and terms, pricing, and other issues, such as export duties.

Under the general EEU framework, a key goal is to establish a single market for electricity (by July 2019), as well as for oil, oil products, and natural gas (by 2025). The details are yet to be developed and will be articulated in two types of documents—Concepts and Programs—for each particular product and market. These arrangements will then be implemented through specific inter-governmental agreements.

But this ongoing integration process has given rise to considerable conflict between Russia and Kazakhstan in respect to their mutual trade in oil and oil products, largely due to the different conditions that Russia applies among the various member states. For example, Russia's Customs Union arrangement with Belarus provided crude oil to Belarus duty-free, but Belarus was obliged to turn over to Russia the export duties generated by exports of refined products derived from Russian imported crude. In the new EEU agreement reached in May 2014, however, this stipulation was removed, enabling Belarus to retain all export duties on product exports. This could mean as much as an additional $4 billion annually for the Belarus exchequer.[8] For other new members joining the EEU, such as Armenia and Kyrgyzstan, export duties on Russian refined products were waived altogether. But for Kazakhstan, which imports both crude and refined products from Russia to satisfy domestic demand, Russia has insisted that Kazakhstan provide compensation for the loss of export duty revenue on its oil deliveries to Kazakhstan. Under the terms of a bilateral agreement signed in June 2012, Kazakhstan agreed to supply 1.5 MMt of crude oil annually to compensate Russia for duty-free deliveries of 1.3 MMt of petroleum products. At that time, Moscow claimed that it would lose the equivalent of about $780 million annually by supplying duty-free products to Kazakhstan (see text box). Another inter-governmental agreement (from 2010) governing crude oil trade envisioned that Kazakhstan's imports of crude oil would occur on a different basis, in which these would be directly offset by equivalent swaps of Kazakh crude that would be made available to Russian shippers. Kazakhstan began compensation deliveries to Russia only in the second half of 2014, sending crude north to Russia to cover the export duties on refined products received since 2012. These bilateral agreements also explicitly prohibit re-exports of duty-free oil and products volumes, and also call for Kazakhstan and Russia to eventually harmonize their export duties, by as early as 2015.

[8] In 2013, Belarus remitted about $3.3 billion to Russia on its exports of refined products. But partly because of the EEU, Russia is greatly reducing export duties on crude oil and refined products and moving taxation to the upstream, through a tax maneuver, to minimize the benefit derived by Belarus.

Russian-Kazakhstan Oil Trade

Russia delivers about 1.2-1.4 MMt of refined products to Kazakhstan annually as part of its existing bilateral trade relationship. It also delivers 4-5 MMt of crude annually, which supplies the Pavlodar refinery. The plan for 2014 was for Russia to deliver about 1.4 MMt of products to Kazakhstan, including 958,000 tons of gasoline and 470,000 tons of diesel. In the spring of 2014, however, amid worries over Kazakhstan's overall dependence on Russian refined product supplies, Kazakhstan imposed strict limits on Russian refined products imports in order to minimize the amount of oil that Kazakhstan would have to provide in compensation for these imports. But these restrictions were subsequently lifted at the end of July, as shortages of motor fuels developed in Kazakhstan, and the country began to look for additional supplies.

KazMunayGaz Onimderi, a subsidiary of KazMunayGaz (KMG), the national oil company, is Kazakhstan's designated operator for handling these import volumes, while KMG is the supplier of the designated crude volumes. On the Russian side, the Kazakh volumes are handled by Rosneft, Gazpom Neft, and LUKOIL on behalf of the Russian treasury. After some delays in implementation, compensation deliveries from Kazakhstan for the refined product imports began in September 2014, and amounted to about 150,000 tons of crude per month. Russia's energy ministry expected that about 2.5 MMt of crude would be delivered in 2015 from Kazakhstan in compensation for product deliveries made in 2012-2013. During the first six months of 2015, KMG reported that it delivered 566,000 tons of compensation crude oil, while Russia reports that it received 966,000 tons, so it appears that it is not just KMG that is sending compensation volumes.

For the EEU electricity market, the member countries agreed to harmonize the legislative bases in order to provide non-discriminatory access to each other's infrastructure (for as long as there is technical capacity available and domestic demand is met), and to eventually secure electricity sellers' and buyers' access to all member countries' individual markets. A mechanism was established for transfers of electricity among the member states that includes a methodology for calculating transmission tariffs. Also in 2015 a concept of creating a common energy market was adopted.

For the EEU natural gas market, the countries agreed to offer access to the gas infrastructure transportation services of their respective national monopolies, with transportation of gas to meet domestic demand given a priority. Transportation tariffs are to be set individually by each country. Although the agreement calls for the countries to eventually establish a common set of prices on a netback parity basis, no details about the timing and specifics of the netback calculation have yet to be officially agreed. Transit access to gas pipeline infrastructure by member countries for export to third-party markets also has not yet been agreed: Russia insists that access should be applicable only to gas deliveries to other EEU countries.

For the oil and oil products market, member states did agree to provide equal access to their infrastructure systems for transporting oil and oil products, continuing a system of transit flows that has existed since the collapse of the USSR. Tariffs, however, remain subject to each country's legislation, although there are plans for these to be harmonized longer term. On oil pipeline tariffs, Kazakhstan and Belarus seek to differentiate tariffs between exports and domestic deliveries, while Russia wants all tariffs to be the same for all types of shipments. As indicated above, accounting for export and customs duties on oil and oil products is regulated by separate agreements.

2.5.2. Outside former Soviet territory

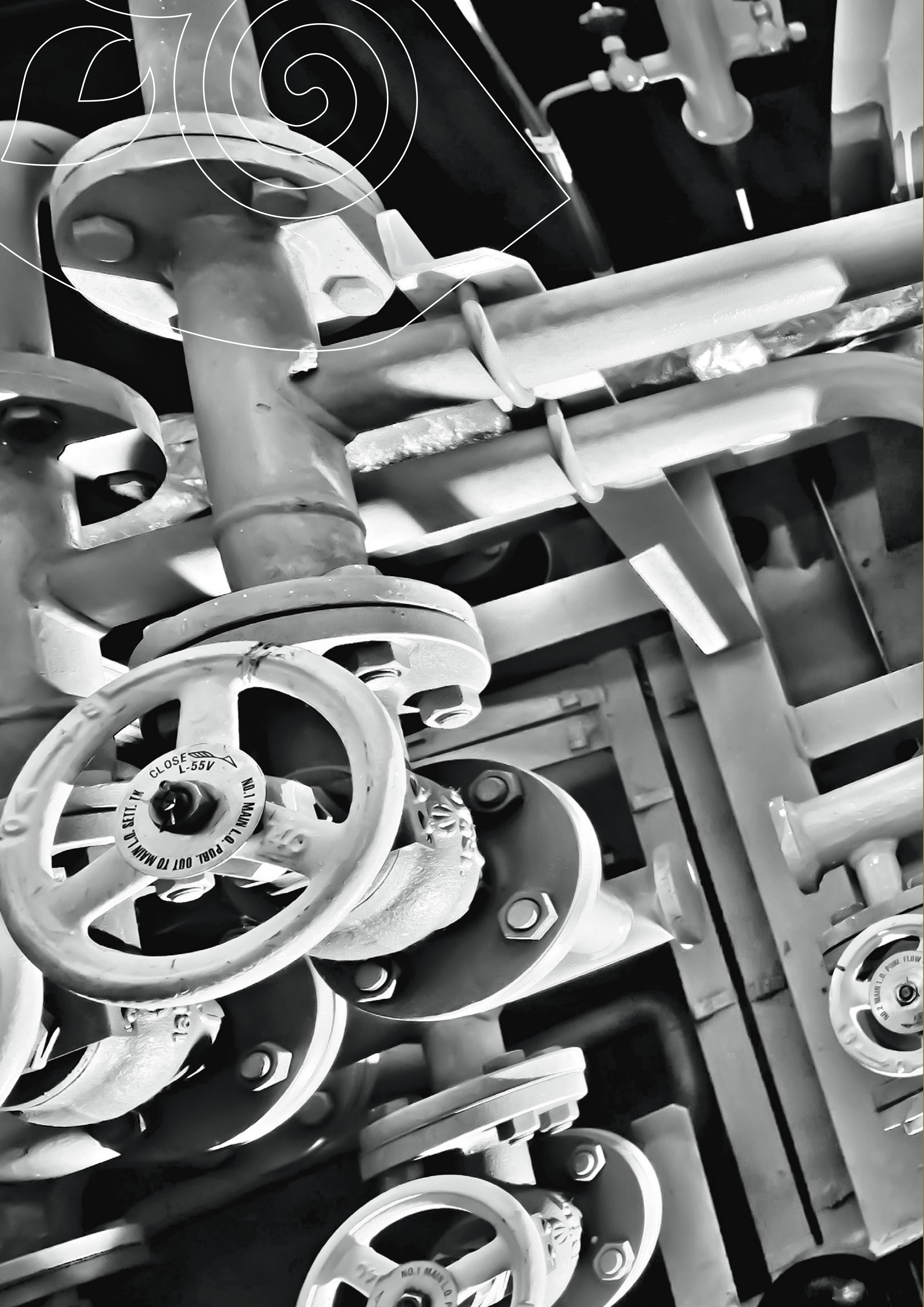
Kazakhstan has been seeking access to the World Trade Organization (WTO) since 1996, and on 22 June 2015 President Nursultan Nazarbayev announced that the country had finalized the terms of its membership, joining the WTO in July 2015. Russia, Kazakhstan's main trade partner, finally joined the WTO after 18 years of negotiations in August 2012, and Kazakhstan, following a similar trajectory, won the trade body's members' formal approval for accession after a 19-year effort. One of the key outstanding issues that had affected Kazakhstan's accession bid is its strong local content requirements. Contrary to WTO rules, Kazakhstan's legislation requires subsoil users to preferentially procure goods and services from local suppliers. While the Subsoil Law does not quantify these requirements precisely, Kazakhstan's Program on Local Content Development had set specific targets: for example, the government had sought for oil and gas producers to reach a local content of 72.5% in works and services and 16% in goods, while these targets for the mining sector (including coal producers) were set at 74% and 12%, respectively. Some subsoil contracts (564 of them) also are embedded with specific local content targets. As part of its accession negotiations, Kazakhstan had agreed that after it accedes to the WTO it would retain local content requirements until 2021, although at a lower level of 50% for services. A new draft of the Subsoil Law currently under discussion suggests eliminating some of the local content requirements for certain categories of subsoil users.[9] Also, the draft law proposes regulation of local content in services and works, but not in goods. Another contentious issue in WTO negotiations was export duties—Kazakhstan earlier had reached an agreement with the WTO that it would have the right to continue to levy export duties after joining the

[9] This category includes subsoil users other than the entities with fifty percent or more of voting shares (participatory interest) held directly or indirectly by Samruk-Kazyna National Wealth Fund or the entities directly or indirectly owned by the state.

organization, and even reserved the right to increase duties on oil and oil products. Although the mechanisms by which these issues (local content, export duties) ultimately were resolved have not yet been publicized, Nazarbayev indicated the breakthrough was achieved by aligning "WTO and EEU requirements bearing in mind our own national interests." The WTO framework should afford Kazakhstan more stable access to foreign markets for its exports and a greater range of goods and services for domestic consumers, make the country a more attractive destination for foreign investment, and provide a clear system of rules (and mechanism for trade dispute resolution) that makes trade more efficient and transparent. The agreement is a milestone in Kazakhstan's efforts to increase the role of international trade in the country's economic development, and is expected to have benefits in the form of job creation and increased income.

Key Recommendations

- A key recommendation would be to continue the current approach to the management of the National Fund and the stewardship of Kazakhstan's oil wealth.
- Economic diversification is important longer term, to reduce Kazakhstan's current high dependence on oil. But at the same time, care must be taken to pursue only truly value-added activities in other sectors, and in particular to take advantage of the economy's considerable competitive advantages in the energy sphere through related backward- and forward-linked activities, such as oilfield services, nuclear fuels processing, and petrochemicals. At the same time, the energy sphere should not be burdened with excessive requirements for local content nor subject to inordinate environmental fines.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ORGANIZATION OF KAZAKHSTAN'S ENERGY SECTOR: GOVERNMENT AND REGULATORY INSTITUTIONS

3. Organization of Kazakhstan's Energy Sector: Government and Regulatory Institutions

3.1. Key Points

- The state exercises a high degree of influence over the energy sector, which is not surprising considering the strategic role of the sector in the overall economy.
- Although the government restructuring carried out in August 2014, which created a large combined energy ministry with multiple functions and responsibilities, resulted in certain improvements, there is still room for streamlining the distribution of authority over the energy sector among government bodies.

3.2. Organizational Overview of State Energy Sector Management

Because of its vital importance to the economy, the energy sector is fairly closely managed and regulated by various government bodies (see Figure 3.1). Nonetheless, it is important to recognize that operation and investment decisions are left to be carried out by corporate entities and companies (albeit many state-owned), with government bodies exercising oversight and policy guidance for the most part.

Regulation/Monitoring/Control

- Presidential Administration
- Audit Committee
- Government of RoK
  - Energy Ministry
    - Ecology Control and State Inspection Committee in the Oil & Gas Complex
    - Nuclear and Power Control Committee
    - Ecology and Renewables Departments
- Finance Ministry
  - State Assets Committee
- Economy Ministry
  - Natural Monopolies Regulation and Competition Development Committee
- Investment and Development Ministry
  - Industrial Development and Safety Committee
- Ministry of Labor and Social Security, Ministry of Education

Policy-making

- President of RoK
- Kazakhstan's Parliament
- Government of RoK
  - Energy Ministry
  - Investment and Development Ministry
  - Finance Ministry
  - Economy Ministry

Operations

- State-controlled companies
- Local private investors
- Foreign private investors
- Foreign state-controlled companies

Energy sector

Figure 3.1 Key players in the energy sector's management

3.2.1. Policy-making

The organization of Kazakhstan's energy-sector management is outlined in Figure 3.1. Kazakhstan's Constitution gives the President the authority to determine the strategic directions of domestic and foreign policy. Typically, the President establishes these directions in his Annual Address to the Nation, and the executive branch is legally mandated to formulate its economic, social, and other policies accordingly. For instance, in his 2014 Annual Address on 18 January 2014, President Nazarbayev announced the development of the country's geological exploration industry, including incentives for foreign investment. Consequently, the relevant government bodies were mandated to include this initiative in their programs and planning. Other examples of presidential initiative include the announcement of the "Nurly Zhol" (Path to the Future) initiative in November 2014, which emphasized investment in transportation and other infrastructure to offset difficult global market conditions for the economy, or his outline of 100 steps in May 2015, aimed at implementing five broad institutional reforms to propel Kazakhstan into the ranks of the 30 most developed countries of the world.

While the Majilis, the lower chamber of Kazakhstan's parliament, does not typically play a policy-making role, it reviews policies developed and proposed by the government and enacts laws accordingly. For example, the Ecology and Subsoil Use Committee of the Majilis regularly holds hearings and invites ministers and other authorities to discuss and present key energy-sector issues as part of the deliberations over pending legislation. The parliament is now in the process of enacting new legislation to reform the Subsoil Use Code.

The key policy-making institution in Kazakhstan's energy sector is the newly formed Energy Ministry, created in August 2014 during a restructuring of the government's ministries, with several ministries being merged into the larger new Energy Ministry. Its authority encompasses such sectors as oil and gas extraction, oil refining, transportation of hydrocarbons, gas processing and distribution, power generation, coal production, and nuclear energy. Also as a result of the August 2014 government reforms, the newly created Energy Ministry took over the environmental regulatory authority of the former Environment and Water Resources Ministry, including responsibility for climate change, emission control, and renewables development policy.

The Investment and Development Ministry, also formed in August 2014, merged the Ministry of Industry and New Technologies, the Transportation Ministry, the Communications and Space agencies, and manages such sectors as mining, machine-building, and chemicals. This larger ministry also has authority over local content and industrial safety policy-making. Development of local content is an important part of its mission, since the ministry has been handed a strategic mandate to promote diversification of Kazakhstan's economy beyond the production of natural resources. As such, the ministry oversees the use of local producers and personnel in major energy projects. It is also responsible for the state's policies for geological exploration and energy efficiency.

The mandate of the Ministry of the National Economy is to develop a coordinated macroeconomic policy through strategic and budget planning. Specifically, the ministry analyzes and projects macroeconomic trends and develops recommendations on tax and budget policies, including in the energy sector. It is also responsible for coordinating the inclusion of strategic goals that are laid out in presidential addresses into macroeconomic and sectoral policy-making. The ministry is also responsible for anti-monopoly policy and regulation through its specialized sub-agencies.

The key task of the Finance Ministry is to develop and implement budget policy, which accumulates revenues from the oil and gas sector. This means that the Finance Ministry is involved in shaping tax policy in Kazakhstan, in particular for the energy sector.

3.2.2. Regulation, monitoring, and control

The Presidential Administration's Socioeconomic Monitoring Department controls the realization of the strategic directions set by the President. It coordinates and monitors all branches of the executive, including central and regional governments. The Presidential Administration also approves the drafts of legal acts, including those pertaining to the energy sector, before they are signed by the President. Another monitoring and control entity that reports directly to the President is the Audit Committee, which executes the state budget. In this role, the Audit Committee can obtain access to financial information from any public or private company, including in the energy sector.

The Energy Ministry performs most regulatory and control functions in the energy sector, including arranging and managing bid rounds, approving and representing Kazakhstan's interests in subsoil contracts, executing various control functions in the gas, power, and nuclear industries, and monitoring and regulating compliance with environmental requirements.

The Investment and Development Ministry's regulatory authority covers the licensing of exports and imports, including energy products. The ministry controls industrial safety and has the right to require termination of the use of machinery and equipment deemed to be unsafe. In terms of local content, the ministry oversees subsoil users' compliance with requirements for the procurement of local goods and services and the employment of local personnel. The ministry also monitors the safety of railroad and maritime transportation networks, which are also used to transport coal, as well as oil and oil products; it also monitors the safety of pipeline operations. In terms of technical regulation, the ministry is responsible for oil product specifications.

The Ministry of National Economy has the authority to examine drafts of subsoil contracts, as well as feasibility studies for upstream projects, looking at the potential economic effect. Under its macroeconomic policy mandate, it regulates markets and prices, including prices for oil products and natural gas; it also develops the methodology for setting limits on dry gas and LPG consumption and for differentiating electricity tariffs. The ministry also approves the investment plans of the state-owned companies, including the country's refineries. In line with its mandate to regulate monopolies, the ministry monitors and regulates economic concentration in the domestic market, including developing methodologies to calculate tariffs for companies viewed as having a dominant or monopoly position; for example, the register of companies subject to anti-monopoly regulation includes two Kazakh refineries as well as KazTransGaz (KTG)—the gas pipeline operator. It should be noted that Kazakhstan's tariff policy is not very flexible with respect to regulated activities.

The Finance Ministry's general regulatory functions include the monitoring of assets deemed strategic by the state. The government-set list of assets encompasses various sectors of the economy, including the energy sector. Specifically, it includes strategic oil and gas entities such as major oil and gas producers. The Finance Ministry monitors, and has access to, a variety of data, including on operations, financials, environmental compliance, use of technologies, and labor utilization. The monitoring results are used in policy-making by various government agencies. The State Revenue Committee of the Finance Ministry also performs regulatory, administrative, and control functions of customs operations, including export duty payments.

The Healthcare and Social Development Ministry and the Education and Science Ministry monitor energy projects with regard to meeting local content requirements for Kazakh personnel.

Two issues arise in the organization of the energy sector. First, as in many complex bureaucracies, state control of the sector involves many cases of overlapping authority. For example, both the Finance Ministry and the Audit Committee exercise similar oversight over state budget issues. Second, some government bodies exercise powers that do not necessarily reflect their official mandate. For example, the Ministry of National Economy's authority includes approving the terms of the design and construction of facilities in bodies of water, and the Investment and Development Ministry's authority includes ensuring gender balance in labor relations—a mandate more in line with the responsibilities of the Ministry of Labor. Finally, one of the roles of the Ministry of National Economy is to perform sanitary-epidemiological audits and monitoring. Thus monitoring of sulfur storage and disposal—a common byproduct of crude oil production in Kazakhstan—falls under its jurisdiction even though this is a task more suited for the Energy Ministry's dedicated arm—the Ecology Control and State Inspection Committee.

3.2.3. Operations

Both private and state-controlled companies operate in the energy sector of Kazakhstan.[1] Kazakhstan's state companies have an important role in the energy sector as they execute state objectives in different segments of the value chain, using their mandate to implement key projects.

The state has centralized control of energy-sector operations under the framework of the Samruk-Kazyna National Wealth Fund. Regulated by law, Samruk-Kazyna was formed in 2008 to improve the management and the operational and financial efficiency of state-owned assets. The entity is the legal owner of and manages most of the state-controlled energy-sector companies, including KazMunayGaz (KMG; oil and gas), KazAtomProm (nuclear energy), and Samruk-Energo and KEGOC (Kazakhstan Electricity Grid Operating Company) in electric power. Samruk-Kazyna, in turn, is owned and managed by the government. The government determines long-term (ten-year) strategies for Samruk-Kazyna and the companies under its umbrella. The entity's leadership mirrors the management of the Kazakh energy sector: the Board of Directors includes representatives from the Presidential Administration, the Prime Minister (who is also Chairman of the Board), and the Ministers of Finance and National Economy. Samruk-Kazyna monitors and executes control over the management and operations of the companies under its umbrella, including their investment programs.

3.3. Organizational Overview of the Oil Industry

As of July 2014, there were 133 oil-producing companies in Kazakhstan. These include foreign and domestic companies, international majors and smaller independents, private, publically traded, and state-owned companies involved in a mixture of consortia and joint ventures. But activity in the sector remains highly concentrated: Tengizchevroil (TCO) alone produced one-third of the overall oil production in Kazakhstan; the five biggest producers account for about 72% of total oil output.

Pipeline oil transportation in Kazakhstan is the province of KazTransOil (KTO), nominally a subsidiary of KMG (although now increasingly operating at arm's length). While KTO owns the main network, certain other pipelines are owned and operated by consortia of investors in which KTO is a shareholder: the Caspian Pipeline Consortium (CPC) exports through Russia to world markets, the Atasu-Alashankou pipeline exports to China, and the Kenkiyak-Atyrau pipeline is used for domestic oil transportation. Kazakhstan's key seaport at Aktau is operated by the state, but certain terminals are privately owned. Caspian maritime shipping involves both state-owned and private companies. Kazakhstan's railroad network is controlled and operated by Kazakhstan Temir Zholy (KTZ)—the state-owned railroad monopoly—but many private operators control sizable rail car fleets and provide transportation services.

All three of the main refineries now are owned by KMG, although Shymkent is actually owned by a joint venture between KMG and Chinese company CNPC (China National Petroleum Corporation) when they acquired privately held PetroKazakhstan Resources in 2005. There are also around 30 mini-plants in the country that produce mostly low quality products, essentially for export, owned for the most part by private investors. A new bitumen plant that opened in December 2013, for example, is owned partly by KMG together with China's CITIC (China International Trust and Investment Corporation).

Oil products marketing and distribution is fairly competitive, with multiple players operating over 4,000 retail stations in the country. The country's three largest retail chains are KMG, Helios, and SinoOil, together holding about 16% of the retail market (according to the number of retail stations rather than by sales volumes).

[1] For the purposes of this report, state-owned companies also mean those included in the Samruk-Kazyna National Wealth Fund group of companies.

3.4. Organizational Overview of the Gas Industry

As of July 2014, there were 64 companies producing gas in Kazakhstan. About half of the gross gas produced in Kazakhstan is associated, and about 40% of total gross extraction is re-injected back into reservoir to support liquids production. Therefore, like the upstream oil sector, the gas sector also is highly concentrated: Karachaganak Petroleum Operating [company] (KPO) produces 42% of the country's total gas, while TCO accounts for 34%, and CNPC-AktobeMunayGaz another 8%.

Except for pipelines built for specific projects, which are constructed and operated as joint ventures, most gas pipeline infrastructure in Kazakhstan is owned and operated by KazTransGaz (KTG)—a subsidiary of KMG. For example, the sections of the Central Asian gas export pipeline on Kazakh territory that carries Turkmen gas to China is owned and operated jointly by KTG and CNPC. The country's three underground storage facilities, with a total active capacity of 4.7 billion cubic meters (Bcm), are part of the KTG system as well. Regional gas distribution and sales also are carried out by KTG and its subsidiaries.

Gas processing is done at four major gas processing plants (GPZs) built by specific upstream projects. KMG owns one legacy plant (KazGPZ) operating in Mangistau Oblast, while other plants are owned by other upstream producers.

3.5. Organizational Overview of the Coal Sector

As of April 2014, there were 12 large coal producers in Kazakhstan—both privately and state-owned companies—whose share of the national output was 98%. The share of the private ERG (Eurasian Resources Group) company in the country's total production of steam coal is about 30%, while the shares of Samruk-Energo (representing state interests) and RUSAL (privately owned Russian Aluminum) are about 20% each. Almost all coking coal is produced by the privately owned ArcelorMittal (mainly for its own use at the Karaganda steel plant).

Coal is shipped to consumers domestically and internationally via the railroad network managed by the state-controlled railroad monopoly KTZ.

3.6. Organizational Overview of the Uranium Sector

State-controlled KazAtomProm (KAP) is the major player in the nuclear industry, but most mining activity is done through joint ventures between KAP and foreign investors. Its entitlement production is about 56% of Kazakhstan's total output. There are 22 existing uranium production contracts in Kazakhstan, with 70% of the production volumes generated by KAP's joint ventures with foreign investors.

There are three dedicated facilities owned by KAP that yield "yellow cake," consisting largely of uranium oxide. Some other mines have their own processing capacities. Kazakhstan does not possess conversion capacity to make hexafluoride out of uranium oxide nor does it possess enrichment capacity to make nuclear fuel out of hexafluoride. A 50-50 joint venture between National Atomic Company (NAC) KazAtomProm and Russia's TVEL created in 2013 holds a 25% plus one share of the Ural Electrochemical Integrated Plant (in Sverdlovsk Oblast, Russia) — the world's largest uranium enrichment facility processing the joint venture's uranium hexafluoride. In addition to the Urals enrichment facility, some of Kazakhstan's uranium is enriched at the Angarsk International Uranium Enrichment Center (IUEC), in which NAC KazAtomProm has 10% ownership. The Ulba Metallurgic Plant owned by KAP has the capability to produce nuclear fuel pellets from uranium-containing compounds and materials.

Uranium oxide exports are tightly regulated by the state; for example, specially designed railroad cars are used to transport uranium to export markets.

3.7. Organizational Overview of the Electric Power Sector

Electricity generation capacity is owned by both private investors and state-controlled companies. At the beginning of 2015, there were a total of 76 power stations in Kazakhstan with installed capacity reaching 20,844 megawatts (MW), 88% of which was thermal, and 12% was hydropower (wind and solar generation are less than 1%). The Law on Electricity confers upon KEGOC—the state-owned electricity company responsible for transmission—the role of System Operator, which provides overall supervision and management of Kazakhstan's power system.

Kazakhstan's high-voltage transmission lines are owned and operated by KEGOC. But most of the regional transmission lines below 220 kV are owned by about 30 Regional Electricity Companies (RECs).

The electricity market is divided into wholesale and retail segments. The wholesale segment, limited by a minimum electricity offtake of 1 MW, includes: a decentralized market where market players purchase and sell electricity under mutually agreed terms; a centralized market managed and operated by the state-owned Kazakh Operator of Electric Power and Capacity Market (KOREM); a balancing market for fixing imbalances on a daily basis; and a market for system services, including electricity transmission and capacity reservation. The retail segment consists of both RECs as well as 179 registered Energy Supply Organizations that sell electricity to end customers.

Key Recommendations

- The government should further streamline the distribution of authority over the energy sector among government bodies.

- A general approach to consider in any further organizational restructuring would be for form to follow function, particularly to align the organizational structure to effectively address the most important issues facing Kazakhstan.

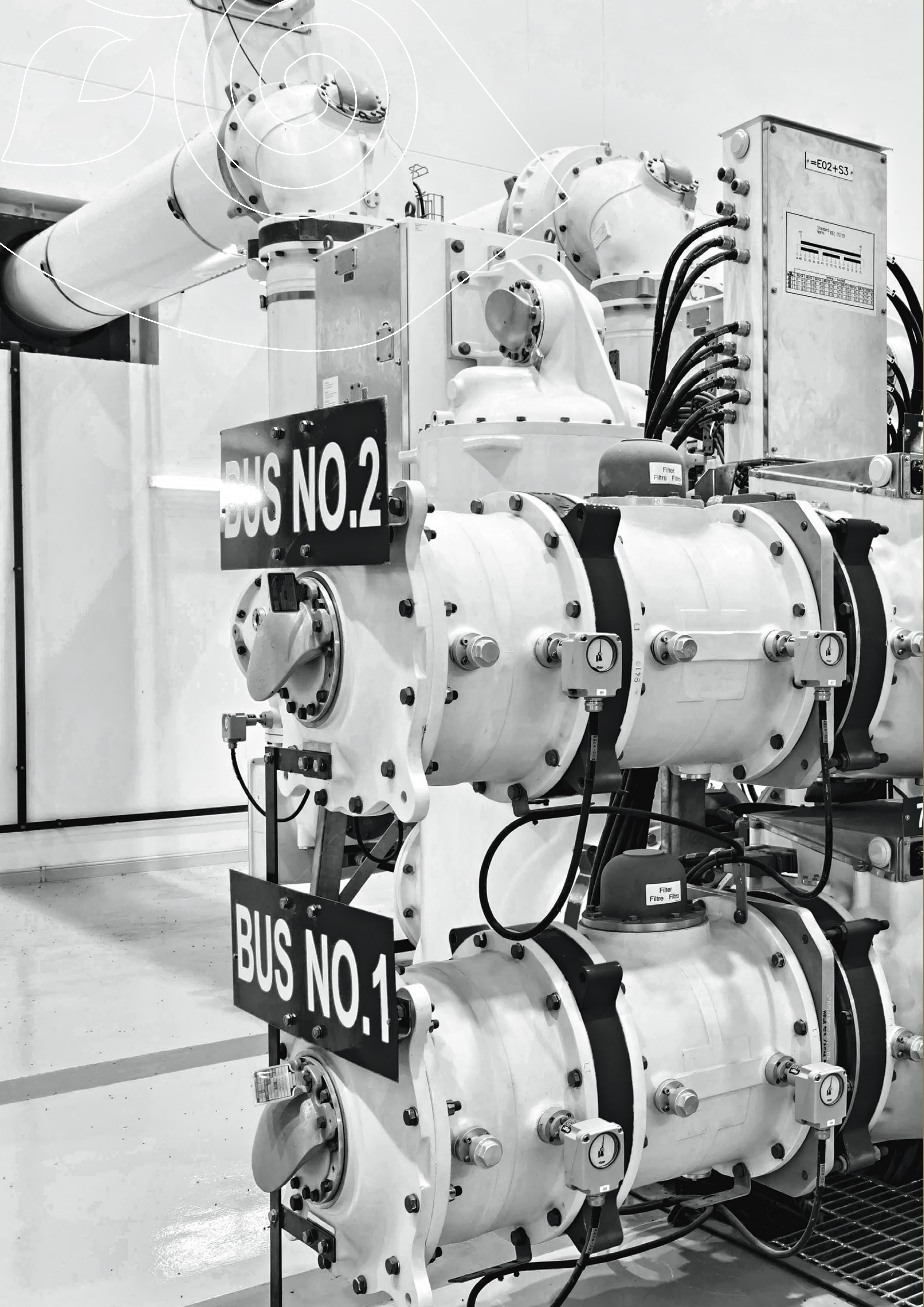
  — Given the overall importance of oil and gas operations in comparison to other parts of the energy sector, Kazakhstan should consider going back to a separate petroleum ministry, separating oil and gas issues from those relating to power and coal or environmental protection.

  — Another approach would be to follow the example of Norway, for instance, which has a separate Petroleum Directorate within the Ministry of Petroleum and Energy.

  — The internal divisions of the streamlined organization should be set up to focus on particular activities of high importance, such as bid rounds and licensing, or international issues, rather than paralleling the production structure present in operating companies.

  — In view of significant environmental problems, it is recommended to create a separate Directorate for Environmental Protection under the Ministry of Energy.

- Kazakhstan's government should consider the issues of differentiation and increasing the "flexibility" of tariff policy in the sphere of natural monopolies regulation in order to stimulate domestic demand, attract investment, and solve environmental issues (e.g., special gas transportation tariffs for gas generation, etc.).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KEY GLOBAL ENERGY TRENDS AND WORLD ECONOMIC BALANCES

4. Key Global Energy Trends and World Economic Balances

4.1. Key Points

- **Unconventional hydrocarbons are changing the energy world.** The understanding of the global hydrocarbon resource base is shifting. For example, the industry has traditionally thought of natural gas supply as lasting about 60 years, based on the narrow metric of proven reserves divided by current production (or consumption). But potentially recoverable global resources of unconventional gas—including both shale gas and coal-bed methane (CBM)—are now estimated at 250 years of current consumption. The United States—reflecting a favorable combination of geology, legislation, openness to technological innovation, and investment capital—has emerged as the leader in unconventional gas production, and as a result now is poised to become an exporter of liquefied natural gas (LNG)—following a decade of common wisdom that the US would need to rely on LNG imports for the foreseeable future. The extent to which the North American experience in unconventional gas development will be replicated elsewhere remains to be determined, and over the near term is clouded by the current low oil price environment.

- **Largely because of unconventional oil development in North America, the global oil market is now oversupplied, and strong global crude oil production growth could outpace weak demand growth, putting strong downward pressure on oil prices.** Strong production growth in North America, Brazil, and Middle East/North Africa (Libya, Iraq) (both conventional and unconventional) has resulted in stronger-than-expected global supply growth. In fact, in 2014 non-OPEC supply growth by itself was more than triple the increase in global demand. This has resulted in a substantial near-term decline (initially falling by over 50% since mid-2014) in global oil prices. A period of readjustment will be required for production to reach a new equilibrium with demand growth, during which downward pressure on prices is expected to remain a strong feature. During this period, new upstream investment will be curtailed, and higher marginal cost producers—including unconventional producers in North America and offshore producers in some regions (e.g., North Sea) will face pressure to restrain production.

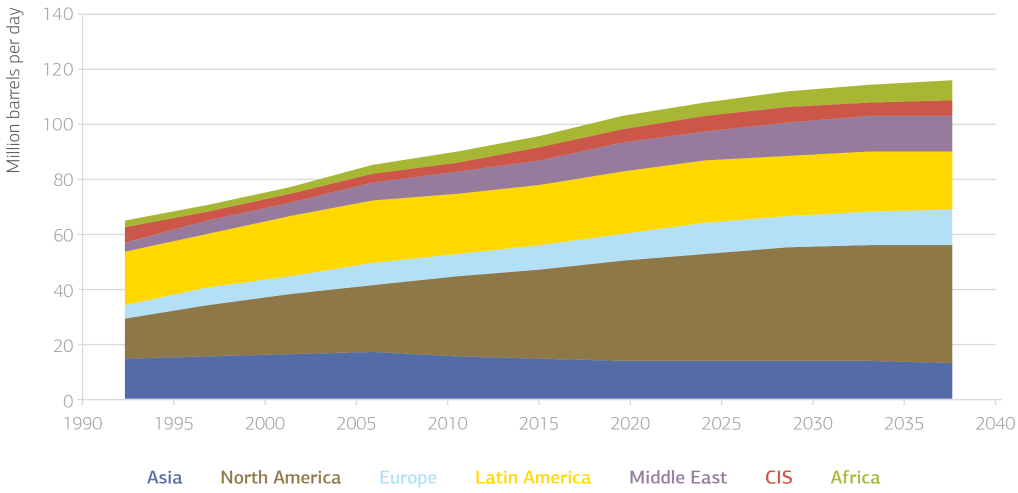
- **But even with only weak oil demand growth globally, the need for high-cost production to be brought into the market means higher prices longer term.** As a result, we expect oil prices to eventually recover to about $100 per barrel in real 2014 dollars by the mid-2020s.

- **Terms and conditions for resource development in host counties, such as Kazakhstan, must also change to reflect the new international situation.** A key implication of rising non-OPEC (North American) oil production, the shifting demand picture and global trade flows, and downward price pressure going forward in global oil markets, is that terms and conditions for resource development in some host countries are no longer competitive for attracting international investment. Whereas in the past oil companies "chased reserves" globally and host countries exploited this need by enhancing the government "take" (in various ways), today an uncertain price environment is leading oil companies to cut back capital spending plans; some may opt to "come home" (to North America) to a more stable investment environment. Global competition is becoming more intense as upstream investment budgets shrink and opportunities remain relatively abundant; at the same time, the international oil companies are under increased pressure to improve operating efficiency and investment effectiveness.

- **Renewables are expected to become a major contributor of new global energy supplies.** As a result of the global scale reached and cost reductions achieved (as well as growing global sentiment concerning the need to reduce carbon emissions), renewable energy should continue to be an important source of new energy supply for global power generation. However, the recent accelerated growth in renewable energy capacity occurred during a period of historically high oil prices. The still relatively high full system costs for renewables, the age of austerity that now confronts many mature economies, and the lower price environment for oil and gas will undoubtedly slow, but not halt, the renewable industry's development and growth. For renewables to play a greater role in the energy mix going forward, deeply embedded structural constraints to the competitiveness of renewable energy must be surmounted. Because technology costs are changing quickly, and continue to decline, countries are shifting renewable support policies away from European-style subsidies to more competitive price mechanisms, such as tenders.

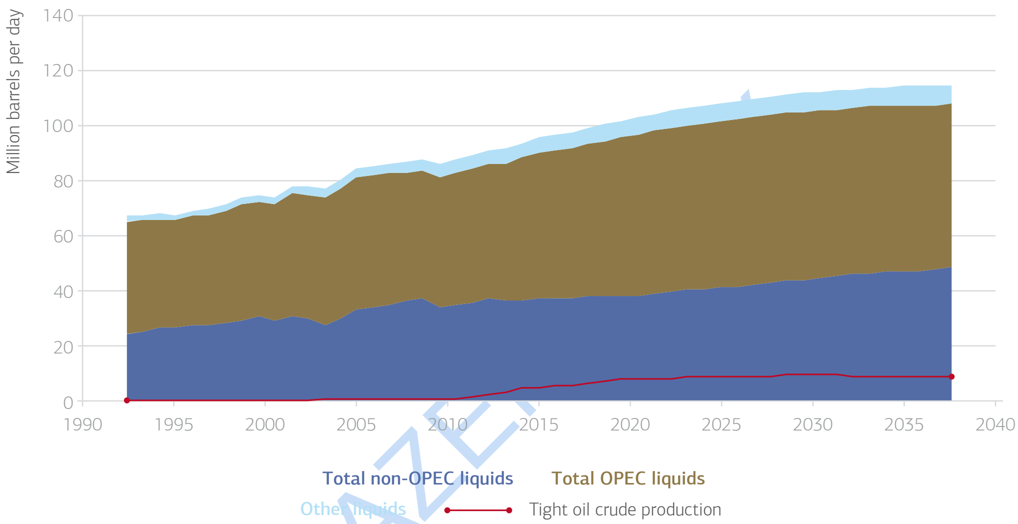
4.2. Global Oil Production and Consumption Forecast

Despite the widely held view a few years ago that the world was approaching "peak oil" (i.e., that global oil production would soon peak and then decline), the unconventional revolution has shown that new extraction technologies make it possible to meet expected demand growth for the foreseeable future (see Figure 4.1). In fact, we are in the midst of a period of oversupply due to strong supply growth, as growth in global demand in 2014 (632,000 barrels per day [b/d]) was much less than supply expansion (2.2 million barrels per day [MMb/d]). Slowing US production is the primary, but not only, key to eventually balancing global markets, although demand growth will play a slight role. Demand growth will improve to about 1.1 MMb/d in 2015 and 1.3 MMb/d in 2016 after the anemic 0.6 MMb/d increase in 2014, but that is still well below supply growth; nonetheless, it will help to work off some of the accumulated storage.



Source: IHS Energy

Figure 4.1a Outlook for global oil liquids demand

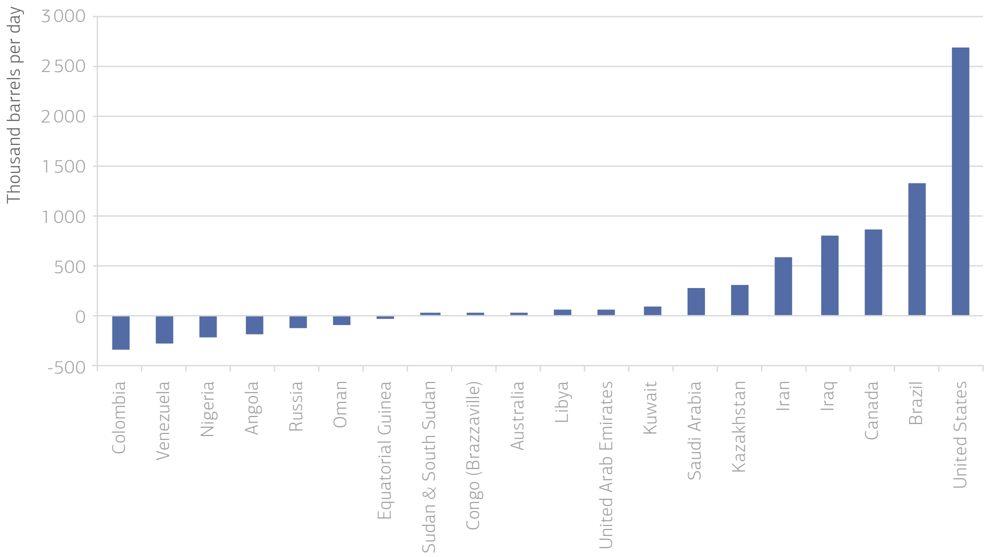


Source: IHS Energy

Figure 4.1b Global oil liquids supply

Four major centers of crude oil production growth—three in the Americas and one in the Middle East—are expected to account for much of the growth in world oil production during the remainder of this decade (see Figure 4.2). After modest gains for most of the past decade, global liquids production has increased rapidly in recent years, from 87.9 MMb/d (4.4 billion metric tons) in 2010 to 93.8 MMb/d (4.7 billion tons) in 2014. Most (86%) of the near-term expansion is expected to be concentrated in Brazil, Canada, Iraq, and the United States— the "Big Four" engines of output growth.[1]

[1] While incursions by the Islamic State (IS) and general regional unrest raise the risk that Iraq could join the countries experiencing significant oil production outages, operations at the country's main southern production facilities have yet to be affected. Only the Kirkuk-Ceyhan pipeline in the north is out of service (since March 2014).



Source: IHS Energy

Figure 4.2 Main sources of global crude oil production growth, 2014-2020

During the remainder of this decade, however, as the global oil market rebalances, global supply growth is expected to be weak—and will even fall in some regions where growth would have been expected in a $100 per barrel (bbl) oil price environment. The supply response will vary, depending on various factors such as whether an upstream project has reached final investment decision (FID), the economics of unsanctioned projects, and a particular company's debt level and access to capital. Here is a look at the supply prospects for major crude oil producers:

- **Low prices and international sanctions on Russia pose a threat for nascent Russian Arctic shelf and shale oil projects; these will undermine longer term oil production growth.** International sanctions imposed in connection with the conflict in Ukraine and less Western activity and investment in Russia raise the significant risk of Russian oil production going into decline beginning as soon as the second half of 2015 and continuing in 2016 and over the next few years. Longer term, of course, the effect will become even more pronounced. The financial sanctions are likely to have a greater impact on Russian oil industry performance in the near to medium term than the current set of restrictions on Russian companies' access to equipment and services. Most of the hard-to-recover plays are at a relatively early stage of development or still only in the exploration phase and are therefore unlikely to contribute substantially to Russian oil output during the current decade. Over the longer term, equipment and service restrictions have direr implications for Russian oil production. Russia is counting on tight oil and Arctic shelf projects in particular to offset ongoing decline in mature basins, particularly as conventional greenfield plays in East Siberia and elsewhere that have so far cushioned this drop themselves reach plateau. With respect to the outlook out to 2025, in the event that sanctions remain in place for a considerable period (even if not necessarily the entire scenario period), a very rough estimate is that Russian production in 2025 could be up to 2 MMb/d (100 MMt) below our current projection for that year of about 10.6 MMb/d (532 MMt). This possible decline scenario would likely come from a combination of higher decline rates in existing fields and less new oil than previously expected. Moreover, in the following decade, with much of Russian new oil slated to come from Arctic offshore and tight oil, the differences could be even more severe between our existing base-case forecast and an alternative with sanctions.

- **Canadian growth slows.** A significant number of Canadian oil sands projects already under construction will deliver growth in the next few years despite the lower oil price environment. Projects not under construction are likely to be delayed, and high-cost conventional and tight oil drilling are likely to register negative effects even sooner. The oil sands have been a major source of global oil supply growth for a decade and have made Canada the largest supplier, by a wide margin, of foreign oil to the United States.[2] Oil sands are among the more costly sources of supply to develop and produce, however, which makes growth vulnerable to the current price downturn. Expansion of export infrastructure is also key to increasing oil sands production. The Canadian Energy Research Institute projects growth in crude output of only 41,000 b/d in 2015 and 17,000 b/d in 2016.

- **Iraq production to increase through revitalization and expansion of existing fields.** Inside OPEC, Iraq's output is second only to that of Saudi Arabia and is rising. Indeed, Iraq in the medium term is expected to be among the biggest gainers in the world oil output stakes, with production expected to rise from 3.7 MMb/d (185 MMt)

[2] Canadian oil production increased from 2.75 MMb/d (137 MMt) in 2008 to 3.8 MMb/d (189 MMt) in 2014. Of this, roughly 1.7 MMb/d (85 MMt) was from oil sands. Canada sends over 95% of its exported crude to the United States.

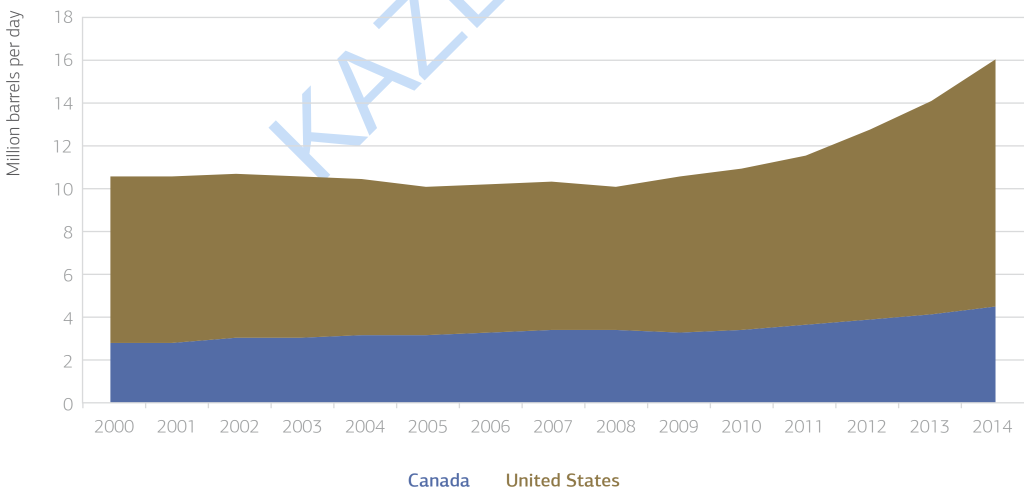
in 2014 to 4.6 MMb/d (230 MMt) in 2020. It is possible, though, that Iraq's financial squeeze could slow the pace of production growth. More supply from Iraq will raise the pressure within OPEC concerning how to accommodate it if Saudi Arabia returns to the role of market balancer.

- **Deepwater developments to be delayed.** Unsanctioned deepwater and other high-cost projects are likely to encounter delays globally. A large proportion of recent global conventional discoveries have been deepwater oil fields, such as in offshore West Africa, Brazil, and the Lower Tertiary play of the US Gulf of Mexico. These projects are often large, complex, and capital intensive. In cases where projects have already moved to the FID stage, first production will move forward regardless of the oil price environment owing to the already significant sunk costs. But some unsanctioned projects will be deferred, which will reduce the pace of global supply growth longer term.

- **Investment in mature basins likely to be deferred.** Lower oil prices are also squeezing the profitability of high-cost mature fields across the world. In many cases operators are likely to defer the types of maintenance required to prolong the lives of these fields. As maintenance is forgone, decline rates will steepen. Mature North Sea oil fields and even some older, less efficient Canadian oil sands operations are potential candidates.

- **Saudi Arabia to remain among the top producers.** Saudi Arabia is projected to remain among the world's biggest oil producers. Its average annual production is expected to edge upward to 10 MMb/d (500 MMt) in 2020. Throughout the outlook period, Saudi Arabia will maintain its preeminent position as the largest holder, by far, of the world oil market's shock absorber—spare production capacity. However, Saudi Arabia's decision not to cut its production in November 2014 has rescinded its long-established role as a market balancer. Among the preconditions of an output policy change would be Saudi Arabia's willingness to resume its role of "market balancing" producer and an understanding on output issues between Saudi Arabia, which is preeminent in OPEC, and the rising star that is Iraq.

- **United States: production growth continues, albeit at a slower pace, driven by tight oil.** The "Great Revival" of US liquids output (see Figure 4.3) has been driven by tight oil production. Still, lower upstream spending (roughly 40% lower this year) was expected to bring month-to-month growth to a halt by second half 2015. But it did not happen quite like that. Indeed the flattening out of production is now only expected by end-2015. This is because production costs are coming down dramatically (by about 20% compared to 2014)—lowering break-even prices. Tight oil producers are becoming more efficient while "high grading" their production (i.e., focusing on drilling their most productive acreage). For the best sections of some tight oil plays, break-even costs have dropped to less than $40/bbl. Although by 1 May 2015 the number of active oil rigs had fallen for a record 21 weeks in a row, to 679 from 1,609 in October 2014, the trend toward further declines appears to be abating. US oil production appears to have stabilized at a level of roughly 9.6 MMb/d (480 MMt on an annual basis) in the first half of 2015. A modest recovery in the Brent price to mid-$50 a barrel from a six-year low of $42 a barrel in early 2015 is expected to actually support some production growth in 2016—300,000 b/d, which is much less than the 1 MMb/d annual average gains of 2012–2014. For US output to fall enough to appreciably erode the global surplus, WTI oil prices need to be in the low $40s per barrel or even $30s for a time. Total US liquids production is projected to rise to 16.0 MMb/d (800 MMt) in 2020.

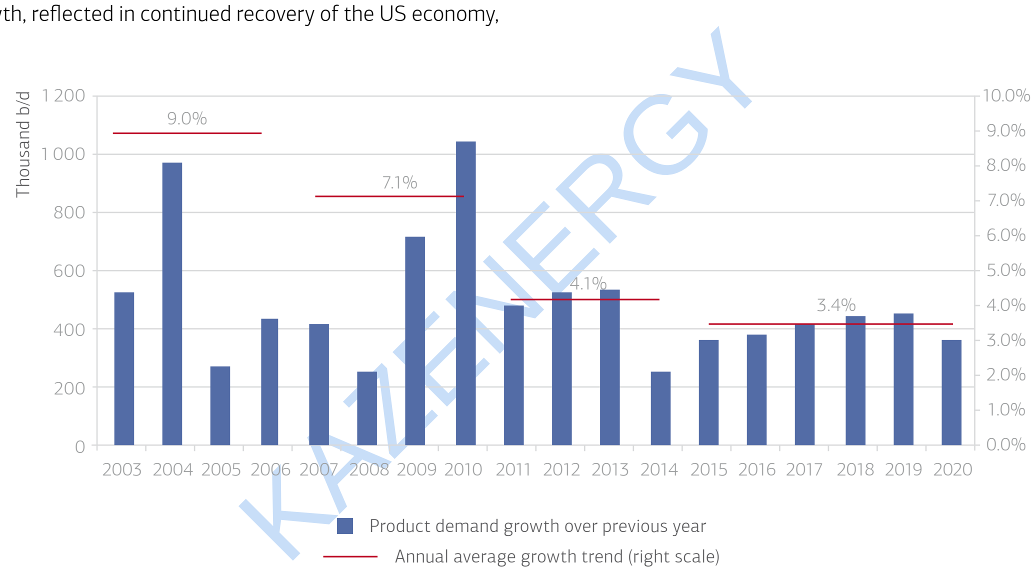


Source: *IHS Energy*

Figure 4.3 North American total liquids production, 2000-2014

- **Iranian production growth now possible.** It is possible, perhaps likely, that Iranian production will also increase. On 14 July 2015, Iran and the five permanent members of the United Nations Security Council (plus Germany) reached a preliminary agreement on lifting the international economic sanctions that restrict Iran's oil exports in exchange for an Iranian scaleback of its nuclear program. If the agreement is approved by the US Congress and the Iranian parliament, and after the International Atomic Energy Agency verifies that Iran has complied with its commitments under the accord, some or all of the sanctions could be lifted as early as end-year 2015. At that time, some 40 million barrels of Iranian crude in floating storage could come to the market[3], and Iran could begin gradually increasing exports by as much as 500,000 b/d (24.9 MMt) in 2016. However, it is doubtful that Iran could restore peak 1970s levels of output (6 MMb/d [303 MMt]) from the current 3.6 MMb/d (169 MMt) without substantial participation by international oil majors. Challenges include the need for major investments to counter declining field productivity, for legislative reforms to encourage competition and clarify state–private sector demarcation of the industry, and agreement by Saudi Arabia and other major OPEC producers to accommodate increased Iranian exports.

Over the near to medium term, global oil demand is poised for a choppy and generally weak period following the 2005 peak seen in aggregate demand in Europe, North America, and Japan before the "Great Recession" of 2008–2009. Low oil prices promote demand growth to some degree, but the impact is not uniform across the world. A modest stimulative impact from lower prices in some countries is offset by weaker economic growth or retail price reform in other countries. In the medium term—between 2017 and 2020—oil demand is expected to be helped by moderately faster global economic growth, reflected in continued recovery of the US economy, an eventual return to growth in Europe, and stable growth for developing countries as a group. Nonetheless, global refined product demand in 2020 may not be much different from the 92.1 MMb/d (4.6 billion tons) registered in 2014.[4] This reflects, among other factors, increasing average fuel efficiency in automobile fleets and the switch from diesel and gasoline to natural gas as a vehicle fuel (see Chapter 7.3.10). Furthermore, China's oil products demand growth is expected to downshift in the next five years, reflecting a change in its underlying economic growth model (see Figure 4.4).



Source: IHS Energy

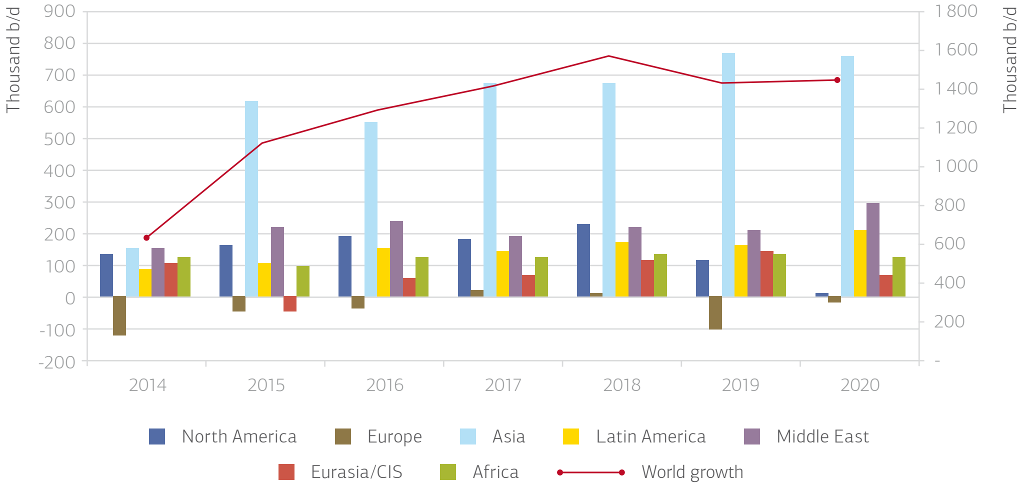
Figure 4.4 China - oil product demand growth has downshifted

The key driver of global oil demand growth since 2000 has been China, accounting for about 40% of world oil demand growth. But Chinese oil demand growth is now decelerating, reflecting broader changes in the economy, both with slowing GDP growth and changes in the sources of economic growth. Looking forward to 2020, we project aggregate demand in Europe, North America, and Japan to remain generally flat, reflecting both the (painfully) slow improvement in economic performance in the wake of the Great Recession as well as improvements in energy efficiency (see Figure 4.5).[5] Demand growth elsewhere (e.g., Asia, Middle East), although weak in the near term (especially in China), is expected to strengthen longer term, thus driving overall global demand growth (see Figure 4.6).

[3] According to some analysts, the stored oil is of poor quality and not suitable for processing in many refineries (e.g., see Clifford Krauss, "A New Stream of Oil, But Not Right Away," The New York Times, 15 July 2015, p. A8).

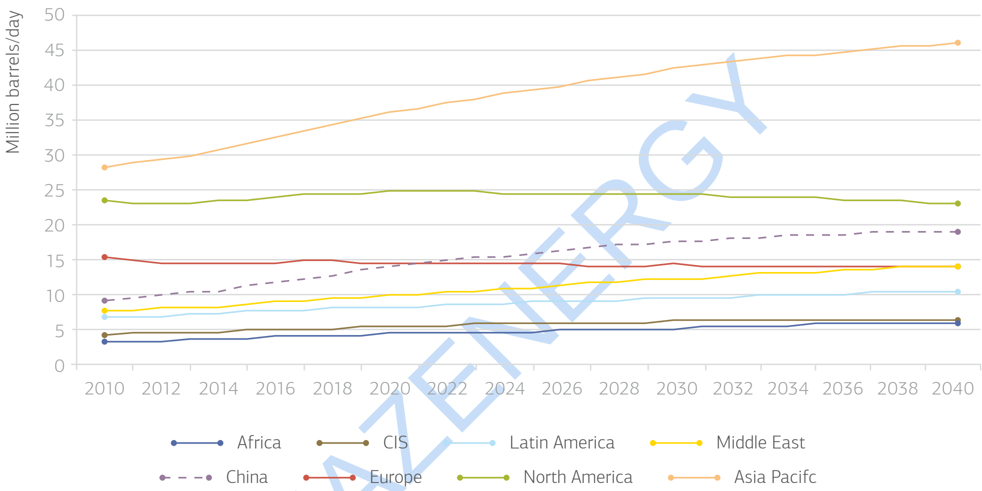
[4] Total world liquids demand, including liquid petroleum gases, will reach about 100 MMb/d (5.0 billion tons) by 2020 (see Table 4.1).

[5] Flat demand for oil products in Europe will not necessarily completely constrain Kazakhstan's ability to sell some incremental crude volumes into this market, as European crude production is projected to fall as well, and indigenous refining is expected to remain flat, even as products demand declines. This combination opens some additional space for crude exports from Kazakhstan (see the text box on European Oil and Product Demand Outlook in Chapter 7.2).



Source: IHS Energy

Figure 4.5 World oil (total liquids) demand outlook: growth picks up in 2017-2020



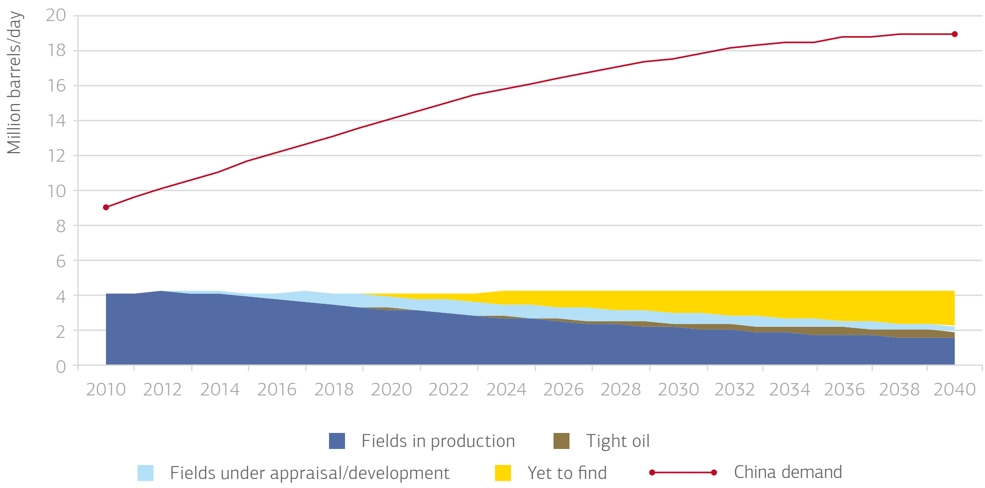
Source: IHS Energy

Figure 4.6 IHS Energy Rivalry base-case scenario of oil liquids demand in world markets

Given the shifting patterns of global oil production and demand, the map of global crude oil trade is being redrawn, leading to significant changes in the 60% of global crude oil production that is traded internationally. Specifically, waterborne trade is shifting away from the Americas—particularly North America—and accelerating its move to Asia. At the country level, this is best exemplified by the contrasting trends in the United States and China. In 2018, we expect China to surpass the United States as the largest oil-importing country in the world. Slowing (but still rising) demand and relatively flat production levels are driving China's imports higher (see Figure 4.7).[6] In contrast, in the United States, rising domestic production and relatively flat demand are reducing imports, from a level of 60% of domestic consumption in 2005 to roughly one quarter last year.[7]

[6] Imports currently account for 59% of China's consumption. In January 2013, in unveiling the country's 12th Five-Year Plan for energy development, China's State Council announced plans to cap oil imports at 61% by 2015.

[7] The US Energy Information Administration projects that imports will fall to 20% of consumption in 2015.



Source: IHS Energy

Figure 4.7 China crude oil supply and demand

We expect North America's (US and Canadian) net crude oil import requirement to drop from its historical peak of nearly 9.4 MMb/d (470 MMt) in 2005 to below 4.5 MMb/d (225 MMt) by 2025. This ~5 MMb/d (250 MMt) of displaced crude oil imports is leading to new trade patterns as it is redirected elsewhere. The flow of crude oil from the Atlantic Basin to Asia is expected to increase from the estimated current level of 4.3 MMb/d (215 MMt) to 7.6 MMb/d (380 MMt) by 2020. Most of this increase is from African supplies that are being pushed out of the Western Hemisphere (North and South America). Some African supplies will also end up in the European market competing with the Kazakh crude. Latin American crude exports are also likely to be pushed towards Asia because of limited space in traditional markets for this crude in North America.

The developments in production, demand, and trade will of course be reflected in oil prices. In addition to the complex interplay between global oil supply and demand, prices can be affected by OPEC behavior, financial market dynamics, industry production costs, and geopolitical events—particularly those that have the potential to disrupt supply. For this report, we adopt the IHS Energy base-case scenario that assumes no dramatic, market-altering disruptive forces on either the demand or supply side of the market. Long-term gains in efficiency on the demand side—such as rising vehicle fuel economy—are built into our outlook. It also assumes sufficient investment in upstream exploration and production (E&P) to meet our projections of global oil demand.

During the period from 2011 to mid-2014, the price for Brent crude oil was well over $100 per barrel (e.g., the average annual price was $111.26 per barrel in 2011, $111.65 in 2012, and $108.64 in 2013).[8] These prices represented the highest levels in recorded history, either in nominal (current) dollars or on an inflation-adjusted basis. However, after peaking at $115 per barrel in June 2014, Brent began to decline slowly (the average annual price was $98.9 per barrel in 2014), before plunging below $50 per barrel in early 2015. The decline was due to both oversupply and slack demand, and it coincided with a decision by Saudi Arabia (the main OPEC producer) to maintain (at least over the near term), rather than reduce, production levels to retain its share in global markets (see below for a detailed discussion of the factors affecting oil prices).

More specifically, a stalemate in place for several years between two countervailing forces—rapid non-OPEC production growth (led by the United States)[9] and political instability focused in the Middle East and North Africa—was finally broken in favor of exceptional supply growth.[10] Non-OPEC supply in 2014 recorded the largest increment to output (2.0 MMb/d) since 1978, more than three times the growth in world oil demand (0.6 MMb/d). This reflects weaker than expected near-term demand in Asia (China, Japan) and emerging markets more generally.[11]

[8] The absolute price for Brent is the starting point for our oil price projections. Brent is a light, sweet crude oil, able to be processed in virtually any refinery in the world, and it competes directly with Middle Eastern and African crudes that serve all major markets.

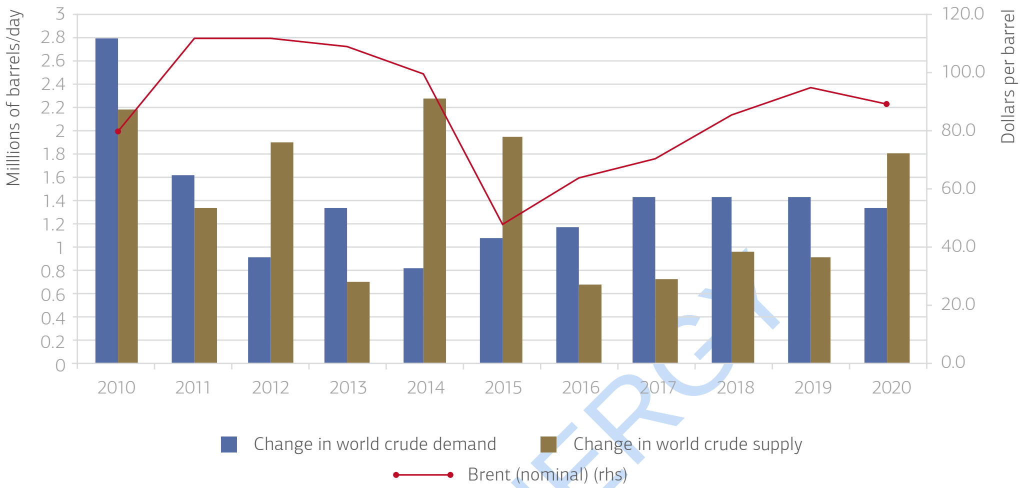
[9] Supply growth in 2014 was also bolstered by rapid recovery in output in the OPEC producer Libya, where production shot up to 900,000 barrels per day despite continuing civil disorder.

[10] See Jamie Webster, Paul Tossetti, Jeff Meyer, Ashley Petersen, James Burkhard, and Bhushan Bahree, Stalemate Breaks: When Will Global Oil Prices Level Out? IHS Energy Market Briefing, Global Crude Oil, 13 October 2014.

[11] After the Fukushima nuclear disaster in 2011, Japan suspended operations at all of its nuclear power plants pending a safety review at each plant. The loss of nuclear capacity resulted in an immediate shift in the country's energy mix. Because Japan meets only about 15% of its primary energy needs from domestic sources, by 2012 the country had become the world's second largest importer of fossil fuels in the world (after China). However, over time, Japan's oil and gas demand is expected to moderate as a result of energy efficiency improvements, the development of renewable energy sources, and the gradual re-commissioning of nuclear reactors deemed not to pose a public safety hazard. Approval for the first such restart came in late 2014 and involved two reactors at the Sendai Nuclear Power station. Sendai 1 resumed commercial operations on 10 September 2015, and Sendai 2 is scheduled to return to commercial power production in November.

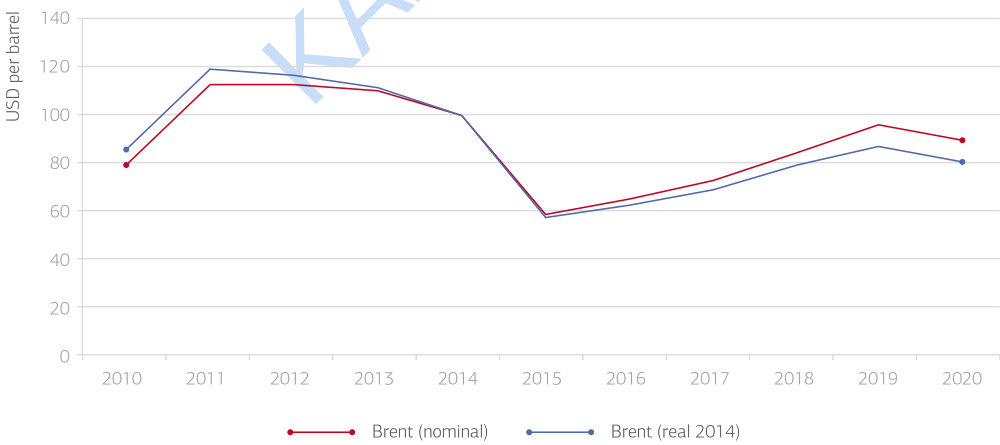
Because the increase in non-OPEC crude production should be more than sufficient to meet most world demand growth near term, swing producers in OPEC (principally Saudi Arabia, but also Kuwait and the United Arab Emirates) as well as unconventional producers in North America will face pressure to restrain production in the next several years.

Thus, the market is in the midst of a multi-year moderation in global prices from the historical annual average nominal highs during the period 2011–mid-2014. In such a moderate pricing environment over the near term, we expect less upstream investment compared with the previous environment of high (and rising) oil prices. But we expect that this combination of adjustments in supply and continued growth in demand will tighten global balances (see Figure 4.8), and will result in a recovery of oil prices by 2019 to about $95 per barrel (in nominal terms) (see Figure 4.9), but because of the high level of uncertainty, a variety of price outcomes are possible (see Figure 4.10). The lower level of capital expenditures will reduce the pace of non-OPEC supply growth later in this decade, something the oil markets will anticipate and reflect with gradually rising prices. Although our Brent outlook beyond 2020 is essentially flat in real terms (see Figure 4.11), oil price cycles will undoubtedly continue; the flat price outlook is indicative of the general price environment (see Section 4.3).



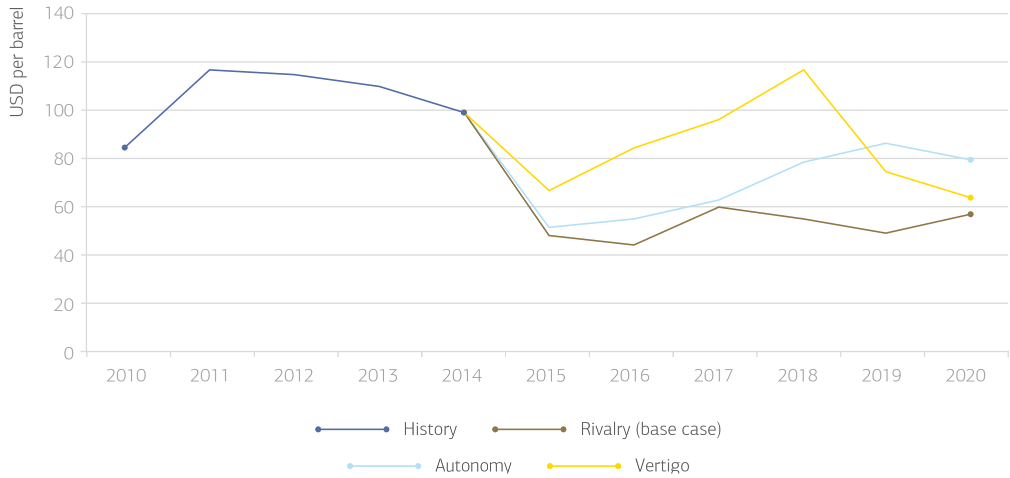
Source: IHS Energy

Figure 4.8 Annual change in world crude demand and supply, 2010-20



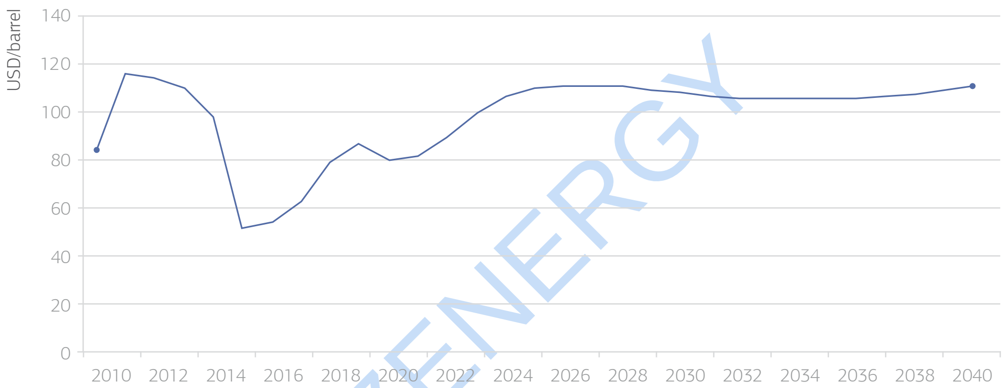
Source: IHS Energy

Figure 4.9 Dated Brent (FOB North Sea) price outlook to 2020 (base case)



Source: IHS Energy

Figure 4.10 Brent crude oil price outook by scenario to 2020

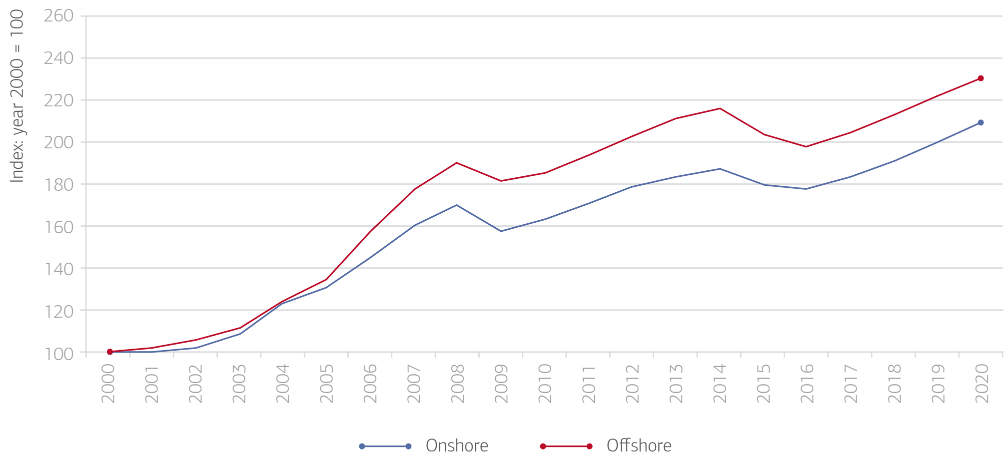


Source: IHS Energy

Figure 4.11 Long-term forecast, Dated Brent, FOB North Sea (base case)

Since 2000, overall oil industry production costs have trended upward significantly, more than doubling between 2003 and 2008, owing to a jump in the costs of steel, labor, and services (among other factors). This cost inflation was itself a function of a tight oil market during much of the past decade, the ensuing rush to develop new upstream projects, and the higher costs of E&P as oil production shifted to more difficult (unconventional, deepwater, tight oil) sources. Inflationary pressures in the industry over the past decade have reset the cost basis at a fundamentally higher level. This, plus the chronic delays and cost overruns that plague the world's mega-oil projects,[12] suggests that a permanent return to the lower crude price levels of the 1990s and early 2000s is unlikely. However, in the current low-price environment, costs are also falling: the IHS Upstream Capital Cost Index declined 4% in 2015 for onshore costs and by 6% for offshore costs (cf. Q1-2000 = 100) (see Figure 4.12). In our base-case scenario, costs are expected to decline slightly in 2016, before rising again thereafter. The upstream cost index is projected to return to the 2014 level in about 2018.

[12] See "Megaprojects: The Problem Big Oil Can't Solve," Petroleum Intelligence Weekly, 6 October 2014.



Source: IHS Energy

Figure 4.12 Upstream Capital Cost Index (UCCI) based on nominal dollars

A key implication of rising non-OPEC (North American) oil production, the shifting demand picture and global trade flows, and downward price pressure going forward, is that terms and conditions for resource development in some host countries are no longer competitive for attracting international investment. Whereas in the past oil companies "chased reserves" globally and host countries exploited this need by enhancing the government "take" (in various ways), today an uncertain price environment is leading oil companies to cut back capital spending plans; some may opt to redirect some of their spending (to North America) into a more stable investment environment. With ample opportunities available, competition among countries for a shrinking volume of upstream investment is intensifying.

End of a 10-Year "Supercycle" for Commodity Prices, Including Oil

The dramatic decline in world oil prices since mid-year 2014 has provided yet more evidence of the end of a decade-long commodity price "supercycle," whereby the combination of accelerating demand and rising commodity prices delivered substantial GDP growth in resource-exporting countries, driven primarily by growth in the Chinese economy. As a result, the economics, spending, and psychology of new project development in the global oil industry are changing, with major consequences for the speed and scale of projects, the ability to deliver projects, and the revenues accruing to host countries. Upstream returns since mid-2014 have been lackluster at best and a new drive to rationalize spending is taking hold internationally. This has important implications for Kazakhstan's flagship projects, including much-delayed Kashagan as well as the planned next-phase expansions at Tengiz and Karachaganak. The more important implications are summarized below.

- Senior managers in the oil and gas industry are no longer driven by the specter of shortage and the imminent need for new supplies (although the replacement ratio is still an important metric) or by the assumption of steadily rising prices arising from surging consumption in emerging markets.

- The development of unconventional oil and gas projects, with shorter time horizons, represents an historic change in the oil and gas industry. Capital spending is being redirected from international expansion back to North America, and not only by the independents.

- Management is deeply alarmed by the continual rise in costs and what it means for margins. Large cost overruns and delays on mega-projects is a chronic problem—Kashagan is one of the more extreme examples, but the same can be seen around the world. There are several reasons for the cost overruns globally that provide a common thread—including more difficult projects in general, tight availability of talent (i.e., limited contractor capacity in high-growth segments such as deepwater and unconventional fields), and over-insistence on local content.

- The new mantra for company managements is "capital discipline" (responding to the demands of the investment community), cost control, and greater selectivity. With the near-term price environment remaining weak, and costs remaining near historic highs, we see no improvement in the near term, but rather a worsening of margins and returns among operators, causing future projects to be reevaluated and pushed back.[13]

- Host countries will need to realign their approach to companies in general due to the shifting competitive balance in the global industry—and the fact that countries are now competing more strenuously with each other for investment. Countries will not find the kind of competitive interest from companies to which they have become accustomed in the last decade. New tenders based upon the kind of terms achieved during the "supercycle" era (and advice based on that era) will need to be revised to reflect the new realities, a process made more difficult by the rising expectations that have been created.
- Countries that move ahead on projects in a timely way will have demonstrated that they recognize the need to be competitive in terms of three key criteria: fiscal terms, local content, and speed and quality of decision-making. Benefits to those countries that adjust to the new environment will come in the form of projects moving forward in a timely manner and a more timely flow of revenues to the government and into the national economy.

However, given the cyclicality of the industry, forces already are in play that eventually could lead to a new round of capital spending on upstream development. A long period of lower prices will make oil more competitive with alternative energy sources and eventually boost oil demand. Furthermore, in some countries geological, technological, and other constraints may limit the potential to increase future production much beyond current levels, thus limiting supply growth and also putting upward pressure on prices. Saudi Arabia and Russia provide salient examples.

4.3. Crude Oil Price Outlook

4.3.1. Key points

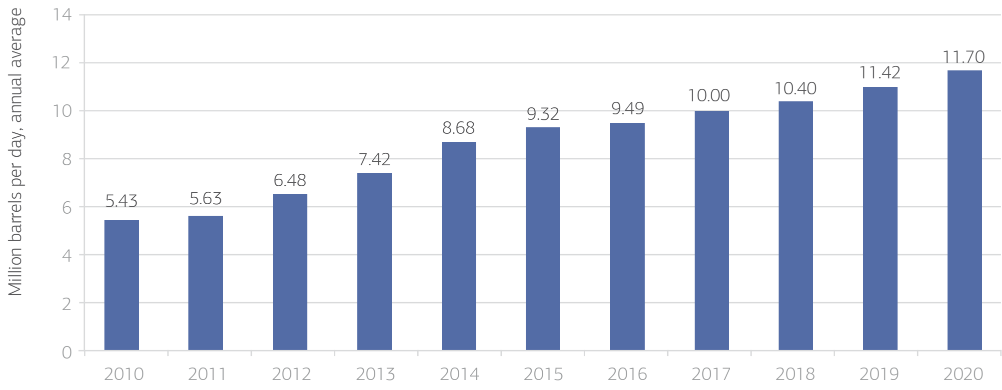
- **Crude oil prices.** Crude oil prices in global markets will remain in the $52 per barrel (bbl) range (for Brent) in 2015 owing to persistent oversupply, which is expected to last into 2016, after which prices will recover slightly to an average of $55/bbl in 2016. In the medium term (2017–2020) average annual oil prices will gradually rise to ~$79/bbl as the market tightens, and as the overall supply picture remains weak. Essentially, the global oil market will eventually return to a higher price level ($100-105/bbl average over 2021–2040), albeit with considerable volatility, driven by the cyclicality of supply and demand and the longer-term need to have more costly supplies of oil in the market to meet rising global crude demand and offset the decline of existing fields.

4.3.2. Crude oil price forecast

Since June 2014, oil prices in global markets have fallen dramatically, with Dated Brent dropping from $115 per barrel (bbl) in early June 2014 to $45 per barrel in January 2015. At the root of plummeting oil prices are weakening fundamentals, with global supply growth outpacing demand growth, and with the excess swelling inventories. The surge in US oil production (particularly "shale" oil production from the Eagle Ford and Permian Basin formations in Texas and the Bakken field in North Dakota), bolstered by additional new supply from Canada, has fundamentally changed the global supply picture.

Since 2008, US oil production has risen 80%, to almost 9 MMb/d (see Figure 4.13). The US increase alone is greater than the output of every OPEC country except Saudi Arabia. Although US and Canadian oil production has been expanding rapidly over the past three years, their production growth was balanced out by supply disruptions in Libya, South Sudan, as well as sanctions on Iranian exports—and robust demand from China's ongoing economic expansion. Consequently, oil prices remained stable at around $100/bbl over the same period. But in the second half of 2014, signs of weaker economic growth and weaker oil demand began to emerge just as Libya quadrupled its output to almost 1 MMb/d. This was an impetus for the further weakening of oil prices starting in September 2014, which accelerated after Saudi Arabia and OPEC's decision in November not to cut production in order to maintain market share.

[13] The new constraints are examined in greater detail in Operators Slash Spending as Returns Collapse, IHS Cost & Strategic Sourcing, Special Report, 13 October 2014.

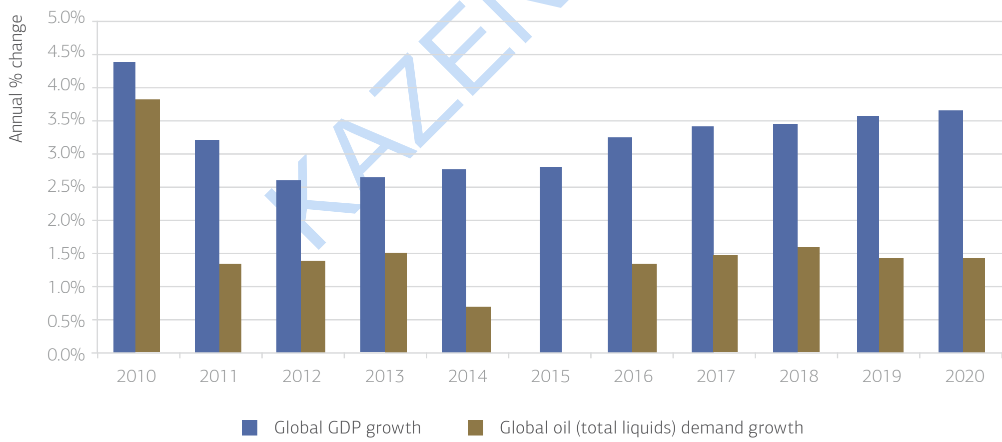


Source: IHS Energy

Figure 4.13 United State's crude oil production profile, 2010-2020

Two factors could help balance the market and drive prices upward: reduced supply or higher demand. In the near term, world demand is unlikely to balance the oil market on its own. China's growing demand, which has been the most important driver of global oil demand growth—accounting for ~40% of global demand growth since 2000—has slowed. The Chinese government has raised oil taxes amid low oil prices, so the potential stimulative impact of lower oil prices on demand growth has been muted. Governments in other countries, like Indonesia, Malaysia, and Angola, took advantage of lower oil prices to reduce subsidies that kept gasoline prices artificially low.[14] Both of these factors, raising consumption taxes and reducing subsidies, limit the impact of lower global oil prices on demand.

As a result, the potential for lower oil prices to significantly increase oil demand is generally limited, but it is possible in countries where taxes account for a relatively small share of retail prices, making lower oil prices more apparent to the end-consumer. The US market is the most obvious example. But the demand boost is likely to be modest, since oil demand elasticity is relatively low, meaning that there is a limit to how much consumers will increase their use of petroleum products in response to falling prices. Meanwhile in those parts of the world where fuel is taxed heavily, such as in Europe, consumers are relatively less exposed to the drop in international oil prices, which again limits a demand-side response (see Figure 4.14).



Source: IHS Energy

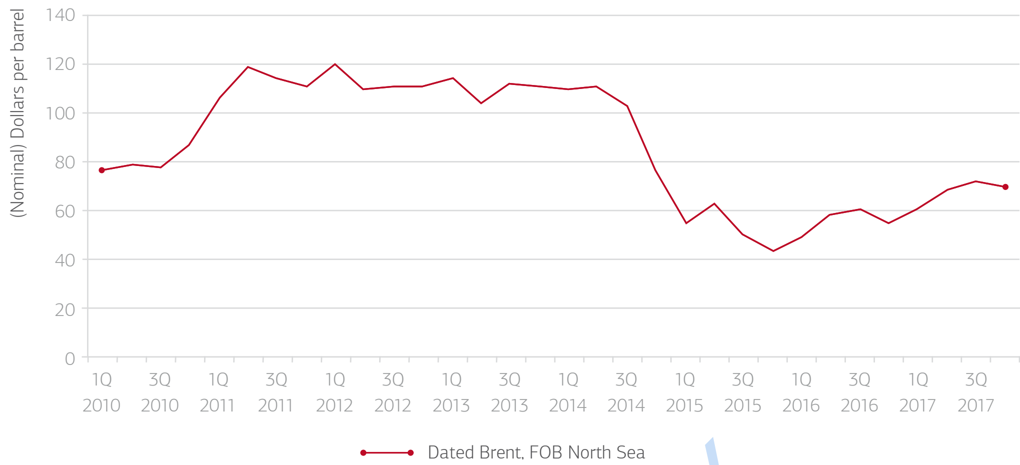
Figure 4.14 World real economic and oil demand growth to 2020*

**Demand is for total liquids, including refined products, biofuels, and natural gas liquids (NGLs).*

Since market rebalancing will not come from the demand side alone, it is the supply side that must adjust most to bring market fundamentals back into equilibrium. However, at the end of November 2014 OPEC decided to forego its traditional role of market balancer and to keep its (target) output level unchanged. In doing so, OPEC has signaled that oil prices now have free rein to respond to other supply and demand inputs to strike a balance. With OPEC withdrawing its support

[14] Other countries, such as Kuwait, India, Oman, and Abu Dhabi, have not reduced gasoline subsidies but have cut those on diesel, electric power, or natural gas. In total, the cuts are only a fraction of the global total of energy subsidies, but are beginning to have an impact.

to balance the market, it is non-OPEC supply sources that will have to reduce production. The low price environment is forcing some operators to shut-in production, while others cut upstream spending, which leads to lower output later on. It also mobilized some producers to seek cost cutting in their production process. Although US tight oil output is more responsive to lower prices than conventional production and the United States has emerged as a swing producer, even in the United States the process of output decline will not be instantaneous; month-on-month production growth is expected to level off only by late 2015. Thus, crude oil prices are expected to remain in the $52 per barrel (bbl) range in 2015, owing to persistent oversupply, which is expected to extend into 2016 (see Figure 4.15).



Source: IHS, Platts (historical)

Figure 4.15 Quarterly Dated Brent price outlook to 2016

A dynamic response to lower oil prices and reduced oil supply is expected from US tight oil producers, which are believed to be the most sensitive to oil price changes because of their need to constantly drill new wells to maintain or grow volumes. For this reason the United States is emerging as a new swing producer, at least over the near term. Although US output in 2015 is still expected to be higher than in 2014, there will be a deceleration in output as 2015 progresses. Next year a 40% year-on-year decline in spending on new wells and other upstream expenditures will become increasingly visible in the form of slowing US production growth. In 2016 prices are expected to recover a bit to an average of $ 55/bbl, as more production is shut-in. However, the rate of the US production slowdown is unexpectedly more tempered, as production costs have come down by 20% in 2015, pushing breakeven prices for tight oil lower. Still, US production growth in 2016 is likely to be just 325,000 b/d—much less than the 1 MMb/d annual average gains of 2012–2014.

Outside of the US tight oil space, the supply response will vary, depending on various factors such as whether an upstream project has reached FID, the economics of unsanctioned projects, and companies' debt levels and access to capital. Still, supply growth is expected to be weak—and will even fall in some regions where growth would have been expected in a $ 100/bbl price environment.

In the medium term (2017–2020) oil prices are expected to rise somewhat as the oil market begins to tighten, reflecting the supply reductions in the prior years. Low prices during 2015–2016 will invariably cause project delays, cancellations, and less spending on producing fields, with a significant impact on projects that otherwise would have added new supply during 2017–2020. However, medium-term oil prices are likely to be lower than the $ 110-plus average that occurred during the period between 2011 and the first half of 2014. The oversupply of rigs, vessels, and even steel, created during the higher oil price period, will lead to lower costs across the industry. The IHS Upstream Capital Costs Index expects costs to decline by around 7% during 2015–2016, but the decline could continue into 2017 if oil prices are lower than projected and keep upstream activity depressed.

In 2017 oil prices are expected to average about $ 63/bbl in real 2014 dollars, as demand continues to grow while supply growth is weak (see Table 4.1.). The world market should continue to tighten as overall global supply growth remains weak, with average annual prices drifting upwards to around $ 79/bbl in 2018 and $ 87/bbl in 2019. By that time, US tight oil rigs are assumed to have returned in force, and the industry's growth accelerates. This is a key assumption, as it remains to be seen whether the US oil industry can revive strong production growth again after the previous slowdown. By 2020, oil prices are expected to dip to an $ 80/bbl average, as the market is better supplied by volumes out of North America, supply growth resumes in regions where projects were deferred in 2015–2016, and oil supply gains are obtained from Iraq and some volumes from Iran.

	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	Annual rate of growth 2014-2020	Annual rate of growth 2011-2015
WORLD LIQUIDS DEMAND													
North America	21.4	21.1	20.7	21.2	21.3	21.5	21.7	21.9	22.1	22.2	22.2	0.68	
United States[1]	19.2	18.9	18.5	19.0	19.0	19.1	19.3	19.5	19.7	19.8	19.8	0.67	
Canada	2.2	2.3	2.2	2.2	2.3	2.3	2.4	2.4	2.4	2.4	2.4	0.78	
Europe[2]	15.8	15.3	14.9	14.7	14.5	14.5	14.5	14.5	14.5	14.4	14.4	(0.19)	
OECD Asia	8.0	8.2	8.4	8.3	8.1	7.9	7.8	7.7	7.6	7.6	7.6	(1.05)	
Non-OECD Asia	20.5	21.4	22.4	22.9	23.3	24.1	24.8	25.5	26.3	27.1	27.9	3.01	
China	9.6	10.1	10.6	11.1	11.3	11.7	12.1	12.6	13.0	13.5	13.8	3.45	
India	3.5	3.7	3.9	3.8	3.9	4.0	4.2	4.3	4.4	4.5	4.7	3.05	
Non-OECD Asia excl. China and India	7.4	7.7	7.9	8.0	8.1	8.3	8.5	8.7	8.9	9.1	9.4	2.36	
Latin America[3]	8.3	8.6	8.9	9.1	9.2	9.3	9.4	9.6	9.8	9.9	10.1	1.66	
Middle East	7.8	8.2	8.7	8.9	9.0	9.3	9.5	9.7	9.9	10.1	10.4	2.39	
Eurasia/CIS	3.7	3.9	4.0	4.1	4.2	4.1	4.2	4.3	4.4	4.5	4.6	1.59	
Africa	3.5	3.6	3.7	3.8	4.0	4.1	4.2	4.3	4.4	4.6	4.7	2.91	
Total world liquids demand	**89.1**	**90.3**	**91.6**	**93.0**	**93.6**	**94.7**	**96.0**	**97.4**	**99.0**	**100.4**	**101.8**	**1.42**	**1.22**
WORLD LIQUIDS PRODUCTION													
Non-OPEC crude													
North America	11.0	11.5	12.8	14.1	16.0	17.0	17.4	18.3	19.3	20.4	21.4	4.94	
United States	7.5	7.9	8.9	10.0	11.5	12.5	12.9	13.6	14.4	15.2	16.0	5.56	
Canada	3.4	3.6	3.9	4.1	4.5	4.5	4.5	4.7	5.0	5.2	5.5	3.25	
Eurasia/CIS	13.7	13.8	13.8	14.0	14.0	14.0	14.0	14.1	14.3	14.6	14.6	0.69	
Latin America	6.9	7.1	7.0	7.0	7.1	7.2	7.3	7.1	7.3	7.5	7.7	1.41	
Brazil	2.1	2.2	2.1	2.1	2.3	2.6	2.7	2.8	3.1	3.5	3.7	8.12	
Mexico	2.9	2.9	2.9	2.9	2.8	2.7	2.6	2.5	2.5	2.4	2.3	(2.85)	
Europe	4.3	3.9	3.6	3.3	3.3	3.2	3.2	3.1	3.0	2.8	2.7	(3.22)	
Asia Pacific	8.5	8.4	8.4	8.3	8.3	8.3	8.2	8.4	8.4	8.3	8.2	(0.19)	
Africa	2.4	2.4	2.0	2.1	2.1	2.1	2.2	2.1	2.1	2.1	2.1	(0.01)	
Middle East	1.8	1.7	1.5	1.4	1.4	1.3	1.3	1.3	1.2	1.2	1.2	(1.96)	
Total non-OPEC liquids	**48.6**	**48.8**	**49.1**	**50.2**	**52.2**	**53.1**	**53.5**	**54.4**	**55.7**	**56.8**	**57.9**	**1.76**	
OPEC crude	31.2	32.0	33.4	32.6	32.6	33.1	33.3	33.5	33.6	33.6	33.7	0.55	
OPEC condensate and NGLs	3.2	3.6	3.7	3.7	3.8	4.0	4.0	4.0	4.2	4.2	4.4	2.39	
Total OPEC liquids	**34.5**	**35.5**	**37.1**	**36.2**	**36.4**	**37.0**	**37.3**	**37.6**	**37.8**	**37.8**	**38.0**	**0.75**	
Processing gains	1.9	2.0	2.0	2.0	2.0	2.0	2.0	2.1	2.1	2.1	2.1	0.81	
Global biofuels	1.8	1.9	1.9	2.0	2.1	2.2	2.3	2.3	2.4	2.4	2.4	2.4	
Other liquids[4]	1.1	1.1	1.1	1.2	1.2	1.2	1.3	1.4	1.4	1.4	1.4	3.11	
Total world liquids production	**87.9**	**89.3**	**91.1**	**91.7**	**93.8**	**95.7**	**96.4**	**97.8**	**99.3**	**00.6**	**101.9**	**1.39**	
Total liquids inventory change[5]	(1.2)	(1.1)	(0.4)	(1.3)	0.3	1.0	0.5	0.4	0.3	0.2	0.1		

Note: This balance is our first indicative estimate of supply and demand through 2020. It may differ from the supply and demand projections provided in the upcoming 2015 IHS Annual Strategic Workbook (ASW).

[1] United States is 50 states plus District of Columbia only.

[2] Eastern Europe is included in Europe.

[3] Mexico, Puerto Rico, and the US Virgin Islands are included in Latin America.

[4] Other liquids is a global figure which includes gas to liquids, coal to liquids, nonrenewable oxygenates, refinery additives, and oil shale.

[5] A positive number indicates a stock build. A negative number indicates a stock draw.

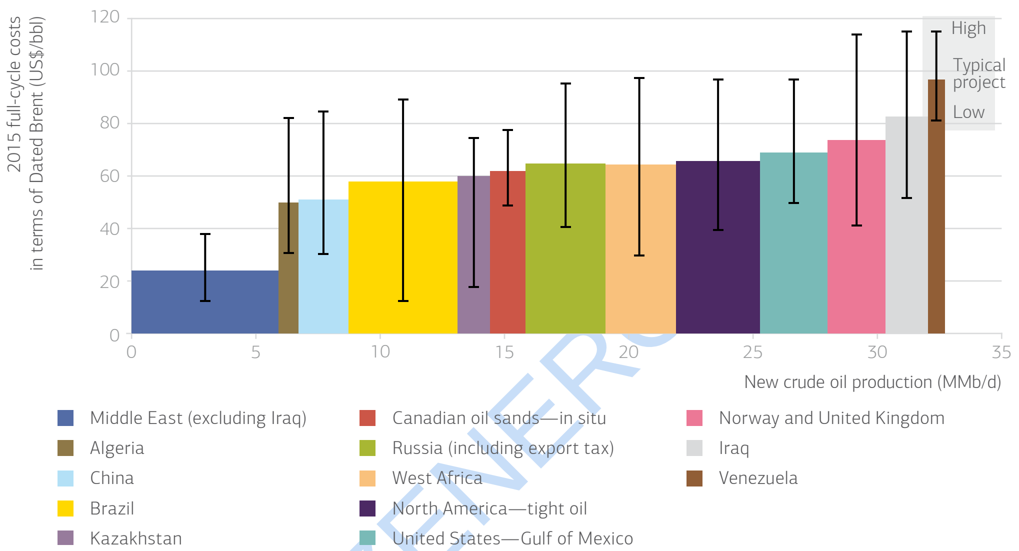
Source: IHS Energy

February 2015 IHS Energy World Oil Watch, The New Math of Oil: The "Inadvertent Swing Supplier"—The United States. Oil Market Outlook to 2020: Weaker Supply Growth to Push Prices Higher.

Table 4.1 Global liquids supply and demand balance, 2010–20.
(Million barrels per day, annual averages)

Industry efficiency and greater budgetary discipline within the producer companies are also likely to improve after the price crash, as companies attempt to drive down break-even costs of projects. Lower costs and improved efficiency should allow the industry to operate more profitably at lower oil prices. Even before the collapse in prices, major oil and gas companies had become preoccupied with the continually rising costs of developing new supply and were heeding the call from their investors and shareholders for "capital discipline." The oil price decline will result in a slowdown and reduction in major new investments around the world. Countries in Africa, Asia, and Latin America are already finding that fewer companies were interested in bidding for new upstream opportunities. If these countries want to attract investments, they cannot insist on very tough terms in taxes, royalties, and other requirements (such as local content) that drive up costs and cause delays in recouping investments.

Longer term, post 2020, the global oil market will remain well supplied, with growth in output coming mainly from the United States, Canada, Brazil, and Iraq. Global oil demand is expected to continue to grow longer term, at a modest average rate of 0.8% per year through 2040 (see Figure 4.1a), albeit moderated by a steady decline in the oil intensity of economic output. Demand flattening is expected in the OECD countries, particularly Europe and Japan. China's demand will continue to grow, although at slower rates than over the past decade or so. As a result, the global oil market will ultimately return to a higher price level of around $ 105/bbl in the period after 2020, driven by the longer-term need to develop more costly supplies of oil to meet the rise in global oil demand and offset field decline (see Figure 4.11).[15]



Note: This cost of oil is expressed by the Dated Brent price necessary for projects to "break even," assuming a 10% IRR. The break-even cost estimates are for greenfield projects. The low- and high-cost projects are chosen from among the approximately 700 that IHS has modeled for our cost of oil analysis. For North America tight oil, the cost estimates are for subplays. The supply outlook is consistent with the IHS 2015 Global Crude Oil Markets Annual Strategic Workbook, released in April 2015. For each region, the supply additions are gross additions in 2015-2030, which are calculated by summing the maximum annual production of fields under development (FUD), of fields under appraisal (FUA), and of yet-to-find (YTF) categories for the areas. Exceptions are North American tight oil, the tight oil components of other producing areas, and Canadian oil sands, all of which are simple new additions. The break-even cost estimates for in-situ Canadian oil sands are based on a steam-assisted gravity drainage (SAGD) project. The break-even cost estimate for Iraq is high owing in part to the security risk to operations; payment of a hazard premium to skilled workers and engineers; and the added cost of building required new oil infrastructure. The Middle East includes Saudi Arabia, Kuwait, Neutral Zone, United Arab Emirates, Oman, Iran, Qatar, and Bahrain. West Africa includes Nigeria and Angola. Break-even costs for groups of countries are weighted by volume.

Source: IHS Energy

Figure 4.16 Cost curve for a selected inventory of potential new oil production capacity to 2025

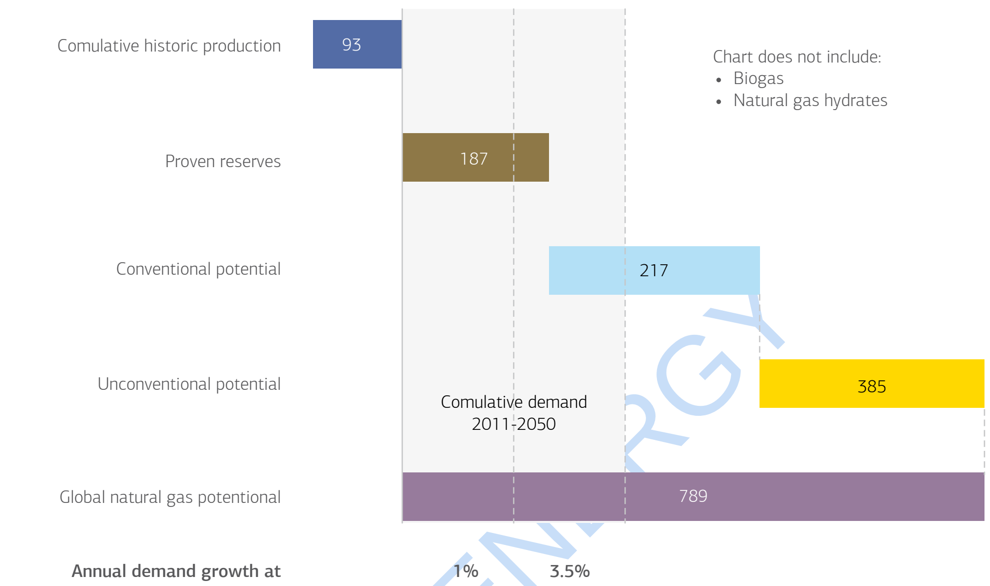
In the current environment, it is important to keep in mind that price cycles have been a feature of the oil market since it came into being in the 19th century. Some cycles heralded momentous change in the oil market—such as the price rise of 1973, the price collapse of 1986, and the multiyear price increase from 2003 to 2008. Now the role of OPEC may be undergoing a historic shift just as the United States is emerging as a potential new swing supplier, albeit an inadvertent one. The range of potential outcomes is wide, and the level of uncertainty is at its greatest in years. There will be surprises during what will be a bumpy ride. Still, relative oil price stability is an important prerequisite for the oil industry, and OPEC members—especially the Gulf countries, with low production costs and high reserves—are likely to use their influence in the future to ensure that price stability is maintained once a new equilibrium is found. For them, the global oil price is a much more important question than it is even for the major consuming countries. The key downside risks to this long-term price outlook, which would appear to be the most relevant for Kazakhstan, all involve the need to bring in lower cost barrels to balance the global oil market longer term, resulting in a lower equilibrium price. These risks include:

[15] The cost curve shown in Figure 4.16 is not intended as a production forecast to be considered against growth in oil demand. Rather, Figure 4.16 shows overall capacity of new projects through 2025, subdivided into regional / national market share along the x-axis and cost of production at the various regions along the y-axis.

- A much lower level of global oil demand;
- A sizable reduction in costs for many countries and segments of production;
- A larger supply than expected from selected segments of lower-cost oil production (e.g., tight oil in the USA).

4.4. Global Outlook for Natural Gas

Unconventional supplies of natural gas also are changing the global outlook for reserves, production, and demand. The industry has traditionally thought of natural gas supply as lasting 60 years, based on the narrow metric of proven reserves divided by current production (or consumption). But today, recoverable resources of unconventional gas—including both shale and coal-bed methane (CBM)—are estimated conservatively at 789 trillion cubic meters (Tcm), or 250 years of current consumption (see Figure 4.17).[16]



Source: BP, IHS Energy, IEA

Figure 4.17 What is the global availability of natural gas? (Tcm)

Although almost all of the production of unconventional gas to date has come from North America (and particularly the United States), exploration efforts targeting unconventional gas resources outside North America are also gradually revealing the scale of the potential for shale gas and CBM that could substantially increase total recoverable gas reserves.[17]

Consequently the traditional conceptual framework for natural gas, which prevailed globally until as recently as 2009, has been called into question. That paradigm posited a continued increase in international trade in natural gas, a trend that had been in place since the mid-1990s, as those countries with limited conventional gas resources increased imports by pipeline, and with growing significance by LNG, from those countries richly endowed with conventional gas. The importing countries were expected to fall into two groups: first, developed economies (i.e., the United States, Japan, Europe, and South Korea), which would face high gas prices but which have the willingness and economic ability to pay; and second, the largest emerging economies (China, India, and possibly Brazil) together with an assortment of smaller developing economies, which were seen as potential large importers but with a greater price sensitivity and therefore a greater level of uncertainty around their possible growth. On the other side of the equation were the exporters, assumed to be primarily Russia, the Middle East, Australia, North and West Africa, and certain Central Asian states (including Turkmenistan) with their large conventional gas resources.

This conceptual model implied a move toward globalization of gas markets. North America, which had long been largely self-sufficient in natural gas, was expected to join the general global market as a consumer and importer because of the depletion of its conventional resources. At the same time, emerging economies were enlarging the number of LNG-importing countries, which had previously been a fairly small, defined set of key Asian and European players. It was a small mental leap to surmise that growing LNG trade and diversity of imports could lead to a global marketplace for natural gas, and a move toward some form of global pricing, as exists for

[16] International Energy Agency, World Energy Outlook, 2010.

[17] See the IHS CERA Multi-Client Study, The New Map of Global Gas, 2013.

other primary commodities.[18]

Three new factors are now influencing this traditional view:

- First, unconventional gas has raised questions concerning previous expectations about resource distribution and potential trade flows, with potential large-scale resources now located in what were previously seen as net importing regions. However, the extent to which the successful North American experience in unconventional gas development—reflecting a favorable combination of geology, legislation, openness to technological innovation, and investment capital—will be replicated elsewhere remains to be determined.

- Second, large conventional finds in the deepwater East Africa, the Eastern Mediterranean, and associated gas offshore Brazil have widened the potential source points for conventional gas exports.

- Third, gas shortages across much of the Middle East, which are spreading to North Africa as well, raise questions about the importance of the Middle East/North Africa region for exports longer term. Although the region contains 40% of the world's proven gas reserves, domestic demand (especially for power generation) has grown rapidly (on the order of 6–7% annually) and supplies are not uniformly distributed: e.g., Iran, Egypt, Qatar and Saudi Arabia have significant reserves, whereas the UAE, Kuwait, Bahrain, Jordan, and Syria do not. The fact that much of this is associated gas (and is used for reinjection in oil fields) or sour gas (difficult to process), together with the investment priority accorded to oil production over natural gas development, has forced some countries (e.g., UAE, Kuwait) to rely on imported LNG to satisfy at least peak seasonal electricity demand and to build new oil- and coal-fired generation capacity. Egypt, once a net gas exporter, recently concluded an agreement to begin importing natural gas from offshore Israeli fields.

As in the case with oil, the sudden growth in global gas production (from 2,989 billion cubic meters [Bcm] in 2009 to 3,461 Bcm in 2014) was accompanied by falling prices in many markets. Yet in the absence of a global gas market, the actual mechanisms underlying price declines have varied according to the pricing structure in the various major regional markets (US, Europe, Asia). In the US, most gas sales occur on the spot market, which allows producers to instantly locate available buyers, rapidly negotiate prices that tend to be volatile (reflecting short-term changes in supply and demand), and deliver energy quickly upon the conclusion of the transaction. However, outside North America—in Europe and especially in Asia—although spot markets exist, most gas is typically sold under long-term contracts at prices that are normally linked to the price of oil (crude or refined products, such as fuel oil or diesel) according to a specific formula. These contracts, which may last 20–25 years, provide secure markets and revenue streams for producers and secure sources of supply for consumers. Price adjustment mechanisms include a time lag (often from three to nine months) between oil price movements and gas price adjustments, as well as provisions for periodic renegotiation of pricing terms (e.g., every 3–5 years).

In the US spot market, for instance, where prices respond quickly to changes in supply and demand, a sudden influx of new North American supply caused Henry Hub prices to fall from $4.57 per million British thermal units (MMBtu) in June 2014 to $3.43 by year's end, and further to $2.73 in June 2015. IHS industry analysts expect that the price will be approximately flat, at around $2.80 per MMBtu, through the remainder of 2015 (averaging $2.82 per MMBtu for 2015 as a whole) as the next wave of pipeline infrastructure expansions comes online in the US Northeast (Marcellus/Utica region), enabling production from those plays to ramp up to meet winter gas demand. For 2016 IHS expects Henry Hub prices to increase slightly, to an average of $2.88/MMBtu for the year.

In the spot market of the UK (and several smaller ones elsewhere in Europe), the relationship between rising global gas supply and falling prices is similar. The UK's National Balancing Point (NBP) price averaged $8.23 per MMBtu for 2014 as a whole, but the annual average concealed a rather large price downtrend on a monthly basis. The January 2014 price was $10.71 per MMBtu, but due to an unusually mild winter (and thus reduced gas consumption in power generation) as well as the accumulation of above-average storage volumes, by July the price had fallen to its lowest level since September 2010 ($6.36 per MMBtu). Although the price recovered to $8.50 by December, as inventories were built in preparation for the 2014–2015 winter season, the shifting of large volumes of Qatari LNG to the UK market from the Pacific Basin—despite comparatively weak demand and price fundamentals—is expected to exert continued downward pressure on the NBP price. IHS expects the NBP price to average only $6.72 per MMBtu in 2015 and $6.45 in 2016 as LNG from other sources starts to penetrate the UK and continental European markets.

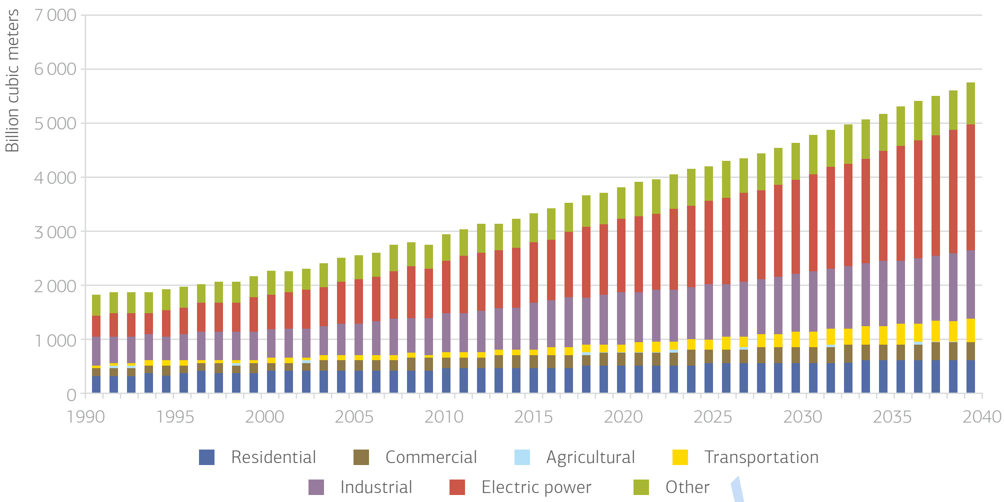
In Japan and other Asian markets, the recent oil price decline is now increasingly evident in the falling prices of gas delivered under long-term contracts. However, Asian gas prices are expected to remain higher than in the US and Europe for a number of reasons, including greater dependence on LNG vis-à-vis pipeline gas and Japan's heavy reliance on LNG imports for power generation given the moratorium on nuclear generation in the aftermath of the Fukushima Daiichi disaster in 2011. Prices in long-term LNG import contracts in Japan (as well as Taiwan and South Korea) are linked to crude oil via the Japanese Crude Cocktail (JCC) price published monthly by the Japanese government.[19] In 2014, incremental supply from Papua New Guinea, Australia, and Nigeria entered an Asian Pacific market already amply supplied by producers such as Qatar and Algeria, and one in which short-term demand growth was marginal (e.g., China, Singapore, Taiwan, India) or negative (South Korea). The Japan LNG Cocktail (JLC; indexed to the JCC) consequently gradually declined from $16.67 per MMBtu early in the year (31 January) to $16.13 (30 June) to $15.62 at year's end (31 December). The JLC's decline continued through first quarter 2015 (to $14.28 per MMBtu), and is poised to drop more sharply by 2017 (projected annual price $9.79 per MMBtu) when incremental Russian and US LNG supply is expected to enter Northeast Asian markets (see below).

Over the longer term, however, despite considerable growth in gas supply, demand growth for gas should be stronger than for oil. World gas demand is expected to nearly double by 2040. Although by the 2030s oil, coal, and natural gas are expected

[18] See Daniel Yergin and Michael Stoppard, "The Next Prize," Foreign Affairs, Vol. 82, No. 6, 2003.

[19] As the name implies, this is the average price of customs-cleared imports of crude oil into Japan.

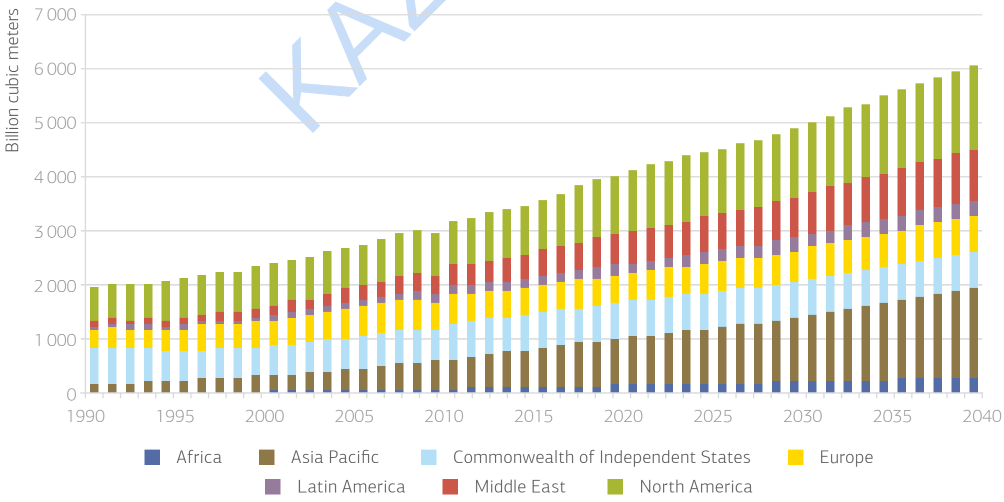
to account for nearly equal shares of global primary energy consumption, by 2040 natural gas is likely to pull ahead as the leading energy source, when gas consumption for power generation is expected to account for 41% of demand (see Figure 4.18). One of the factors supporting growth in gas-fired capacity is the growth of installed wind and solar power generating capacity, which requires balancing with the help of gas-fired generation. Another possible factor is the retirement of coal and nuclear power generation capacity in the US, and its replacement by gas-fired plants, which will increase gas demand. There is also increasing evidence for a possible upside in the transportation sector, where gas (especially in the form of LNG as ship bunker fuel and as a fuel for heavy-duty trucks) could make bigger inroads and undercut the oil price.



Source: *IHS Energy*

Figure 4.18 Global natural gas demand by sector, Rivalry scenario

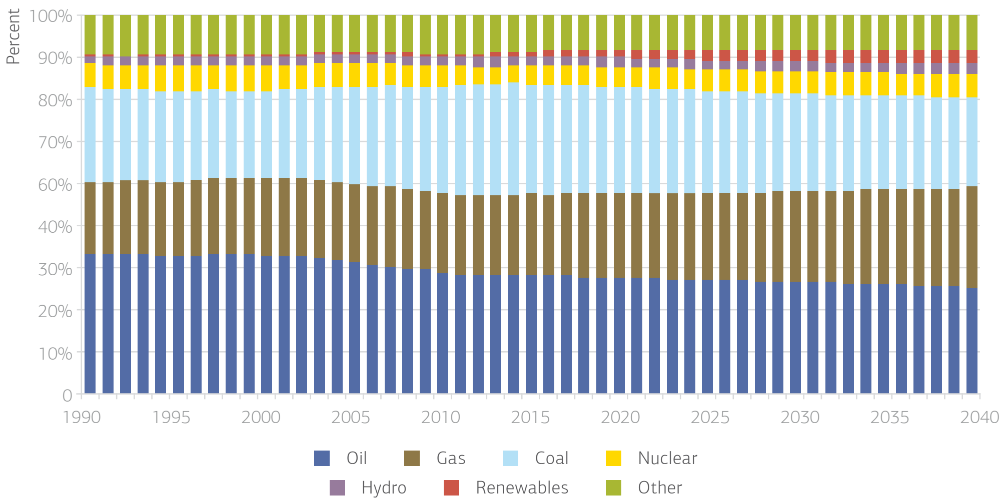
The Asia-Pacific region is projected to be the largest area of gas demand, accounting for over one quarter of world demand in 2020 and almost 30% in 2040 (see Figure 4.19). China's consumption of natural gas has doubled over the past 5–6 years, and IHS Energy projects that its demand could quintuple by 2040, by which time it would become the largest gas consumer in the world.[20] However, even by that time, gas is expected to account for only about 15.5% of China's primary energy consumption, considerably below the world average and comparable shares of the total for Japan (27%), Russia (54%), and the United States (34%). For the world as a whole, the share of gas is expected to rise from 21% in 2014 to about 27% in 2040 (see Figure 4.20).



Source: *IHS Energy*

Figure 4.19 Global natural gas demand by region, Rivalry scenario

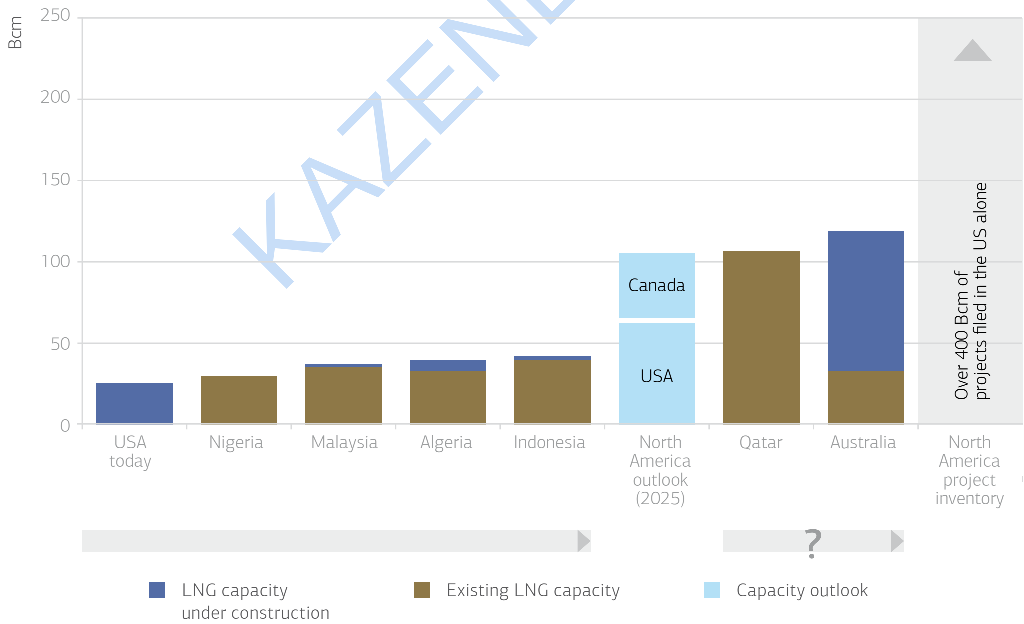
[20] Unlike China's slowing demand growth for oil and electric power, which became evident in 2014, natural gas demand growth is still expected to increase by roughly 10% annually through 2018. The continued strength in gas demand reflects a number of factors, including structural change in the economy, increasing use as a transportation fuel, and efforts to ease air pollution in the country's eastern regions.



Source: IHS Energy

Figure 4.20 Share in global primary energy demand (percent)

Much of the gas consumed in the Asia-Pacific region is delivered by sea in the form of LNG. LNG was experiencing a renaissance of sorts; the amount of new capacity added between 2004 and 2012 equaled that of the previous 40 years. And much more capacity is committed for the future or is being considered (see Figure 4.21). Much of the planned incremental capacity is based upon the unconventional gas revolution, so the wild card in global LNG supply is the United States. Its vast low-cost gas resource has already incited many investors to develop LNG for export to other parts of the world as the industry eyes higher-priced markets in Europe and Asia as another outlet for growing domestic supply. Export applications for some 2.2 billion cubic meters (Bcm) per day of LNG had been filed from the US Department of Energy (DOE) as of September 2014.



Source: IHS Energy

Figure 4.21 North America project inventory and capacity outlook relative global LNG capacity installed under construction

As of that same date, over 30 US companies had received approval from the US Department of Energy (DOE) to export LNG.[21] The total quantity of LNG approved for export thus far exceeds 440 Bcm per year.[22] It should be emphasized that this figure for the United States includes many projects that are nothing more than an application for an export permit, and may never materialize for a number of reasons, including failure to obtain siting/construction approval by the Federal Energy Regulatory Commission (FERC) and lack of financing. But if even half the approved capacity is actually constructed, this would make the United States one of the leading LNG exporters in the world, perhaps outpacing even Australia and Qatar. These projects have been opposed by those in the United States who fear that implementation of these projects would increase domestic gas prices to the detriment of gas consumers, including industrial users, and under the relevant legislation, the DOE has the duty to consider the public interest in assessing such applications, including the trade-offs between the suppliers and consumers. Opposition also has been voiced by environmental groups such as the Sierra Club, citing the increased scale of fracking that would be needed to support LNG exports as well as the heightened GHG emissions (both at well sites and at sites of final consumption).

It is appropriate here to explore briefly what impacts the launch of US exports to international markets might have on other natural gas producers (including Kazakhstan), at least in the medium term. First, because of falling world oil prices (to which long-term contracted LNG prices are commonly indexed) and rather modest demand growth in key demand centers such as China, US LNG exports are poised to enter a changed environment of abundant supply and downward pressure on spot market prices.[23] Although demand in Japan (post-Fukushima) and Taiwan, in particular, has tended to support the short-term market, LNG demand growth in China (unlike total gas demand) fell sharply in summer 2014, reflecting higher gas pricing for domestic LNG consumers (due to recently instituted price reforms) and caution on the part of wholesalers who had incurred losses on LNG imports the previous year. As a consequence, the estimated Northeast Asia spot price for LNG fell from $15.87 per MMBtu in 2013 to $14.75 by November 2014.[24] In such an environment, any US volumes that are not contracted ahead of time with commercial customers will face considerable competition from such established players as Qatar, Malaysia, Australia, Nigeria, Indonesia, and other LNG-producing countries that may be better located to serve particular (e.g., Asian) markets, as well as from Russian and Algerian pipelines into Europe.

US exports are going to begin in 2016, at which time initial shipments will be rather small in magnitude. Initial shipments in the range of 4–5 MMt per year are expected to roughly double to 12 MMt by 2017.[25] Construction permits have currently been issued by the FERC to four LNG export terminals in the lower-48 United States on the Gulf or Atlantic coasts (Sabine Pass, Cameron, Cove Point, and Freeport), with construction now proceeding on the first three projects. Exports from one or more of these terminals that are projected for 2017 would amount to slightly less than 4% of overall world LNG supply. How quickly US output ramps up beyond the launch of these terminals remains an open question at this time given the current price environment and uncertain market conditions.

Third, the ultimate destination of the bulk of US LNG exports remains uncertain at this point. The expectation is that the European Union will be one likely market, given the commitment of its member states to carbon emissions reductions (and some of the limitations now confronting its renewable energy rollout to attain clean energy goals) and their recent concerns with Russia, a major supplier, regarding terms and prices of piped gas deliveries. However, European interest in expanding the role of natural gas (as opposed to renewable energy) as part of a program to achieve carbon emissions reductions has thus far been rather lukewarm, as evidenced in the opposition to unconventional gas drilling in many EU member states.[26]

Nonetheless, IHS Energy analysis indicates that with rising supply and lackluster global demand growth for LNG, more residual gas will end up being directed to Europe (as the residual market), which ultimately will begin to displace some Russian gas after 2017.[27] Europe's liquid spot markets allow flexible LNG to enter the market and put pressure on gas prices. The year 2015 is expected to be a turning point, of sorts, for Europe as it represents the first year since 2010 that demand for natural gas in the power sector (especially in the UK) is projected to grow. Going forward, recovery in the

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[21] "Long Term Applications Received by DOE/FE to Export Domestically Produced LNG from the Lower-48 States (as of 10 September 2014)," available at http://www.energy.gov/fe/downloads/summary-lng-export-applications-lower-48-states

[22] Extant legislation states that any export of gas, including LNG, to countries with which the United States has a free trade agreement [FTA] should be automatically deemed to be consistent with the public interest, and therefore approved. The United States currently has FTAs in place with 20 countries, including potential LNG importer South Korea. Although permission for export to non-FTA countries is in theory not so easily obtained, seven projects approved to date are allowed to export to both FTA and non-FTA markets, suggesting that this is being decided on a case-by-case basis.

[23] Between 2014 and 2020, 130 million metric tons per year (MMt) of new liquefaction capacity is expected to come on line (see Killi Maleckar Krasity and Terrell Benke, "The Costs of Flexible LNG Supply in a Loose Market," IHS Energy Private Report, December 2014). Furthermore, 64–74 MMt of existing LNG supply contracts will expire between 2015 and 2022, of which only 13% have been replaced by new or renewed contracts, adding to the proportion of supply not firmly anchored into end markets. These flexible volumes will compete for demand with projects whose supply contracts are expiring, exerting downward pressure on LNG prices.

[24] See "Market Stalls on Oil Prices and Weak Spot Demand," IHS Energy Monthly Briefing: Global Liquefied Natural Gas, 28 October 2014, p. 2.

[25] See Benjamin Gage, "More Commercial Innovation or Risk?," IHS Energy Market Briefing: Global Liquefied Natural Gas, 21 November 2014, p. 7.

[26] See Daniel Yergin and Michael Stoppard, "The Future of Global Gas," IHS CERA Special Report, 2013, p. 5.

[27] IHS Energy projects that Russia's annual gas exports to Europe between 2013 and 2020 will fall by 27 Bcm (from 153 to 126 Bcm), while LNG imports (from all sources) will rise by 38 Bcm (from 46 to 84 Bcm) (measured in international standard units).

power sector (and to a lesser degree industry) is expected to offset longer-term declining demand in the residential and commercial sectors, barring new policy constraints. This reflects both Europe's eventual improvement in economic conditions as well as expected retirement of some coal and nuclear generating capacity.

Another market, for which US LNG deliveries already actually have been scheduled, is Japan, the world's foremost LNG-importing country, which accounted for 36% of global imports in 2013. In Japan, US LNG is expected to compete for market share with Russia (as well as with Australia, Qatar, and other major producers). Although Japanese LNG demand is expected to decline slightly due to the restart of some nuclear generating capacity by 2016, Japanese companies have already contracted for imports of 16.9 MMt per annum from American suppliers by 2020.[28] This is more than the ~10 MMt of LNG Japan currently imports from Russia.

An important takeaway is that to date there is little evidence that US LNG exports are poised to make major inroads in markets (e.g., China) that are important for Kazakhstan's pipeline natural gas exports. Even in markets in which Kazakhstan's partner Russia appears to be susceptible (e.g., Europe), the favorable economics (for meeting base demand) of exports via an existing pipeline infrastructure (vis-à-vis LNG deliveries) places a limit on the erosion of Russia's market share by imported LNG.

4.5. Petrochemicals in a Global Context

Economic events and trends are very important influences in determining the long-term expansion and profitability of the petrochemical industry. Over time, these factors heavily influence the supply of fuels and chemical raw materials (feedstocks) such as natural gas, ethane, or naphtha. Similarly affected is the demand for basic petrochemicals, such as ethylene, propylene, and butadiene, which are the building blocks (starting materials) used to manufacture derivative products actually used by consumers such as plastics and fibers.

Petrochemical demand links directly into products that have end-uses segmented into both durable and non-durable applications. Demand can also be analyzed through specific end-uses (e.g., construction, automotive, electronics) and also at the composite level across all sectors. Each end-use has its own market dynamics, and an aggregate view can be built up from sector indicators such as industrial production, construction, etc.

Gross domestic product (GDP), which is the sum total of all goods and services produced in an economy, is an important measure of overall economic activity in a given country or region. The ratio of demand growth for a petrochemical product to GDP growth, its GDP elasticity, differs considerably on a regional basis, but for the world as a whole for basic petrochemicals, this indicator is relatively high (historically around unity or higher), meaning that the growth of demand for basic petrochemicals proceeds in near lock-step with economic expansion (GDP growth). Light olefin demand growth, in particular, tends to be highly correlated with economic growth. Global demand for ethylene and propylene has historically grown at a slightly higher rate that world gross domestic product (GDP); i.e., it has an elasticity of about 1.1 vis-à-vis GDP growth.

But this also means that olefins manufacture tends to be quite cyclical in nature, usually (but not always) moving together with the normal business cycles of regional and global economies. Periods of high industry profitability (generally driven by high utilization rates) tend to alternate with times of poor profitability (generally characterized by low utilization rates), leading to subsequent periods of over- and under-investment in new capacity. Long construction lead times of four to five years typically result in waves of capacity additions toward the end of the expansionary phase, thus exacerbating already weakening market conditions when a downturn comes. The ensuing cyclical downturn and low profitability tends to rein in capital spending, leading to an extended period of very slow capacity growth that tends to coincides with demand growth during the economic recovery phase. This, in turn, tends to create very tight market conditions.

4.5.1. Key petrochemical industry market dynamics

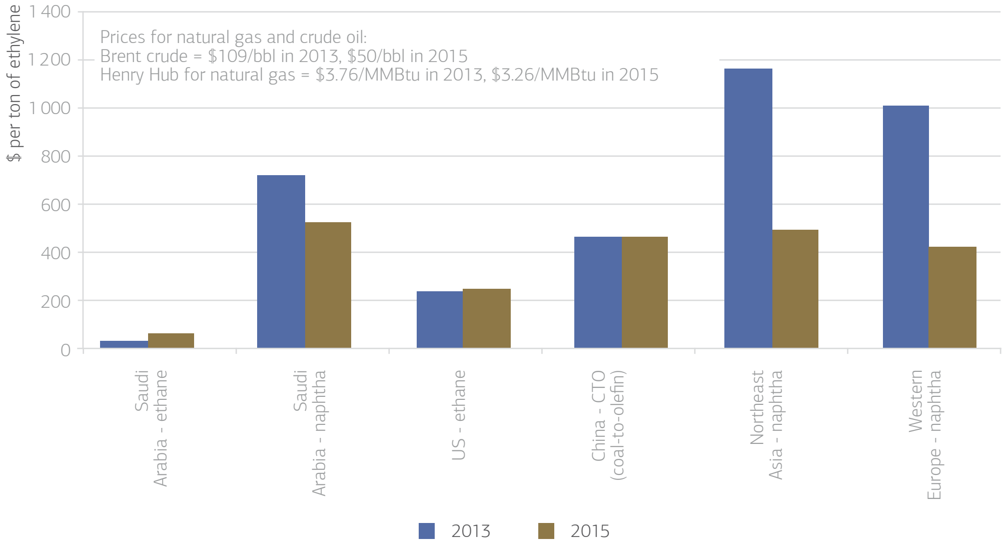
Because of this close association with aggregate economic growth, basic petrochemicals production normally expands at an impressive pace. Demand for basic petrochemicals has expanded by about 4.5% per year for the last 20 years (e.g., 4.2% even in 2014). IHS Chemical forecasts that in the future, this pace of growth will moderate somewhat, mainly because of slower economic expansion, but will nonetheless remain quite robust (3.3% per year on average in 2010-20), largely due to a relentless pursuit of an improved standard of living by citizens in developing countries around the globe.

Although profitability in the global ethylene industry is very cyclical, with periods of over-investment typically followed by periods of poor profitability, which in turn cause under-investment followed by periods of high profitability, there are some differences in profitability trends among regions that reflect differences in feedstock costs. In the US, the availability and low price of ethane support high ethylene margins. This, along with the expansion of ethane supply as a result of the unconventional expansion, is creating a very profitable environment for producers. Ample supplies of natural gas liquids from shale development will keep ethane prices low relative to other steam cracker feedstocks globally, such as naphtha.

In fact, light olefin production costs are mostly determined by underlying feedstock prices that derive from either natural gas (ethane, butane, and propane) or crude oil (naphtha and gas-oil). While steam crackers in Western Europe and Asia are mainly naphtha-based, production in the Middle East and North America (as well as parts of Southeast Asia and South America) use mainly gas-based feedstocks. Changes in the price of natural gas relative to crude oil, therefore, have a ma-

[28] "Market Stalls," ibid., p. 2.

jor role in determining the competitiveness of petrochemical producers globally (see Figure 4.22).



Source: IHS Energy, IHS Chemicals

Figure 4.22 Comparative cash cost of ethylene production for major global producers, 2013 versus 2015

Ethane prices in the Middle East range from $0.75 to $2.00 per MMBtu, which is even more competitive than North American ethane supplies. Middle East governments price their ethane so low to monetize stranded hydrocarbons, diversify their economies, and to provide employment opportunities. A wave of new Middle East capacity started up in 2008-2010, and the region will continue to leverage this cost advantage in the future. However, new crackers in the region will be largely based on mixed LPG feeds which will decrease the cost advantage slightly. Exports of petrochemical derivatives from the region, however, will remain the lowest cost in the world.

In Europe and Asia, the geographic proximity to the Middle East will make these regions a preferred destination for Middle Eastern exports of ethylene and ethylene derivatives. In addition, a massive wave of steam cracker capacity additions in China, Thailand, and Singapore is putting additional pressure on the Asia region. These factors have kept margins for naphtha-based producers at a cyclically low level. Operating rates, nonetheless, should move higher toward the middle of the decade; together with lower prices for naphtha, this should lead to rising margins, supported by a tighter global ethylene market as it approaches the next cycle peak.

Growth in ethylene derivative consumption will be mainly driven by the more rapid pace of economic growth in Asia; particularly in China and increasingly also India. Today the Asian region, including Southeast Asia, Northeast Asia, and the Indian Subcontinent, accounts for an estimated 45% of the global ethylene equivalent consumption contained in derivatives. Asia's share is expected to increase steadily as the other major consuming regions, North America and Western Europe, are expected to grow more modestly. Asian growth prospects are further illustrated by its still very low per capita consumption rate. At 12 kg per capita in 2011, the region remains far below the consumption level of developed areas. An increase in the per capita consumption value to 16 kg per capita would increase Asia's ethylene equivalent demand by around 50% of the current value, which IHS Chemical expects will be reached by 2020.

The considerably lower level and slower growth of ethylene equivalent consumption in the Middle East contrasts with its large production, which is basically exported in the form of ethylene-based derivatives. Although most countries in the Middle East will likely continue to experience rapid economic growth, the relatively small populations and lack of processing industries will limit future consumption growth. Without the ability to produce finished and semi-finished goods, the local market for ethylene derivatives in the Middle East will likely remain small; however, some Middle East governments are pushing to develop manufacturing parks in order to increase employment.

Per capita consumption in North America and Western Europe stagnated or barely grew during the last decade. Domestic demand in the USA did rebound quite strongly from the depths of the recession, although it remains significantly below the peak consumption levels of 2004-2007. The development of low-cost ethylene production in the USA may begin to limit the import of finished goods, mainly from Asia. In contrast, Europe without a production cost advantage will continue to experience competition from imports of raw materials and finished goods.

Capital investments in basica petrochemicals are shifting to areas that offer either advantaged feedstock costs, such as many Middle Eastern countries and North America (or Kazakhstan), or rapid demand growth as exemplified by China. In contrast, producers in the traditional production centers of Western Europe and parts of Asia lacking these characteristics will concentrate on projects that focus on energy and feedstock cost reductions as well as rationalizations of older, non-integrated facilities, to more closely align supply with demand. North American producers will continue to pursue efficiency projects, such as expanding their ethane cracking capability, but will also consider adding capacity through low-cost incremental expansions or grassroots projects to take full advantage of the low ethane cost. Several grassroots cracker projects have already been announced for the US Gulf Coast, as a result of the favorable feedstock cost position stemming from the unconventional hydrocarbon revolution.

Therefore, the key drivers of petrochemical expansion vary by region. Swings in capacity additions over the past 30 years have become larger as projects have increased in size and fluctuations in profitability widened. The coincidence of global recessions during waves of capacity additions, as in 2001 and again in 2008-09, further exacerbated the gaps between the peaks and valleys in the amount of annual capacity additions. The amount of ethylene capacity installed globally in the 2010-15 period was 17.5 MMt (with only 4 MMt of new capacity added in 2011), compared with 29.4 MMt expected to be added in the 2015-20 period.

The key drivers of petrochemical expansion in the major regions include:

In North America (USA):

- Leverage low-cost natural gas-based feedstocks into new investments in manufacture of ethylene, propylene, and methanol, and then expansion of downstream production of derivatives based on these building blocks;
- Invest to establish export channels for these low-cost manufactures.

In the Middle East (Saudi Arabia):

- Moderate investment pace, using the region's low-cost, diversified feedslate to support downstream market development and continued industrial expansion well beyond ethylene chemistry.

In Northeast Asia (China):

- Strong growth in demand for petrochemicals, caused by higher pace of economic expansion;
- Strong investment in petrochemicals focused on reducing import dependencies;
- Leverage coal-to-chemicals technology near term.

4.6. Carbon Policy and the Rise of Renewables

An increasingly urgent concern for environmentalists and policymakers in much of the world has been the growing concentrations of carbon dioxide and other greenhouse gases (GHG) in the earth's atmosphere and the possible linkage with recent increases in global mean temperature and climate disruptions relative to the historical norm (so-called "climate change" or "global warming"). The major cause of the rising GHG concentrations is posited to be the combustion of fossil fuels in industry, transportation, residential, and other sectors. Among the major fossil fuels in use today, the combustion of coal, oil, and natural gas generate the highest GHG emissions, respectively, on an energy equivalent basis.[29] The industrialized countries have been responsible for much of the past and present GHG emissions, but the recent economic development of emerging economies (especially those with large populations such as India and China) represents a major additional source of emissions going forward.

The United Nations Framework Convention on Climate Change (UNFCCC), adopted in 1992, created an international framework for action on climate change, and in 1997 the Kyoto Protocol established a legally binding framework for (signatory) developed countries to reduce their GHG emissions. Progress toward a coordinated international effort to reduce emissions has since slowed, as the leading CO_2-emitting country at that time (United States) has not ratified the agreement, and the present world leader (China) did not commit to binding reduction targets. Furthermore, other major countries involved in the framework (e.g., Russia, Japan, and Canada) refused to set, or later abandoned, emissions reduction targets. An additional problem limiting the agreement's effectiveness was the virtual collapse of carbon markets, with the falling price of carbon credits not covering the set-up costs for projects to reduce GHG emissions. A successor framework to the Kyoto Protocol is scheduled to be negotiated by the parties to the UNFCCC in 2015 in Paris (see Chapter 13).

However, during roughly the same period a major initiative has gathered momentum in individual countries, led by the European Union (EU) member states, which has the potential to reduce GHG emissions by making wind, solar, and other naturally abundant renewable resources available as potential energy sources. Given that the carbon footprint of the world economy is presently so large—over 86% of the world's current primary energy consumption is based on coal, oil, and natural gas[30]—the scope for carbon emissions reduction is potentially enormous. And the benefits are not limited to the environment. Renewable energy provides additional opportunities for fossil fuel–poor countries to become more energy secure, and all countries a chance to stimulate economic growth through new investment in a developing, technologically-driven sector.

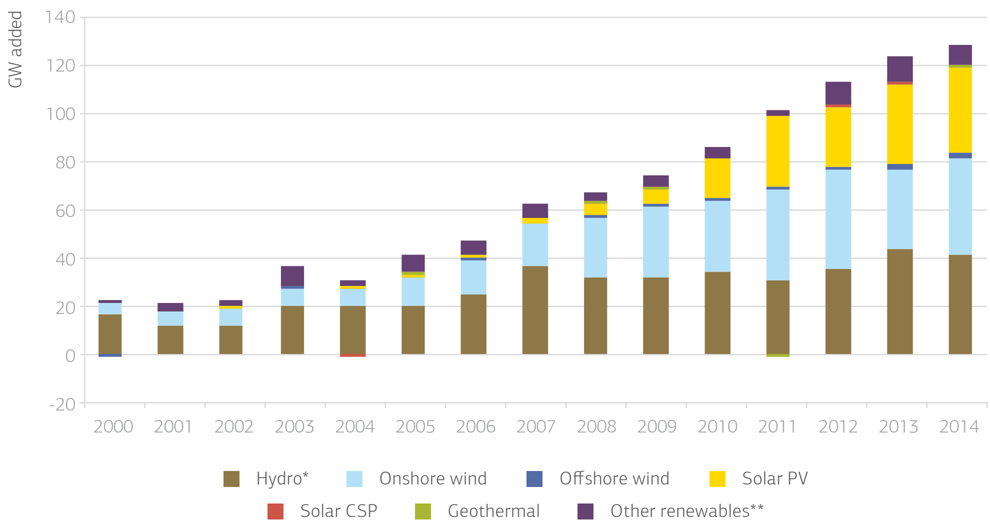
Government policies supporting renewable energy have led to more than $1 trillion of investment in renewable power capacity worldwide since 2000. However, increasing government austerity in Europe and elsewhere in the wake of the "Great Recession," combined with the revolution in unconventional gas in the US (as a cleaner-burning fuel than coal or oil), has altered the trajectory of policymaking and of general market growth.

Over the past decade, a robust renewable energy industry has been established with spreading global roots. Annual renewable power capacity added globally (excluding the category of "hydro" in Figure 4.23, which includes both small hydro [renewable] and large hydro [non-renewable]) has doubled from just under 40 gigawatts (GW) in 2008 to about 80 GW in 2013 and another 88 GW in 2014. The scale

[29] In relative terms, the GHG emissions coefficient of natural gas (metric tons of GHG emitted per thousand tons of oil equivalent consumed) is only 55% that of coal, 72% of oil, and 35% that of such "other sources" as peat and wood.

[30] BP Statistical Review of World Energy, June 2014. London: BP, p. 41.

attained demonstrates that renewables have the potential to reshape the energy mix of the world's power sector, albeit over several decades, and the resilience to weather the up and down cycles that characterize energy prices, technology, policy, and costs.

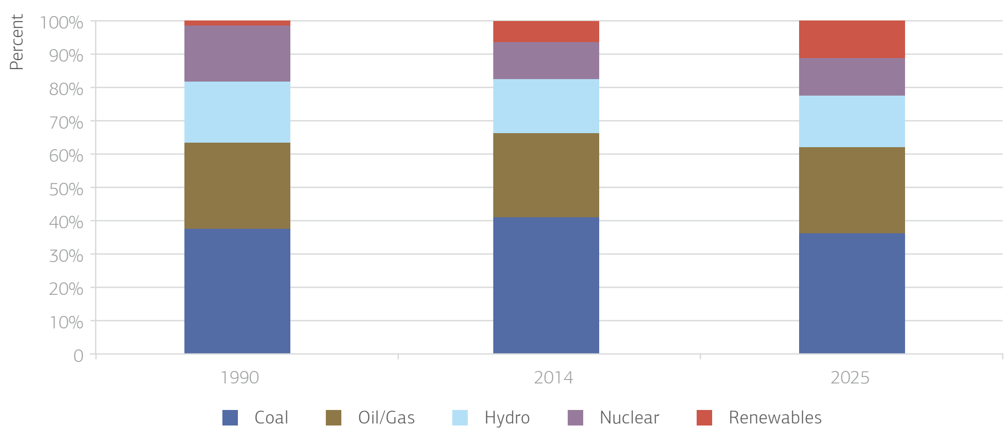


** Includes small and large hydro*
*** Includes biomass, ocean, others*
Source: IHS Energy

Figure 4.23 Additions to world renewable power generation capacity, 2000-2014

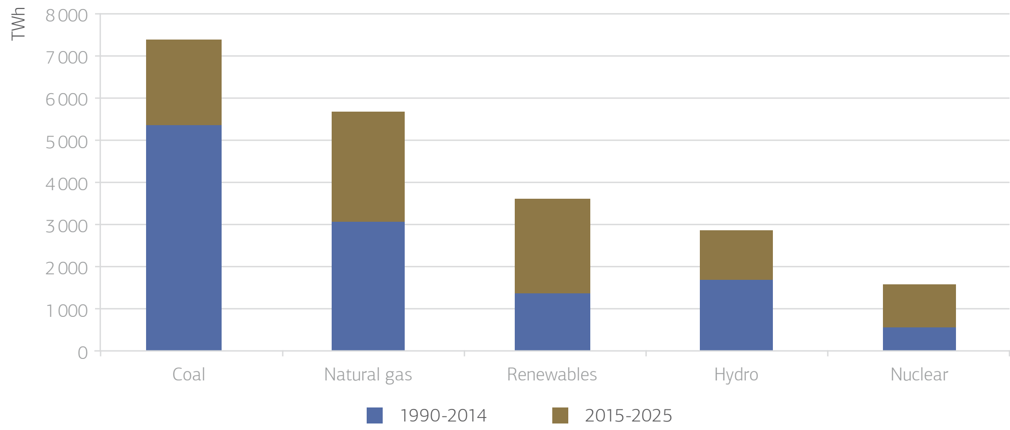
Nonetheless, renewable energy's contribution to the global energy mix is expected to grow only gradually, reflecting both the need to formulate effective policies to support the renewables industry in the near term, and infrastructure constraints over the longer term. Wind and solar power, which form the basis for much of current renewable capacity, have a number of fundamental issues that impede their integration into established grid power systems. They are intermittent (requiring system-wide back-up), cannot produce exactly when demanded, are virtually impossible to store for extended periods, and are often far from load centers, requiring investment in new transmission. In the case of wind, in particular, when grid capacity is insufficient there is the potential problem of oversupply (leading to curtailment) when inflexible baseload generation from conventional sources is already sufficient to meet demand. In addition, integration of renewables substantially increases grid-level "system costs"—the total costs above plant-level costs to supply electricity at a given load and level of supply. These include connection expenditures, grid extension and reinforcement costs, short-term balancing costs, and long-term spending to maintain adequate back-up capacity.

Another challenge faced by renewable energy is the inertia embedded in existing capacity, i.e., the slow pace at which power infrastructure changes. Only 25% of the capacity installed globally traditionally turns over every decade. Nevertheless, global demand for new energy sources will grow, with the size of the global power sector overall to expand 50% by 2025 (see Figures 4.24 and 4.25).



Source: IHS Energy

Figure 4.24 Global power generation (percent), 1990-2014-2025



Source: IHS Energy

Figure 4.25 Incremental change in generation, TWh

Finally, two factors—the age of austerity that confronts mature economies and the ongoing unconventional oil and gas revolution led by the United States—will undoubtedly slow, but not halt, the renewable industry's development and growth. Wind and solar—the backbone of renewables growth recently—still account for less than 2% of global power generation on an energy-equivalent basis, up from less than 0.5% in 2000. If renewable energy growth were to maintain current annual installation levels, it could reach 10% of power supply on a global basis by 2025. But for renewables to play a greater role in the energy mix, energy policy adjustments must be accompanied by major market design changes. These are needed to overcome deeply embedded structural constraints to the competitiveness of renewable energy—an outcome that has become less likely to materialize in an age of austerity in several of the largest power markets that could last a decade or more. Because technology costs are changing quickly, and continue to decline (for solar if not for wind), countries are shifting renewable support policies away from European-style feed-in tariffs to more competitive price mechanisms.[31]

Concerned by Kazakhstan's sizable carbon footprint (including heavy reliance upon coal for electricity generation) and the high energy intensity of its economy (energy consumption per unit of GDP), on 30 May 2013, President Nursultan Nazarbayev signed a decree that will guide the country's future transition toward a "green" economy. The decree charts out an ambitious transition toward renewable energy sources and away from coal, seeking to phase in renewables gradually, using the country's sizable natural gas reserves as a bridge between coal and renewable sources for electricity in the interim. The volume of coal consumed in the production of electricity, for example, is not envisioned as declining in absolute terms before 2025, but the increment to electricity production is to come primarily from cleaner sources.

The decree includes targets for the shares of the various energy sources in the production of electric power in 2030 and 2050. By 2030, 11% of electricity generation is planned to come from wind and solar sources, 10% from hydro, and 8% from nuclear, with the remainder being derived from coal (49%) and natural gas (21%).By 2050, if more ambitious targets are achieved, the share of wind and solar sources could increase to as high as 39%, nuclear and hydro (combined) could account for 14%, gas for 16%, and the remaining 31% would come from coal-fired stations (albeit upgraded facilities using cleaner-burning technologies).[32] Even partial fulfillment of these targets will represent substantive progress toward Kazakhstan's commitment to reduce its greenhouse gas emissions as part of a global effort to address climate change (see Chapter 13).

[31] One popular alternative to feed-in-tariffs are renewable portfolio standards—government requirements (e.g., in the US) that existing major power suppliers deliver to customers a certain percentage of their electricity that has been generated by renewable sources. Because these suppliers may opt to meet these requirements either from building their own renewable capacity or purchasing the power from independent renewable energy providers, the price is not set by an administrative procedure but by the market, although the demand for green electricity is derived from the original government directive. Another popular mechanism is the tender (or demand auction), whereby a government or large utility solicits bids for the installation of a certain amount of renewable capacity from a particular renewable source or from a group of eligible technologies. Again an element of competition is involved, in that the government evaluates the bids on the basis of price or other desirable criteria (e.g., local content). Both tenders and renewable portfolio standards reduce the risks of conveying windfall profits to producers when administrative pricing schemes (e.g., feed-in-tariffs) overestimate generation costs.

[32] Scenarios also are outlined whereby these targets can be adjusted to reflect changes in natural gas prices and in the geographical extent of the natural gas distribution system.

Key Recommendations

- The environment for attracting international hydrocarbon investment is becoming increasingly competitive. Kazakhstan can facilitate the process by which foreign investors and domestic-country partners move ahead with project development by offering competitive terms in three key areas: fiscal terms, local content, and speed and quality of decision-making. A major benefit is a more timely flow of revenues to the government and into the national economy.

- Despite the current relatively low price of oil, higher cost barrels will need to be brought into the market in the medium term (2017–2020), when prices will gradually rise to $85/bbl as the market tightens, and in the longer term, when prices eventually return to a higher price level ($90–95/bbl average over 2021–2040). Kazakhstan—as the source of most of Eurasia's projected production growth—should be prepared to supply major oil export markets in China (where total crude imports are projected to increase by ~2% annually to 2040) and Europe (where crude oil production is declining).

- Although it is not certain the extent to which Kazakhstan (and other countries) will be able to replicate the North American experience in unconventional oil and gas development, government and industry officials should—as appropriate within the context of a national hydrocarbon development strategy—undertake further research to ascertain the magnitude of the unconventional oil and gas resource as well as contemplate initiatives (via legislation, tax incentives, and licensing) that could encourage companies of all sizes to engage in exploration and production of unconventional resources. The benefits of having a large number of producers working a wide variety of deposits is a reduction in annual production swings associated with accidents and delays at a small number of very large deposits (i.e., a stabilization of annual output).

- Wind and solar power, which form the basis for current renewable capacity, have a number of constraints and costs (e.g., total "system costs") that impede their integration into established grid power systems. Kazakhstan should consider these constraints and costs carefully, as an overly rapid build-out of capacity could lead to disruption of grid stability in certain locations. New renewables capacity should be considered when economically feasible and capable of operating symbiotically within the electrical grid; therefore, Kazakhstan should review its renewable support policies in order not to subsidize and over-build renewables capacity.

INVESTMENT CLIMATE IN KAZAKHSTAN

5. Investment Climate in Kazakhstan

5.1. Key Points

- Kazakhstan's final composite index score for investment attractiveness (a composite that includes several different components important to investors) is second worst among the 12 peer group jurisdictions analyzed (based upon a new typical upstream project of comparable size that reflects the type of projects available in each country), after only Russia. This relatively poor result suggests that a few targeted measures to further improve the investment environment could yield considerable results in the country's attractiveness to potential new investors in its oil and gas industry. Government take, revenue risk, and the nature of changes in fiscal terms are the major relative contributors to Kazakhstan's poor overall score.

- Kazakhstan's overall fiscal terms index score, one of the major components in the composite index, indicates that fiscal terms for investors are more favorable than in Russia, Malaysia, Angola, and even the deepwater Gulf of Mexico in the United States, but less favorable than in seven other peer group jurisdictions that compete for investment in the upstream oil and gas industry. A relatively high government take is the major detractor for the country's attractiveness as an investment destination.

- Perhaps just as important, among the 12 peer group jurisdictions compared, Angola, Russia, and Kazakhstan obtained the highest shares of their total revenues early in fields' producing lifetimes. This indicates that investors are confronted with significantly greater revenue risk (vis-à-vis the government) than in comparable investment destinations.

- Relative to their peer group, foreign investors in Russia, Kazakhstan, and the UK experienced considerable uncertainty (instability) over the past five years in terms of the type, scope, intensity, and frequency of change in the fiscal environment.

5.2. IHS Investment Attractiveness Index for Oil and Gas Industry Investment

Many basic elements of the fiscal environment for foreign investment in Kazakhstan's oil and gas sector are outlined in the country's 2009 Tax Code, which specifies a wide variety of taxes, fees, and duties to be paid by subsoil users (hydrocarbon producers; see Section 7.5 on hydrocarbon taxation). Yet the total taxation paid is only one dimension of the overall investment climate that must be considered when comparing Kazakhstan's attractiveness relative to other major hydrocarbon-producing countries. A broader assessment should include other critical factors, including the costs of finding and development in each jurisdiction, and take into account the variability of commodity prices, distance from liquid markets, the actual size of discoveries, well productivity, water depth, and technological challenges associated with each environment and resource type. In order to provide a useful comparison of Kazakhstan's investment attractiveness with other major opportunities elsewhere in the world, this chapter of the report utilizes a proprietary IHS composite index of investment attractiveness that compares not only fiscal regimes incorporating government take but also broader criteria such as measures of profitability, revenue risk, and fiscal stability, applying them to a typical new project in each jurisdiction.

The index applies economic analysis of a typical or hypothetical new upstream project in each of several peer group jurisdictions. Our cost models account for the exploration success rate (including abortive exploration efforts), applicable risk premiums associated with each jurisdiction, and the cost of environmental compliance. Outputs from the models provide detailed information on capital expenditure and operating costs, tangible and intangible expenditures, and processing and transportation costs (which often may be deducted from royalty payments).

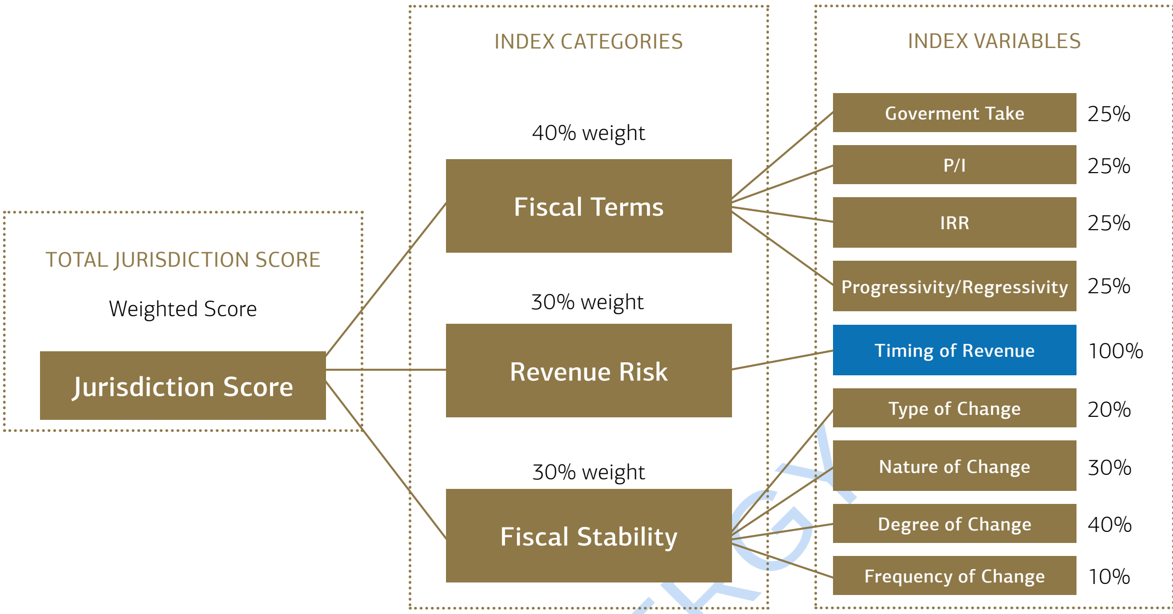
Project economics were computed in real terms to avoid the need to make assumptions about escalation rates for capital and development costs, so our models do not explicitly incorporate price escalation or inflation. In addition, we developed three different field development schedules in order to analyze the impact of varying "estimated ultimate recoveries" (EUR) of the projects in question.

Project models incorporate a cost scenario that utilizes IHS Energy's proprietary Capital and Operating Costs Indexes with an outlook to 2030. Dated Brent was used as the benchmark price and price differentials were applied to account for crude quality. Distance from liquid markets is taken into account by computing the netback price of crude to the wellhead, i.e., we deducted the cost of transportation from the Brent price that was adjusted to account for the quality differential. For the purpose of this comparison, we used a baseline average price of Brent crude of $ 100 per barrel, which is consistent with the long-term oil forecast (out to 2040) for IHS Energy.

For modeling natural gas economics in the projects—for which presently no global market exists—we chose a set of three generic natural gas prices (for North America, Europe, and Asia, respectively), reflecting the market structures of each region. For North America, where there is a mature spot market, we selected a natural gas price of $6 per thousand cubic feet (Mcf) (or $212 per Mcm), netted back to the wellhead. Gas sold in European markets, where both spot and term contracts apply, was analyzed at $8 per Mcf ($283 per Mcm). For Asia, we chose a gas price of $10 per Mcf ($353 per Mcm), reflecting long-term contract prices for liquefied natural gas (LNG). For CIS countries, a hypothetical netback calculation is applied from the European market to derive the intrinsic value of any gas.

Companies would rather invest in a country that has a 90%

government take but provides a 20% return on investment (ROI) than a country where a 50% government take promises only a 10% ROI. This is because companies pay more attention to their ROI than to the size of the government take. As such, rather than relying on a single measure of investment attractiveness, such as "government take," our measure uses a composite index that captures multiple dimensions of project economics and fiscal system competitiveness, which companies use as metrics in assessing the risked ROI of their potential investments. This index includes measures of profitability, fiscal system flexibility, revenue risk, and fiscal stability. More specifically, it incorporates three index categories of fiscal terms, revenue risk, and fiscal stability, which are assigned weights of 40%, 30%, and 30%, respectively, for calculation of the final composite index (the "total jurisdiction score" in Figure 5.1). The index categories are further broken down into index variables, also weighted as a proportion of the category total.



Source: IHS Energy

Figure 5.1 IHS composite investment attractiveness index

To provide a consistent comparison and ranking of the variables within the index categories, we developed a relative rating and ranking system that assigns each variable a score of zero to five, where a score of five indicates a high government take, highly progressive/regressive fiscal system, low rate of return to investors, low profit-to-investment ratio, low risk of revenue to the government, and unstable fiscal terms. On the other end of the spectrum, a score of zero indicates low government take, high rates of return and profit-to-investment ratios, a neutral fiscal system, high risk of revenue to the government, and stable fiscal terms. Discussion of each of the categories and their constituent variables follows, together with an assessment of how Kazakhstan's situation as measured by them compares with a small subsample (drawn from a broader IHS Energy database) of 11 other major oil- and gas-producing countries (or major regions in such countries) of the world.[1]

5.3. Assessment of Attractiveness Indicators

5.3.1. Fiscal terms

The index category for fiscal terms includes four variables—government take, profitability index (PI), investor after-tax internal rate of return (IRR), and the progressivity/regressivity index.

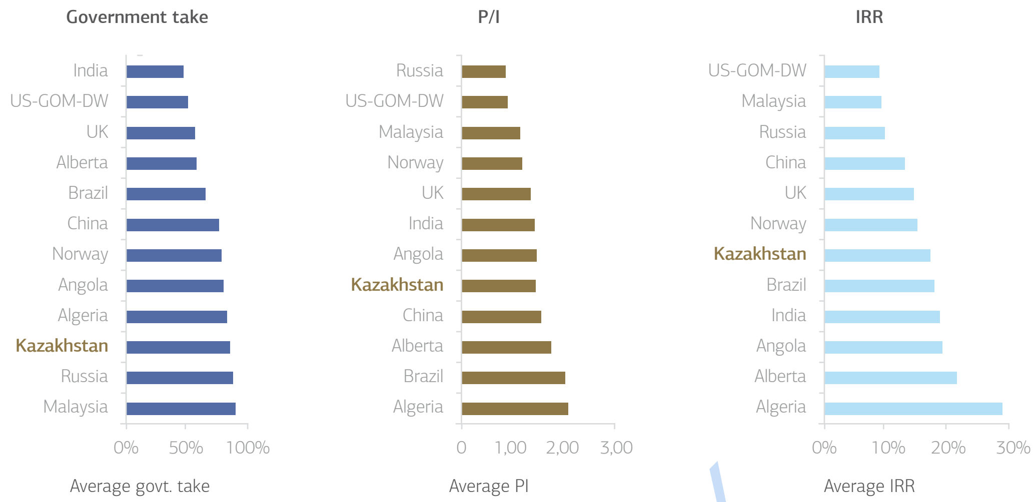
- The government take refers to the percentage of a project's net pre-tax cash flow that accrues to the government.
- The PI indicator measures profitability by comparing the proposed project's cash flows with its required capital investments. More specifically, this is the ratio between the net present value (NPV) of the sum of project cash flow and total capital invested to the NPV of the total capital invested. Thus, a PI of 1.20 means that for every dollar invested in the project, the total value created is $1.20, for a net profit of $0.20 for each dollar invested.

[1] In the remainder of this chapter, we shall refer to this set of countries and major regions within countries as "reference countries" or "peer group."

- The IRR expresses the nominal discount rate that would generate an NPV of zero when applied to an investor's net cash flow after all levies and taxes.

- Finally, the progressivity/regressivity ratio measures the relationship between government take and project profitability. In progressive fiscal systems, the relationship is positive (the government take increases as profitability does), whereas in regressive systems, an inverse relationship prevails (government take falls with increasing profitability and vice versa).

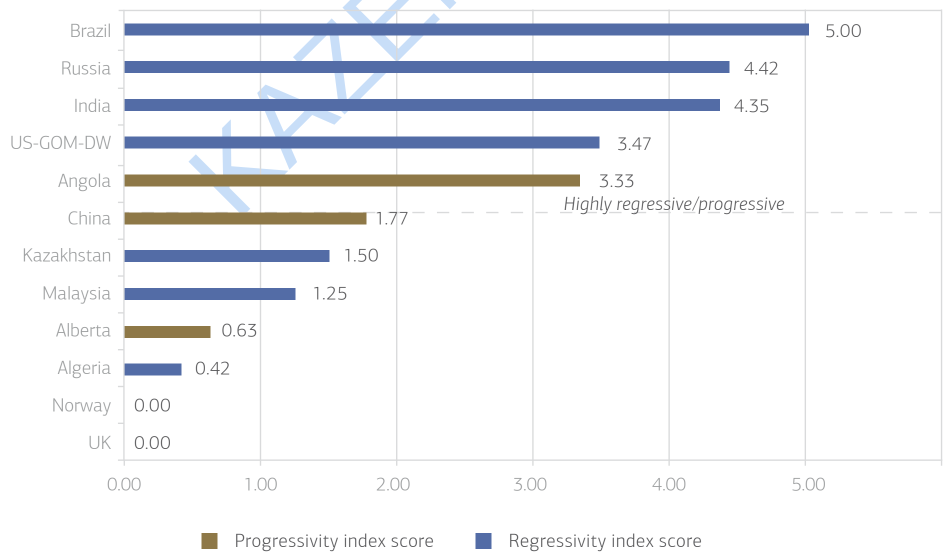
We now turn our attention to how Kazakhstan performs relative to the 11 reference countries (peer jurisdictions) in terms of government take and profitability indicators (see Figure 5.2).



Source: IHS Energy

Figure 5.2 Government take and profitability indicators

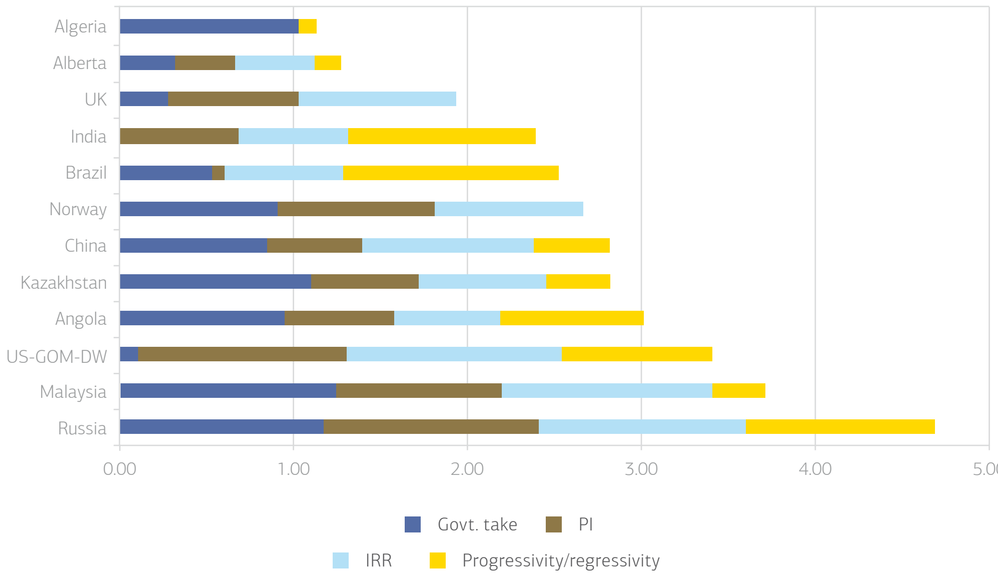
Compared to the reference countries, the government take in Kazakhstan is higher than in any except Russia and Malaysia; however, the country's PI and IRR scores fall within an intermediate range. The fiscal picture (both for investors and the Kazakhstan government) is also ameliorated by the country's moderately regressive fiscal regime (Figure 5.3).



Source: IHS Energy

Figure 5.3 Progressivity / regressivity index scores

Using the rating system (0–5) described above to measure the aggregate effect of the four fiscal terms variables, the fiscal index score for investors in Kazakhstan (developing a hypothetical new project) is more favorable than the scores for Russia, Malaysia, Angola, and even the deepwater Gulf of Mexico in the United States [US-GOM-DW], but less favorable than for a number of other reference countries (see Figure 5.4). As the chart demonstrates, the high government take is the major input contributing to the overall fiscal index score.



Source: IHS Energy

Figure 5.4 Fiscal terms index scores

5.3.2. Revenue risk

A second major component of the IHS composite investment attractiveness index is revenue risk, or the timing of revenue accruing to the government as a measure of risk sharing between resource owners and investors. The high level of uncertainty in oil and gas exploration and development raises serious questions as to who should undertake the risk and to what extent should the government as resource holder share in that risk. The sources of risk are varied, and they can occur at all stages of an upstream oil and gas venture. Some of the main risks associated with oil and exploration and development include:

- Geological and geophysical risks. These relate to the probability of finding substantial, technically and economically recoverable deposits. Such risks accompany all phases of an upstream venture. It is only when the deposit is fully exhausted that operators know precisely the size of the reserve.

- Price. Price volatility is one of the major risks that upstream oil and gas investments face throughout a project's lifetime. While high commodity prices may lead to a significant upside, depressed prices can have a devastating impact on project economics and at times may cause the premature cessation of upstream activities. This is especially salient in the current period of low oil prices worldwide and low natural gas prices in markets where output is expanding (e.g., North America).

- Cost. As commodity prices increase, the increased demand among producers for goods and services usually drives costs up. This impacts project economics and ultimately the before-tax profit to be shared between the government and the investor.

How the risk is apportioned and in what measure is essentially a policy decision. While companies hedge against risk by investing in a diverse global portfolio of projects, governments hedge against risk by transferring part of it to the private investors. As a result, there is a fundamental tension between the government and the oil producers over the division of risk and reward from upstream hydrocarbon investment. Both parties seek to maximize rewards and shift as much risk as possible to the other party. Equally, countries must provide such terms that will attract investors, but companies without projects will go out of business. Therefore, the choice and the design of the petroleum fiscal system reflect the trade-off between each party's interests.

Table 5.1 shows the degree of relative risk exposure associated with a number of widely utilized fiscal instruments in the oil and gas sectors. Different fiscal instruments expose the government to varying levels of revenue risk. These range from generally low-risk instruments such as bonus payments and ad valorem payments such as royalties and export duties, to high-risk ones such resource rent taxes and equity participation.

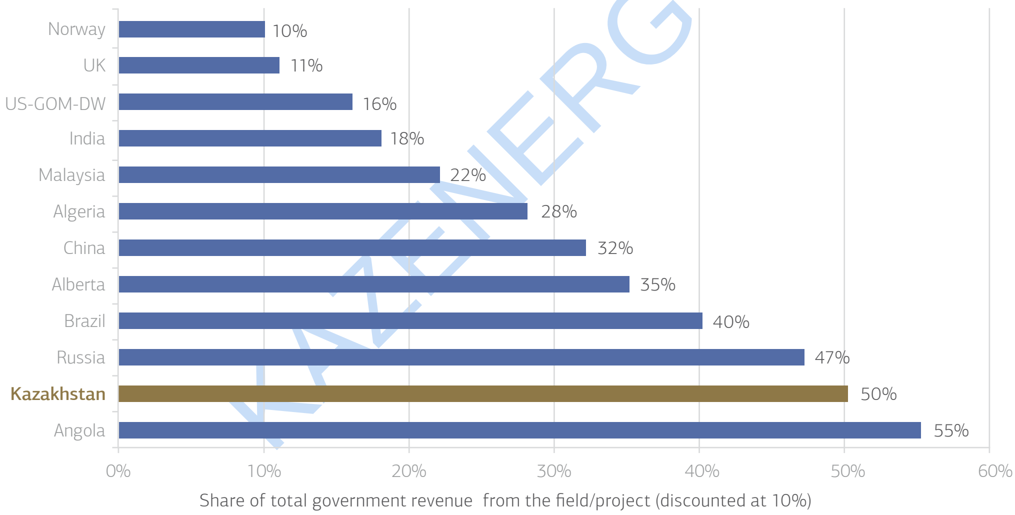
Fiscal instrument	Risk to government
Bonus payments	Low
Ad valorem payments *	Low
Cost recovery ceiling	Low
Corporate income tax	Medium
Resource rent tax	High
Profit sharing	Medium
Equity participation	High

** Includes royalties and export duties*

Source: IHS Energy

Table 5.1 Revenue risk to government from various fiscal instruments

To provide a consistent comparison across fiscal systems with respect to revenue risk and to ascertain the extent to which the various reference countries' governments share in project risk, we estimated the revenue accruing to the government when a field/project has reached one quarter of its producing life against the total revenue accruing to the government from each individual project at the end of its productive lifetime (see Figure 5.5). As shown in Figure 5.5, Angola, Russia, and Kazakhstan obtain relatively large shares of their total revenues (nearly 50% or higher) early in a project's producing lifetime. This indicates that investors experience significantly greater revenue risk (vis-à-vis the government) in these countries compared to their set of peers.



Source: IHS Energy

Figure 5.5 Share of total benefit accruing to the government at one-fourth of producing life of a field/project

5.3.3. Fiscal stability

The third and final major component of the IHS composite investment attractiveness index is fiscal stability. When considering where to invest, investors often assess the stability and predictability of the prevailing fiscal and regulatory environment. Stability affects the confidence of investors in government policy because a fiscal system that is subject to frequent change increases overall risk and reduces the value placed by investors on future income streams. In addition, as described above, oil price volatility is a key element injecting instability in oil and gas fiscal systems. The desire to capture the upside when commodity prices are high creates pressure to increase government take and assert greater control over natural resources.

Our fiscal stability index measures changes in fiscal terms over the past five years and assesses stability of fiscal terms on the basis of four variables:

- Type of change: the mechanisms used to increase (or reduce) the government take
- Nature (applicability) of change: whether the change is applied only to new investments or retroactively to all investments

- Degree of change: i.e., the percentage increase (decrease) in overall government take
- Frequency of the change: several jurisdictions have changed fiscal terms more than once over the past five years.

When assigning risk scores for the type of change, actions such as nationalization and renegotiation of fiscal terms are associated with the highest investor risk.[2] For the nature of change investors consider piecemeal renegotiations to existing and future investments and retroactive application to existing investments among the greatest risks.[3] In terms of the frequency of change in fiscal regime, our index indicates that Kazakhstan and Russia, followed by the UK, have the most uncertain environments for foreign investors among their peers (see Table 5.2).

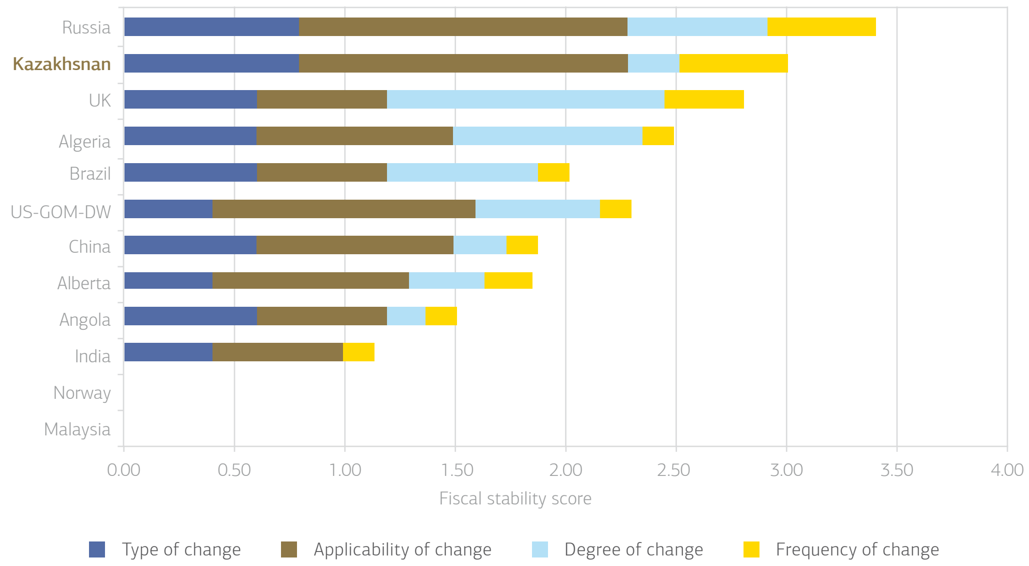
Jurisdiction	Score
Alberta	2.14
Algeria	1.43
Angola	1.43
Brazil	1.43
China	1.43
India	1.43
Kazakhstan	5.00
Malaysia	0.00
Norway	0.00
Russia	5.00
US-GOM-DW	1.43
UK	3.57

Table 5.2 Jurisdiction scores on frequency of change

When the four individual fiscal stability variables are aggregated into a single fiscal stability index (see Figure 5.6) Russia, Kazakhstan, and the UK score particularly high, indicating relatively high risks for investors. In other words, investors in the oil and gas sectors of these countries have experienced considerable uncertainty over the past five years in terms of the type, scope, intensity, and frequency of change in the fiscal environment.

[2] More specifically, risk scores for type of change are ranked on a scale of 0 (lowest) to 5 (highest) in the following sequence (scores are indicated in parentheses): no change (0.00); incentives/tax decrease (0.00); tax/royalty increase and incentives (2.00); tax/royalty increase (3.00); renegotiation (4.00); renegotiation, tax/royalty increase, and incentives (4.00); and nationalization (5.00).

[3] More specifically, risk scores for nature (applicability) of change are ranked on a scale of 0 (lowest) to 5 (highest) in the following sequence (scores in parentheses): existing and future investment incentive (0.00); future investment incentive (0.00); future investments (bid variable; 1.00); future investments (2.00); existing and future investments (3.00); existing and future investments, retroactive application (4.00); existing and future investments, piecemeal renegotiation (5.00); and piecemeal renegotiation (5.00).



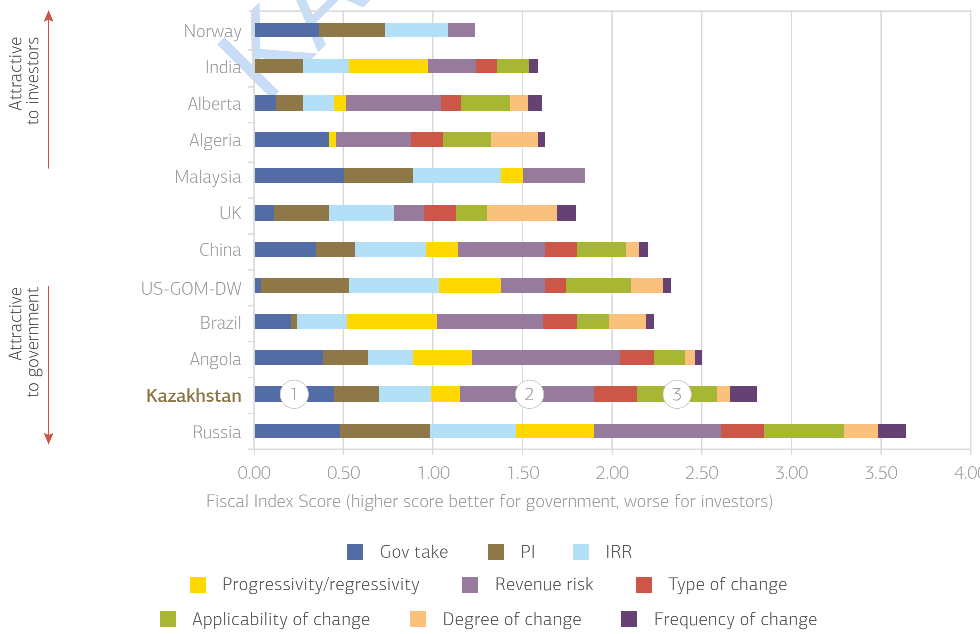
Note: The fiscal stability index scores reflect tax code changes during 2009-2014. Norway and Malaysia had no such changes during the given period.
Source: IHS Energy

Figure 5.6 Fiscal stability index scores

5.3.4. Composite attractiveness index

As outlined above, in order to examine the attractiveness of investment in Kazakhstan's oil and gas sector relative to alternative country energy markets, we have employed an aggregate IHS investment attractiveness index that provides consistent comparison and ranking of government take, rate of return, profit-to-investment ratio, and progressivity/regressivity of fiscal systems with other factors such as risk of return and flexibility and stability of fiscal systems. The index utilizes a relative rating and ranking system that assigns each variable a score of zero to five, where a score of five indicates a relatively unattractive environment for investors, and a score of zero indicates a highly attractive environment.

The final composite index scores for Kazakhstan and the 11 other reference countries (shown in Figure 5.7) include the contribution of each (weighted) index variable to the final score. Kazakhstan's final index score (roughly 2.8) is the second highest among the countries analyzed in our sample, after Russia.



Source: IHS Energy

Figure 5.7 Composite investment attractiveness index scores

This suggests that a few targeted measures to reform the investment environment could yield considerable improvement in the country's overall attractiveness to new investors in its oil and gas industry. As a starting point for focusing such measures, one might identify those variables which make the greatest relative contribution to Kazakhstan's overall score (the widest segments of its overall horizontal bar in Figure 5.7). Three such segments stand out: government take, revenue risk, and applicability (nature) of change. In the current highly competitive international investment environment—shaped by relatively low world oil and gas prices and increasing production in regulatory environments (e.g., North America) that are more familiar to many outside investors than Kazakhstan's—Kazakh officials may wish to review, in particular, policies regulating the percentage of projects' net pre-tax cash flow that accrues to the government as well as policies apportioning early production revenue between the government and private investors. They may also wish to reassess the effects of piecemeal renegotiation of fiscal terms (and the retroactive application of changes in such terms) on investor confidence and the value placed by investors on future income streams.

5.4. General Indicators of Investment Attractiveness

In addition to the insights provided by IHS Energy's composite index of attractiveness specifically for oil and gas industry investment, it is instructive to briefly review how Kazakhstan's overall business environment has been evaluated according to widely used comparative international indicators as well as the assessments of major multinational consulting firms and international financial institutions. The World Bank Group's "Ease of Doing Business Index" is perhaps the best-known such comparative indicator, the data from which—since its inception in 2001—have been used in more than 800 academic research papers.[4] In 2014, Kazakhstan ranked in the top half of all states analyzed, ranking 77th of a total 189 countries, and ahead of such important economies as China, Brazil, Uruguay, Argentina, and India. It earned better than average (below 50th percentile) scores in registering property, protecting minority investors, paying taxes, and enforcing contracts.

Another example of an annual assessment of investment attractiveness based a standard methodology is the EY attractiveness survey.[5] EY (known as Ernst & Young until 2013) is the third largest professional services firm in the world, providing auditing, tax, consulting, and advisory services to a worldwide client base.[6] For the 2014 survey for Kazakhstan, EY contacted (by phone, face-to-face interview, and online questionnaire) 211 international business leaders from 28 countries.[7] The survey results indicated improving investor awareness of opportunities available in Kazakhstan relative to previous surveys in 2012 and 2013. More specifically, 47% of respondents believed that Kazakhstan's attractiveness for investment would increase over the next three years (2015–2017), compared with 41% of those who shared this view in 2013 and 43% in 2012. The figure was even higher (55%) for respondents whose companies already had invested in the country; over three-quarters of these respondents cited Kazakhstan's macroeconomic stability, stable political and social environment, low level of corporate taxation, and telecommunications infrastructure as features they considered attractive. Overall among respondents who had invested in Kazakhstan, 57% indicated that they had met their business objectives over the past five years.

Finally, the International Monetary Fund—as one part of a staff report prepared following discussions between an IMF field team and government officials, private sector actors, and representatives from civil society and multilateral development banks in Almaty and Astana in April 2014—utilized inter-country comparisons to evaluate important dimensions of investment attractiveness.[8] More specifically, the report contained a series of graphics comparing Kazakhstan and other countries in terms of banking system vitality as well as broader economic indicators such as firm-level business constraints, labor market efficiency, and governance indicators. Kazakhstan's banks, relative to a set of comparator countries in its general region (i.e., Russia, Turkey, Ukraine, and Uzbekistan), were found to have the highest share of nonperforming loans and relatively low ratios of capital adequacy and bank assets to GDP, but also the highest real and nominal returns on equity.

For comparison on the broader indicators, a set of reference countries was utilized, including EM (Emerging Markets), World, CAA (Caucasus and Central Asia), OECD (Organization for Economic Co-operation and Development), LIC (Low-Income Countries), Oil Exporters, and MENA (Middle

[4] The Index ranks countries according to the degree to which a country's regulatory environment is conducive to the operation of a business. The Index averages a country's percentile rankings on 10 component indicators to derive a composite score, which is then used to assign a final "Ease of Doing Business" ranking. Low percentage scores indicate good performance (e.g., a ranking of 1% indicates the top ranking, a ranking of 50% a median ranking). The 10 indicators measure the ease of: starting a business; dealing with construction permits; getting electricity; registering property; obtaining credit; protecting minority investors; paying taxes; trading across borders; enforcing contracts; and resolving insolvency (see http://www.doingbusiness.rog/rankings).

[5] See EY's Attractiveness Survey. Kazakhstan 2014. The Brand Paves the Way. EY, 2014.

[6] Their attractiveness surveys, which have been administered for over a decade, are designed to help businesses make informed investment decisions and governments to improve their respective business environments by reducing barriers to future growth. They measure the perceived attractiveness of a host country in the eyes of foreign investors, combining indicators of a country's image, investors' confidence, and their perception of its ability to provide competitive benefits accruing from foreign direct investment.

[7] The survey was conducted in January and February 2014, prior to Kazakhstan's tenge devaluation on 11 February 2014.

[8] International Monetary Fund, Republic of Kazakhstan: Staff Report for the 2014 Article IV Consultation. Washington, DC: International Monetary Fund, 20 June 2014.

East and North Africa).[9] Among the more salient results of this comparison were that Kazakhstan: (a) was roughly at the world average in terms of firm-level business constraints; (b) ranked highest in labor market efficiency;[10] and (c) ranked higher in governance (e.g., government effectiveness, regulatory quality, rule of law, and control of corruption) than the CCA, LIC, and oil exporting countries as a group. The IMF report emphasized that investor confidence is critical in attracting foreign direct investment (FDI) to finance the "private-sector led non-oil growth and job creation" that is to be a key element in Kazakhstan's drive to diversify its economy. Kazakhstan's ongoing work with international financial institutions to accelerate economic reforms can be viewed by investors as evidence of this commitment.

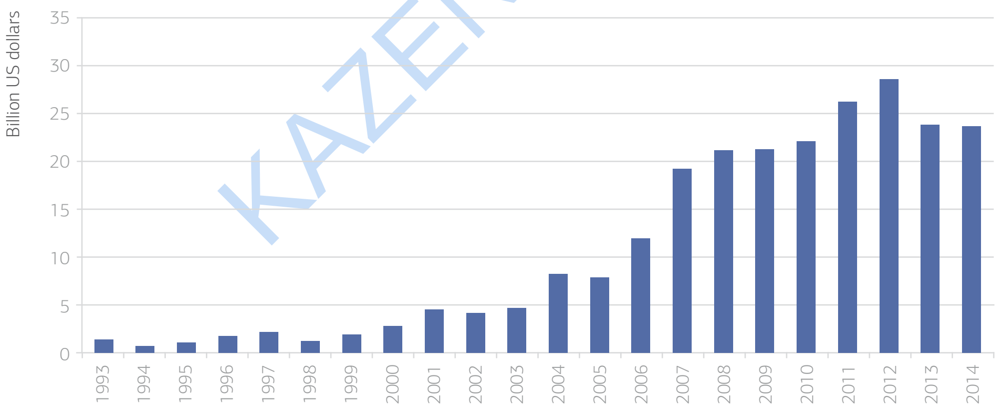
5.5. Foreign Direct Investment and The Energy Sector in Kazakhstan

Foreign investment contributes greatly to economic development in national economies, even though it generally accounts for a relatively small share of gross investments, as it is a key means of obtaining technologies, capital, management skills, and access to export markets. Kazakhstan's success in attracting substantial inflows of foreign investment in the years since independence has accelerated the country's national development and the overall transition to a market economy, especially in the energy sector. Initially, during the Soviet period, the only available form for investment by foreign nationals were joint ventures, but Kazakhstan has established a variety of other vehicles, including wholly-owned foreign subsidiaries and equity investment in domestic firms.

Foreign direct investment (FDI) can be quite important in a country's overall balance of payments, as it helps finance current account deficits and fiscal deficits, in addition to its role in funding investment in the host economy.[11] Along with capital, FDI brings other key intangibles, such as technologies and skills, which are critical for improvements in productivity. Indirectly, FDI may positively affect the overall business environment as the host country seeks to adjust economic policies to attract these investments. FDI, even if largely confined to certain sectors, also has considerable potential to affect other sectors of the economy across other parts of the overall value chain.

For Kazakhstan's energy sector, the importance of FDI is that it allows the country to utilize its enormous resource potential by carrying out projects that otherwise simply could not have been realized, either because of their scale or their technical challenges. Specifically, such operationally and technologically challenging projects as Kashagan, Karachaganak, or Tengiz required engineering and managerial capabilities available only outside of Kazakhstan, found largely in the leading international oil companies (IOCs). In turn, the expenditures on these projects in-country drive expansion and change in many other supporting sectors across the economy.

Total gross inflows of foreign direct investment (FDI) in Kazakhstan's economy have increased from $1.3 billion in 1993 to a peak of $29 billion in 2012 before decreasing slightly to $24 billion in 2013 and 2014 (see Figure 5.8). The total stock (cumulative amount) of gross direct foreign investment for the entire economy since 1993 reached $241.9 billion by the end of 2014. The bulk of this, nearly 86%, has come since 2005.



Source: IHS Energy, Central Bank of Kazakhstan

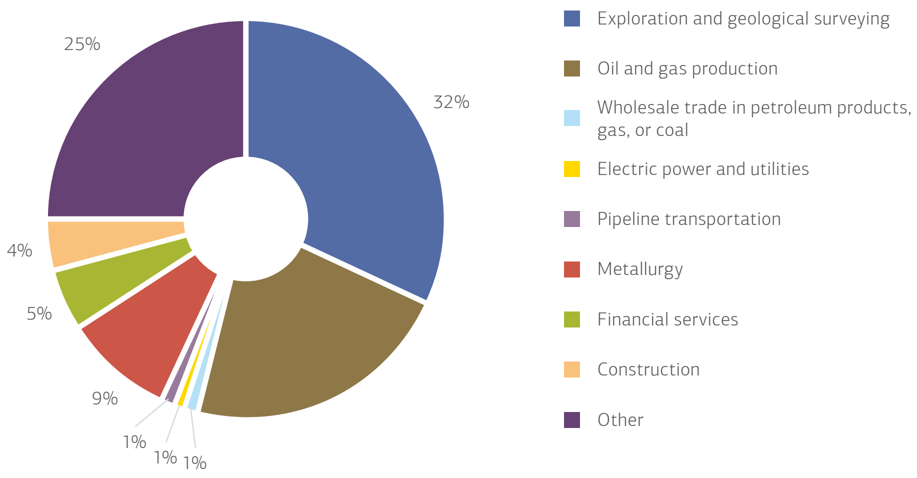
Figure 5.8 Gross FDI inflows to Kazakhstan

[9] Sources of data for the comparison included not only IMF staff calculations, but the World Bank BEEP Survey and Worldwide Governance Indicators, and World Economic Forum Global Competitiveness Report.

[10] Labor market efficiency measures the ability of companies to flexibly manage their labor force (e.g., hiring/firing, wage flexibility, transfers, and female labor force participation).

[11] FDI is defined as cross-border investment by a resident entity in one economy with the objective of obtaining a lasting interest in an enterprise resident in another economy. The threshold level used in OECD countries for distinguishing direct investment from portfolio investment is a 10% stake. The statistics compiled and released by Kazakhstan's National Bank, which are used in this section of the report, comprise acquisition of more than 10% of voting shares by foreign investors, their share of reinvested income (retained earnings), and any gross increase in loans by such enterprises.

FDI inflows have been growing across multiple sectors, but were made primarily into oil and gas production, exploration and geological surveying, metallurgy, retail and wholesale trade, financial services, and construction (see Figure 5.9). The dominance of the oil and gas sector reflects execution of multiple upstream projects with foreign partnership. The slight decline in FDI inflows in 2013 and 2014 is probably due to current stasis in the investment cycle for the big upstream projects (see Chapter 7).

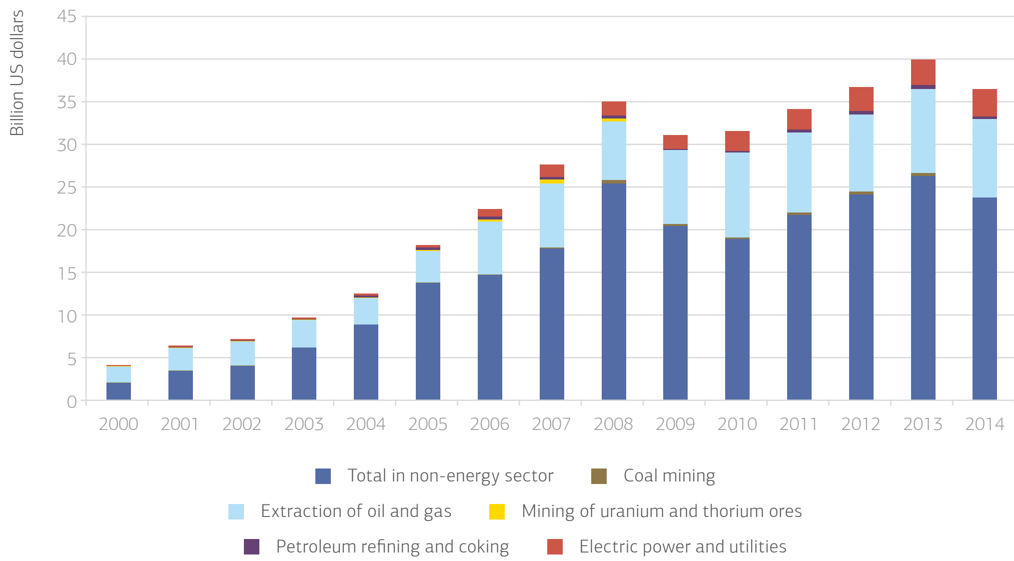


Source: IHS Energy, Central Bank of Kazakhstan

Figure 5.9 Distribution of Kazakhstan's cumulative gross FDI inflows by key sectors (2005-2014)

At the same time, total annual investments in fixed capital in Kazakhstan's economy have steadily increased, from $6.4 billion in 2001 to about $40 billion in 2013, although it declined slightly to $37 billion in 2014 (see Figure 5.10).[12] The total stock (cumulative amount) of fixed capital investment for this period amounted to almost $350 billion. While the extent to which fixed capital investments were financed by FDI (FDI also can be used to finance a company's deficit or pay off loans) remains somewhat illusive, available data on fixed capital investments by foreign companies show cyclical changes: first, their share in total investments in the overall economy decreased from 31% in 2001 to 18% in 2004, then bounced back to 31% in 2009 and fell to 17% in 2014. At the same time, the share of Kazakhstan's private companies went up from 54% in 2001 to 67% in 2004, decreased to 50% in 2009 and eventually bounced back to 64% in 2014. On a cumulative basis, fixed capital investments by foreign entities amounted to $83 billion between 2001 and 2014. This represented about 24% of the overall total for the entire economy during this period.

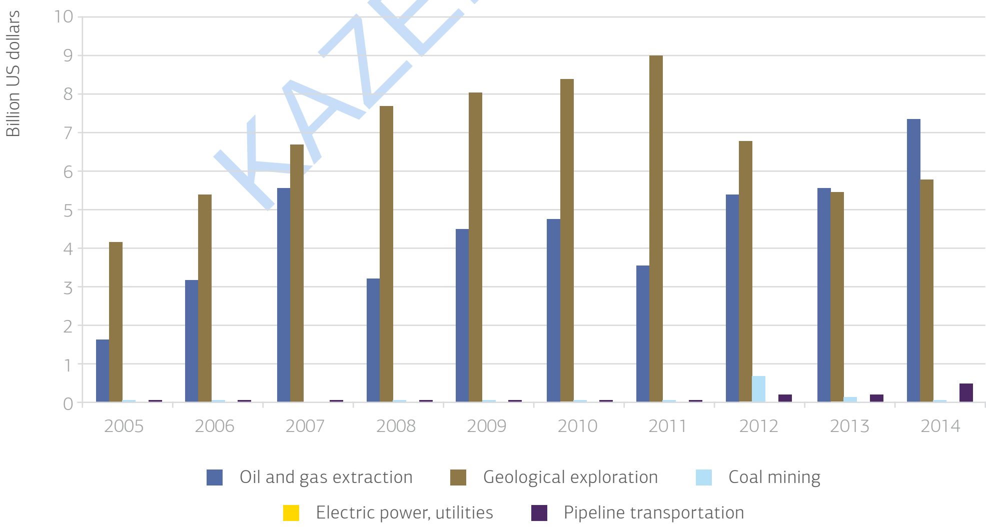
[12] Fixed capital investment by a firm is defined as investment in durable (fixed) assets such as buildings, machinery and equipment, or other infrastructure or structures that a firm holds for at least one year.



Source: IHS Energy, Kazakhstan Statistics Committee

Figure 5.10 Total investment in fixed assets in Kazakhstan's economy

Not surprisingly, the major destination for FDI in Kazakhstan has been natural resources extraction. Specifically, between 2005 and 2014, cumulative gross FDI in oil and gas production accounted for 22% of the FDI total for the entire economy (about $44.6 billion), and investment in another related category, geological surveying and exploration (which includes non-energy minerals such as metal ores), accounted for 32% of the overall total (about $67.2 billion). Comparatively, FDI in such sectors as coal production and pipeline infrastructure are much smaller, accounting for about 1% each of the total, respectively (see Figure 5.11). Annual inflows of FDI in geologic exploration reached nearly $9 billion in 2011, and have declined since, while annual inflows in oil and gas extraction have continued to rise, reaching $7.4 billion in 2014.



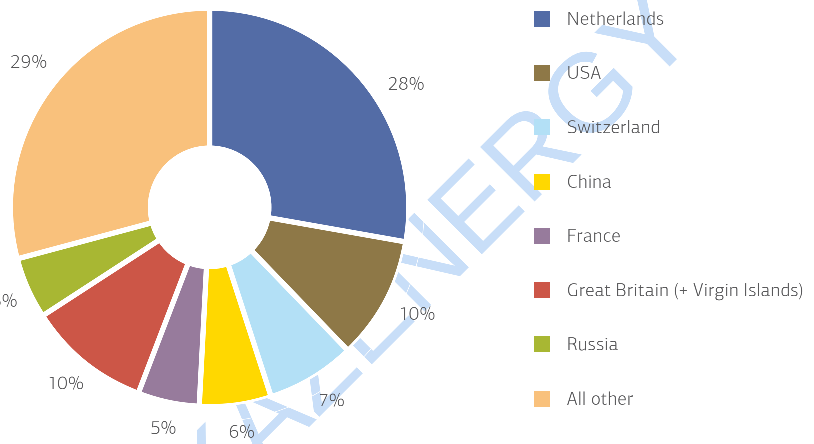
Source: IHS Energy, Kazakhstan Statistics Committee

Figure 5.11 Gross FDI inflows for energy-related sectors in Kazakhstan (2005-2014)

As for fixed capital investments in the overall Kazakh economy, these went predominately into industry, which attracted $4 billion in 2001 (58% of the total economy's fixed capital investments) and $20 billion (53%) in 2014. Within the industrial segment, the energy sector has been the leading destination for fixed capital investments.[13]

Annual investment in the energy sector increased in absolute terms from $3 billion in 2001 to $13 billion in 2014 (see Figure 5.10). As a share in the total economy, the energy sector's fixed capital investments followed the overall business cycle trend, decreasing from 46% in 2001 to 24% in 2003, then increasing to 40% in 2009 before decreasing again to 35% in 2014. The share of oil and gas extraction investments in the total economy's investments decreased from 41% in 2001 to 20% in 2005 before increasing to 32% in 2010 and falling again to 25% in 2014. There is a trend related to a change in the destination of fixed capital investments inside the energy sector: the share of fixed capital investments in oil and gas extraction decreased from 89% in 2001 to 71% in 2014; at the same time, the share of investments in electric power and utilities increased in the same years from 6% to 24%, reflecting a series of projects in power generation and transmission since 2005.

The breakdown of FDI inflows by country essentially reflects the composition of investments by industry. For example, countries that host major oil and gas companies, not surprisingly, are leading sources of FDI. The Netherlands have the leading position with $55.5 billion of the cumulative FDI inflows – or 28% of the cumulative total FDI – between 2005 and 2014 (see Figure 5.12). This is explained by the fact that major projects, such as Kashagan and Karachaganak, are operated by entities registered in the Netherlands. The United States, with cumulative inflows for that period of $19.3 billion, or 10% of total FDI, is the second largest investor, closely followed by Great Britain (when combined together with the British Virgin Islands) at about 19.2 billion. The importance of the United States reflects the fact that a key foreign investor in the oil and gas sector – Tengizchevroil LLP, which develops the Tengiz oil field – is an affiliate of US-based Chevron, with a major shareholding by ExxonMobil. Switzerland and China follow with about $12.9 billion and $12.3 billion, respectively (6-7% of the total). Kazakhstan's northern neighbor, Russia, ranks seventh, with a total investment of about $8.5 billion (5% of the total).



Source: IHS Energy, Central Bank of Kazakhstan

Figure 5.12 Distribution of Kazakhstan's cumulative gross FDI inflows by country (2005-2014)

Cross-country comparative statistics, available from the World Bank, tracks net inflows of FDI (i.e., new investment inflows less disinvestments). Relative to other countries, Kazakhstan has been successful attracting FDI given the size of its economy, particularly among CIS states. FDI net inflows to Kazakhstan amounted to 8.6% of GDP on average annually between 2000 and 2013. During the same period annual FDI in Russia averaged just 2.6% of GDP, while in Azerbaijan it was much higher, at 15.9%, while in Turkmenistan it was about the same as in Kazakhstan at 8.3%, and in Uzbekistan a mere 1.8%. The reason for Azerbaijan's high FDI inflows, of course, is the implementation of two offshore "mega" projects with foreign investors in oil and gas—Azeri–Chirag–Guneshli (AGC) and Shah Deniz—as well as associated export pipeline infrastructure. Turkmenistan's relatively high FDI is primarily due to implementation of the Bagtyyarlyk gas project by CNPC and related pipeline export infrastructure as well as other upstream projects in western Turkmenistan (e.g., by Dragon, Petronas, Eni/Burren).

In broader international comparison, Kazakhstan ranks well above the average for the world as a whole (normalized against GDP), of 2.6% for the 2000-2013 period, as well as the average among all the countries in the World Bank survey (a total of 257 countries) of 4.9%. Kazakhstan's ratio of FDI to GDP is much lower than for small open economies, such as

[13] The energy sector includes coal mining, extraction of oil and gas, mining services, mining of uranium ores, petroleum refining and coking, electric power and utilities. Kazakhstan's statistics committee began reporting mining services investments separately only from 2009 without further breaking this down to separate services related to oil and gas from other mining services. Mining of uranium ores was reported separately only till 2008.

Ireland, Singapore, Luxembourg, Mozambique, or Mongolia, where the ratio is in the range of 13-20%. Kazakhstan's ratio of 8-9% since 2000 is comparable to those for countries such as Hungary, Panama, Georgia, Iceland, and Turkmenistan.

Key Recommendations

- To improve Kazakhstan's investment climate, we recommend the government review the following issues:

  — The tax measures that determine the percentage of projects' net pre-tax cash flow that accrues to the government as well as those that apportion early production revenue between the government and investors. High government take and high revenue risk (the large share of early revenue accruing to the government) are among the factors challenging Kazakhstan's attractiveness as an investment destination.

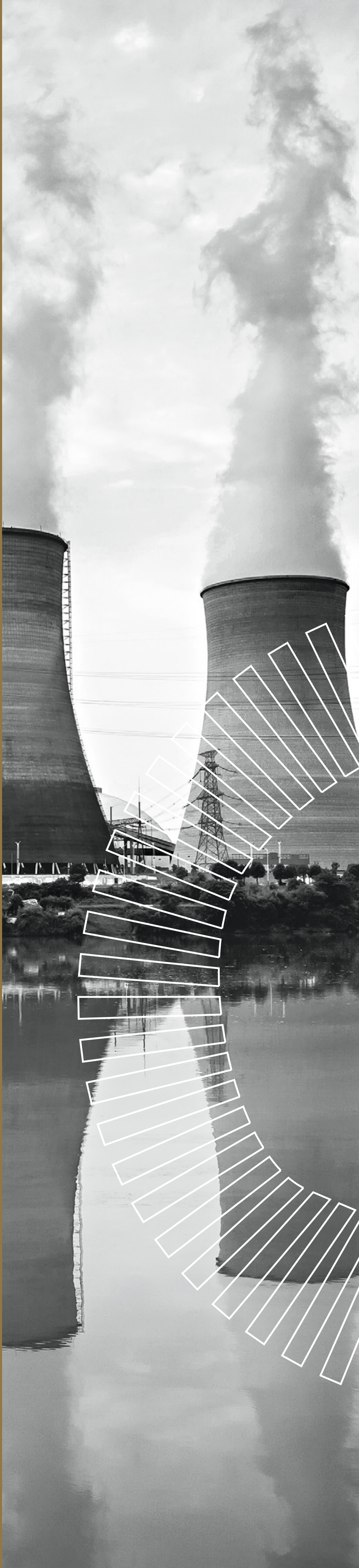
  — The effects of piecemeal renegotiation and retroactive application of fiscal terms on investor confidence and the value placed by investors on future income streams. Frequent and unpredictable changes reduce fiscal stability and increase investment risk.

  — The investment environment in which small hydrocarbon producers operate. These companies accounted for a growing share of output but are disproportionately affected by a rising fiscal burden and regulatory changes.

  — Cooperation with international financial institutions to accelerate economic reforms. Kazakhstan's ongoing effort to introduce reforms can be viewed by investors as evidence of a commitment to improve the investment environment.

  — The indirect benefits (in addition to capital) that FDI brings to an economy, such as technologies and skills, which are critical for improvements in productivity and positively affect the overall business environment.

STRATEGIC ROLE OF CHINA IN KAZAKHSTAN'S ENERGY SECTOR



6. Strategic Role of China in Kazakhstan's Energy Sector

6.1. Key Points

- Since its independence Kazakhstan has pursued a "multi-vectoral" approach in its energy development strategy, seeking diversity both in sources of investment capital for upstream development and pipeline construction as well as in markets for its energy exports (and related transport routes). Although oil output from early major projects involving Kazakhstan's, Russian, and international oil company investors reached outside markets via pipelines largely traversing Russia, over time Kazakhstan's geographic proximity and economic complementarity with China (Kazakhstan as a major hydrocarbon producer; China as a major hydrocarbon consumer) have meant that oil and gas pipelines to China can serve as logical alternatives for diversifying the country's exports.

- A substantial number of Chinese companies, both state-owned and private, are involved in Kazakhstan's energy development, in activities mainly focused upon hydrocarbons, including upstream development and pipeline construction, as well as domestic oil refining and gas processing. The most significant Chinese investor is state-owned China National Petroleum Corporation (CNPC), followed by state companies China International Trust and Investment Corporation (CITIC) and China Petroleum and Chemical Corporation (Sinopec). As energy-sector cooperation between the two countries gained momentum after 2000, the Chinese equity share in Kazakhstan's oil production increased rapidly, reaching about 25% in 2009. Although this share has now leveled off, China remains a key strategic partner in the energy sector, and could play an important role in future projects (e.g., Kashagan's Phase 2); it is also the largest market for Kazakhstan's uranium exports.

- Chinese companies currently participate in four significant hydrocarbon-producing assets in addition to many smaller ones. Because these assets mostly involve mature fields, the potential for production growth is limited; in fact, their aggregate output has been declining in recent years. However, this might change following CNPC's acquisition of an ownership stake in the Kashagan field, which could substantially increase Chinese production if the field's Phase 2 development is sanctioned. Unlike oil and gas, for which export pipelines to China are already operational and potential exists for future expansion, the prospects for exports of coal or electricity from Kazakhstan to China appear limited.

- The Chinese government appears committed to a momentous shift in the country's macroeconomic policy priority, away from an investment-led growth strategy based on exports of manufactured goods toward one focused more on increased domestic consumption and expanded tertiary- and quaternary-sector activity. This has major implications for rates of national GDP growth and energy consumption, which are expected to moderate as a consequence. The widely accepted notion that escalating Chinese demand will continue to support rapidly rising imports of a wide range of energy commodities now requires recalibration, which will have major implications for commodity exporters worldwide, including Kazakhstan.

- Technological advances in ultrahigh-voltage (UHV) transmission of electricity have enabled China to rapidly increase power generation in its interior provinces using previously untapped coal, hydro, and other energy sources for the purpose of supplying power to demand centers in coastal provinces. This UHV power is cost competitive with coal-fired generation in the coastal provinces as well as imported LNG. UHV transmission thus also will contribute to slowing growth in China's energy imports from neighboring countries relative to the recent past. However, many existing supply arrangements should continue, reflecting China's commercial and strategic interests as well as a desire for supply diversification.

6.2. China and Kazakhstan's Geostrategic Location

One of the key trends shaping global energy markets in the last two decades has been the emergence of China. This chapter evaluates how Kazakhstan's location between two powerful neighbors—Russia and China—creates both constraints and opportunities in the energy arena. Since the disintegration of the Soviet Union, Kazakhstan has taken great strides in energy infrastructure development, but that infrastructure still reflects the legacy of an earlier period in which Kazakhstan and Russia were involved in numerous forms of shared cross-border activity as constituent republics of the USSR. This is reflected, for example, in the layout of Kazakhstan's regional electricity grids, deliveries of Russian crude to the Pavlodar refinery, processing of Karachaganak condensate in Orenburg, and the routing of export pipelines through Russia. The 2015 launch of the Eurasian Economic Union (EEU) is designed to lead to even greater cooperation and integration, and may lead to the eventual harmonization of prices, tariffs, and other regulatory and technical standards in its member states.

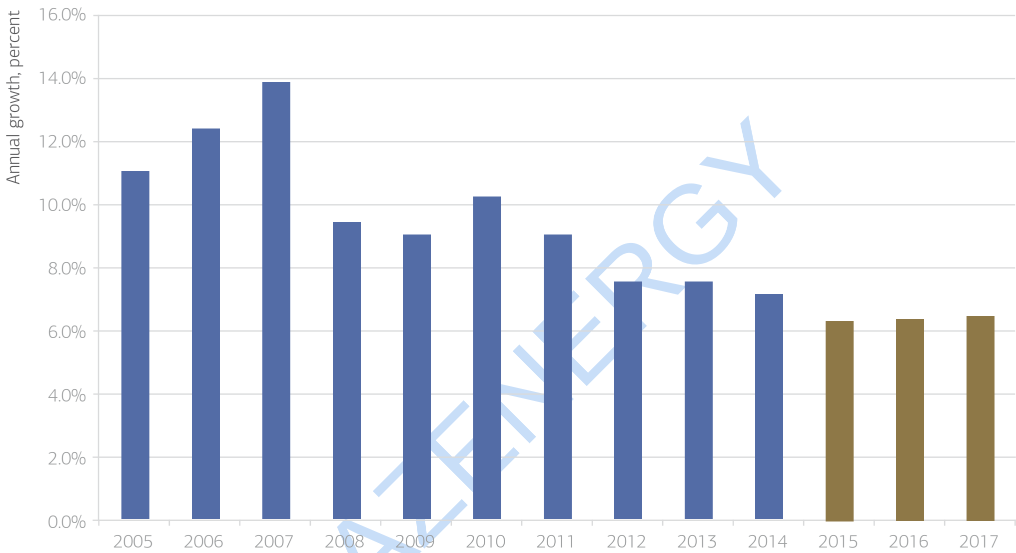
It is unlikely that Kazakhstan and Russia will become each other's major energy trading partners,[1] since both have abundant supply and are major energy exporters. However, Kazakhstan's other large neighbor, China—with a population of over one billion and still-growing energy needs—clearly appears to be a complementary partner, both as an export market for its raw materials and as a source of investment capital for upstream development and infrastructure, such as pipelines, for delivering Kazakhstan's production to its markets. This is evidenced by the fact that Chinese compa-

[1] A possible and somewhat limited exception is Kazakhstan's exports of coal to Russia (see Chapter 8).

nies (led by CNPC) now source about 400,000 b/d (20 MMt) of oil output from investments in fields in Kazakhstan, and CNPC has acquired an 8.33% stake in the Kashagan offshore megaproject (see below). In addition, an oil export pipeline to China has been in service since 2005, and a large gas export pipeline system from Central Asia, to which Kazakhstan is eventually expected to supply some gas, has been in operation since 2010.[2]

In addition to the commercial benefits of energy trade between Kazakhstan and China, such trade is an important element in China's efforts to diversify its sources of supply, reflecting national security considerations. By importing energy from many countries and through a variety of transport modes (e.g., pipelines, tankers), China seeks to avoid overreliance on any specific supplier or world macro-region. It is particularly keen not to rely too heavily on sources that are potentially susceptible to disruption (e.g., those that must transit areas of geopolitical tension such as the South China Sea, traverse key global shipping chokepoints such as the Straits of Malacca or Hormuz, or take land routes [pipelines] that must pass through third [transit] countries). We reemphasize the strategic importance of diversification to China as one of its overall key energy policy goals.

However, developments within China also affect its energy imports. China is in the midst of a transition from an export-led growth model to one in which growth is based increasingly on domestic consumption. This is being accompanied by a deceleration of very rapid rates of annual economic growth compared to the past (see Figure 6.1).[3] Due to the significant overall volume of Chinese consumption, this shift will exert downward pressure globally on the prices of many industrial commodities, including oil and gas; although China will remain the biggest market for many of these commodities, there will no longer be the high growth in demand for them that has been typical over the past decade. While the decreased rates in China's consumption growth have the potential to moderate energy prices in the years ahead, so does the emergence of new sources of energy supply within China.



Source: IHS Energy

Figure 6.1 China GDP real growth outlook

With respect to consumption growth, China's energy demand growth is moderating as annual rates of GDP growth decelerate from 10.45% (2010) to 7.35% (2014); without additional stimulus, GDP growth may fade to 6.5% in 2015.[4] By the end of 2014, a confluence of factors—including slowing residential construction, the onset of reforms in the energy sector including those affecting natural gas pricing, mild summer weather—led to an oversupply of LNG in China's eastern coastal provinces, declining consumption of fuel oil and petroleum coke, an excess of refining and electric power generation capacity, and a glut in coal accompanied by falling coal prices.[5] Demand growth in 2014 for oil (2.5%) and electric power (4%) were well below recent-year norms (6.5% and 12%, respectively), and coal consumption decreased by

[2] Kazakhstan's gas exports will feed into the third string of the Central Asia–China natural gas pipeline. It is not clear at this time when the first gas deliveries via this pipeline to China will begin; small amounts of Kazakh gas have been exported to China since 2013 via a small local pipeline in eastern Kazakhstan.

[3] Average annual per capita GDP growth in China over the past three decades has been in the range of 6–10%, the longest such period of sustained high growth ever recorded.

[4] IHS Energy, Life after the Super Cycle: China's Energy Oversupply Casts a Global Shadow. China Energy Watch, December 2014.

[5] Declines in fuel oil demand are mostly due to lower use as a feedstock by China's independent refiners, largely being displaced by crude oil. China has historically been a net importer of petroleum coke, consumed most heavily in the metallurgical sector. That sector has fared particularly badly during the recent economic growth deceleration, so that in August 2014 China became a net exporter for the first time since 2011. In the electric power and refinery sectors, rates of capacity build (calibrated to meet the needs of the old export-based economy) over the past 3–4 years have greatly exceeded rates of consumption growth. Electric power consumption

2.2% as increasing amounts of electric power were from hydrogeneration (see below).[6] Many of the factors behind the 2014 commodity slowdown are temporary, although when stronger demand returns it will remain muted by the standards of recent history. The conventional wisdom that China could always absorb spare global capacity in a variety of energy commodities is now called into question. For example, the country's imports of coal may already have peaked.

New sources of supply within China also will have an impact on energy imports. More specifically, technological advances in the long-distance transmission of extrahigh-voltage (EHV) and ultrahigh-voltage (UHV) electricity in China—from source regions of coal, hydro, and renewable energy in the country's interior to demand centers on the coast—have made such power competitive on a cost basis with imported LNG and pipeline gas as well as with electricity generated locally at coal-fired power plants.[7] Although this has implications for China's imports of natural gas as well as its domestic coal consumption, it is unlikely to reverse most existing arrangements, as discussed below.[8]

In addition to further expanding and diversifying the sources of energy supply to meet electric power demand, EHV and UHV generation enable China's government to address urgent air quality issues in the heavy populated eastern provinces by shifting the sites of power generation to interior locations. Development of heavy industry in air pollution control areas in the east is restricted, including a ban on permitting for new coal-fired stations, steel foundries, cement and petrochemical plants, and nonferrous metal smelters. Existing plants are subject to stricter emissions regulations and enforcement. In Beijing, coal-fired power plants are being phased out altogether. The first such plant was closed in July 2014, with the three remaining plants scheduled for decommissioning by 2016.

In concert with environmental policy, the volume of long-distance power transmission moving across China has ramped up rapidly. UHV lines only began transmitting significant volumes of coal-generated power from far western China in 2012. Yet in just a few short years, the power supply from UHV lines has already overtaken the supply generated from either gas turbines or nuclear plants. With this technological bottleneck broken, further ramp-up of long-distance power transmission is occurring rapidly.

Whether from hydroelectric sources in southwestern China or from coal and wind in north-central and far western China, high-voltage power transmission has already transformed the supply mix and greatly reduced the need for new coal-fired power stations in coastal China. The share of long-distance power transmission in China's total coastal power supply is expected to increase from the current 7% to about 16% in 2020. The total volume of power sent over long-distance lines now exceeds 500 terawatt-hours annually.

The increase in long-distance power transmission volumes has been made possible by heavy investment in the high-voltage network. The total length of long-distance transmission lines in China increased from 6,000 km in 2006 to 39,000 km by mid-2014—nearly enough to circle the earth. An estimated RMB 232 billion ($37.9 billion) has been invested in the long-distance transmission network to date. Four new UHV lines with a total capacity of 25 GW have come online since the start of 2013, bringing the total number in operation to eight. A further 12 UHV lines are expected to be added by 2020 to the existing eight, providing a total transmission capacity of over 130 gigawatt-amperes (GVA) (Figure 6.2).

in China, for instance, grew by 4% in 2014, only one-third the 12% annual average growth rate for 2002–2011. Capacity addition in Q3-2014, in contrast, was 8% year on year. This (at least temporary) oversupply in capacity in turn had an effect on coal prices; the Chinese benchmark (Qinhuangdao FOB) price has fallen from RMB 540 ($88.18) per metric ton in September 2013 to RMB 462 ($74.57) in April 2015.

[6] Unlike the energy resources mentioned above, demand for natural gas (other than imported LNG, which fell 1.8% year on year for the third quarter of 2014 and stayed flat in the fourth quarter of 2014) remained strong and grew by 10.3% in 2014.

[7] Much of the discussion that follows is based on Alex Whitworth, Inland-to-Coast Power Transmission in China: A Growing Long-Distance Relationship, IHS Energy Decision Brief, China Energy, October 2014.

[8] Absent from this discussion is the impact of the development of China's domestic shale gas resource, believed to be one of the largest in the world. However, initial optimism has been tempered somewhat by the greater depth of the resource (relative to North American shale), and the lower than expected recovery rates obtained using hydraulic fracturing and horizontal drilling technologies. The target level for shale gas production in 2020 has now been lowered from 60 billion cubic meters (Bcm) to 30 Bcm.

Source: *IHS Energy*

Figure 6.2 Current state of power transmission in China

Stranded hydroelectric power is the main beneficiary of UHV to date. China is the largest hydro power generator in the world, but has tapped only just over half of its technically feasible hydro resources. Expansion had been constrained by geography until recent progress in "hydro-by-wire" UHV technology. The country added 70 GW of hydropower capacity in southwestern China over the past five years alone, with about half designated for export through UHV lines. Five of China's eight UHV direct current lines unlock stranded hydropower, generating large energy flows to the coast. With an estimated feasible potential for 200 GW of further hydro development in southwest China, including in Tibet, further ramp-up is expected.

Compared to hydro-by-wire, there are at present relatively few coal-based long-distance transmission lines (coal-by-wire). But this number is expected to increase rapidly in coming years. Four coal-by-wire projects were approved in 2014 by the National Energy Administration (NEA), and at least another two approvals are expected in 2015. China's coal resources are increasingly concentrated in north and northwest China, particularly in Xinjiang and the Ordos basin in Inner Mongolia. Government policy has strongly encouraged mine-mouth power generation and transmission because it can use cheaper inland fuel resources, decrease the costs and environmental impacts of transporting coal, and reduce pollution on China's densely populated coast.

A significant driver for the ramp-up of long-distance UHV power transmission is cost. Taking into account transmission tariffs and losses, the delivered cost (to China's coastal provinces) of imported hydro-by-wire is comparable to local coal-fired power, while coal-by-wire is slightly cheaper.[9] Long-distance transmission, along with nuclear, is a cost-effective

[9] The hydro-by-wire calculation is based on published regulated transmission tariffs, while the coal-by-wire is based on a cost-plus levelized cost tariff estimate.

option for replacing local coal-fired generation in China's coastal regions. Gas-fired power, including that using LNG, is about double the cost of coal-fired and hydroelectric power imported over UHV lines, which means the future of gas in the power sector faces some uncertainty.[10]

Another potential competitor to imported pipeline gas and LNG in China's eastern regions is synthetic natural gas (SNG) derived from coal.[11] "Stranded" coal deposits, remote from China's rail network, appear to be a very low cost raw material that can be converted into gas and transported by pipeline to eastern demand centers.[12] IHS Energy calculations of the economics of an existing SNG plant in eastern Inner Mongolia indicate that given a 75% utilization rate the break-even cost for production and delivery to Beijing is around $8 per MMBtu (ca. $280 per thousand cubic meters [Mcm]). This is well below the Beijing citygate price for incremental demand (above the 2012 gas consumption level) of $13–14 per MMBtu ($470–$500 Mcm). At this price, SNG plus transportation cost is competitive against pipeline imports as well as LNG at the demand centers along the coast. The technology is still somewhat in the developmental stage, and adoption has been slowed by a rather lukewarm response by the federal power regulator, the National Development and Reform Commission (NDRC), starting in the period 2010–2012. Nonetheless, by mid-year 2014, the inventory of proposed SNG projects under review by the NDRC had already reached 191 Bcm; nine projects (>60 Bcm capacity) have received preliminary approval and three, with a combined annual capacity of 3.1 Bcm, already are in operation (Figure 6.3).

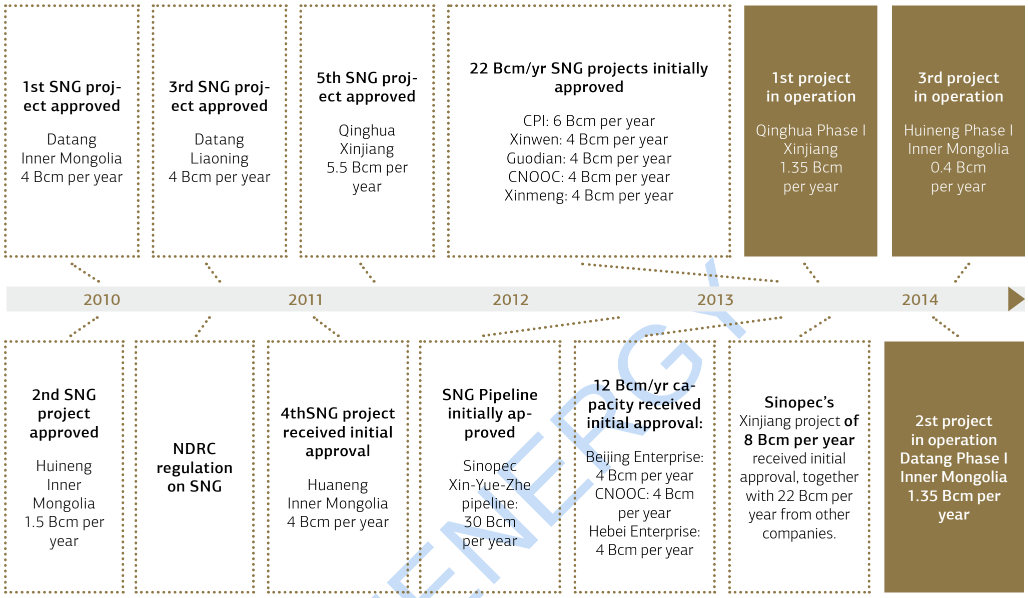


Figure 6.3 Coal-sourced synthetic natural gas in China

Source: IHS Energy
Note: CNOOC = China National Offshore Oil Corporation

SNG transport to demand centers is expected to rely upon a combination of dedicated SNG pipelines and the existing natural gas pipeline transportation infrastructure. Both the China Petroleum and Chemical Corporation (Sinopec) and the China National Offshore Oil Company (CNOOC) have announced plans to construct long-distance dedicated SNG pipelines from sites of production (Xinjiang, Inner Mongolia) to demand centers in central and eastern China. One of these, Sinopec's Xinjiang-Guangdong-Zhejiang (Xin-Yue-Zhe) pipeline, has already received official approval (Figure 6.3). In addition, if certain processes (e.g., catalytic hydromethanization) are incorporated into the SNG production train, the methane content can be elevated to the point where it can be fed directly into the existing natural gas pipeline transmission network. For example, CNPC's Yining-Khorgos SNG pipeline in Xinjiang, completed in September 2012, connects directly with China's third West-East gas pipeline string, expected to become operational in late 2015.

Despite the cost advantages of UHV power and SNG, they are not poised to displace gas-fired generation any time soon. China's energy policy is governed by multiple considerations in addition to pricing, not least of which is the improvement of air quality in the densely populated coastal provinces (as discussed above). Hydro-by-wire, which accounts for the majority of current long-distance power transmission, greatly reduces air pollution emissions compared to fossil fuel combustion. Even coal-by-wire has major environmental benefits, and

[10] See LNG's Unconventional Competition in China: Long-Distance Power Transmission, IHS Energy Insight, 30 September 2014, p. 5.

[11] SNG should not be confused with syngas (sintez-gaz, or "manufactured gas"), widely utilized in much of the world until the mid-20th century and containing large quantities of C_O and H_2. Syngas is used to produce SNG.

[12] See Zhouwei Diao and Jenny Yang, Coal-Based Synthetic Natural Gas: The Bridging Supply Source for China? IHS Energy Decision Brief, China Energy, October 2014. Some technologies involved in the process, which involves gasification of a coal slurry, gas cleanup and shift, methanization, and SNG dehydration and compression (ultimately yielding a product that is over 90% methane), have been known for quite some time, but there has been little previous experience in commercial-scale operations.

although generation emits a similar level of pollution to local coal-fired generation, the strategy effectively keeps pollutant emissions in remote and more sparsely populated northern and northwestern China, greatly reducing the exposure of the population. Furthermore, wind power is being developed to bundle with coal-by-wire, potentially contributing over one-third of power-by-wire (UHV) volumes and further improving the environmental benefits of transmission. Environmental issues pose a greater uncertainty to the large-scale development of SNG. SNG production consumes large volumes of water, which is almost completely used up in the process, and there is also a greenhouse gas (GHG) impact owing to the carbon dioxide (CO_2) emissions and methane leakage.

Arguably an even more important goal of energy policy is national energy security through diversification of supply sources. Although China will continue to rely on imported oil to meet growing transportation demand, the share of oil in power generation is insignificant. In power generation, long-distance UHV transmission contributes to national energy security by bringing new domestic energy resources to market at reasonable cost and slowing energy import growth. It also provides a means of offsetting costly imports of LNG and pipeline gas (as well as local generation from renewable energy) by making available other, cheaper power sources such as hydro and coal, all within the same unified distribution network.

The relatively high cost of imported natural gas has so far not prevented considerable capacity build-out of gas-fired units on the coast, and this is expected to continue. To some extent, gas-fired power generation is complementary to UHV in that it provides a flexible response to unexpected peak loads and line outages and thus can demand a premium over other forms of generation to provide supply security. But because of underlying economics, while nuclear, coal, and UHV transmission are targeted for high-utilization baseload operation, gas is increasingly used for peaking and mid-merit generation.

Finally, it is useful to keep in mind that China has a long-term commercial and strategic interest in energy imports from neighboring countries—particularly in Central Asia—that transcends energy development per se, extending to broader trade and regional security initiatives. Ongoing business relationships between Chinese and Central Asian companies in the energy sector, for instance, will likely support a certain level of imports going forward, regardless of strictly economic considerations. China is keen to avoid over-reliance on sources of supply from any particular part of the world, or (as noted above) that must negotiate key global transit chokepoints (such as the Straits of Malacca or Hormuz). This makes pipeline gas deliveries from Myanmar and Central Asia and LNG and future pipeline gas deliveries from Russia a welcome source of diversification. Chinese officials may also perceive that joint participation (for example, between Chinese and Kazakh companies) in upstream energy development and pipeline construction affords enhanced supply security. In Kazakhstan, in addition to the role of wholly owned CNPC subsidiary Trans-Asia Gas Pipelines, Ltd. and the China Development Bank in financing the Beyneu-Bozoy-Shymkent pipeline—which will deliver western Kazakhstan gas into Kazakhstan's section of the Central Asia–China gas pipeline—Chinese companies are actively involved in Kazakhstan's upstream hydrocarbon industry. The Chinese equity share of Kazakhstan's oil production had risen from only a couple of percent in 2000 to almost one quarter by 2012 (see below).

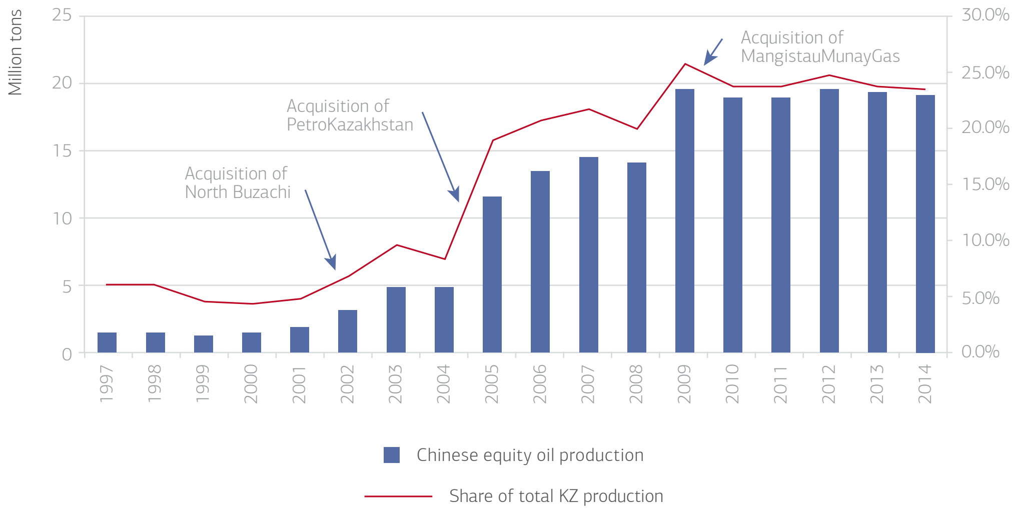
6.3. Milestones in China's Participation in Kazakhstan's Energy Sector

The history of Kazakhstan's oil industry since the 1990s is characterized by a search for diversity in investors and export routes—a multi-vectoral approach to both upstream development and export pipelines. Lacking a developed indigenous oil industry, a sizeable services and supporting manufacturing base (like Russia), or the capital to undertake expensive upstream projects, Kazakhstan opened its resource base to foreign investors for development, particularly for its most complex fields (e.g., Tengiz and Karachaganak) and offshore areas.

China became involved in Kazakhstan's energy sector shortly after this initial opening to foreign investors. Despite the early westward orientation of oil and gas export flows involving projects with Russia and IOC partners, Kazakhstan's geographic proximity to China meant that over time oil and gas pipelines to China increasingly came to be seen as logical alternatives for diversifying the country's exports. Moreover, Kazakhstan's interest in oil-and-gas-sector investment and China's interest in gaining access to Kazakhstan's energy resources led to Kazakhstan opening its market to a wide array of activities for Chinese companies. On the upstream side, Chinese companies have invested sizeable sums, often in projects that had not attracted other investors, and have become one of Kazakhstan's key strategic partners in the process. Chinese companies to date have invested in a broad range of activities that include:

- both onshore and offshore upstream assets (for oil and gas production for supply to China)
- a cross-border oil pipeline dedicated to the Chinese market
- both domestic and transit gas pipelines, including pipelines that cross Kazakhstan from Turkmenistan and Uzbekistan to China
- a domestic refinery (Shymkent), and
- a domestic gas processing plant (the Zhanazhol plant, which belongs to the field operator CNPC-Aktobemunaygaz).

As energy-sector cooperation between the two countries gained momentum, particularly in the oil sector, the Chinese equity share of Kazakhstan's oil production increased rapidly, reaching 25% by 2009, albeit decreasing slightly in subsequent years (Figure 6.4). The most significant Chinese investor is state company China National Petroleum Corporation (CNPC), followed by state companies China International Trust and Investment Corporation (CITIC) and China Petroleum and Chemical Corporation (Sinopec), but this includes many other smaller private Chinese companies as well.



Source: *IHS Energy*

Figure 6.4 Chinese equity share of Kazakhstan's oil production, 2000-2014

The wide range of Chinese state and private companies in Kazakhstan is unusual in respect to foreign investment in the country. Probably no other country has as diverse a group of investors represented. Also, Chinese investors are present across the entire country, not just in the western hydrocarbon region, in contrast to the international oil majors. In addition, a key goal for Chinese investors in Kazakhstan is to secure overland deliveries of energy resources for China, augmenting maritime shipments, which means that they are not as focused on purely economic aspects of the projects, such as rates of return and pipeline netbacks.

Chinese companies currently participate in four significant producing assets along with many smaller ones. Although the four main assets in aggregate accounted for roughly 15.7 MMt (314,300 b/d) of liquids production (~19% of Kazakhstan's total) in 2014, because they mostly involve mature fields, prospects for their production growth are limited. The actual amount invested by these Chinese companies thus far has involved several billion dollars, including the cost of asset purchases and subsequent expenditures developing the upstream and pipeline projects, as well as sizable Chinese state loans that were extended to the Kazakh counterparties involved in these projects. The four major upstream assets are summarized below.

6.3.1. Four significant onshore producing assets

1. CNPC-Aktobemunaygaz operates two fields, Zhanazhol and Kenkiyak. CNPC paid $ 325 million for a sizable stake in this asset in 1997, purchasing the remaining shares in 2003 for $ 150 million. It pledged to invest a further $ 4 billion, including in associated infrastructure. In 2014, CNPC-Aktobemunaygaz produced 5.0 MMt (101,300 b/d) of liquids.[13]

2. CNPC acquired 100% of Canadian-registered PetroKazakhstan Kumkol Resources Inc. (PKI) in 2005 for $ 4.18 billion. CNPC then faced pre-emption claims by KazMunayGaz (KMG) E&P, and CNPC's stake subsequently was whittled down to 67%, with KMG E&P holding the rest. PKI controls the South Kumkol field through 100% ownership of PKI Kumkol Resources, while the North Kumkol field is operated through the 50/50 Turgay Petroleum JV with Russia's LUKOIL. PKI also has a 50% stake in KazGerMunay (KMG held the other original 50%), operating three fields in the South Turgay Basin: Akshabulak, Nuraly, and Aksay. In 2014, PKI produced 2.2 MMt (44,400 b/d) of liquids.[14]

3. CITIC, China's premier state investment vehicle, paid $ 1.91 billion in 2006 for the assets of Canada-based Nations Energy (CCEL Karazhanbasmunay), which operates the Karazhanbas oil field in Mangistau Oblast. In 2007, KMG E&P acquired a 50% stake, leaving CITIC with 50%. In 2014, CCEL Karazhanbasmunay produced 2.1 MMt (42,808 b/d) of liquids.

4. CNPC bought a 50% stake in MangistauMunayGaz (MMG) in 2009 for $ 1.4 billion from Central Asia Petroleum (CAP). KMG owns the other 50%. MMG's (heavy) oil production comes from two onshore fields in Mangistau Oblast, Kalamkas and Zhetybay. In 2014, MMG produced 6.3 MMt (119,000 b/d) of liquids.[15]

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[13] The Zhanazhol field also has sizeable associated gas production, and CNPC has built a sizable gas processing plant at the field; in 2014 gas shipments from the field began flowing south through the Bozoy-Shymkent section of the pipeline, initially supplying the domestic market in southern Kazakhstan.

[14] As part of the PKI deal, CNPC also acquired a 50% stake in the 5.25 MMt per year (105,000 b/d) Shymkent refinery, with KMG holding the other 50%. It is currently undergoing refurbishment and its capacity is expected to rise to 6 MMt per year (120,000 b/d) by 2016.

[15] As part of the MMG acquisition by CNPC, Kazakhstan received a $10 billion loan: CNPC extended $5 billion to KMG, while China's Export-Import Bank lent another $5 billion to the Development Bank of Kazakhstan (DBK). The CNPC loan helped KMG pay for its share of MMG. The loan to DBK helped facilitate the purchase of Chinese equipment.

6.3.2. Smaller onshore producing assets

Partial and whole Chinese ownership is also significant in many smaller onshore assets, which in aggregate weigh significantly in terms of their potential contribution to future national output growth. As of 2014, a total of 15 smaller Kazakh oil producers have at least some Chinese ownership. Together these 15 entities produced an aggregate 6.0 MMt (120,000 b/d) of liquids in 2014. Several of the more prominent include:

1. Buzachi Operating Company (now owned 50-50 by CNPC and Sinopec), with an output of 2.0 MMt in 2014;
2. KuatAmlonMunay (KAM) (originally owned by the Berlanga Group, which sold it in 2009 to CNPC and private company Zhen Hua Oil Co.), with an output of 663,200 tons in 2014;
3. Kazakhoil-Aktobe (now 100% owned by Sinopec after several changes in ownership), with an output of 838,000 tons in 2014;
4. KaraKudukMunay (KKM) (100% owned by Sinopec), with an output of 810,500 tons in 2014;
5. CNPC-Ai-DanMunay (ADM) (100% owned by CNPC), with an output of 360,340 tons in 2014.

6.3.3. Chinese role in Kashagan development

BG's negotiations with CNPC and Sinopec in 2003 to sell its 16.67% stake in Kashagan were one of the reasons that led to the passage in November 2004 of the government priority/pre-emptive right amendment to the Subsoil Law. This amendment gave Kazakhstan the right to pre-empt the acquisition of shares in producing assets, and the government prevented a BG sale to the Chinese companies. In the event, 50% of BG's Kashagan stake (or 8.33%) was bought by KMG in 2005 and the remaining 50% was split among the existing Kashagan partners.

Post-2004, however, the willingness of Chinese companies to pay a premium for Kazakh assets increased the pre-emption costs for KMG. Moreover, through 2013 the government began to shift subsoil ownership back into Kazakh hands where possible, which also somewhat limited the possibilities of Chinese investors in the country. This policy appeared to end in August 2013, however, when KMG pre-empted the purchase of ConocoPhillips's 8.39% stake in Kashagan to Indian company ONGC, and then turned over an 8.33% stake in the Kashagan offshore field to CNPC. The reported price was $5.4 billion. The balance of the shares remained with KMG, which now holds the largest share (16.88%) of the Kashagan project.

At present, Kashagan may be the only Kazakh field with a Chinese shareholding that has significant production upside potential. While the current Chinese equity share in Kazakhstan's total oil production is about 24% (see Figure 6.4), this position could increase substantially if phase 2 of the Kashagan project is sanctioned, as well as development of other smaller offshore fields in the license area of the North Caspian Operating Company (NCOC), which operates the Kashagan field.

6.4. Kazakhstan-China Oil Export Pipeline

In addition to cooperation in the development of upstream assets, Kazakhstan and China also have collaborated in the construction of pipeline infrastructure in Kazakhstan to facilitate hydrocarbon exports to China. Kazakhstan launched the first stage of its cross-border oil export pipeline to China—the 962-kilometer, 10 MMt per year (200,000 b/d) Atasu-Alashankou pipeline—in December 2005. The $700 million pipeline was built as a 50-50 joint venture between KMG subsidiary KazTransOil (KTO) and CNPC subsidiary China National Corporation for Exploration of Oil and Gas. Thus, while Chinese companies continued acquiring upstream oil assets to help provide pipeline fill, the October 2005 PKI acquisition was seen as critical for Atasu-Alashankou, as it provided the closest source of supply. Furthermore, PKI's production base was already connected to KTO's eastern pipeline system, so it could be rerouted into the Atasu-Alashankou pipeline to China.

However, the erosion of CNPC's oil supply base of Kumkol crudes from PKI through splits with KMG (see above) as well as commitments to supply the Shymkent refinery made filling the pipeline challenging. An additional hurdle was the high paraffin content of PKI's Kumkol crude, which meant that Russian oil imports were required (through the Omsk-Pavlodar-Shymkent pipeline) to blend with PKI crude in Atasu-Alashankou.

The Atasu-Alashankou link to China's western border was planned to be part of a much longer 2,200-kilometer (Atyrau-Kenkiyak-Atasu-Alashankou) oil route that started at the Caspian Sea and would carry 20 MMt (400,000 b/d) annually, planned to eventually ramp up to 40 MMt (800,000 b/d). The second stage of the project—the 794-kilometer Kenkiyak-Kumkol link—was completed in July 2009. The other piece of the pipeline—the 450-kilometer Atyrau-Kenkiyak link—was completed in 2004, but runs in reverse mode from Kenkiyak to Atyrau for now. A decision has been made to change the pipeline's direction (from Atyrau to Kenkiyak), which may be implemented in 2016. Thus the Kazakhstan-China pipeline should be physically able to carry oil to China from fields in western Kazakhstan's Atyrau and Mangistau oblasts, with a capacity of 20 MMt (400,000 b/d) over the entire length.

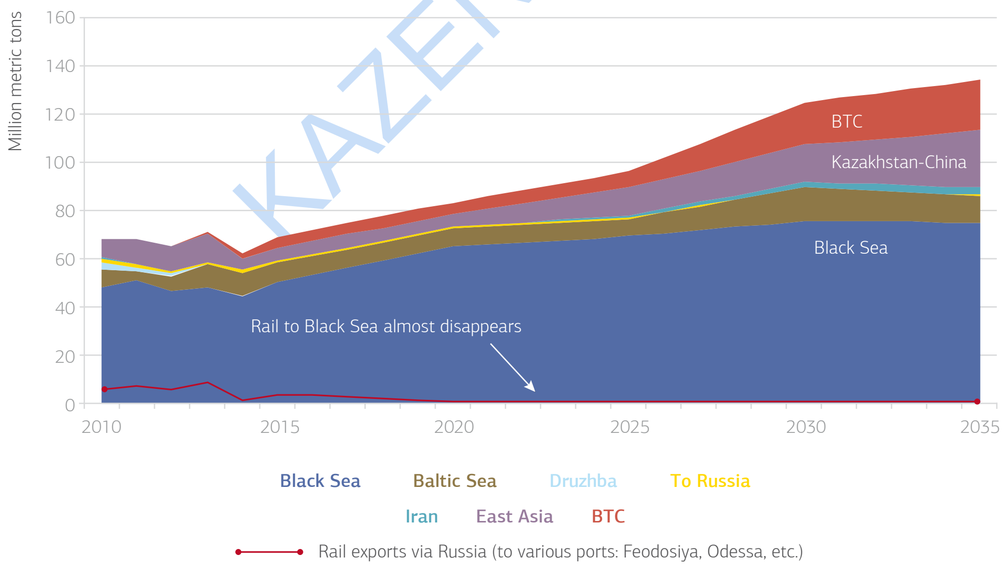
While current calculated netbacks to ship oil from Atyrau to Alashankou would be among the lowest among available export routes for producers in western Kazakhstan, this will not necessarily be a disincentive for Chinese producers, who are motivated by the opportunity to ship their oil to China. Still, oil from other producers in western Kazakhstan will flow to China only if a better price is offered on the Kazakh-Chinese border. However, two trends are at work that on balance should work in the direction of increasing netbacks for Kazakh exports to China. The two major components that determine netbacks are transportation costs and delivered prices offered to exporters at the border. Transport costs on the Kazakhstan-to-China export route for crude oil have been falling (e.g., by 14% between 2005 and 2014), as the build-out of pipeline segments of the Kazakhstan-China pipeline (Atasu-Alashankou and Kenkiyak-Kumkol) enabled pipeline transport to increasingly displace more expensive rail deliveries. Transport costs should decline still further in the near future, as the reversal of flow on the final segment of the pipeline (Atyrau-Kenkiyak) will establish a complete pipeline route from western Kazakhstan to the Chinese border. Plans call for the establishment of a "competitive" unified tariff for the entire route.

More importantly, developments are promising as well with respect to the second netback component, the China delivered-at-place [DAP] price for crude. The DAP is currently tied to Brent with a lag, and historically has been lower and less responsive to world crude price fluctuations than other prices that Kazakh exporters have earned (e.g., Brent, Urals Blend, CPC Blend). In part this was because the DAP was the product of China's internal economic calculations, which placed caps on prices to promote domestic economic development and to boost consumers' purchasing power. Also, with Xinjiang long on both crude and products, the acquisition price for crude at the refineries in Xinjiang was designed to make their products competitive in coastal markets after sizable transportation expenditures. However, the precipitous decline in the world oil price since mid-2014 now opens the window for China's leaders to proceed with long-planned reforms of the oil pricing mechanism, perhaps linking the DAP for Kazakh crude more strongly to competing world prices during a time when lower prices will exact less of a toll on the Chinese economy and population. Over the longer term, as oil supply and demand reach a new equilibrium, a revised Chinese DAP price should be more competitive than in the past relative to the other prices Kazakh producers obtain for export, thus improving the netback.

Crude exports to China through the Atasu-Alashankou pipeline held at 11.8 MMt (235,000 b/d) in 2014, about the same amount as in 2013, but the bulk of this flow is now considered to be Russian crude rather than Kazakh. In January 2014, Russian state company Rosneft began deliveries of 7 MMt (140,000 b/d) through the Atasu-Alashankou pipeline under the terms of a swap deal with Kazakhstan. Russian oil shipments amounted to 7.0 MMt (140,000 b/d) last year, so theoretically "Russian" shipments accounted for about 60% of the overall volume, while "Kazakh" shipments amounted to 4.8 MMt (96,000 b/d).[16] Currently, Kazakhstan has a major challenge securing crude for the pipeline given flat national production (and especially declining output in Aktobe and Kyzylorda oblasts, the key sources of supply for eastern exports) and the need to supply both the Shymkent and Pavlodar refineries.

In May 2014, Kazakhstan and China agreed to eventually expand flows through the Kazakhstan-China pipeline to 40 MMt per year (800,000 b/d), and even build a second string to the existing pipeline. The key issue is the availability of crude. These plans are probably contingent upon developments at the Kashagan field.

IHS expects Kazakhstan's crude oil exports to China to reach about 24 MMt (480,000 b/d) by 2035, with the total flow to China via Kazakhstan (including Russian transit crude) reaching about 31 MMt (620,000 b/d) by that time. This will be one of the key areas of growth in Kazakhstan's exports, along with CPC expansion and the trans-Caspian route via Azerbaijan and the Baku-Tbilisi-Ceyhan pipeline (see Figure 6.5).



Source: *IHS Energy*

Figure 6.5 Outlook for Kazakhstan's crude oil exports by route (October 2014 base-case)

[16] However, about 5 MMt of the incoming Russian crude is physically delivered to the Pavlodar refinery, with this volume being swapped for Kazakh oil delivered at Alashankou. So the crude blend delivered at Alashankou physically includes only about 2 MMt of Russian crude (17%) of the total.

6.5. Gas Pipelines and Gas Processing Plants

TOO BBS, a joint venture between KMG subsidiary KazTransGaz and CNPC subsidiary Trans-Asia Gas Pipeline, is building the Beyneu-Bozoy-Shymkent pipeline. The pipeline ties into Line C of the Central Asia Gas Pipeline (CAGP) network, to eventually supply exports to China. Currently, the pipeline delivers gas for domestic consumption, and it remains unclear when large-scale Kazakh gas exports to China will start, given the lack of available production to supply both the domestic market and exports (see the gas section in Chapter 7 of this Report).

The Beyneu-Bozoy-Shymkent pipeline will initially supply gas to oblasts in Kazakhstan's south, where the government intends to reduce long-standing import dependence on Uzbekistan. Construction of the Beyneu-Bozoy-Shymkent pipeline began in August 2012 and its estimated $3.8 billion cost is being financed largely through loans from the China Development Bank. The long-term plan is for the pipeline to carry up to 15 Bcm per year (including the 5 Bcm of Kazakh gas destined for export to China), but its initial capacity is 10 Bcm per year (essentially for the domestic market). Its initial section (Bozoy-Shymkent) started up in September 2013, while the remaining section, between Beyneu and Bozoy, may not be operational until 2016.

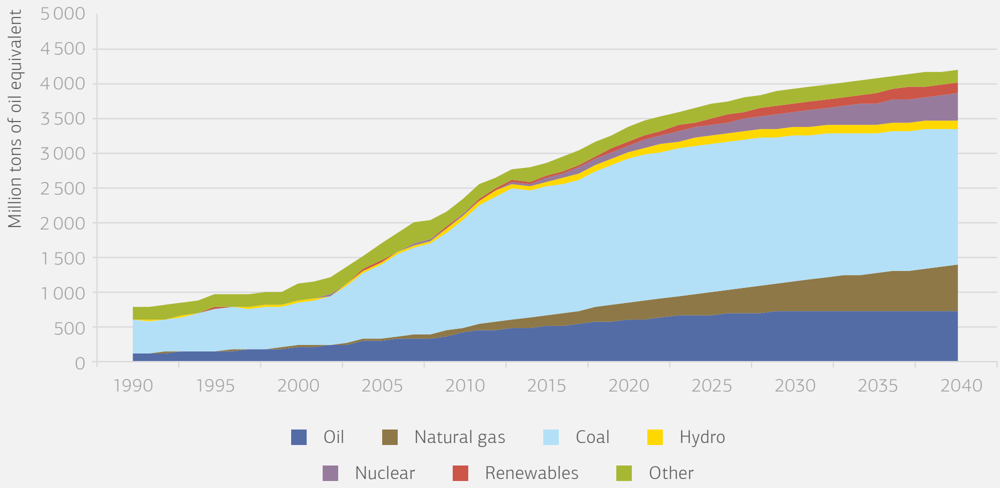
Gas supplies for the Beyneu-Bozoy-Shymkent pipeline are initially being sourced from Aktobe Oblast, including CNPC's Zhanazhol gas processing plant. Other gas supply sources may include CNPC and KMG's Urikhtau gas field and KMG's Shagyrly–Shomyshty gas field. Zhanazhol was expected to have available gas after the second and third trains of its gas processing plant were completed by CNPC, which occurred in 2014. Additional gas for Beyneu-Bozoy-Shymkent will eventually be available from Atyrau and Mangistau oblasts, including the Kashagan field.

6.6. Limited Prospects for Coal and Electricity Trade

Like Kazakhstan, China is a significant producer and consumer of coal. Both countries have abundant reserves and both annually rank among the top 10 producers in the world in mine output (see Chapter 8). Indeed, China is by far the world's leading producer and consumer of coal. However, growth in demand for coal is weakening in China for a number of reasons. First, in order to reduce air pollution in its eastern cities, and honor the country's recent commitment to reduce its greenhouse gas emissions, China's leaders have announced their intention to cap coal consumption growth by no later than 2020. Second, demand growth has also weakened as a result of structural changes in China's economy as well as competition from a surge in alternatives, including new hydroelectric generating capacity. Third, as noted above, advances in long-distance transmission of electricity in China via extrahigh-voltage and ultrahigh-voltage lines enable electricity generated in interior regions with locally plentiful hydroelectric, coal, natural gas, and wind energy to be efficiently dispatched to demand centers in the east.

Trends in China's Primary Energy Consumption

Chinese primary energy demand was 3.1 billion tons of oil equivalent (Btoe) in 2014, having grown by 3.5 times from 868 million tons of oil equivalent (MMtoe) in 1990 (see Figure 6.6). In particular, rapid growth occurred between 2000 and 2010—year-on-year growth in demand equaled or exceeded 10% for four of those years—during which primary energy consumption grew from 1.2 Btoe to 2.6 Btoe. China's primary energy consumption is expected to continue growing through 2040, albeit at a slightly slower pace as China's population and industrial growth rate declines. Thus, energy demand is expected to grow from 3.1 Btoe in 2014 to 4.3 Btoe in 2030, then reach 4.6 Btoe by 2040; i.e., an average annual growth rate between 2015 and 2040 of 1.5%. Thus, China's primary consumption is expected to expand by about 50% between 2014 and 2040.



Source: IHS Energy

Figure 6.6 Primary energy consumption in China by fuel source, 1990-2040

China relies on a combination of fuels to meet its demand, but is particularly reliant on coal. Coal has been the dominant fuel in China's energy mix, accounting for about 65% of the total in 2014, and will remain prevalent through 2040, although its share is expected to decline to 47%. Coal demand has grown rapidly since 2000, reaching 2.0 Btoe by 2014. IHS forecasts that coal demand will peak in 2025 at 2.3 Btoe, before declining slowly to 2.15 Btoe by 2040, as natural gas, nuclear power, and renewables consumption gradually supplants coal. Industrial and power generation sectors are coal's largest consumers: in 2014, coal accounted for 83% of total energy intake in the power sector and 59% in the industrial sector. Coal's share of primary energy hit a peak of 69% in 2012.

Natural gas consumption, on the other hand, has grown steadily both in market share and in absolute volume over time: in 1990, gas consumption was 12.8 MMtoe (accounting for a mere 1% of total primary energy consumption), but by 2014 gas consumption had grown to 154 MMtoe, or to 5% of the total. The IHS outlook is for the share of gas, used primarily in the industrial, power, and residential sectors, to reach 15.5% by 2040.

Oil is the second-most important fuel in primary energy consumption in China (535.1 MMtoe in 2014), but while consumption has grown over time (rising from 117 MMt in 1990), oil's market share has remained in the 17–20% range since 2000 and is forecasted to remain so through 2040. China also has hydro, nuclear, and renewables sectors, which in 2014 together accounted for approximately 5% of total primary energy. Together, these three energy sources are expected to account for about 16% of primary energy consumption by 2040.

China relies heavily on imports of fuels to supplement domestically-sourced energy supply, especially for hydrocarbons. But since the early 2000s, China has also imported some coal as well. Once a marginal oil exporter, China currently imports more than 60% of its total oil supply, primarily from the Middle East, Russia/CIS, and other producers in the Asia-Pacific region: in 2014, China imported 337 MMtoe of oil, with the other 198 MMt produced domestically. With Chinese production expected to peak in 2016, oil imports are forecasted to reach nearly 460 MMtoe in 2020 and nearly 600 MMtoe in 2040. While Chinese gas production covered demand until the mid-2000s, rising demand has pushed imports up considerably. In 2014 domestic production accounted for only 67% of total gas demand. Gas imports also are expected to continue to rise with the demand, reaching 180 MMtoe by 2030 and nearly 220 MMtoe by 2040. China imports gas via pipeline from Central Asia (and will eventually import gas from Russia) and as LNG from a variety of countries, including Qatar, Africa, and the Asia-Pacific region.

With China's abundant and undeveloped energy reserves and the government policy to stabilize and then reduce consumption of coal, Kazakh coal will be competitive in Chinese markets only at prices equal or below those offered by Chinese domestic coal producers—and these prices are now falling. Taking transportation costs into consideration, Kazakh coal would have to be sold at a much higher price than prevailing domestic prices in China to break even.[17] Hence, prospects for

[17] On 19 August 2015, the Qinhuangdao FOB price for 5500-kilocalorie per kilogram coal, widely used as a benchmark for the Chinese coal market, was roughly RMB 410 ($64.20) per metric ton at the current exchange rate, down from RMB 480 ($75.02) at the same time in 2014.

energy coal exports from Kazakhstan to the Chinese market appear to be limited.

A similar situation appears likely for electricity exports from Kazakhstan. Negotiations have begun with the Chinese on exporting electricity to China. Kazakhstan's Energy Minister, Vladimir Shkolnik, has reported that plans for the construction of an electricity transmission line from Kazakhstan's Ekibastuz plant to the Hami substation in the Xinjiang Uygur Autonomous Region in northwestern China would allow the export of up to 6 GW of electricity to China. However, despite advances in long-distance extrahigh-voltage transmission, the distance from Ekibastuz to China's major consuming centers is prohibitive, and it would be difficult to compete with indigenous generators in western China, who also have access to vast untapped coal resources, and are much closer to China's demand centers. Xinjiang has the largest but least developed coal resources in China, which are just now beginning to be fully explored (its 1.8 trillion metric ton resource base is 40% of China's national total). As a result of accelerated exploration activity, the province's proven coal reserves have nearly doubled since the mid-point of the previous decade, rising from 161 billion metric tons in 2006 to 312 billion tons in 2012.[18] Rather than focusing on importing large quantities of electric power, the Chinese government plans to build power plants in northwest China to create jobs and boost economic activity in this region during the present period of decelerating economic growth (nationally) and rising social tensions (regionally) over income disparities.

6.7. Uranium Trade

The commercial relationship between China and Kazakhstan is particularly salient in the uranium trade. China is the largest importer of Kazakhstan's uranium and accounts for over half (56%) of Kazakhstan's total exports. Between 2010 and 2014, trade statistics show that China imported over 80 thousand metric tons (Mt) of uranium—or an average of 16 Mt annually, 70% of it from Kazakhstan. However, this level of demand may not be sustainable over the longer term (see Chapter 9.4). More specifically, China's uranium imports have increased much more rapidly than what is needed to meet domestic demand growth, and the surplus has gone into building up inventory; since 2010 the Chinese have undertaken the single biggest civilian uranium inventory build in the world, which could exceed 70 Mt.

The rapid inventory growth can be interpreted as a prudent step to support the nuclear power goals of the State Council's Energy Development Strategy Action, which envisages nearly a tripling of installed capacity between 2014 and 2020 (from 19 GW to 58 GW). However, inventory building cannot be expected to continue indefinitely, and so the question arises as to when and at what level China's imports might be scaled back. Estimated volumes that China is currently importing exceed those traded on the world spot market, and consequently have a major effect not just on Kazakhstan's exports, but on prices in the global uranium market. However, global demand for uranium is expected to increase over the next two decades due to nuclear capacity additions in the developing countries, so the prospects for exports remain favorable through further diversification of trading partners.

Key Recommendations

- Kazakhstan should continue to pursue a "multi-vectoral" approach in its energy development strategy. This has important benefits in diversifying its sources of investment capital for development, establishing alternative export routes, and in securing access to an important market for its energy exports.
- A key element of this approach is Kazakhstan's engagement with China, leveraging the strategic advantage provided by its geographic location. With a population of over one billion and still-growing energy needs, China should remain a complementary energy partner, both as an export market and as a source of investment capital for upstream development and infrastructure.
- At the same time, as part of this "multi-vectoral" approach, it is important that Kazakhstan remain open and attractive to other important global players, including Europe, Russia, the United States, and other East Asian countries.

[18] Estimates of Xinjiang's coal resource base and proven reserves are provided by IHS China Energy.

OIL AND GAS INDUSTRY

7. Oil and Gas Industry

7.1. Geology and Hydrocarbon Exploration

7.1.1. Key points

- Hydrocarbon exploration in Kazakhstan has become moribund in recent years, with the onset of the down-shift in activity coming well before the decline in global oil prices and general upstream retrenchment: investment and drilling activity have been waning for several years, and new discoveries have been quite limited. This is apparently due largely to above-ground issues, as Kazakhstan's geological potential remains high; but much of Kazakhstan's remaining potential is found in complex geological settings with consequences for costs of any subsequent development.

- In an attempt to revive this all-important activity, Kazakhstan is reviewing recognized international best practices in administering subsoil use rights for subsequent implementation, and is moving forward with a new subsoil code.

- Kazakhstan also is planning to replace its existing resource classification system (a legacy of its Soviet heritage), with an international system. A major driver of the change is to make the country more attractive to investors. Currently, much of Kazakhstan's mineral resource base is already being calculated using both systems.

- Kazakhstan has several petroleum basins with proven hydrocarbon occurrences (the nomenclature of which varies among different sources), among which the Pre-caspian (North Caspian) Basin stands out as by far the most prolific, with both the largest proven and potential resources: the basin's initial 2P (proven+probable) oil and gas reserves comprise 79% of the country's total. Other hydrocarbon basins include:

  — Mangyshlak–Central Caspian

  — North Ustyurt (Ustyurt-Buzachi and Aral basins)

  — Turgay (South Turgay and North Turgay basins)

  — Chu-Sarysu

  — Zaysan depression

  — North Caucasus platform (minor part of the basin's offshore sector in the Caspian Sea)

  — Volga-Urals (southeastern margin).

- Additionally, there are several prospective basins including:

  — Syr-Darya basin

  — Alakol depression

  — Balkhash depression

  — West and East Ili depressions (Ili basin)

  — Teniz depression

  — West Siberian basin (extreme southern margin).

7.1.2. Kazakhstan's petroleum basins

The basin nomenclature used in this section reflects that of IHS. Kazakhstan's specialized geological analytical centers employ a different nomenclature that identifies 15 sedimentary basins in Kazakhstan (see Figure 7.1.1.).

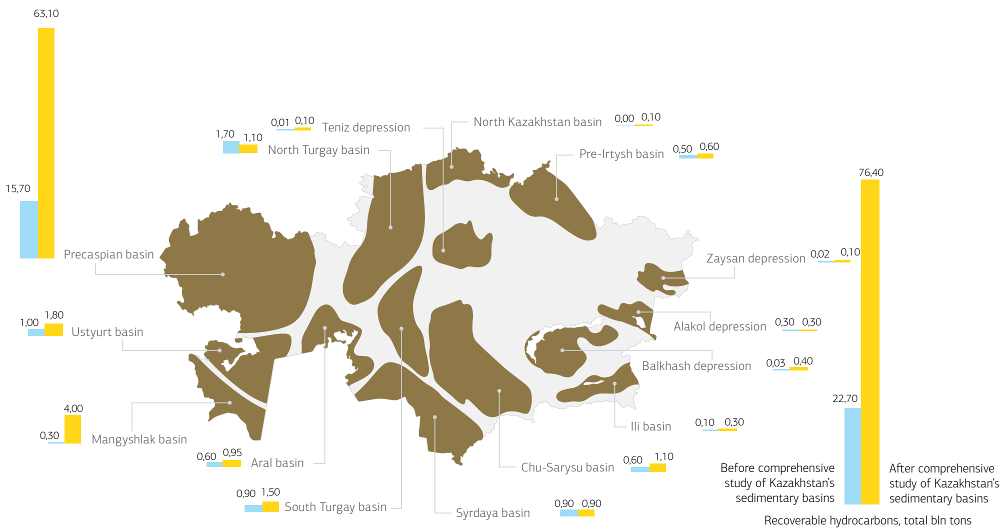


Figure 7.1.1 Annual increments to oil reserves in Kazakhstan since 2003

Precaspian Basin and the Caspian Sea Offshore

The Precaspian (or North Caspian) Basin lies in Kazakhstan's northwest area. Most of the basin's territory is in Kazakhstan, although its northwestern and western sectors are located in Russia. Most of it is situated onshore, although the southern margin extends offshore into the Caspian Sea.

The basin's sedimentary cover is split into two major sections, the presalt (below) and the postsalt (above), separated by a thick Kungurian (Lower Permian) evaporite layer. The Kungurian salt forms large diapirs (salt domes) across most of the basin, which can reach several kilometers in thickness and present a significant complication in exploring the basin's most prospective section, the presalt. The presalt is composed of Upper Paleozoic sediments represented primarily by carbonate rocks, as well as some clastics. The postsalt section consists of Upper Permian, Mesozoic, Tertiary, and more recent formations dominated by clastic rocks.

The presalt carbonates comprise several regional plays, including the Intrabasinal Carbonate Platforms, the Carbonate Escarpments, the Cretaceous-Tertiary Carbonates, and the Shelf Carbonates. The basin's super-giant discoveries such as Kashagan, Tengiz, Karachaganak, and Astrakhan/Imashevskoye (the latter located mainly in Russia) belong to the Intrabasinal play, which holds around 65% of the country's initial 2P hydrocarbon reserves. However, these reservoirs and their fluids are characterized by several factors complicating both their exploration and production, including the subsalt occurrence, the great depths, the reservoir lithology (carbonates), overpressure, and the presence of large quantities of hydrogen sulfide in solution and non-associated gas.

The postsalt section's potential is moderate in comparison with the presalt; however, its small fields contain mainly oil, which is sweet and occurs in much shallower clastic reservoirs usually lacking overpressure. The basin's first discoveries, which date back to the late 19th century, were made in these reservoirs.

The first discovery was made in 1892 at Karashungul in the South Emba region in the southeastern Precaspian. In 1911, an important discovery was made at Dossor, also in this region. Between 1911 and 1917, 11 producing wells were drilled at Dossor, flowing at rates of between 1.5–525 metric tons per day.

After the 1917 revolution and the ensuing civil war, exploration did not resume in South Emba until 1923, and was concentrated on the postsalt formations until the late 1950s. A number of small, salt-dome related oil fields (e.g. Karaton, Munayly, Terenuzuk, and others) were discovered during this period.

From the early 1960s, exploration moved to the basin's eastern part, where several larger discoveries were again made in the postsalt (e.g., Kenkiyak). However, toward the end of the 1960s, success rates had dropped significantly and the exploration strategy had to be changed. The focus was on an entirely new target, i.e., the presalt section, which had remained completely unexplored until then. In the late 1970s, several very important oil and gas condensate discoveries were made within a short period of time, including **Zhanazhol** in 1978 (0.9 billion barrels or 120 MMt), **Karachaganak** (1.1 Tcm of gas and 3.9 billion barrels [520 MMt] of liquids), and **Tengiz** (7.8 billion barrels/1 billion tons) in 1979. The latter two fields are among the world's largest.

A series of smaller discoveries followed in the 1980s and early 1990s; toward the end of this period, with the growing economic difficulties and the eventual break-up of the Soviet Union, Kazakh organizations significantly reduced their exploration activities. However, the end of the 1980s saw the first foreign oil companies demonstrating an active interest in E&P opportunities in Kazakhstan (e.g., Chevron at Tengiz).

This trend successfully developed in the 1990s with a large number of foreign major and independent companies obtaining exploration and development licenses in the Precaspian Basin's Kazakh sector. Notably, a consortium comprised of several international majors and the Kazakh national oil company (the KazakhstanCaspiyShelf Consortium, or KCS) was established in 1993. The consortium included such international majors as Eni/Agip, British Gas, BP, Statoil, Mobil, Total, and Shell. The new organization introduced state-of-the-art exploration techniques to the region. The consortium covered the entire Kazakh sector of the Caspian Sea, where only a limited amount of surveying had previously been done, with advanced 2D seismic (26,000 line-km).

Having received preferential rights to choose exploration blocks, the consortium went on to drill exploration wells. All of the 19 exploration wells drilled by OKIOC, the successor to KCS, were successful, and five discoveries were made between 2000 and 2003, including the Kashagan supergiant (11 billion barrels/1.5 billion tons) as well as Kashagan Southwest, Aktoty, and Kairan (in the Precaspian Basin) and Kalamkas-More (offshore in the North Ustyurt Basin). These were followed by significant discoveries onshore in the Precaspian Basin by Chinese operators at North Truva (~450 million barrels or 60 MMt) and Umit (~270 million barrels/36 MMt), and by the TengizChevroil JV at Ansagan (~200 million barrels/27 MMt).

An important gas discovery was made at the Rozhkovskoye gas and oil field in the northern part of the basin in 2008. Exploration/appraisal work is still ongoing at this presalt discovery, whose gas reserves are currently estimated at 15 Bcm. Nearby, a very small part of the Volga-Urals Basin's southern margin, also known as the "Precaspian Basin's Outer Flank Area," extends into Kazakh territory. This area has the important Chinarevskoye gas, condensate, and oil field (55.5 Bcm of gas and 222 million barrels/30 MMt of liquids), which was discovered in 1991.

Kashagan was Kazakhstan's first "proper" offshore Caspian discovery, as all previous finds were made in very shallow near-shore waters (due to the sea's fluctuating level, they have changed their locations from off- to onshore and back several times). There are no discoveries so far in the Kazakh sector of the Aral Sea.

As Caspian offshore exploration continued, additional, albeit less significant discoveries were made in other basins' offshore extensions, at Hazar, Auezov, and Naryn (North Ustyurt Basin, 2007–2013), and Zhambyl (2013). The latter is the only discovery in the North Caucasus Platform's Kazakh sector, and exploration drilling at this find has not yet been completed.

Caspian offshore exploration has also seen several setbacks, including dry wells at Atash, Tyub-Karagan, and Kurmangazy, and inconclusive results in the Area N exploration block (Mangyshlak–Central Caspian Basin). Logistical and environmental problems have prevented a LUKOIL-led consortium from drilling a well on the Zhambay offshore prospect in extremely shallow waters (the Precaspian Basin), which has estimated resources of 244 MMt (~1.8 billion barrels).

Mangyshlak–Central Caspian Basin

The Mangyshlak–Central Caspian is the country's second most important petroleum basin, holding 10% of Kazakhstan's gross initial 2P hydrocarbon reserves. The basin is located in western Kazakhstan. Most of its territory lies onshore, but its western portion extends offshore into the Caspian Sea. Kazakhstan shares its eastern onshore part with Uzbekistan and Turkmenistan. This oil- prone petroleum basin is dominated by two major onshore fields, Uzen and Zhetybay, which contain 70% of the basin's discovered initial oil reserves. In terms of exploration maturity, the basin's onshore part is well explored, while most of its future potential lies in the offshore Caspian extension. Most of the basin's offshore reserves belong to Kazakhstan, with much smaller parts in the Turkmen, Russian, and Azeri sectors.

In the mid- to late 1950s, an exploration drilling program was initiated in the basin's onshore portion, and in 1960–1961, two giant oil discoveries were made, Zhetybay (952 million barrels/127 MMt) and Uzen (3.7 billion barrels/490 MMt). Both fields lie in the Zhetybay-Uzen Step, a structural area in the basin's north, and the bulk of their oil is concentrated in Middle Jurassic clastic reservoirs, with additional pools in the Cretaceous. The two fields still hold almost 90% of the basin's 2P oil reserves.

In 1964, the Tenge 1 exploration well, drilled south of the Uzen field, struck gas. Tenge, whose initial recoverable gas reserves of 395 Bcm made it the largest onshore gas find in Kazakhstan at the time, was the first in a series of primarily gas discoveries in the Zhetybay-Uzen Step, and are located south of the Uzen and Zhetybay oil trend. This gas trend also includes Tenge West, Pionerskoye, Tasbulat, and Zhetybay South. Tenge also has relatively significant oil reserves of 100 million barrels (13 MMt). Its main reservoirs are also in Middle Jurassic sandstones.

In 1969, the Dunga 1 exploration well drilled close to the Caspian coast tested oil and became the first discovery outside the Zhetybay-Uzen area. The field has relatively large oil reserves (129 million barrels/17 MMt); all the later oil discoveries onshore in the Mangyshlak area were smaller than 100 million barrels, with an average size of just 19.5 million barrels (2.5 MMt). In the late 1980s, the exploration focus shifted to the deeper Triassic plays. Several discoveries were made in the Zhetybay-Uzen area and in the Segendyk trough. The exploration effort slowed with the economic and political troubles of the late 1980s/early 1990s. In the 2000s, onshore drilling picked up again at modest rates, while its focus shifted to the basin's offshore part.

Previous offshore drilling (1970s–1980s) was limited to shallow structure test and exploration wells in the near-shore areas and had resulted in only one minor discovery (Skalistoye-More, subcommercial). A new exploration phase offshore Caspian began in 1993 with the KCS consortium's seismic program.

In the late 1990s, Russia's LUKOIL started an exploration drilling program in the basin's Russian sector, which resulted in several discoveries including Khvalynskoye, 170th Kilometer, and Kuvykin (Sarmatskoye). In 2005, LUKOIL moved to the Kazakh sector and spudded the first exploration well in the Tyub-Karagan block. However, all three exploration wells drilled in this block and in the Atash block in 2005–2011 were unsuccessful and the company has now relinquished both contract areas.

In 2008, the Tsentralnaya 1 exploration well drilled by LUKOIL and Gazprom made an oil and gas discovery in the Caspian Sea's Russian sector. The reservoir is represented by Upper Jurassic fractured limestones with siltstone interbeds, in the same play as was originally discovered at Khvalynskoye. The discovery's reserves are estimated at 50 million barrels (6.7 MMt) of liquids and 20.5 Bcm of gas. Tsentralnoye and Khvalynskoye are shared by Kazakhstan and Russia based on the 1998 Caspian delimitation agreement between the two countries.

In 2010–2012, the N Company joint venture (consisting of ConocoPhillips—the JV operator at that time—Mubadala Development Co., and KMG), the operator of the Area N (Nursultan) offshore Caspian block in the Kazakh sector, had drilled two exploration wells at the Rakushechnoye-More and Nursultan structures. Both wells have produced "inconclusive" results. It is understood that they have encountered overpressured intervals and have not been fully tested due to the drilling rig's contractual limitations (a well drilled in this block in the 1970s experienced a gas blow out and fire, destroying the rig). According to KMG, the current block operator, an independent audit has estimated the Area N block's contingent reserves at 31.5 MMt (236 million barrels) and 19 Bcm of gas, while contingent resources stand at 244 MMt (1,820 million barrels). The operator will drill further exploration wells in the contract area, as the JV's exploration program provides for drilling at least three mandatory exploration wells.

A total of 60 discoveries have been made in the Mangyshlak–Central Caspian Basin's Kazakh sector, with initial recoverable 2P reserves of 5.5 billion barrels (730 MMt) of liquids and 950 Bcm of gas (of all types).

Middle Jurassic sandstones are the basin's main play, containing 91% of its 2P oil. Upper Jurassic carbonates represent the basin's other important play, which contain almost half of its gas reserves. Other plays are associated with Lower Jurassic clastics, Cretaceous clastics, Triassic carbonates and clastics, and a weathered basement surface.

North Ustyurt Basin

This basin is located in southwestern Kazakhstan, mostly onshore, but its western and eastern parts extend offshore into the Caspian and Aral seas, respectively. Kazakhstan shares the basin with Uzbekistan, and a minor part of it also extends into Turkmenistan.

The basin comprises three sub-basins. The Buzachi sub-basin occupies its smaller western part and is an oil-prone region, whereas the much bigger Ustyurt sub-basin is a gas-prone province. The East Aral sub-basin has no discoveries so far in the Kazakh sector. Some geologists believe that the Buzachi sub-basin should actually be included in the Precaspian Basin, as its oil originates from the latter's source rocks.

Between 1956 and 1960, a limited number of wildcats were drilled in the basin's Kazakh sector. In 1964, the first discoveries in the sector were made by in the Chelkar trough in the northeast part of the Ustyurt sub-basin. Gas was found in Eocene sands at Zhaksykoyankulak and Zhamankoyankulak (jointly known as the Bozoy group of fields). The Bozoy discoveries were followed by two more Eocene finds, at Shagyrly-Shomyshty in 1965-1966, and at Kyzyloy in 1967. Shagyrly-Shomyshty (18 Bcm) holds 20% of the basin's total 2P recoverable gas, but is only now being developed.

In 1968, Arystanovskoye (12.4 million barrels/1.7 MMt) became the first oil discovery in both the Kazakh sector and in the basin as a whole. The field has oil pools in four Middle Jurassic clastic reservoirs.

The basin's major oil fields were discovered in the northern Buzachi sub-basin within a short interval of time between 1974 and 1976. In 1974, Karazhanbas became the first find. Exploration well Karazhanbas 4 tested heavy, waxy, sulfurous crude from a Lower Cretaceous reservoir at just 300 m depth. The field is the second largest in the basin (622 million barrels/89 MMt). In 1975, North Buzachi well 1232 struck oil and gas east of Karazhanbas (547 million barrels/78 MMt). The field's crude is also viscous and heavy, with a high sulfur content. North Buzachi was followed by the Kalamkas field, the basin's largest (1.2 billion barrels/166 MMt). Its crude's API averages 25°. These three fields hold 70% of the basin's oil reserves. They all have their main reservoirs in shallow Middle Jurassic clastics.

Between 1976 and 1986, eight more oil finds and one gas discovery were made in the Kazakh sector. All of them were small, with an average of 18 million barrels (2.6 MMt) of recoverable oil. They included the first discoveries in the transitional on/offshore zone on the Buzachi Peninsula's northern coast (Karaturun, Arman, Kultuk, and Komsomolskoye).

Exploration activities in the Buzachi area came to a virtual halt at the beginning of the 1990s, and the next discovery was not made until 1998, when Oryx Energy drilled the Ostrovnaya 1 exploration well in the Mertvy Kultuk block, in shallow waters off the Buzachi Peninsula's north coast. The well was drilled from an artificial island and made a noncommercial oil discovery (~30 million barrels/4.5 MMt) in Mesozoic clastics. Ostrovnoye is so far the latest discovery in the basin's Buzachi area.

In the Ustyurt region, several deep exploration wells drilled in the northwestern part of the Chelkar trough in the 1970s yielded no discoveries. In 1998–1999, JNOC drilled an exploration well down to the Paleozoic section in the Chelkar trough, but neither hydrocarbon indications nor reservoirs were reported.

Since 2007, Tethys Petroleum has been conducting successful exploration drilling in this area (the Akkulka and Kul-Bas exploration blocks, Chelkar trough). The company has made several shallow gas discoveries in Eocene sandstones, followed by the important Doris and Dione oil discoveries in Upper Jurassic carbonates and Lower Cretaceous clastics, which are new plays in this part of the North Ustyurt Basin. The company's Kalypso exploration well, which is yet to be tested, is expected to prove a new gas play in Paleozoic carbonates.

The Kashagan consortium (NCOC) spudded its first wildcat in the basin's offshore sector on the Kalamkas-More structure in 2002. The well discovered an oil pool in a Middle Jurassic reservoir. The discovery's recoverable 2P reserves are estimated at 421 million barrels (56 MMt). Kalamkas-More became the basin's first offshore discovery outside the transitional zone on the Buzachi Peninsula's northern coast.

In 2007–2013, it was followed by three more offshore discoveries in the Zhemchuzhiny (Pearls) block northeast of Kalamkas-More. The Hazar, Auezov, and Naryn discoveries are estimated to contain 258 million barrels (34.4 MMt) of recoverable oil.

In the East Aral sub-basin, several deep exploration wells were drilled onshore east of the Aral Sea in the late 1960s to early 1970s. Limited hydrocarbon gas shows in Middle–Upper Jurassic and Lower Cretaceous sections were only reported for these wells. On the Aral Sea's northern periphery, several onshore stratigraphic test and exploration wells were drilled in the 1990s and between 2001 and 2007, including wells drilled on islands in what remains of the Aral Sea, but again no discoveries were made.

Turgay Basin

This large, elongate basin, located in central Kazakhstan, comprises two sub-basins, North Turgay and South Turgay. Commercial petroleum occurrences have only been proven in Mesozoic and basement plays in the smaller South Turgay sub-basin, while no discoveries have so far been made in the north.

Exploration in the basin actually began in the North Turgay sub-basin, where it was carried out in 1959–1960 and 1964–1972, and has since been practically halted. In South Turgay, exploration drilling started in the early 1980s and has been actively proceeding since 1984 when the Kumkol 1 well made a large oil discovery. The Kumkol field still remains the basin's largest (673 million barrels/90 MMt), holding 36% of its initial 2P oil reserves. The field's main reservoirs are in Upper Jurassic clastics (the Kumkol Formation), with additional reservoirs in the Neocomian Aryskum sandstones (the Daul play) and in the Doshan sandstones (Lower–Middle Jurassic).

Sixteen further finds were made between 1985 and 1993, including the relatively large Akshabulak oil field (323 million barrels/43 MMt) in 1989. As the financing of state-funded operations dried out, no new exploration was carried out in the mid- to late 1990s; the last discovery of the period (Blinovskoye) was made in 1993.

Exploration drilling was resumed by foreign operators and private companies in the late 1990s, the leader being PetroKazakhstan (formerly Hurricane Hydrocarbons). A majority of E&P licences in the basin are currently controlled by China's CNPC via PetroKazakhstan, Turgay Petroleum, KazGerMunay, and CNPC-Ai Dan Munay.

There are 29 fields/discoveries in the Turgay Basin. Most of the basin's fields are small—excluding Kumkol, the size of the average historical oil discovery is just 47 million barrels (6.3 MMt). These discoveries contain mostly oil accumulations, in Mesozoic (Jurassic and Cretaceous) continental clastic reservoirs and in the weathered basement rocks. The North Turgay sub-basin's prospective plays are different. They are represented by Late Paleozoic carbonates and clastics; however, only some shows of oil have so far been registered in several exploration wells drilled in this sub-basin.

Chu-Sarysu Basin

This gas-prone basin, which in addition to hydrocarbon gases also has significant reserves of helium and nitrogen, is located in central-southeastern Kazakhstan. Its reservoirs occur in Late Paleozoic (Upper Devonian, Permian, and Lower Carboniferous) carbonates and clastics and in weathered basement rocks.

Exploration in the Chu-Sarysu (Shu-Sarysu) Basin began in the mid-1950s and continued until the mid-1980s. Mapping of the subsurface geology and structures included various programs of remote sensing utilizing gravity anomaly and aeromagnetic regional surveys, followed by regional exploration and detailed geophysical survey programs. The first two stratigraphic test wells were drilled in the basin in 1959. In 1961, the first gas discovery was made at Usharal-Kempyrtobe, which has three reservoirs in Lower Permian clastics. However, the field's gas is almost entirely nitrogen with some helium and carbon dioxide.

In 1972, the basin's second largest discovery was made at **Pridorozhnoye** (5 Bcm of initial recoverable gas). The field has two reservoirs, in the Lower Carboniferous carbonates at 930 m and in the Upper Devonian sandstones at 2,191 m.

In 1975, **Amangeldy**, the basin's largest field (13.5 Bcm of hydrocarbon gas, with significant additional reserves of nitrogen) was discovered. Amangeldy has four reservoirs in Lower Carboniferous and Lower Permian clastics and carbonates. The field is the largest in a group of discoveries made between 1968 and 1982 and known as the Amangeldy group of fields, which also includes Kumyrly, Ayrakty, Anabay, and Barkhannoye. The group's gross initial 2P gas reserves are 20.5 Bcm, or 70% of the basin's total.

By 1982, a total of 13 discoveries had been made in the basin. Except for Pridorozhnoye and Amangeldy, all other discoveries' reserves do not exceed 3 Bcm in size.

In 1984, oil was discovered in the neighboring Turgay Basin, and the exploration emphasis shifted away from Chu-Sarysu, as oil was seen as more valuable than natural gas. Since then there was practically no exploration activity in the basin until 2008.

In 2008, Condor Petroleum of Canada (via operator Marsel Petroleum) started exploration drilling in a block in the basin's north. The company made a new gas discovery at Asa in 2012 (1.3 Bcm), and appraised the existing sub-commercial Tamgalytar discovery, upgrading it to a commercial find. Marsel Petroleum was recently sold to a Chinese investor.

Zaysan Basin

This basin is associated with the Zaysan sedimentary depression, located partly in eastern Kazakhstan and also extending into China as the Dzhunggar Basin. It is a relatively large intermontane depression within the Altay Fold Belt, with the large Lake Zaysan occupying its central part. The basin's sedimentary fill consists of Late Paleozoic, Mesozoic, and Tertiary rocks.

The initial geological field work in the Zaysan Basin began in the 1940s, and seismic surveying commenced in 1982. Between 1982 and 1988, more than 3,500 km were acquired. In 1985–1988, well **Sarybulak** P1 was drilled on the Sarybulak structure. The well discovered a heavy oil accumulation in an Upper Permian reservoir.

In 2002, Gulf Star Investments (Kuwait) spudded well **Sarybulak 2,** which had discovered commercial gas. Sarybulak currently has gas reservoirs in Triassic, Middle Jurassic, and Paleogene strata, and a subcommercial heavy oil reservoir in the Upper Permian. The field's gas reserves stand at 3.2 Bcm and it is the basin's only discovery. Gulf Star sold Sarybulak to Xinjiang Guanghui Industries of China, which is producing a small amount of gas from the field (operator Tarbagatay Munay LLP).

Project Summary: Comprehensive Survey of Sedimentary Basins in Kazakhstan

A comprehensive survey of Kazakhstan's sedimentary basins was launched 2009 and completed in 2012. It was performed under an agreement between the Geology and Subsoil Use Committee and KazMunayGas (KMG). The project was financed by KMG (from the company's own funds) and performed by Kazakhstan design and engineering entities. JSC Kazakhstan Oil and Gas Institute (KING) acted as the key organizer of the work and was a direct participant as well.

The comprehensive survey aimed at revaluation of the structure, resource base, and hydrocarbon potential of Kazakhstan's basins. This was the first work of its type to be carried out in independent Kazakhstan, with the previous analogous work done over 20 years ago. External materials were used in the survey as well, including published results of similar surveys performed in neighboring CIS countries. Work on the project employed archive materials of 234 reports from the Republican Center of Geological Information (RCGI or KazGeoInform) and more than 300 reports from the geological archives of KMG, much of them done previously by Kazakhstan's specialized geological analytical centers. The Project also reviewed the 2010-2011 Precaspian Basin aeromagnetic survey data and other types of geological and geophysical surveys as well as the results of ongoing re-estimations of oil and gas reserves performed for operating fields as well as any other structures which were either considered or had demonstrated relatively high dynamics for commercial reserves growth. The available data and results came from various regional and areal seismic and geological and geophysical works, exploration drilling results, and integrated surveys for the period 1990-2009, covering all the basins.

The activities covered in this large survey included:

- Preparation of geological seismic and drilling exploration coverage maps and structure contour maps for the main seismic horizons (1:500,000 and 1:200,000 scale), gravity and magnetic anomaly maps and geophysical field transformation maps (1:200,000 and 1:500,000 scale). Thermal field maps (1:500,000 and 1:1,000,000 scale) were plotted for all 15 basins. In addition, 1:500,000 scale local structure location maps, as well as oil and gas field maps were plotted, and potential prospects and hydrocarbon potential maps were prepared.

- A 1:1,000,000 scale comprehensive gravity and magnetic anomaly map was plotted, covering all sedimentary basins in the country.

- 1:200,000 scale double plotting method was used for all the sedimentary basins.

- Potentially productive areas were identified by basin (Caspian basin, Aral basin, Syrdarya basin, etc.), identifying the probable presence of large Paleozoic plays, at depths of 6.5-7.0 km.

The key results of the survey included:

- Overwhelming support for the the leading role of fracturing in the formation of oil and gas traps in most basins, confirming that this is one of the important factors in searching for new hydrocarbon-bearing areas and local plays; this came from several case studies in specific basins.

- A more precise geological and structural configuration model for all the basins was developed.

- General forecast (or inferred) resource estimates for all the basins were updated based on the new information and more precise data, including more detailed plotting and revised geological models.

- A preliminary map of the magnetoactive surface (1:200,000 scale) linked to the basement surface was plotted for all western Kazakhstan for the first time, allowing the position of large areas to be correlated, and clarifying the boundaries between the different elements.

- Recommendations for follow-on region and area survey work, including seismic and other types of surveys, were established. The priority sequence and methodology of 2D/3D seismic surveys on the territory of the sedimentary basins were set out.

- A control (reference) network of seismic profiles as well as priority exploration and stratigraphic test wells were suggested for carrying out a systematic exploration of the potential of individual areas and basins as a whole.

The project results were summarized in separate reports for each of 15 sedimentary basins together with a general summary report for the country as a whole. The survey results were analyzed and summarized (in the main text as well as exhibits containing graphics and text). All data used or developed as part of the survey were digitized and presented in an electronic form convenient for time-efficient and practical application in analysis. These are contained in an updateable geological and geophysical database.

Digital 3D geological and basin models of the survey objects were created based on the generalized and analyzed materials. These models are expected to be used as the main basin models going forward.

7.1.3. Exploration potential

Hydrocarbon Prospectivity

Precaspian Basin

The Precaspian Basin remains the country's main prospective area for conventional petroleum resources. According to Kazakh estimates, the basin holds around 80% of the country's undiscovered resources. The basin's presalt section in general is its most prospective. It is believed that the Presalt Carbonate Platforms play still holds significant potential for large to medium-sized discoveries.

However, as already mentioned, the presalt exploration has significant limitations, including great depth, reservoir quality risk, overpressure, and presence of sour gas, all of which complicate development and increase costs. There currently are several drilled but uncompleted/untested wells that may yield important discoveries in the near future. For example, the Shyrak 1 well drilled in the northern Precaspian (total depth 6,552 m) east of the Karachaganak field has had a strong gas blow-out from the presalt section; 19 hydrocarbon-saturated intervals have been logged in the well. The gas reportedly contains no hydrogen sulfide, but the bottom-hole pressure is 1,200 atmospheres. Prospective resources are estimated at 300 MMboe (40 MMt).

The recent Project Eurasia initiative aims to address the issue of the Precaspian Basin's remaining potential. The initiative has been approved by the Kazakh government and was officially launched by the Kazakh and Russian presidents in October 2014.

The project seeks to identify the Precaspian Basin's deep potential by drilling 7–9 km deep exploration wells, both in the Kazakh and Russian sectors. The activity is expected to run for around five years (2015–2020) and to be implemented by a consortium of Kazakh and international companies, which is yet to be formed. Companies such as LUKOIL, Rosneft, Shell, and Chevron have reportedly expressed interest in the project.

The project would comprise three stages, the first being existing data collection and processing. A second stage should acquire a series of regional seismic lines. Stage three would drill a new deep reference/stratigraphic test well. The president of the Association of Petroleum Geologists of Kazakhstan, Dr. B. Kuandykov, who also serves as the project coordinator, estimates the basin's deep potential to be around 40 billion tons of oil equivalent in up to 20 fields.

Offshore Caspian

The offshore Caspian remains significantly unexplored, in all four petroleum basins extending into the shelf from the onshore. All these basins now have proven offshore fields, and a recent government-sponsored seismic program (The National Seismic Library) has identified several attractive prospects. Factors slowing down this exploration are mainly above-ground issues (see below).

Mangyshlak–Central Caspian Basin

The Mangyshlak–Central Caspian Basin's onshore part is probably very mature for oil, but may hold significant potential for gas. An example is the Rakushechnoye onshore field, which has the largest non-associated gas reserves in the basin's Kazakh sector (15.6 Bcm). The field was discovered in 1974, but has still not been fully explored/appraised. The recent acquisition by an overseas investor (Sumatec of Malaysia) may accelerate work at the field.

North Ustyurt Basin

The North Ustyurt Basin's offshore extension (the Buzachi trend) is prospective for oil, as already proven by several discoveries. However, its offshore sector's area is quite small. Onshore, the basin has historically been more gas prone than oil prone. It was quite poorly explored through the end of the Soviet period, while recent exploration results have proved oil plays where gas only was previously discovered (Tethys Petroleum's Doris discovery). A breakthrough may occur in 2015 when Total and its partner are supposed to complete drilling their first exploration well on the Kairgeldy structure, with estimated oil resources of 1 billion barrels (130 MMt). Additionally, a new gas play may soon be proved by Tethys Petroleum's Kalypso well, which has logged gas in Paleozoic carbonates, a previously untested play in this basin.

Chu-Sarysu Basin

The Chu-Sarysu Basin's potential is gas only. Exploration in the basin was neglected for many years. However, it has already been demonstrated that application of state-of-the-art technologies can yield incremental reserves even in existing discoveries that previously had been deemed sub-commercial, as well as new discoveries.

Other Sedimentary Basins

There are several sedimentary basins in the country that have hydrocarbon potential and where variable volumes of exploration work have been conducted. Different geological factors limit their prospectivity, and estimates of their potential are purely speculative at this stage.

Unconventional Hydrocarbon Plays

With so much sedimentary cover in its various petroleum basins, Kazakhstan is most probably well-endowed with unconventional hydrocarbon plays as well. It is possible that several types of such plays could be prospective in the country, including shale oil and gas, tight sands, and coal-bed methane (CBM). Of these, only the CBM occurrences have been examined in any detail (the Karaganda coal basin). Existing estimates of the CBM gas resources in place in Kazakhstan put them at 1.66 Tcm, which, if proved, could add significantly to the country's gas reserve base. However, no systematic analysis of potential unconventional plays has so far been carried out in Kazakhstan.

7.1.4. Estimates of potential resources

Kazakh Estimates

According to the most recent estimates of a comprehensive study of the Republic of Kazakhstan's sedimentary basins (see below), Kazakhstan holds total hydrocarbon "reserves" of 76.4 billion tons of standard fuel (coal equivalent), or 53.4 billion tons of oil equivalent. To attract investments into exploration and production, Kazakhstan is considering a transition to an international standard of reserves classification (See Text Box: "Reserve Classification Schemes for Mineral Reserves").

Reserve Classification Schemes for Mineral Reserves

Kazakhstan is considering the replacement of its existing resource classification system, a legacy of its Soviet heritage, with an international system. A major driver of the change is to make the country more attractive to investors. But the decision to change should take into account the underlying reasons for the switch and whether it would really serve this key goal.

Globally, at least eight major resource classification systems exist, each of which was created for a different purpose. Some were introduced by securities market regulators to provide for consistent assessment so that investors could compare companies' performance and value (SEC and SORP); others were developed by governments seeking to assess and manage their mineral resources; while the United Nations (UN) and Society of Petroleum Engineers (SPE) systems were aimed at creating international standards that would allow for consistency in cross-country, project, and field/play resource assessments and comparisons (see Table 7.1.1).

Country	System/Agency	Purpose	Year last updated
UK	SORP	Securities disclosure	2001
Norway	NPD	Government reporting	2001
China	PRO	Government reporting	2005
Russia	GKZ	Government reporting	2005
US	SPE-PRMS	International standard	2007
US	SEC	Securities disclosure	2008
UN	UNFC	International standard	2009
Canada	CSA-COGEH	Securities disclosure	2015

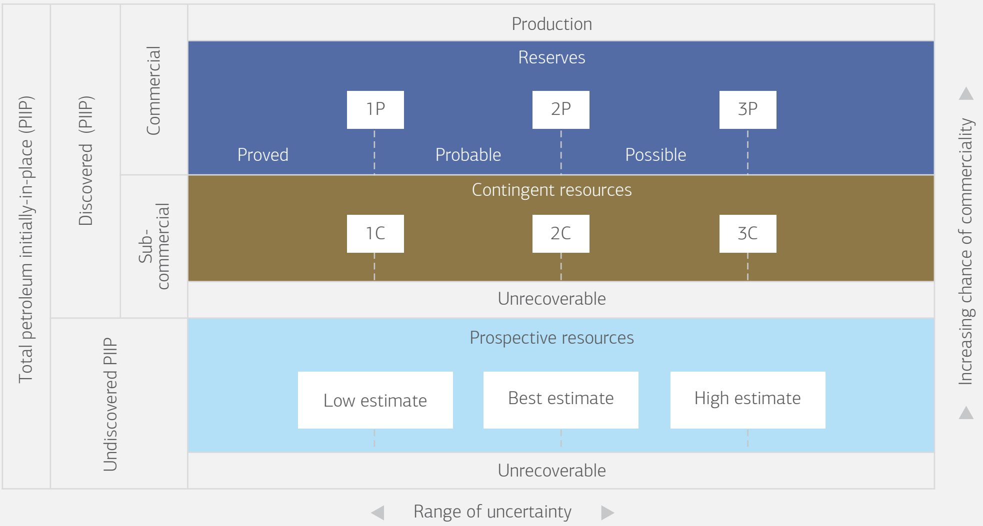
Source: Society of Petroleum Engineers, Oil and Gas Reserves Committee

Table 7.1.1 Major resource classification systems in the world

Most of the classification systems are similar in that they employ a conceptual framework consistent with the classical schema proposed by the American geologist Vincent Ellis McKelvey (the so-called McKelvey box), which considers mineral resources along two axes: one is geologic, which represents the degree of geological and/or engineering certainty about the existence and technical characteristics of the minerals. The other axis represents the range in economic feasibility of recovery of the minerals (see Figure 7.1.2.)[1]

Along the horizontal (or geological) axis, mineral resources are arrayed depending on their discovery status and degree of geological assurance (certainty/uncertainty) about their eventual extraction. These generally fall into three broad groups: high uncertainty ("possible" or "prospective" supply), medium uncertainty ("probable" supply), or low uncertainty ("proven" supply). However, the category normally considered to be "proven" reserves must be able to be estimated with reasonable certainty to be technically recoverable, but also under current economic conditions.

This brings into play the vertical axis of the box, which considers the commerciality of mineral development. After the reservoir is discovered, the commerciality of its development is contingent on multiple factors—cost of production, access to markets and prices, availability of infrastructure, and regulatory or technological constraints among them—which may make development either economic or uneconomic. However, there is no single criterion that would characterize development as economic—e.g., whether project revenues will cover costs during the life of the project. Commerciality is also judged by the intent of a company to bring the project to the production stage; such intent can be demonstrated by financial plans, regulatory approvals, etc.



Source: V.E. McKelvey, "Mineral Resources Estimates and Public Policy, American Scientist," Vol. 60 no. 1 (1972), pp. 32-40

Figure 7.1.2 Schematic of the geological and economic recovery of mineral resources

The horizontal axis of the McKelvey box mainly pertains to technical considerations, which are the key criterion employed in the Kazakh legacy system (typically, such indications of mineral extraction should be obtained through a conclusive production [well flow] test or wireline formation test, supported by logs, cores, and seismic data). A key issue that affects uncertainty in the legacy system is the exploitation phase and/or well density. However, it does not consider uncertainty that is related to recovery efficiency, which is typically taken at a certain rate set in the field's development plan. In measuring the level of uncertainty, some classification systems use a probabilistic approach, which involves applying target probabilities to classify mineral resources—i.e., probabilities that reserves will be produced. And even within the sub-category of classification systems that use a probabilistic approach there is considerable variety in terms of methods for assigning probabilities, although the standard probabilities are usually P90, P50, and P10 (90%, 50%, and 10%) to represent the proved, probable, and possible categories, respectively.

There are multiple factors limiting the classification of reserves as proved (i.e., belonging in the highest certainty level):

[1] McKelvey was the Director of the US Geological Survey. The concept is presented in V.E. McKelvey, "Mineral Resources Estimates and Public Policy, American Scientist, Vol. 60 no. 1 (1972), pp. 32-40.

- First, if a water/hydrocarbon contact is not penetrated in a wellbore, most classifications limit assessments of proved reserves to the lowest elevation of a known hydrocarbon occurrence (lowest known hydrocarbons, or LKH), as supported by well logs and core analysis.

- Second, some classifications limit proved reserves to nearby offset locations provided these locations have lateral continuity with the productive wells.

- Third, most classifications identify proved reserves as reserves that can be commercially recoverable under existing economic conditions. However, there are differing views on what prices and costs should be used for evaluation. For example, the Securities and Exchange Commission of the United States (SEC) requires the use of 12-month average prices at the beginning of each month, while in the UN classification the criterion for pricing is absent.

While using Improved Recovery (IR) methods may result in additions to proved reserves, the rules governing such extension of proved reserves also vary among the different classification systems. For example, the SEC requires successful testing by a pilot project in the reservoir in question or in analogous reservoirs (e.g., with similar rock and fluid properties). However, the legacy Soviet classification does not require implementation of a successful pilot project.

Typically, proved reserves are further grouped into two categories—developed or undeveloped—depending on the status of upstream infrastructure. The former are expected to be recovered using already-existing infrastructure; the latter require additional capital expenditure—to drill new wells or deepen/recomplete existing wells, for example.

Kazakhstan's Legacy Classification System. Kazakhstan's legacy reserve classification scheme defines reserves differently than international ones, the main difference being that the legacy classification, reflecting its origins in the Soviet period, tends to disregard the commercial constraints of economic profitability and focus instead on what is technically feasible under the best possible conditions. In fact the main merit of the system is that it is focused on calculating geological reserves to the maximum possible from an engineering perspective.

The nomenclature designates different reserve categories in descending order of geological certainty, reflecting the degree of exploration that has occurred (i.e., A, B, C, and D). In this methodology, explored reserves are considered to be the sum of categories A, B, and C (A+B+C). "Proven" reserves are defined as the sum of categories A, B, and a subset of C referred to as C1 (A+B+C1), as these constitute the quantities used to plan the level of oil and gas production for a given field or development project. A and B are typically known reserves in producing fields, while well test or log data are required for reserves to be certified as C1 or higher. C2 reserves typically pertain to extensions of proven fields. C3/D0 "reserves" (or more appropriately, "resources") are based only on seismic data, while D1 and D2 are speculative estimates of yet unsurveyed prospects in established or even non-established petroleum provinces.

The A+B+C1 figure is more comparable to international definitions of "proven plus probable" reserves (see Figure 7.1.3). Procedures for determining oil and gas reserves internationally are those established by either the SEC or the SPE. The SEC methodology is the more stringent and therefore results in the smallest estimate of "proven" reserves.

The key distinguishing features of the current reserve classification system in Kazakhstan, in contrast to systems employed internationally (e.g., SPE and SEC), are as follows:

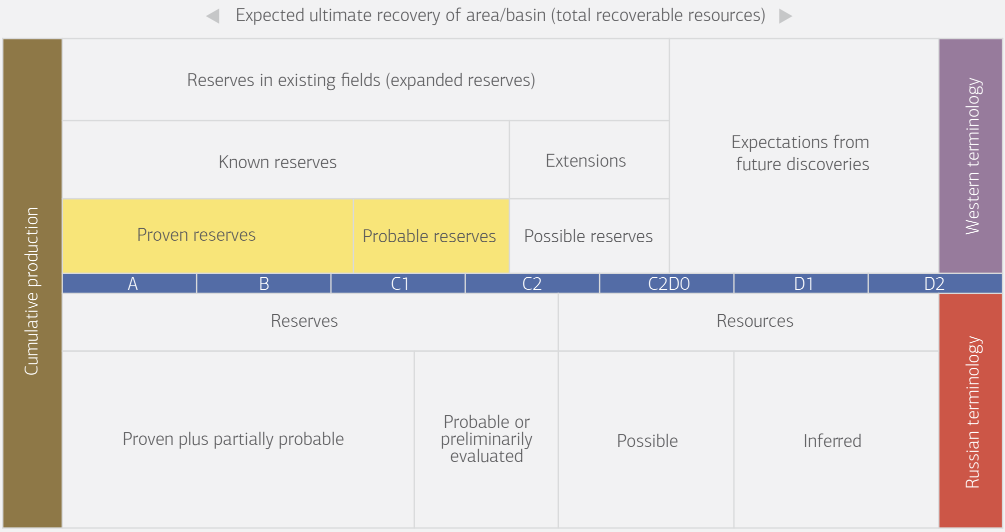
- **Evaluation based primarily on geological attributes.** Specifically, the basis for evaluation of reserves and resources in Kazakhstan is an accumulation (a field), while in international practice it is usually a specified contract area.

- **Technical criteria of recoverability prioritized over economic criteria.** The Kazakh system does not view factors related to production economics as essential, whereas the international classifications are tied to the commerciality of reserves; e.g., in the US the volume of reserves is limited by the contract term (how much can economically be produced during the life of the contract).

- **More emphasis on comprehensive analysis of resources.** Key resource elements emphasized by the Kazakh system include reservoir structure and productivity, fluid characteristics, and verification of recovery factors. The systems applied in the US, in contrast, place more emphasis on drilling footage (although a higher degree of development by this measure does not necessarily provide for better information about resources).

- **Reserve classification.** In Kazakhstan, the Geology and Subsoil Committee under Kazakhstan's Investment and Development Ministry is in charge of classifying and categorizing mineral reserves (including hydrocarbons), and still uses the Soviet legacy system. As elsewhere, the companies and resource holders estimate their own reserve base (according to these centralized criteria and standards), which they supply to government regulatory bodies; many companies also use international classification systems for calculating their reserve numbers.

- **Kazakhstan's legacy system does not use a probabilistic approach.** For example, reserves of the A and B categories in Kazakhstan's classification system do not really reflect geological risk. In contrast, the international classifications imply a certain degree of risk for even the proved category.



Source: DeGolyer and MacNaughton, IHS Energy

Figure 7.1.3 Comparison of reserve methodologies

In Kazakhstan, as in other oil-producing countries of the CIS, oil resources in the ground remain the property of the state. Oil companies (both private and state) explore and develop under state licenses. Oil above the ground becomes the companies' property, but the state, as the license-giver, remains the steward and overseer of all the companies' operations. Companies must submit field development plans to the state and make regular reports on their implementation, including discoveries and reserve additions. At the same time, since the end of the Soviet era, Kazakhstan's oil industry has been largely privatized. As a result, the privately-owned oil companies operating in Kazakhstan and other CIS countries now serve, in effect, two masters—the sovereign owner of the oil in the ground, and their owners, the private sector shareholders—and they must report to both.[2]

A fundamental problem is that these "two masters" have different aims and concerns:

- The government, as the owner of a strategic and non-renewable resource, is concerned about the long-term basis of its wealth and its national security, and uses a methodology that evolved out of the planning needs of the state's policy-makers.

- The shareholders, in contrast, are interested above all in the companies' ability to operate profitably, particularly in the near term. Since many of their shareholders are foreign, the oil companies producing in Kazakhstan have an increasingly international audience that includes analysts and regulators, who demand maximum transparency and disclosure, particularly about reserves, and use a methodology for reserves estimation that focuses on economics.

De facto, of course, much of Kazakhstan's mineral reserve base, particularly of hydrocarbons, is already being calculated in two ways—under both Kazakhstan's legacy standard and an international standard. For example, many oil companies in Kazakhstan must satisfy both of these audiences, even including the state-owned national company, KMG. Their ratings in the international community are the key to their valuations, but their continued access to licenses is the key to their survival. Managing this awkward dual allegiance is not an easy task for the oil companies, and there has naturally been growing interest in the possibility of a switch to an

[2] For an analysis of the resulting problems in the Russian case, see the IHS Energy Private Report, The Controversy over Oil Exploration and Reserves in Russia, May 2005.

international reserve classification system, more in keeping with the commercial priorities of private sector shareholders. Such a move could also save costs by working with only one classification system. But there are some risks and trade-offs involved in such a potential change, especially in the case of the SEC system.

A key consideration in the case of reserves that are currently only classified according to the Kazakh system is that recalculation of these reserves under a new system would likely result in smaller proven reserve volumes. Since the commerciality of production is not taken into account in the Kazakh reserve classification system, Kazakhstan's classification produces higher numbers than in the classifications used elsewhere (e.g., in the US, especially when compared with SEC, the most conservative classification system). Thus, switching to such a system would most likely result in lower reserve numbers, including reclassification of reserves into resources, in light of the impact of economic factors such as the lack of infrastructure.

It is also worth bearing in mind that the type of resource classification used in a country is not the most significant factor in an investor's decision on whether or not to enter a country's upstream sector. There are other, far more important factors considered by a typical investor. Indeed, the history of Kazakhstan's upstream sector suggests that the current reserves classification system did not materially impede the participation of international majors in key projects; performing a reserves audit according to international classification criteria is a service that is widely available on the global market and IOCs use this regularly in their international operations.

Turning to the unique risks and benefits associated with individual international classifications systems, there are several distinct drawbacks of the SEC rules, whereas the alternative SPE system is more likely to suit the needs of Kazakh companies.

IHS Energy identified four primary ways in which the SEC's reserve disclosure regime, which remains dominant in financial markets, has become outdated since its establishment in 1978, and remains in need of modernization:[3]

- **Globalization of the industry and capital markets.** Less than 20% of SEC registrants' reserves are located in the United States today, compared with more than 65% when the reserves reporting system was established in 1978.

- **Technological advances.** With technological innovation transforming what were previously considered to be noncommercial resources into future proved reserves, the current SEC system remains rooted in the technology of the 1970s and lacks a consultative forum or process to address technological change in reserves evaluation. Yet companies rely on these modern techniques to support multibillion-dollar investment decisions.

- **Changed anatomies of major projects.** Nontraditional projects (e.g., tight oil, shale gas, extra heavy oil, and gas-to-liquids) are drawing an increasing proportion of exploration and production (E&P) expenditures. Not all of these resources are adequately accommodated in the SEC's existing system of reserve disclosures.

- **Globalization and commoditization of oil and gas markets.** Deregulated gas markets have emerged in Europe and North America, along with third-party access regulations. Furthermore, the highly liquid, deeply traded spot markets for oil and gas, which did not even exist in the 1970s, have significantly increased the daily volatility of prices.

Furthermore, the 1978 system focuses on proved reserves as defined by a standard of "reasonable certainty" pegged to "direct contact" with an existing well. This measure may be suitable for reserves forecasts of individual producing wells but is unsuited to an increasing proportion of the modern oil and gas industry, particularly to larger offshore projects. The result can be to disconnect many companies' official reserves disclosures from the reality of their investment plans and decision-making processes.

In contrast to the SEC approach, the definitions of the SPE along with the World Petroleum Congress and the American Association of Petroleum Geologists—among the most prominent technical organizations operating in this arena—incorporate the changes that have occurred in the industry since the 1970s. These standards recommend the use of all available data that companies employ for internal investment decisions. Furthermore, the United Nations Framework Classification, as it relates to petroleum, is consistent with SPE definitions for oil and gas reserves and resources. It has even apparently been adopted by the Russian government.[4]

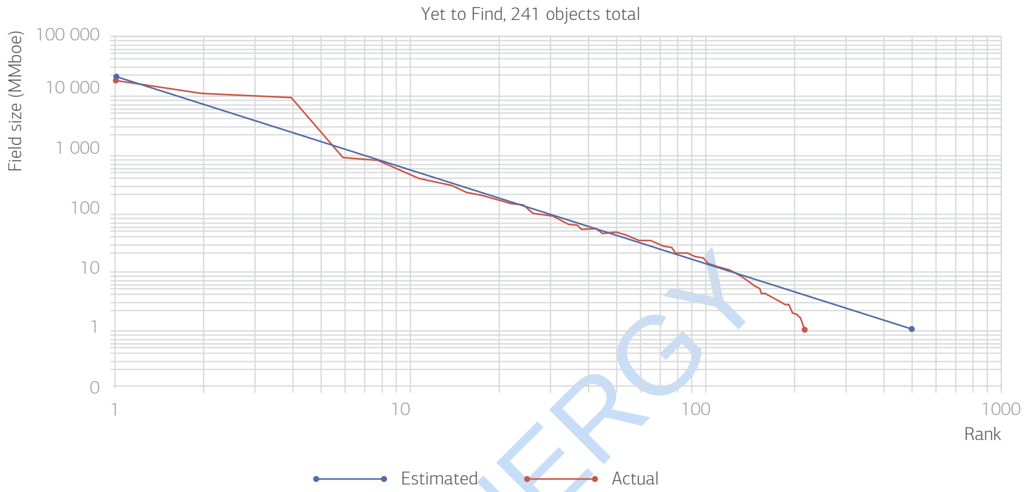
[3] See the IHS Energy Special Report, In Search of Reasonable Certainty: Oil and Gas Reserves Disclosure, April 2005; and the IHS Energy Special Report, Modernizing Oil and Gas Reserves Disclosures, February 2006.

[4] In February 2016, the Russian government is planning to introduce a new hydrocarbon reserve classification system, including criteria for categorization of reserves based on economic recoverability.

Results of YTF Analysis for Kazakhstan's Main Basins

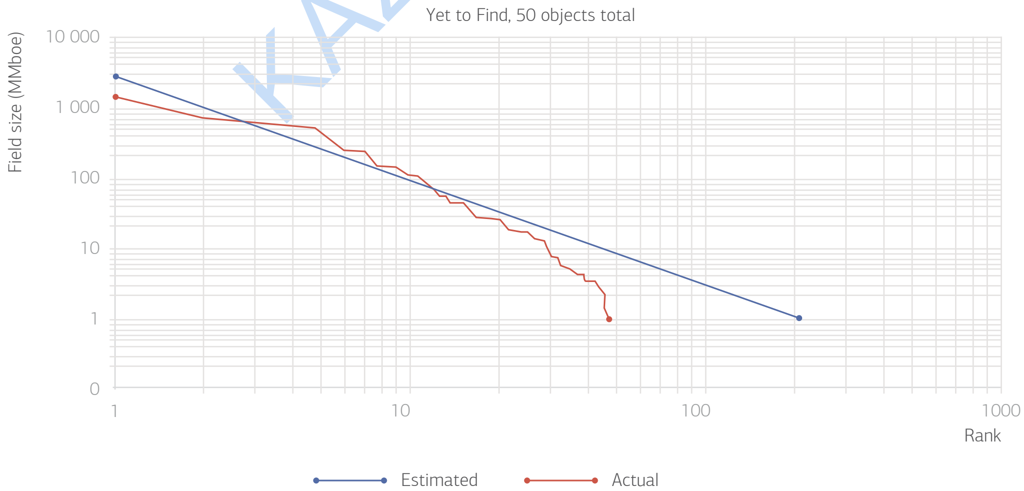
A YTF (yet-to-find) resource analysis carried out at the basin level demonstrates that the country has significant exploration potential remaining across all of its existing petroleum basins. As in the case of proved reserves, the Precaspian Basin is at the top of the list, with around 36% of the YTF resource concentrated within its limits. It is followed by the North Ustyurt and Turgay basins (between 22% and 27% in each) and the Mangyshlak–Central Caspian Basin (15%).

An exploration efficiency or creaming curve is the usual tool employed to evaluate exploration maturity, and the likely amount of YTF that might yet be found in a basin. In this process, incremental reserves are plotted against the number of wildcats drilled (in chronological order), and the resulting "creaming curve" displays cumulative reserves per number of wildcats drilled in a basin or area. In general, creaming curves demonstrate a logarithmic pattern with a steep initial slope, and then leveling (or "creaming") off to a horizontal plateau during the more mature phase of exploration. In other words, the largest prospects are often discovered and drilled in the initial phase of exploration, and therefore generate the biggest reserves increases during that phase. When exploration matures, subsequent discoveries tend to become smaller and the curve levels off at a maximum plateau equal to the total reserves that can ultimately be discovered in the basin. Creaming curves for Kazakhstan's four main hydrocarbon basins are shown in Figures 7.1.4-7.1.7.



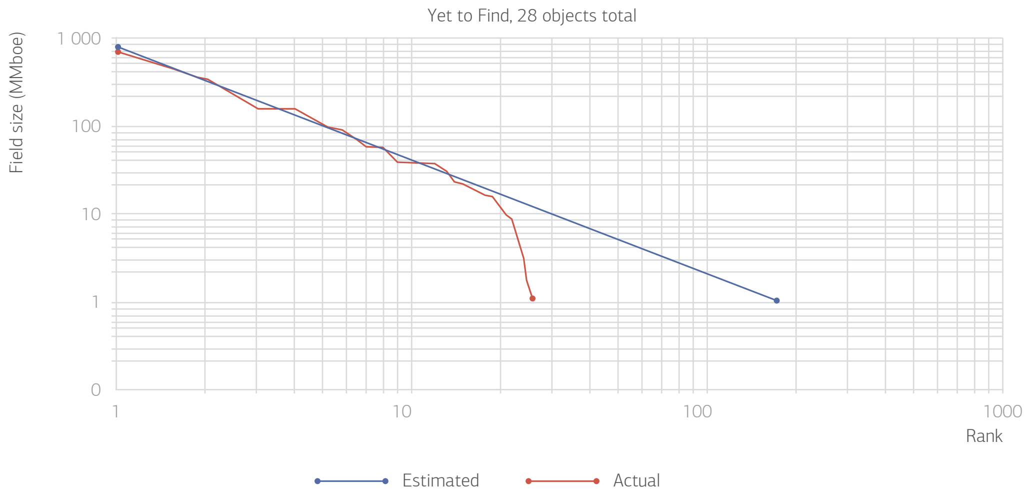
Source: IHS Energy

Figure 7.1.4 Precaspian (North Caspian) Basin



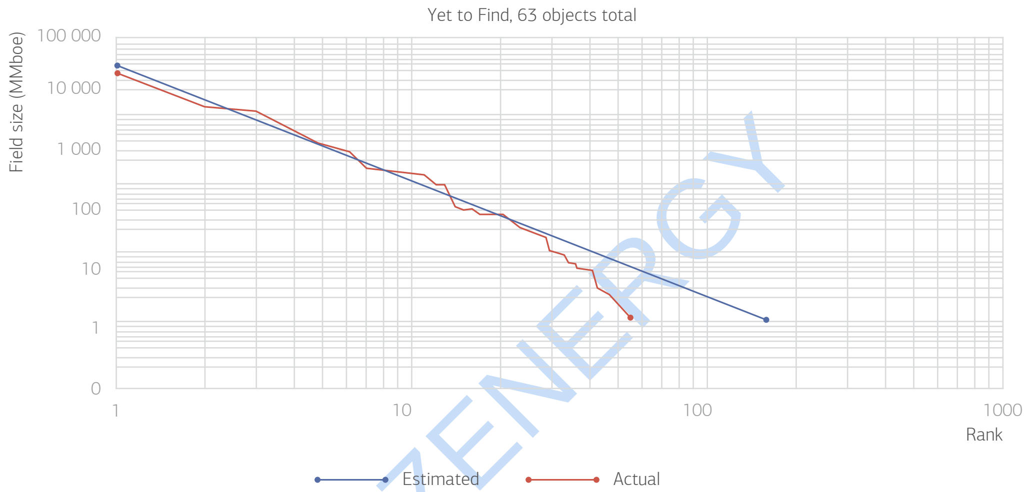
Source: IHS Energy

Figure 7.1.5 Ustyurt Basin



Source: *IHS Energy*

Figure 7.1.6 Turgay Basin



Source: *IHS Energy*

Figure 7.1.7 Mangyshlak Basin

7.1.5. Key above-ground factors limiting exploration success

Exploration Activity Declines

Recent years have seen a significant decline in the exploration activity/success rates both in the Precaspian Basin and across Kazakhstan in general, both by KMG and, partly, by the international oil companies (IOCs). There have not been many significant recent discoveries despite the expectations of the country's large potential.

The key factors contributing to the decline in exploration activity/success rates decline have been underinvestment in exploration domestically, and low levels of external investment flows due to a combination of factors, including relatively unfavourable legislation. Several above-ground factors have had a negative impact on the exploration process in Kazakhstan.

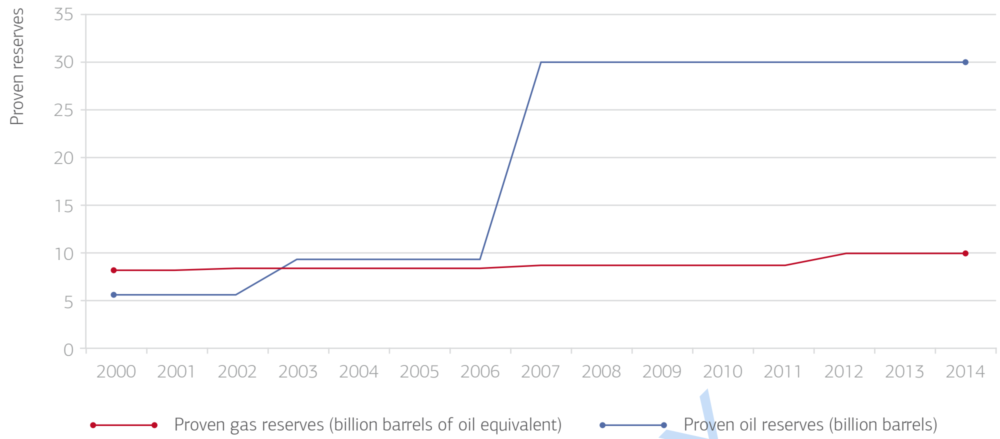
In the legislative/business area they include:

- the abandonment of production-sharing agreements (PSAs),
- the bid round moratorium since 2006,
- the increasing trend for greater state control and ownership of petroleum assets,
- the difficult, protracted negotiating process (particularly offshore),
- the challenging business environment and lack of transparency.

Technological limitations have also played a role, including a persistent shortage of drilling rigs capable of operating in the waters of the Caspian Sea, until very recently, when demand essentially disappeared with the collapse in international prices. The rig shortage slowed down not only wildcat exploration, but also the appraisal of existing discoveries. Also, limited access to geological information, both for potential investors and for the companies already active in the country, is a significant hurdle in developing new projects as well. High costs, both in the exploration and in the development phase (e.g., Kashagan), have been another important issue.

A combination of these factors has resulted in several large companies suspending negotiations on important offshore projects, such as Zhenis (Total), Shagala (Eni), and Abay (Statoil). ConocoPhillips has sold out of the Kashagan and Area N offshore projects.

Aggregate results for Kazakhstan's hydrocarbon resource base, as presented by a well-known industry source, the BP Statistical Review, are shown in Figure 7.1.8. By this measure, proven hydrocarbon reserves ('1P') in Kazakhstan have remained essentially static since 2007 at about 38-39 billion barrels of oil equivalent. The bulk of this (~75%) is comprised of oil.

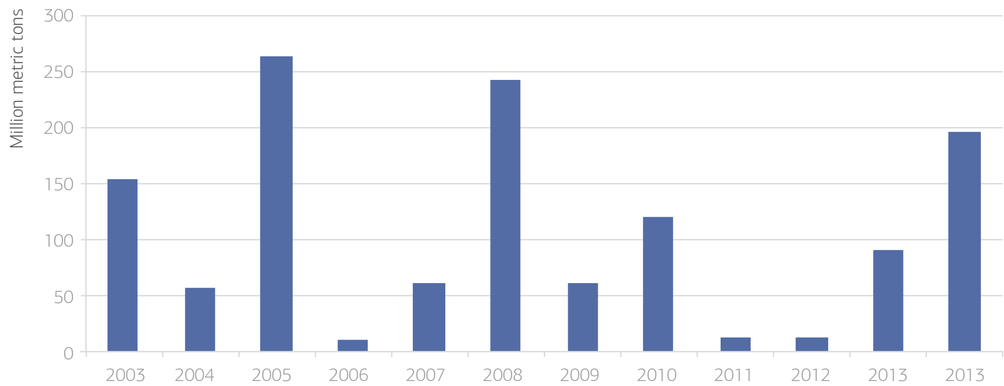


Source: BP Statistical Review 2015

Figure 7.1.8 Proven oil and gas reserves for Kazakhstan, 2000-2014 ("1P")

In contrast, Kazakhstan's Geology Committee reports that in the past decade (since 2003), a total of 1.3 billion tons of oil "reserves" (presumably A+B+C1+C2, and apparently mostly in the C2 category from re-estimations at already discovered fields) have been added to the state balance (see Figure 7.1.9). Annual oil reserve additions have varied between a low of 11.6 million tons in 2006 to a high of 263.7 million tons the previous year, in 2005. According to the Geology Committee, the main additions over this period (since 2002, when Kashagan's reserves were added) have been:

- 2005 – Karamandybas and Karakuduk, as well as a re-estimation of Kashagan's reserves;
- 2008 – Kozhasai, Kalamkas-More, Arystanovskoye, and Kayran;
- 2010 – Central Akshabulak, Kondybai, Zhangurshi, Tasym, Tamdykol, Mortuk, and East Tengiz
- 2012 – East Akkar, Southwest Karabulak, Bashenkol, Novobogat, Southeast Nadkarnizny, Chinarevskoye, Kashagan (re-estimations), and Urikhtau.



Source: Kazakhstan Geology Committee

Figure 7.1.9 Annual increments to oil reserves in Kazakhstan since 2003

President Nazarbayev's "100 Tangible Steps" Plan and the Geology Sector

The "100 tangible steps" plan was announced by President Nazarbayev during a government meeting in Astana on 6 May 2015 and published in the KazPravda newspaper on 20 May 2015. The 100 steps plan is Kazakhstan's "response to global and internal challenges, as well the nation's ambition to be among the 30 leading developed countries in a new historic environment." It consists of five institutional reforms:

- Professional government
- The rule of law
- Industrialization and economic growth
- Identity and unity
- State accountability.

The geology sector is a part of "industrialisation and economic growth" reform and has two steps dedicated to it.:

- **Step 74.** Increasing transparency and predictability in subsoil use through implementation of international reserves classification systems CRIRSCO and SPE-PRMS.
- **Step 75.** Simplify (subsoil) contracting procedures by using global best practices.

These emerging issues, in a broad sense, have been included in President Nazabaryev's recently announced "100 Step" plan for Kazakhstan (see Text box "President Nazarbayev's "100 Tangible Steps" Plan and the Geology Sector"). To revive the interest of international investors and producers in its exploration sector, Kazakhstan is also looking to learn from internationally recognized best practices used elsewhere by countries that are leading producers of hydrocarbons. These include having a designated "Competent Body" responsible for all tendering and exploration policy (See Box: "University of Dundee: Internationally Recognized Best Practices for Subsoil Contracts").

University of Dundee: Internationally Recognized Best Practices for Subsoil Contracts

A report commissioned by KazEnergy, prepared by the Centre for Energy, Petroleum and Mineral Law and Policy at the University of Dundee (UK), presents an overview and analysis of current recognized international best practices in granting subsoil use rights (SUR) for geological studies, prospecting, and exploration and production (E&P) of hydrocarbons, and the related issues including control and monitoring of activities conducted by SUR holders.[5] The main conclusions and recommendations are as follows.

Key Principles Related to Subsoil Rights

Globally, subsoil rights (for use and exploitation) are routinely granted to private companies, with the common practice for this becoming fair, transparent, and competitive exploration bid rounds, which is increasingly replacing a "first come–first served" policy (also called the "open door policy"). In preparation for this, the country should select the acreage to be tendered for exploration and prioritize these among the rounds, checking if exploration terms—legal, fiscal, and contractual—are competitive, and compiling clear licensing terms of reference (TOR) along with a related data package. This also usually involves promoting the bid round internationally to foster more interest and more bids. To promote competition, the bidders should be given sufficient time to prepare bids—the time between the bid round announcement and bid submission deadline should be a minimum of three months, but optimally six months.

[5] Analysis of International Practice of Granting Subsoil Use Rights to the Geological Study of the Subsoil (GSS), Exploration and Production (E&P) Related to Crude Oil and Natural Gas and Mining, Vol. 2, Part 4, Professor Peter Cameron FRSE, Director of the Centre for Energy, Petroleum and Mineral Law and Policy, University of Dundee (UK), November 2014.

Availability of sufficient data on the areas to be licensed is very important. For the licensing to be successful, the country needs to regularly carry out its own geological studies, acquire related data, and perform prospecting work, before holding the round. The country should consider limiting the data's confidentiality period: the typical period commonly used globally is from three to four years (in contrast, for exclusive subsoil rights, the period is typically set at ten years). The geological studies and data acquisition are performed by a designated "Competent Body" (a government agency, typically a ministry) that administers the subsoil and is responsible for organizing and running the bid rounds. These preliminary studies and analyses are usually done at its cost (and at its own risk). This activity is considered positive for the country in the long run, and therefore, needs to be funded directly from the state budget; the costs incurred are rarely reimbursed by the licensees. Such data also can be obtained through nonexclusive prospecting licenses, in situations in which prospective licensees are anxious to determine the mineral prospects and to perhaps speed up the overall process; they can carry out such activities at their own cost and at their own risk, through a Technical Evaluation Agreement (TEA) with the Competent Body (CB). But this does not bind the CB to a particular timetable nor does it confer upon the company carrying out such activity any exclusive rights to the resulting data.

The roles, missions, and duties of the government entities participating in the subsoil use activity should be clear. The regulatory and supervisory functions are performed by the CB, while a national oil company (NOC) assumes the role of a typical business entity, even though it may have certain preferential rights.

An exploration contract should guarantee licensees/potential investors the right for a production phase license/contract to be awarded in case a commercial discovery is made during the exploration phase. A separate license application and administrative process should not be required, and the applicable rules regarding the process to change over to a production license should be clear to avoid delays. For instance, it should be clear to which hydrocarbons and at what depth the license applies; most countries now limit subsoil rights to specific hydrocarbon types, or specific plays, or by depth.

Other aspects of best international practices in this regard include:

- The process of obtaining a time extension for the license should be clearly described at the outset, and established as part of the overall process.

- The license should not be terminated unilaterally by the CB. Rather, conditions that lead to termination, along with the process of termination, should be clearly set.

- To minimize delays and reduce operating costs, the license holder should be allowed to conduct as part of the regular license most any type of applicable work in the license area. For other activities, which are not routine, the process of getting approvals for such works should be clarified, while the authority of the respective authorities should be defined with clarity.

- It is important to have clarity in control and monitoring of operations. In order to prevent uncertainties, the main state authority in each sphere of activity should be clearly identified.

- Related to this issue is that there are regulations, including technical, safety, and environmental, with which the licensees must comply. While traditionally such regulations were based on specific rules, the new approach internationally is to make regulations based on objectives for the licensees to achieve. For example, one objective might be to follow best world industry practices and recognized industry standards, thus making compliance a moving target following regularly improved best practices.

The design of a fiscal regime is a two-criterion optimization task: on the one hand, the regime should be competitive to attract investors; on the other, the state should maximize its revenues. The key element of a fair fiscal regime is progressive taxation, which depends on the profitability of the project, rather than on gross revenues or production. To minimize disputes, the fiscal framework should offer detailed tax rules, procedures, and guidance notes.

The licensee should have the right to transfer its interest, provided the licensee received it through a bidding process from the CB and pays any associated taxes (such as capital gain tax). The transfer right should be granted both for a direct sale of interest by the licensee, and for the indirect transfer of interest when a third party company becomes an owner of the licensee. The legislation on capital gain taxation should be clear.

Main Legislative Regulation of the Individual Stages of Subsoil Operations

A difference between the minimum exploration obligation (MEO) program and the annual work program (AWP) should be taken into account: while the former is an absolute multi-year obligation of the licensee with certain deadlines for specific work, the latter is not a part of the license per se and can be revised on a regular basis. A breach of MEO would be the key reason for license termination.

In recent legislation globally, the stage of discovery appraisal is being separated from the exploration stage. The legislation should address the case of multiple discoveries in one area; typically, each discovery is the subject of a separate license.

In the event the exploration licensee makes a discovery, best practice is to offer production rights to the licensee, provided the corresponding Field Development Plan (FDP) is approved by the CB. A specific "Guidance Note" should indicate the detailed scope of the FDP and its approval process. The production phase should start only after the FDP is approved. Again, the details and timeline involved need to be clearly spelled out.

There are two key objectives for any producer—to maximize the economics, and to extend the project's economic life. The common related practice is to require producers (through fiscal and non-fiscal measures) to apply sound reservoir management, including regularly updated reservoir engineering and improved oil recovery/enhanced oil recovery (IOR/EOR) studies to identify best recovery processes and their related economics.

The differences between production of oil and gas (besides the underlying technical and economic aspects) need to be reflected in the underlying legislation as gas production often requires both fiscal and non-fiscal incentives, related to domestic market conditions, as this is usually the initial market that is accessed for gas. Specifically, market access must be assured and domestic market prices need to be reasonable. The legislation, taxation, and regulation should also differentiate between associated and non-associated gas.

Commitments to local social and economic development, and related local content requirements, employment, training, healthcare, and infrastructure development, should be different during the production phase from those required during the exploration phase.

Fostering Private Investment in Mineral Exploration and Production

Attracting private investment in the development of the mineral resource base needs to be based on two key principles:

- Offering a fair and competitive legal and fiscal regime
  - — Legislation should provide for best practices used in leading producing countries.
  - — Fiscal and contractual terms should be reasonably competitive.
  - — Major fiscal terms should be based on tax stability and predictability.
  - — Legal security should be supported by an established dispute settlement procedure.
- Proper regulation of sector operations
  - — There should be clarity in regards to the roles of the authorities, including the CB, the NOC, the finance and environment ministries and other players; overlapping or duplication of authority should be avoided.
  - — The regulatory framework should be based on goal-setting regulation and internationally recognized standards.
  - — Licensees should be required to use recognized best practices available in the industry.
  - — Allocation of acreage should be timely and regular to attract new entrants.
  - — Licensing rounds should be transparent, competitive, and supported by a clear TOR.
  - — Any work authorizations under the license by relevant authorities should be timely and provide for limited discretionary power.
- Specific measures encouraging exploration investments include:
  - — Legislation, taxation, and regulations should be clear—i.e., with uncertainties and ambiguities minimized—and supplied with guidance notes and model contracts. "Plain language" should be used in these instructions.
  - — Past experience should not necessarily be counted on to eliminate barriers to private investments, as conditions are constantly changing.
  - — Legislation and taxation provisions for oil and for gas should be differentiated.

— Subsoil contracts should be stable and secure.

— Contract administration, control, and monitoring of operations should be efficient and clear, providing for timely approvals without delays.

— Clear tax rules, administration, and audits, should be implemented by a dedicated central (specialized) petroleum tax office.

— Similarly, within the environment ministry, a dedicated office focused upon mineral resources should work with licensees on the issues of health, safety, and environment.

— Exploration rounds should be competitive and timely, and allow for sufficient time to study the related data and prepare offers.

— All data—geological, geophysical, geochemical, and well—should not be confidential, but rather easily accessible. The data obtained by, or on behalf of, the state should be offered at a low cost in advance of the exploration rounds.

— The selection of the winning bidder should be transparent and fair, and pursuant to the TOR.

— The confidentiality period for the data should be short (typically three to four years).

Underfinancing of exploration work and limited technological capabilities have meant that KazMunayGaz's own exploration effort, however limited, has seen little success, with several wildcats either being dry or having never been spudded. The government and national oil company seem to have recognized these problems. Changes in the Subsoil Law aimed at simplifying the subsoil contracting process are being currently reviewed. Among the more important innovations included in the legislation are the minimization of the tax burden at the exploration stage of field development, the return to joint exploration and production contracts, relaxation of local purchases and local content requirements, simplification of administrative requirements, and improved transparency and access to geological information, and others. These aspects are covered in other chapters of the report. One item not yet specified in the draft Subsoil Code are some specifics about geological information. In particular, international best practices indicate that a specialized agency, a geology committee, should be responsible for compiling the national reserve figures, and creating and maintaining a unified information system of geological data. Best practice also indicates that this entity should be a separate independent government entity.

Understanding about what level of investments in exploration is necessary is an important question for Kazakhstan in order to set realistic goals in regards to its resource base, and to develop effective strategies for attracting investors into its upstream. One metric is the spending trends for major international companies (See Text Box: "Exploration Spend by Global Companies Rising").

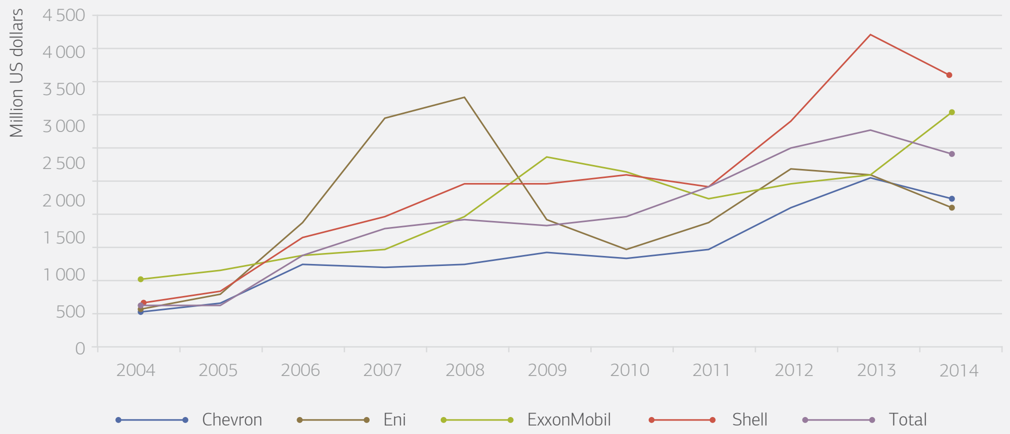
Exploration Spend by Global Companies Rising

As Kazakhstan scales its own hydrocarbon exploration efforts, the amounts large global oil and gas companies are spending on this activity provide a useful benchmark. In general, the link between exploration spending and discovered barrels (much less actual produced barrels) is largely indirect and depends on multiple factors, including most importantly geology, but the general geographical setting (particularly onshore versus offshore), the technologies used, the resource type, etc. all figure prominently in this equation. The relation is also subject to a strong learning curve effect, when every additional dollar spent on exploration at certain acreages tends to increase the likelihood of making a discovery.

One approach for evaluating the level of exploration spending in Kazakhstan is to look at the ratio of exploration spending per unit of production of the so-called Global Integreds—a group of international majors that includes BP, Chevron, Eni, ExxonMobil, Shell, and Total—during the last decade (2004–2014). The key trends are:

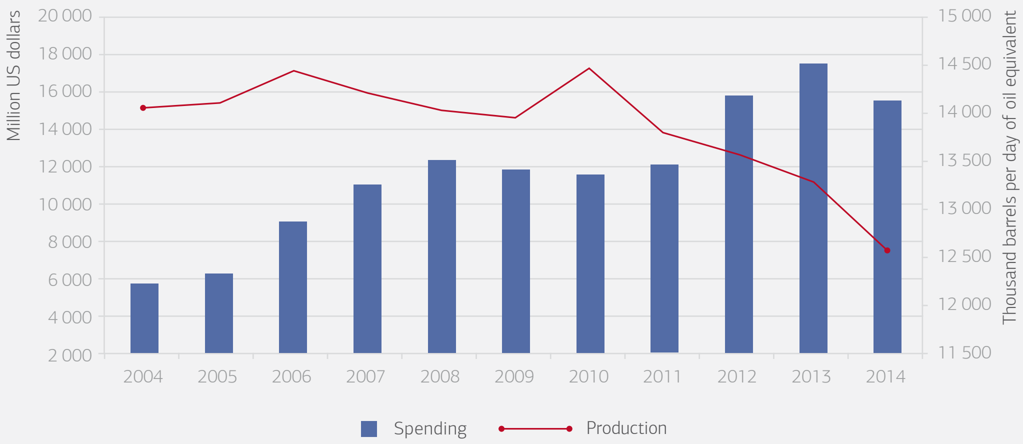
- Total combined exploration expenditures of these majors outside North America increased by 12.5% per year on average, rising from \$4.2 billion in 2004 to \$15.3 billion in 2014 (in nominal dollars) (see Figure 7.1.10). Annual spending by the individual companies varied between \$1.9 billion and \$3.6 billion on this activity in 2014.

- But at the same time, aggregate production of hydrocarbons (also, outside North America) for these companies as a group, our size scalar, contracted from 14.1 million barrels per day of oil equivalent (MMboe/d) to 12.6 MMboe/d (an average annual decline rate for the group of 1.0%) (see Figure 7.1.11).



Source: IHS Energy

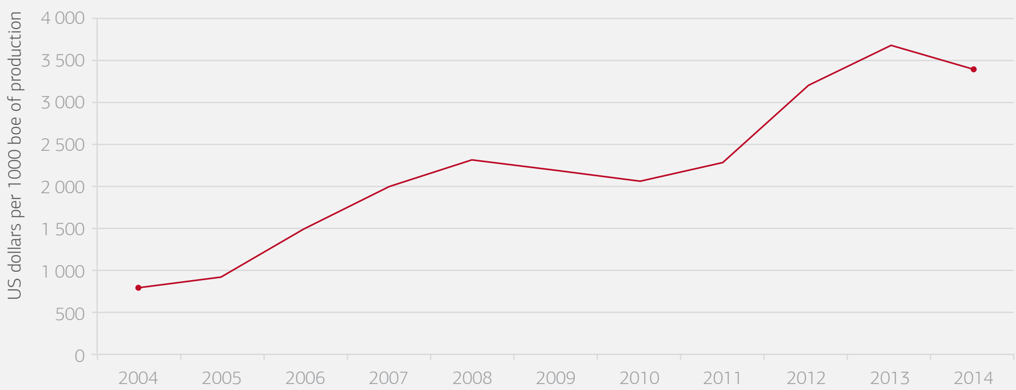
Figure 7.1.10 Net exploration spend by oil majors outside North America



Source: IHS Energy
Note: Global integrated companies include BP, Chevron, ENI, ExxonMobil, Shell, and TOTAL

Figure 7.1.11 Spending trends for international exploration vs production for global integrated companies

Therefore, scaling their exploration spending by the amount of hydrocarbon production, the spend of the Global Integrated companies as a group on international exploration increased from $821 per thousand boe produced in 2004 to $3,342 per thousand boe in 2014 (see Figure 7.1.12).



Source: IHS Energy
Note: Global integrated companies include BP, Chevron, ENI, ExxonMobil, Shell, and TOTAL

Figure 7.1.12 Aggregate exploration spending trends for global integrated companies per unit of production

In comparison, KMG E&P spends about $100 million on exploration in its core assets annually, which have a production of about 165,000 boe per day, so the ratio for the company is about $1,660 per thousand boe of production, a level substantially lower than the Global Integrated companies. Looking at Kazakhstan as a whole, the 2014 international ratio applied to Kazakhstan's hydrocarbon production of 2.203 MMb/d means that the country as a whole would need to be spending about $2.7 billion per year on hydrocarbon exploration if it was going to expend a similar level of effort as the large international E&P companies.

Another way to estimate the amount of investment needed for Kazakhstan to replace its current levels of production with reserves (a typical goal for many producing entities to ensure the longevity of the activity) is to look at the average finding costs in dollars per boe. For the past decade the weighted average annual finding cost per boe outside North America for a mix of IOCs and independents was $11.23 per boe. Kazakhstan produced 2.203 MMbdoe in 2014, or on an annual basis 804 million boe. To replace this amount at $11.23/boe means that Kazakhstan needs to spend $9.03 billion per year.

Summary of Recommendations

- Kazakhstan should follow through in its plan to change its reserves reporting system (in a moderately paced transition over several years) to the widely used international classification of reserves; there is little advantage to remaining with the existing legacy system inherited from Soviet times. Such a change would eliminate the need for companies (and the government) to maintain two sets of books, and the inherent incompatibility between the two systems.

- In terms of international systems, the technical guidelines issued by the SPE offer a much better view of the true production potential of resources than the more conservative and outmoded SEC system, better serving the needs of both the government and the producers.

- To revive the interest of international producers in its exploration sector, Kazakhstan should apply internationally recognized best practices used by leading hydrocarbon-producing countries, including having a designated "Competent Body" responsible for tendering. Another key measure is to establish a separate specialized entity that compiles and maintains geological information. Some of these recommended measures and practices are already embodied in the new draft Subsoil Code.

7.2. Crude Oil and Gas Condensate Production

7.2.1. Key points

- Kazakhstan currently ranks 17th in global oil production (up considerably from 30th two decades ago in 1995), accounting for about 2.0% of the world total in 2014 (versus 0.6% in 1995). Kazakhstan's crude production has tripled since the late 1990s. However, since 2011 production growth has stagnated. Kazakhstan's production profile depends heavily on its "mega" projects, so trends in national output have become increasingly uncertain as growth became contingent upon the expansion plans and spending patterns of just a few (big) projects.

- Kazakhstan has a significant oil and gas condensate reserve base and holds 12th place globally in proven reserves. Approximately 97% of the country's oil and gas condensate reserves is located in western Kazakhstan and about 70% is found in just its top five fields. There is considerable potential for further significant oil discoveries, however, especially offshore.

- In addition to the "mega" projects, Kazakhstan also has significant potential in smaller upstream projects to strengthen and stabilize the production outlook. Independents, perhaps working in cooperation with larger companies, can play an important, positive role in Kazakhstan's oil and gas industry by reworking mature ("brownfield") deposits more intensively and by creatively developing new resource plays (including unconventional oil), which then may become available to the larger companies. But to realize this potential, a recalibration of Kazakh oil sector policy is needed, particularly reform of its fiscal, contractual, and domestic content rules that especially tend to impact smaller producers even more negatively than the industry at large.

- Oil is the pre-eminent export commodity for Kazakhstan's economy. The long distances involved in moving crude oil to markets from the landlocked heart of the Eurasian continent mean relatively high costs for transportation (compared to other world-class oil exporters), and export routes often involve transit through third countries. Therefore, concerns over the reliability of some of these export routes have driven Kazakhstan to embrace a "multi-vectoral strategy" of multiple routes going north, south, east, and west.

- For Kazakhstan, the second largest oil exporter within the Commonwealth of Independent States (CIS), crude exports are projected to rise substantially between now and 2040, driven upward by a combination of rising production and fairly modest crude oil consumption growth. In fact, much of the overall growth in total CIS crude oil output over this period is expected to come from Kazakhstan.

- Kazakhstan's most important export route is the Caspian Pipeline Consortium (CPC) system terminating at the Black Sea; in 2014 over half (56%) of the country's total crude exports moved via CPC.[6] Oil evacuation via the Black Sea (CPC and other routes) accounted for 72% of exports. Longer term demand for crude oil in Europe is projected to remain basically flat, while indigenous production is expected to decline, so Europe's overall need for crude imports will rise. As such, the Black Sea is expected to remain a major export direction for Kazakh crude, including some incremental expansion. However, exports via the Baku-Tbilisi-Ceyhan (BTC) pipeline to the Mediterranean and to China are likely to be the main growth points longer term.

7.2.2. Crude oil and condensate reserves in Kazakhstan

As of 1 January 2014, the State Commission on Reserves listed Kazakhstan's petroleum liquids (oil and gas condensate) reserve base (state balance) at 5.18 billion metric tons.[7] Of this, 4.82 billion tons are crude oil reserves, while the rest (360 million metric tons [MMt]) is gas condensate. The official state balance lists oil and gas condensate reserves for 313 fields, including 252 oil fields and 61 gas condensate fields.

In terms of the smaller category of just proven reserves, according to the BP Statistical Review of World Energy, in 2014 Kazakhstan had 3.9 billion metric tons (30 billion barrels) of total liquid reserves, which include crude oil, gas condensate, and other natural gas liquids (NGLs). This constitutes 1.8% of the world's total liquids reserves and puts Kazakhstan in 12th place worldwide (see Table 7.2.1.). Among CIS countries, Kazakhstan's total liquids reserves are the second largest after Russia, accounting for 22.8% of the regional total.

Rank	Country	Billion tons	Billion barrels	Share of total
1	Venezuela	46.58	298.35	17.5%
2	Saudi Arabia	36.68	267.00	15.7%
3	Canada	27.88	172.92	10.2%
4	Iran	21.68	157.80	9.3%
5	Iraq	20.24	150.00	8.8%
6	Russian Federation	14.13	103.16	6.1%
7	Kuwait	13.98	101.50	6.0%
8	United Arab Emirates	12.98	97.80	5.8%
9	Libya	6.30	48.36	2.8%
10	US	5.89	48.46	2.9%
11	Nigeria	5.00	37.07	2.2%
12	Kazakhstan	3.93	30.00	1.8%
	Total world	239.8	1700.1	100.0%

Source: BP Review of World Energy 2015

Table 7.2.1 Proved oil reserves at year-end 2014

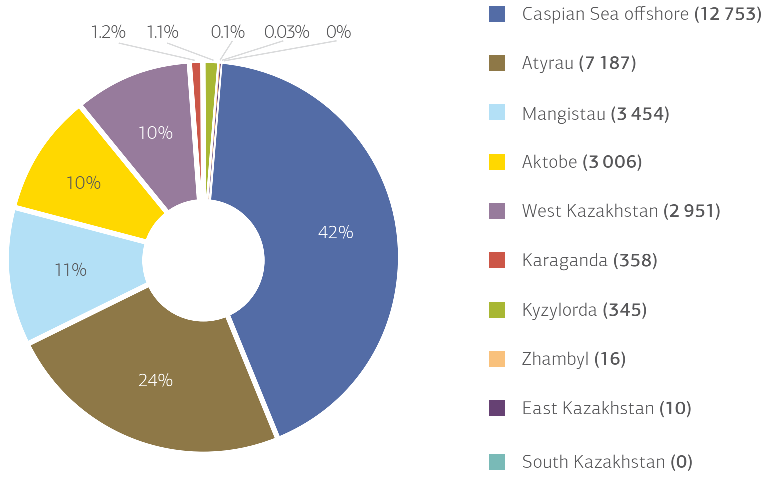
Approximately 97% of the country's oil and gas condensate 2P reserves is located in western Kazakhstan (i.e., Mangistau, Atyrau, West Kazakhstan, and Aktobe oblasts together with the Caspian offshore), and about 70% is found in the country's five largest fields (e.g., Tengiz, Kashagan, Korolevskoye, Karachaganak, and Zhanazhol) (see Figure 7.2.1.).[8] Most of these are subsalt deposits, characterized by considerable depths (up to 5 kilometers), multi-component composition, and high sulfur content, all of which greatly complicate development and production.

In terms of operatorship, the top four holders of oil and gas condensate reserves are North Caspian Operating Company (NCOC) (40%), TengizChevroil (TCO) (21%), Karachaganak Petroleum Operating (KPO) (8.5%), and KazMunayGaz (KMG) (5%). They account for three quarters of all (proven+probable) reserves (see Figure 7.2.2.). Two other significant reserve holders—CNPC-AktobeMunayGaz and MangistauMunayGaz—account respectively for 4.9% and 2.5% of Kazakhstan's total. Therefore, six resource holders hold 82% of Kazakhstan's total oil (2P) reserves.

[6] This calculation does not include Russian transit volumes to China as Kazakh exports. Including these volumes, the share would be 50%.

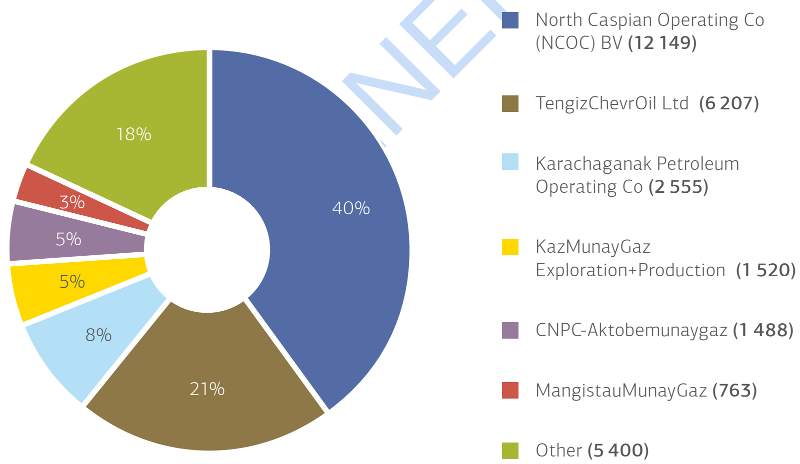
[7] This is reported according to the domestic definition (in categories A+B+C1+C2). Kazakhstan's remaining proven+probable "2P" reserves (roughly the international equivalent of the domestic definition of A+B+C1) is 3.45 billion tons (or about 25 billion barrels); IHS Energy estimates a slightly larger amount of 2P reserves for the country in 2014, at 30 billion barrels.

[8] West Kazakhstan Oblast's Karachaganak field contains 2.4 billion barrels of recoverable liquids, Kazakhstan's largest for condensate reserves.



Source: IHS Energy

Figure 7.2.1 Kazakhstan's 2P petroleum liquids reserves by oblast in 2014 (million barrels)



Source: IHS Energy

Figure 7.2.2 Kazakhstan's 2P oil reserves by operator in 2014 (million barrels)

7.2.3. Historical production trends

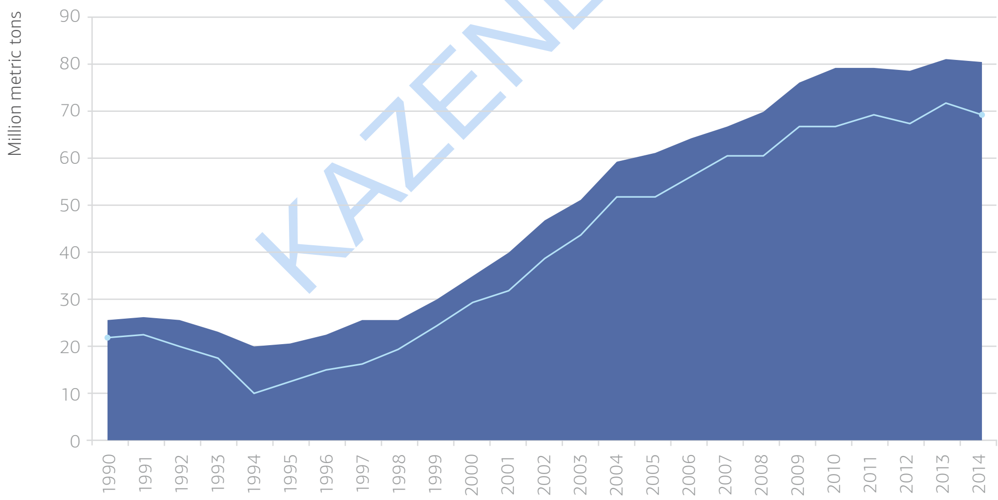
Kazakhstan is the second largest oil producer among the CIS states after Russia, accounting for almost 13% of aggregate oil output in 2014 for the region as a whole. Among the countries of the world, Kazakhstan currently ranks 17th in oil production (up considerably from 30th in 1995), accounting for about 2.0% of the world total in 2014 (versus 0.6% in 1995) (see Table 7.2.2.). Kazakhstan's crude production has tripled since the late 1990s from 25.9 million metric tons (MMt) (or 534,000 barrels per day) in 1998 to 80.8 MMt (or 1.7 million barrels per day [MMb/d]) in 2014 (see Figure 7.2.3.).[9]

[9] As is the convention statistically, the national production figures include both crude oil proper and gas condensate.

Rank	Country	Production (thousand b/d) 2014	Production (MMt) 2014
1	US	11 644	519.9
2	Saudi Arabia	11 505	543.4
3	Russian Federation	10 838	534.1
4	Canada	4 292	209.8
5	China	4 246	211.4
6	United Arab Emirates	3 712	167.3
7	Iran	3 614	169.2
8	Iraq	3 285	160.3
9	Kuwait	3 123	150.8
10	Mexico	2 784	137.1
11	Venezuela	2 719	139.5
12	Nigeria	2 361	113.5
13	Brazil	2 346	122.1
14	Qatar	1 982	83.5
15	Norway	1 895	85.6
16	Angola	1 712	83.0
17	Kazakhstan	1 701	80.8

Source: BP Statistical Review 2015.

Table 7.2.2 World's top oil producers in 2014



Source: IHS Energy; Kazakhstan statistical agency; Ministry of Energy
Note: Includes crude and condensate.

Figure 7.2.3 Kazakhstan's oil production profile and exports, 1990-2014

However, since 2011 production has been stagnant, increasing only by 0.4% during that year. Output declined in 2012, falling by 1% relative to 2011 (see Table 7.2.3.). This decline was Kazakhstan's first since 1994, and was mainly due to a dip in output at the TCO project (the Chevron-led entity operating the Tengiz field).[10] The fall in Tengiz output in 2012 was connected with a major capital overhaul of field facilities, both the second-generation plant and the sour gas injection facility (SGP/SGI). This turnaround set the stage for a rebound in Tengiz production growth, up 12% in 2013,

[10] TCO's current partners include Chevron (50%), ExxonMobil (25%), KazMunayGaz (20%), and LukArco (5%).

raising Kazakhstan's total oil output by 3.2% in 2013. But in 2014 national output declined again, by 1.2%, mostly due to TCO undergoing another round of maintenance, although TCO production was down only 2% in 2014. The Kashagan field remained shut-in and did not contribute to national output.

Much of the expansion of oil production in Kazakhstan over the past decade has been driven by two large projects, Tengiz (accounting for 33% of total national output in 2014) and Karachaganak (15% of total output in 2014), being developed by consortia that include major international oil companies as well as the national oil company, KMG. This is a trend that will clearly continue into the next decade with the re-launch of the first-phase development of the Kashagan field, slated to occur in late 2016 or 2017. Production by TCO has gone from 10.5 MMt in 2000 to 26.7 MMt in 2014, an increment of 16.2 MMt, while output at Karachaganak has increased during this period from 4.6 MMt to 12.1 MMt. The increment from these two fields alone provided 52% of the total national increment in output between 2000 and 2014.

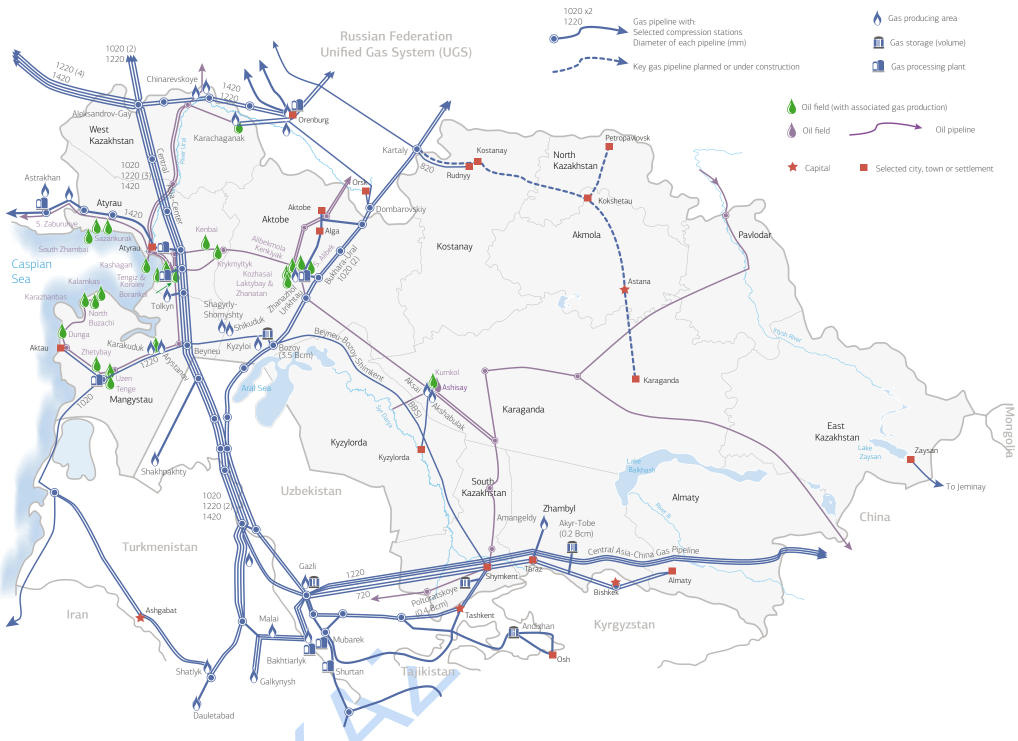
	2000	2005	2010	2011	2012	2013	2014	Percent change 2013-2014
Crude oil production	35.3	61.9	79.7	80.0	79.2	81.8	80.8	-1.2
Apparent domestic crude consumption	7.0	13.2	19.7	17.5	17.2	16.7	17.9	7.0
Refinery throughput	6.4	11.2	13.7	13.7	14.2	14.3	14.9	4.3
Direct use of crude/unidentified*	0.6	2.1	6.0	3.8	3.0	2.4	3.0	23.0
Crude oil exports	29.3	52.4	67.5	69.6	68.1	72.2	70.0	-3.1
Outside the Former Soviet Union	21.3	49.7	65.8	67.9	67.4	71.4	68.6	-3.9
via Russian pipeline system (non-Makhachkala)	10.6	14.8	15.5	15.4	15.4	15.4	14.6	-4.8
via Caspian Pipeline Consortium	-	28.2	28.5	28.3	25.3	28.7	35.2	22.6
via Atasu-Alashankou pipeline	-	-	10.1	10.8	10.4	11.8	11.8	0.2
via railroad	7.2	1.2	5.7	7.3	6.1	8.7	1.8	-79.7
via Russian railroad (to Finland, etc.)	6.4	0.4	5.7	7.3	6.1	8.7	1.8	-79.7
via Kazakh railroad to China	0.8	0.8	-	-	-	-	-	
via Caspian	3.4	8.1	9.3	5.8	7.6	6.0	5.2	-13.3
through Azerbaijan/Georgia	2.5	0.9	5.2	2.3	3.8	3.2	3.5	9.2
to BTC	-	-	-	-	-	0.6	2.4	285.1
to Iran (including direct shipments by rail)	-	1.4	0.5	0.0	-	-	-	
to Novorossiysk (via Makhachkala)	1.0	4.0	3.6	3.4	3.8	2.8	1.7	-38.5
Former Soviet republics*	8.0	2.7	1.7	1.7	0.7	0.9	1.4	63.6
Russia	6.1	2.6	1.2	1.2	0.7	0.9	1.4	63.6
via Karachaganak-Orenburg pipeline	4.6	2.6	1.2	1.2	0.7	0.9	0.7	-16.2
Crude oil imports	1.0	3.7	7.4	7.1	6.1	7.2	7.0	-1.6
Outside the Former Soviet Union	-	-	-	-	-	-	-	
Former Soviet republics	1.0	3.7	7.4	7.1	6.1	7.2	7.0	-1.6
Russia	0.9	3.7	7.4	7.1	6.1	7.2	7.0	-1.6
to Kazakhstan-China pipeline (official shipments)	-	-	2.6	0.2	-	-	7.0	

** Does not include sea-borne deliveries via the Black Sea to Ukraine.*
Note: Russian oil swap volumes in 2014 (7 MMt) are shown as imports and exports for Kazakhstan for comparative purposes with 2013.
Source: Compiled by IHS Energy from various official Kazakh and Russian sources: foreign trade statistics, pipeline and logistics statistics, etc.

Table 7.2.3 Crude oil balance for Kazakhstan (million metric tons)

The rest of Kazakhstan's national oil output (outside the three "mega" projects) can be described either by the size of the projects' output or by their geographical location. In terms of size, notable categories are core KMG producing assets, medium-sized producers with annual output between 2 and 6 MMt each, and small producers with annual output under 1 MMt. Geographically, Kazakhstan's producers can be divided into Turgay Basin producers, Aktobe Oblast producers, legacy west Kazakhstan producers (not to be confused with the Kazakh oblast of the same name), and other remaining small producers and joint ventures (JVs) (see Figure 7.2.4.).

National company KMG is a major oil producer. The company owns stakes in almost all significant oil and gas assets in Kazakhstan and has pre-emption rights to any divestments by existing license holders; legally, it must hold a 50% stake in all new offshore licenses in the country. KMG has a 20% share in the Tengiz project, a 16.9% share in the Kashagan project, and a 10% share in the Karachaganak project. The company also operates a number of legacy fields, with the most significant being the Emba, Zhetybay, and Uzen fields, within its 100%-owned upstream subsidiaries, UzenMunayGaz and EmbaMunayGaz.[11] Production from the legacy fields amounted to 8.18 MMt in 2014 and accounted for 10% of Kazakhstan's total 2014 production, while the total share of KMG (based upon equity ownership) in the country's oil production amounted to 27.7% in 2014%.[12]



Source: SEEPX Energy, IHS Energy

Figure 7.2.4 Map of Kazakhstan's major oil and gas deposits and associated infrastructure

A major challenge for KMG's legacy production is the company's relatively high production costs, particularly now in the current low oil price environment. For example, KMG disclosed in early 2015 that the breakeven price for its two core producing assets, UzenMunayGaz and EmbaMunayGaz, was $87 per barrel and $66 per barrel, respectively. There are many reasons for this, but the key problems revolve around mature fields that are now in decline, and require more extraction effort (higher water cuts, lower pressures, more pumping power, higher consumption of electricity, etc.). Related to this, of course, are relatively high staffing levels, a typical problem of national oil companies worldwide, resulting in high labor costs per unit of output.

Another group of significant producers, whose output ranges between around 2 MMt and 6 MMt per year, includes CNPC-AktobeMunayGaz, Buzachi Operating, KarazhanbasMunay, and three KMG JVs: KazGerMunay (KMG's share 50%), MangistauMunayGaz (KMG share 50%), and PetroKazakhstan Kumkol (KMG share 33%) and several others. These producers accounted for almost 30% of total national output in 2014.

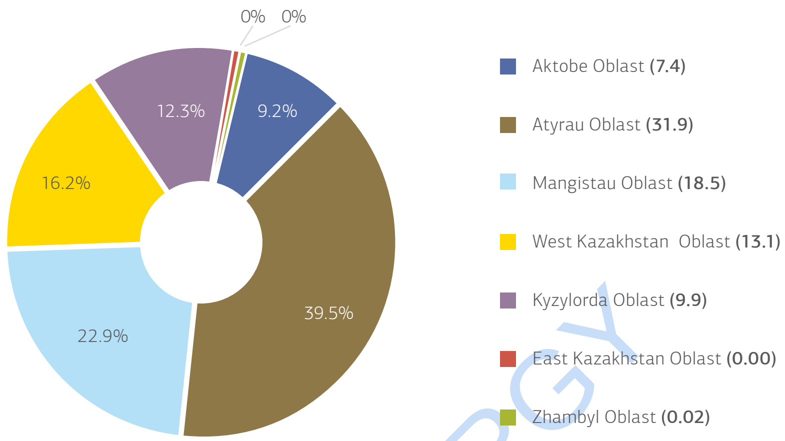
Finally, a significant contribution to the country's growth in production has also come from smaller developments. In 2014, all together small producers accounted for 10.0 MMt of output, representing 12.4% of the national total. In comparison, in 2000, this same category of producers had an output of only 1.2 MMt, representing a mere 3.5% of the national total. This reflects the fact that over the years, the number of these small producers has continued to proliferate (now numbering 70 that registered oil production in 2014) despite a relatively difficult investment climate.

[11] Fields worked during the Soviet period that now belong to KazMunayGaz.

[12] Legacy assets include UzenMunayGas, EmbaMunayGas, Amangeldy, and KazGPZ.

Geographical distribution of production

Kazakhstan's main oil-producing area is located in the northwestern portion of the country (Mangyshlak/Buzachi region in Mangistau Oblast as well as neighboring Atyrau Oblast), basically lying along the eastern littoral of the Caspian Sea. Oil production from Mangistau Oblast and Atyrau Oblast accounted for 63% of total Kazakh production in 2014 (see Figure 7.2.5.). Geologically, the Mangyshlak fields are located in the Mangyshlak Basin, and are a subsection of a much larger, fairly productive geological structure, the North Caucasus–Mangyshlak Basin (see above). Meanwhile, the fields found just to the north, on the Buzachi Peninsula, are part of a westward extension of an entirely different geological structure, the North Ustyurt Basin, although still in Mangistau Oblast. In contrast, oil production in Atyrau Oblast, West Kazakhstan Oblast, and Aktobe Oblast is from the North Caspian (Precaspian) Basin (see Section 7.1.2. Petroleum Basins). West Kazakhstan and Aktobe oblasts accounted for about 25% of total production in 2014. Crude oil and condensate is also produced in Kyzylorda, Zhambyl, and East Kazakhstan oblasts, accounting for the remaining 12% of total 2014 production.[13]



Source: IHS Energy

Figure 7.2.5 Kazakhstan's 2014 oil and condensate produciton by oblast (MMt)

7.2.3.1. Small producers—a critical source of growth that requires policy change to be realized

Just as Kazakhstan has worked to diversify its export routes, it has also sought to diversify its investor base as well. Investors from many different countries, representing a wide variety of companies, are now working on upstream projects in Kazakhstan. Despite this, Kazakhstan's production profile will remain dominated by its three "mega" projects, and the decisions by the small number of investors in these projects. But because of this, trends in national output have become more uncertain as growth has become so dependent upon the expansion plans and spending patterns of so few (big) projects. Large projects inherently tend to have more delays and uncertainties associated with them than an aggregation of many smaller projects. National output profiles therefore also tend to be less volatile when they reflect the cumulative effect of a larger number of smaller projects rather than a few big ones.

Moreover, experience around the world has demonstrated that smaller independents play an important, positive role in a nation's oil and gas industry. They operate in a more entrepreneurial fashion and often will look at prospects in new ways that lead to the development of new resource plays, which then become available to the larger companies. The independents also have an incentive to more intensively develop smaller fields that may not, in each case, be material to larger companies but that, when added up, have a noticeable impact on national output.

Kazakhstan actually has a large number of smaller producers, defined as those with production of less than 1 MMt of oil per year (about 20,000 b/d). Their cumulative share in national output remains minor, amounting to 10 MMt, or 12.4% of the national total in 2014. However, the smaller firms emerged as a dynamic force in the Kazakh production equation during the 2000s, more than doubling their share of total Kazakh production. The smaller companies' average annual production growth rate during 2000–2014 was 17.8%, compared with 7% for Kazakhstan as a whole during the same period. In the future, small producers possess the potential in their existing reserve base to contribute an even larger share of Kazakhstan's oil output, even without factoring in potential new discoveries in new projects.

[13] Hydrocarbon production in these oblasts is from other, smaller basins, such as the Turgay Basin in Kyzylorda Oblast.

Critical Success Factors

Although small companies have successfully expanded their oil production, their recipes for success vary, as do their ownership structures. Some are wholly owned by a foreign investor, others are partnered subsidiaries of the state company KMG, and many others were formed as joint ventures (JVs) between foreign and local partners. Still, in addition to good geological prospects and experienced management and personnel, four other factors appear particularly crucial to the success of smaller oil ventures in Kazakhstan: access to markets, proximity to transportation routes, access to financing, and a trusted and effective local partner.

Access to markets provides small companies with an opportunity to sell their crude to make a profit. Export prices have tended to be much higher than domestic prices in the past decade, and oil exports have provided a better netback than domestic sales despite higher transportation costs.

Yet in the past several years domestic and export prices have been converging. Crude prices realized in the domestic market (i.e., the price at which producers sell at the wellhead) have increased in the past decade in terms of both absolute value and also as a share of the export price. Whereas in 2001 the domestic crude price was about half of the export (Urals Blend) price, by 2014 the average domestic price amounted to about 70% of the export price. As a result, some small companies have been able to operate profitably even without any export sales.

Proximity to transportation routes. Proximity to main trunk pipelines or rail-loading points is crucial in keeping transportation costs down; outlays on transportation by these producers have risen rather steeply in recent years.

Access to financing. Crucial for implementing both exploration and production activities, financing has tended to become more problematic over time. During the early post-Soviet era, foreign companies active in Kazakhstan were able to tap into foreign capital markets with relative ease. However, organizing funding is now more difficult, especially for smaller companies, following the adoption of new and more restrictive financing requirements since 2009.

A trusted and effective local partner. Having a knowledgeable and capable partner is especially valuable in Kazakhstan given the country's complex bureaucratic and regulatory environment. In short, partnering with a local company that can navigate vague and changing state requirements has proven to be vital to success in Kazakhstan.

Fiscal, Regulatory, and Other Challenges

Despite their relative proliferation and moderate success, all companies (but especially small ones) face significant challenges in Kazakhstan, as the government began introducing tougher business regulations in the past decade. The main result of this shift has been to reinforce the state's role in the oil and gas sector by increasing the scope of activities of KMG and legislation that allows greater government control over asset sales and upstream activity in general. This policy shift affected all Kazakh oil producers, but smaller companies in particular, and is manifested in four key challenges:

- **Rising fiscal burden.** Since 2000, the general fiscal pressure on Kazakh oil producers has increased as the government sought to increase revenues from the oil and gas industry, particularly following the introduction of the new Tax Code in 2009 (see Section 7.5 on Hydrocarbon Taxation). In 2007–2008, for example, Kazakhstan introduced an export duty. At one point in the second half of 2008, the export tax climbed to $140 per ton, even as international oil prices plunged, leading some of the smaller producers to shut in production. Subsequently the duty was suspended and then reinstated at a much lower level (initially set at $20 and then at $40 per ton, but raised to $60 per ton in April 2013 and further to $80 per ton in April 2014) following the recovery in international oil prices during that period. The export duty was reduced to $60 per ton in March 2015, however, to reflect the decline in global crude prices. The government ultimately responded to producers' complaints as oil prices fell during the global recession in 2008–2009 and again in 2015, adjusting the level of the duty to avoid a decline in production.

  Investors have confronted uncertainties as to their tax obligations and a risk that the government will revisit their contract terms and apply new taxes retroactively. Following the introduction of the Tax Code, the government began to revise all subsoil contracts, including PSA contracts, in an attempt to harmonize older agreements with the new tax code. The Tax Code subjects all new hydrocarbon development projects to a mineral extraction tax based on output and an export rent tax tied to world oil prices. Particularly for smaller companies, which generally have less available cash flow in the earlier (investment) phase of their projects, unpredictability of tax stability is problematic as they have less ability to weather fiscal uncertainty.

  PSAs signed prior to 2010 are supposed to remain valid, at least for projects deemed geologically complex or strategically important. But the PSAs that have thus far been "grandfathered" still may be unilaterally terminated by the state if judged a "national and economic threat" (according to criteria that have not yet been specified). The government has also challenged the legitimacy of some previously concluded PSAs on the grounds that they have not gone through an obligatory tax review procedure, although no review was required when the original PSAs were concluded. In 2011, for example, a number of projects operating under PSAs were terminated as the exploration phase expired. Although these steps were taken to strengthen and protect the interests of Kazakhstan, they inadvertently created a sense of uncertainly in the investor community that figures prominently when decisions to invest in a country are made.

  Additionally, oil and gas companies working in Kazakhstan contribute to social and economic development of the country not only through taxes, but also through expenditures on research and development (R&D), and training and social programs. In accordance with Law 291-IV On Subsoil and Subsoil Use, oil and gas companies are obliged to invest at least one percent of the total annual income or one percent of annual capital investment on local personnel training as well as research and development projects through local providers of goods and services. Most subsoil contracts include clauses that also specify amounts of spending on local social and economic development projects, development of infrastructure, commitments to local content, and personnel training.

- **Property and contractual issues.** In 2005, the government amended Kazakhstan's subsoil legislation to ensure preemptive rights in oil asset sales, enabling KMG to acquire stakes in key projects as the buyer of first resort. Two other licensing regulations imposed in 2007 had a more significant impact on smaller producers than on larger ones, narrowing the definition of license holders' rights:

  — A law introduced in January 2007 requires license holders to hold their assets for at least two years before selling the licenses to a third party—except in cases where the acquiring party is a Kazakh national company. This action was implemented with the aim of reducing speculation in assets and improving the prospects for development.

  — A February 2007 amendment to the Resources Utilization Law enabled the state to prohibit a company from participating in a tender if "giving the right to develop a deposit would lead to its noncompliance with enforcing national security." To date the government has not exercised this particular clause, but it remains an issue that inhibits prospective bidders.

  In December 2014 Kazakhstan updated its Subsoil Law, which governs available types of subsoil use contracts. If before there were uncertainties regarding the rights to develop any new fields that a company might discover, with the new amendment there is an option for a combined exploration and production license, although separate exploration and production licenses remain available. The law stipulates a number of ways that in the event a "significant" discovery is made, the contract can still be revised to reflect the economic interests of the state. The law also stipulates that the government may unilaterally terminate a contract of a strategically important field, if the subsoil user's actions could lead to impingement of the economic interests of Kazakhstan and thus pose a threat to national security. Kazakhstan maintains a list of fields of strategic importance that fall under this provision, including over 40 hydrocarbon fields at last report. A strategic field is considered to contain over 50 MMt of oil or over 10 Bcm of gas.[14]

- **Environmental policy.** Kazakhstan's associated gas utilization requirements illustrate the tendency of state authorities to emphasize punitive measures instead of incentives when formulating environmental policy. These measures include very strict utilization requirements even though local gas markets remain poorly developed and gas offtake prices remain quite low. For smaller companies, the obstacles to effective utilization and monetization of associated gas are often imposing, given the relatively minor and noncommercial volumes frequently involved (compared with the associated gas production of larger oil companies).

  Kazakhstan's emerging regime for regulating greenhouse gas (GHG) emissions represents another source of growing environmental costs for oil companies in Kazakhstan (including some small producers), at least through time lost on new paperwork to meet official requirements. Specifically, effective January 2013, companies emitting more than 20,000 metric tons of CO_2 equivalent annually must apply for emissions quotas covering different periods of time till 2020 (see Chapter 13).[15]

- **Project delays and government interference.** Oil companies, big and small, in Kazakhstan confront another set of challenges arising from the bureaucratic character of Kazakhstan's state structure, including delays from lengthy permitting processes and inspections. The costs associated with these issues are proportionally much higher for small oil producers given their relatively limited personnel and expense budgets.

  Oil companies are subject to multiple layers of governmental oversight, which creates confusion as to exactly what the various state requirements are, as well as problems of overlapping authority (see Chapter 3). Companies must comply with regulations issued by both the central government and local authorities, and in some cases the latter have the right to increase fines several-fold compared with the base fines instituted at the central level (penalties for gas flaring are an example).

  Periodic reorganization of Kazakh state structures also typically sets back the timetable for completion of government paperwork and approvals related to company projects. For example, in 2010 the Ministry of Energy and Mineral Resources was reorganized into the Ministry of Oil and Gas, resulting in delays at all levels of the decision-making apparatus until the new responsibilities and lines of authority were clarified. Similar delays occurred after August 2014, with streamlining of various ministries into five core ministries and consolidation of the Ministry of Energy.

  At the same time, the Kazakh government has made some attempts to streamline its regulatory framework for the benefit of small companies (along with others). For example, the procedure for registering a business has been substantially improved. The government has also introduced an automated electronic system that tracks companies' local content requirements.

....

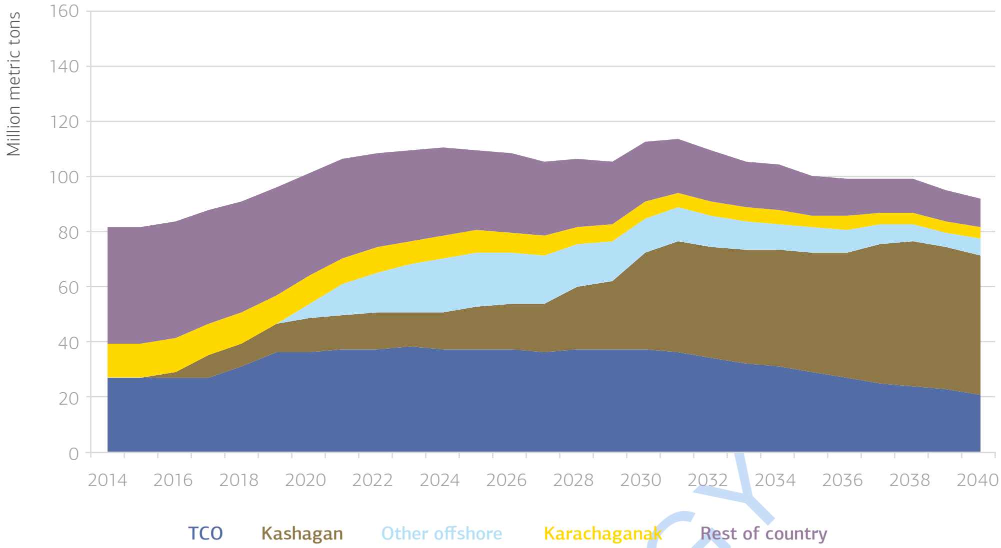
[14] The Kazakh decision to separate exploration and development licenses paralleled Russian practice. The Kazakh law's "strategic" field clause also is similar to a provision in Russia's 2008 law on foreign investment in strategic sectors. However, the option to have a unified license is an attractive feature for investors, as it reduces uncertainty; this is an improvement not yet available in Russia.

[15] The scheme, originally planned for implementation in 2013, was postponed after foreign investors and the domestic business community expressed opposition. Investors objected that they already pay various taxes for CO_2 emissions in the country, as well as administrative penalties and damage recovery sums. Domestic industrialists, who wish to attract foreign investment, complain that the emissions trading scheme (ETS) introduces an element of uncertainty into the business environment, complicating efforts to plan budgets and forecast rates of return. Government officials have promised to loosen emissions targets and soften penalties for noncompliance when the new ETS is rolled out.

7.2.4. Oil production outlook

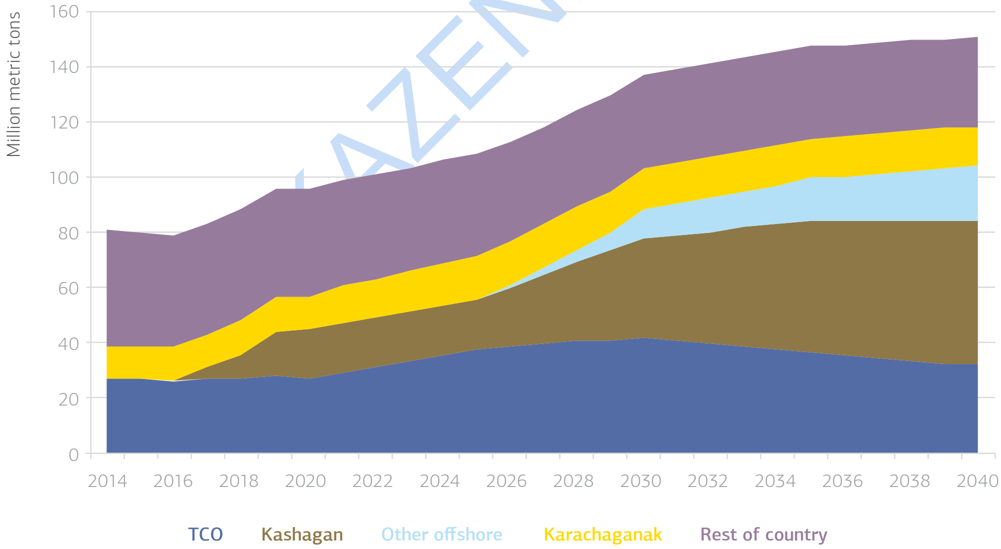
7.2.4.1. Official forecast and IHS forecast

The Energy Ministry's most recent oil production forecast (issued in April 2015) differs significantly from the current base-case IHS Energy forecast (issued in March 2015). The Ministry projects total crude production at 91.5 MMt (1.83 MMb/d) in 2040, whereas IHS projects national output to reach 150.5 MMt in the same year (3.01 MMb/d), a difference of 59 MMt (1.2 MMb/d) (see Figure 7.2.6. and Figure 7.2.7.).



Source: Ministry of Energy, Republic of Kazakhstan

Figure 7.2.6 Energy Ministry's outlook for Kazakhstan's oil-condensate production, March 2015



Source: IHS Energy

Figure 7.2.7 IHS Energy's oil-condensate production outlook for Kazakhstan (base case), March 2015

The key differences in the general assumptions underlying these forecasts are as follows:

- **Legacy fields' production in the Ministry's forecast is projected to decline steadily, and at a fairly brisk pace.** For example, MangistauMunayGaz output declines from a projected 6.2 MMt in 2015 to 4.7 MMt in 2025 and to 3.0 MMt in 2035. This represents an average annual decline rate over the 20-year period of 3.6%. Other legacy fields in aggregate display a similar declining trend. However, IHS envisions more attenuated declines in legacy production, basing this forecast on general tendencies seen in other mature fields globally.[16] But critical in this is implementing additional incentives for operators to intensify recovery activities at older, mature fields, such as special tax incentives. When coupled with the ability to bring in new oil recovery technologies, these can help prolong the life of older fields and improve the recovery rate at hard-to-recover deposits.

- **Karachaganak output in the Ministry's forecast declines from 12 MMt in 2015 to 7.2 MMt in 2025 and to only 4.8 MMt in 2035 (an average annual decline of 4.5%).** The underlying assumption is based on no further field expansion, where liquid hydrocarbons production declines while the gas ratio increases. In contrast, IHS sees a generally flat liquids production profile for Karachaganak, with production declining slowly after 2025 following another expansion phase. IHS sees Karachaganak as a still somewhat under-produced field, with remaining recoverable liquid reserves constituting about 61% of total recoverable reserves of the field.[17] But the specifics of the expansion concept remain undefined and uncertain at this time.

- **Offshore production.** The Ministry expects "other offshore" production, namely the Zhemchuzhina field and Project "N," coming online quite quickly, as early as 2019 followed by a fairly rapid production ramp-up in the period to 2025, after which production begins to decline. IHS sees the other offshore blocks[18] coming on-stream much later, around 2026, with a much slower ramp-up, reaching 15.5 MMt in 2035.

- **Kashagan Phase 2.** Both the Ministry's and IHS forecasts envision sanctioning of Kashagan Phase 2 expansion.

- **TCO** production in the Ministry forecast reaches its peak already in 2021 at 37.8 MMt, and then holds at a plateau of around 36.8 MMt from 2026 through 2031, after which TCO production begins to decline quite rapidly, falling to 29 MMt in 2035. In the IHS base-case, TCO production rises only after 2021 when the Future Growth Project expansion is launched, reaches a maximum of 42 MMt in 2030, and then declines slowly to 36 MMt in 2035.

- **Yet-to-find production.** The IHS base-case also includes a category of "yet-to-find" future production—that is, production from new fields yet to be discovered as a result of ongoing exploration activities. This is a typical convention for long-term oil production forecasts.[19] The IHS forecast also includes production from development of new fields/reserves that are expected to be discovered by existing license holders longer term. In contrast, the Ministry forecast includes output only from existing producers from existing or known resources.

In summary, the base-case IHS forecast for 2040 is higher because it assumes a later start-up of some projects, a more attenuated output decline in mature fields (or those approaching maturity), and "yet-to-find" future production from revived exploration activities and discoveries from existing license holders. The Ministry forecast takes a more conservative approach, while the IHS forecast is predicated on the implementation of the recommendations of this report in key policies.[20]

7.2.4.2. Kazakhstan's oil production outlook in the IHS forecast

The recent sharp decline in global crude oil prices and the continued delay in bringing the Kashagan field onstream have undoubtedly dampened the general prognosis for Kazakhstan's oil production. But the situation in the upstream going forward, although challenging, remains far from gloomy. Kazakhstan still has significant reserves potential, but policy needs to be recalibrated to more effectively encourage exploration and to incentivize producers to invest and expand their operations in Kazakhstan, especially smaller and medium-sized ones.

Kazakhstan's crude oil production is projected to increase substantially in the period to 2035 under the base scenario, though not as much as previously assumed given the Kashagan delay. In fact, much of the overall growth in CIS crude oil output between now and 2040 is expected to come from Kazakhstan. In the base-case, Kazakh oil production is projected to grow from 80.8 MMt (1.7 MMb/d) in 2014 to 95.4 MMt (2.0 MMb/d) in 2020, to 147.2 MMt (3.12 MMb/d) by 2035, and to 150.5 MMt (3.2 MMb/d) by 2040; this represents an average annual rate of growth of 2.4% over the 2015–2040 outlook period (see Figure 7.2.8.).

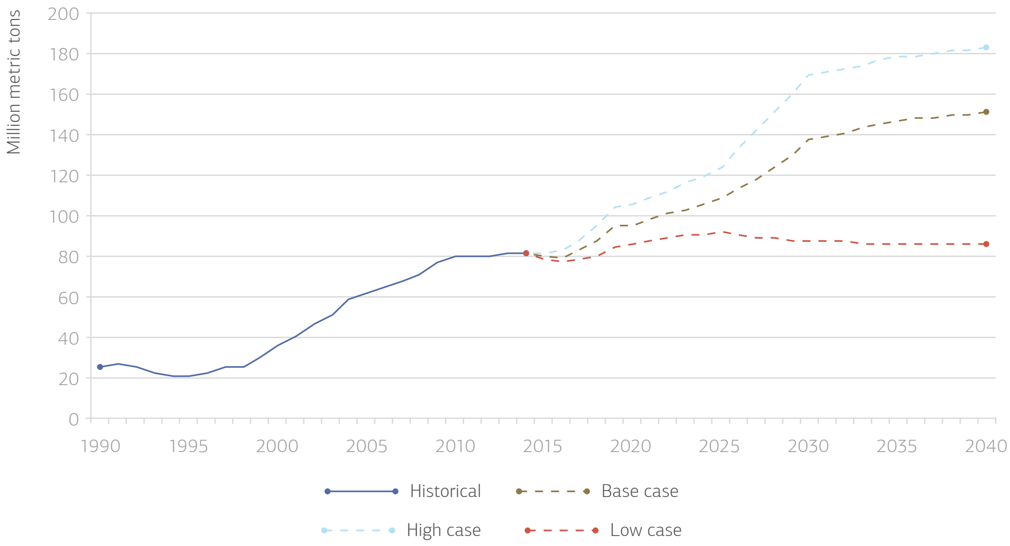
[16] See the IHS Energy Private Report, Finding the New Critical Numbers: Estimating the Burden of Global Production Attrition, January 2012.

[17] This includes oil and condensate reserves.

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

[19] See the IHS Energy Special Report, The Future of Global Oil Supply: Understanding the Building Blocks, November 2009; the IHS Energy Private Report, Pausing for Breath Part 2: Understanding the Building Blocks of Capacity Through 2030, November 2009; the IHS Energy Decision Brief, Pillars of Supply—A Balancing Act for the Future, June 2008; and the IHS Energy Private Report, Russian Oil Production Outlook: Can the Recent Rapid Rise Be Sustained, and for How Long?, February 2005.

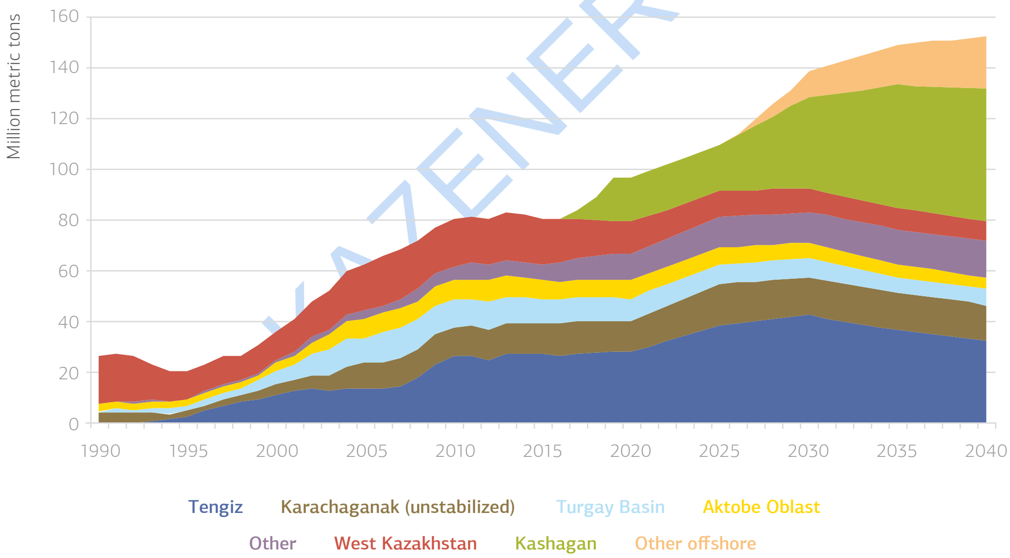
[20] The IHS oil production outlook also is consistent with the IHS long-term crude oil price forecast, which sees global prices returning to an average price of about $105/bbl in the long term.



Source: IHS Energy, EOEO

Figure 7.2.8 Outlook for Kazakhstan's oil production by scenario

As noted above, the principal developments driving Kazakhstan's overall oil production trend will continue to be the three "mega" projects: Tengiz, Karachaganak, and Kashagan (see Figure 7.2.9.). Given that the contracts for these projects expire in 2033, 2037, and 2041, respectively, to ensure that the long-term productive potential of these projects is realized, policy needs to include provisions for continued investments and effective operation. This may include contract extensions to provide sufficient payback period or other contract adjustments.



Source: IHS Energy

Figure 7.2.9 Kazakhstan's oil production outlook, base-case

Besides these three big projects, a host of smaller projects also figure in Kazakhstan's oil development going forward, albeit less prominently. The overall forecast is built up from developments in eight main categories of producers, either major projects by themselves or grouped together by location, crude quality, or type of operation. These are described in more detail below.

Overview of IHS Energy's Base, High, and Low Oil Production Scenarios for Kazakhstan

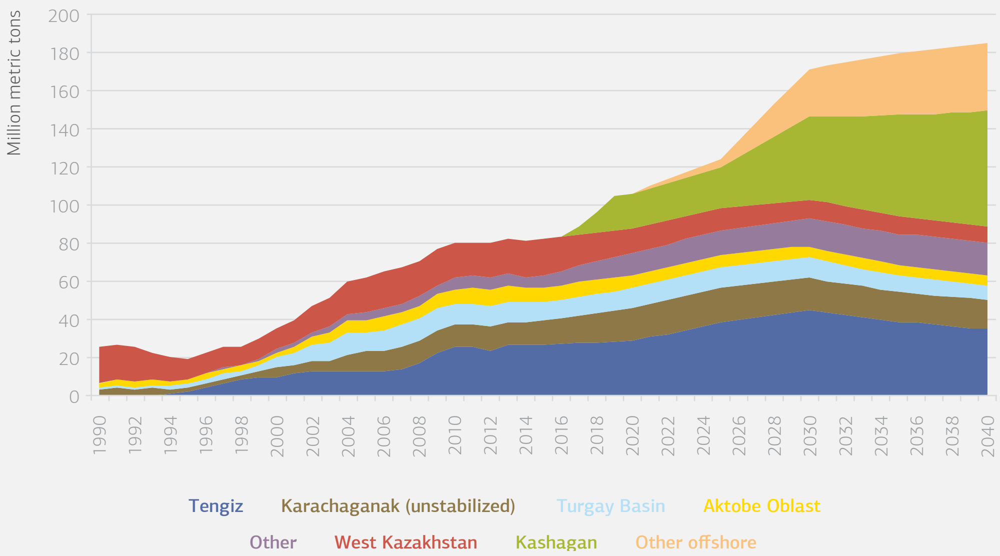
Major projects run by international companies in Kazakhstan benefit from IHS Energy's access to credible, probabilistic production outlooks from informed sources close to these projects. There is, of course, considerable uncertainty attached to such production outlooks, but this derives from the inherent uncertainty of field development rather than from difficulties in access to information.

Projections for state-operated production are less certain. They are based on official outlooks when available, filtered through IHS Energy's own views of what may or may not be realistic given geological potential, capital availability, and other factors such as logistics and politics. For oil production, in our base-case IHS Energy has tried to approximate a so-called P50 outlook: the actual results have an equal likelihood of being higher or lower than the base-case projections. The high case figures approximate a P90 outlook: the actual results have a 90% probability that they will be lower than the outlook numbers. Similarly, the low case is intended to approximate a P10 outlook: the actual results have only a 10% probability that they will be lower than the outlook numbers. These probabilities are intended only as rough guides in interpreting the production projections.

Experience demonstrates that publicized development plans for relatively new, pioneering regions such as the North Caspian basin tend to be optimistic about timing—schedules often slip because of infrastructure constraints as well as disagreements that delay decision making. Such development plans also often turn out to understate ultimate production volumes, given what seems to be a natural inclination toward conservative initial estimates of well productivity and ultimate recoverable reserves. We have built these tendencies into our outlooks from the outset.

In the base scenario, existing development projects in Kazakhstan proceed more or less as intended, but not entirely so: a variety of constraints and difficulties create small but significant delays and thus production shortfalls for particular years relative to what is currently announced. In the base-case, total crude production in Kazakhstan is projected to grow from 80.8 million metric tons (MMt) (1.7 million barrels per day [MMb/d]) in 2014 to 95.4 MMt (2.0 MMb/d) in 2020 and to reach 150.5 MMt (3.2 MMb/d) in 2040; this represents an average annual rate of growth of 2.4% during 2015–2040 (see Figure 7.2.9.).

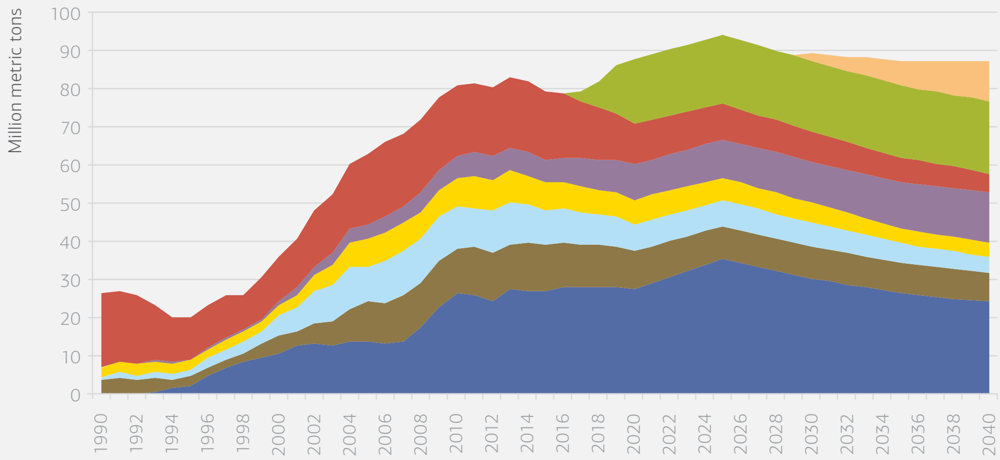
In the high scenario, development is assumed to proceed more smoothly, without significant delays, and producers exceed their currently envisioned "probable" production profiles as a result of productivity that is higher than initially expected. Under this scenario total production in Kazakhstan is projected to grow even more substantially, from 80.8 MMt (1.7 MMb/d) in 2014 to 105.3 MMt (2.2 MMb/d) in 2020, and to reach 183.0 MMt (3.9 MMb/d) in 2040; this represents an average annual growth rate of 3.1% over the outlook period (2015–2040) (see Figure 7.2.10.).



Source: IHS Energy

Figure 7.2.10 Kazakhstan's oil production outlook, high case

In the low scenario, development proceeds more slowly than in the base-case because of more significant delays. Total production in Kazakhstan is projected to remain fairly flat over most of the outlook period, with output projected to be at a lower level over the outlook period. In this scenario, Kazakh oil output regional output rises to a maximum of 92.3 MMt (1.95 MMb/d) in 2025 and declines thereafter, falling to 86.0 MMt (1.8 MMb/d) in 2040 (see Figure 7.2.11.). This represents an average annual growth rate of only 0.2% during 2015–2040. Although all of the upstream components differ between the three scenarios, the key difference for the low case is that it does not assume Kashagan Phase 2 is sanctioned.



Source: *IHS Energy*

Figure 7.2.11 Kazakhstan's oil production outlook, low case

There is, however, a major source of uncertainty in the Kazakh outlooks that should be highlighted: the potential contribution of currently undeveloped or undiscovered fields, mainly offshore. IHS Energy has made conservative (although not overly pessimistic) assumptions about the contribution of such fields by 2040. It seems sensible from a general planning perspective not to build in huge amounts of undeveloped or undiscovered (and thus speculative) production. Still, by 2040, the conservative high scenario sketched in above overtakes the base-case scenario in which there would be considerable exploration success offshore. The discovery and relatively rapid development of several sizeable fields in the Caspian offshore area could make the current high case outlook look low by 2040.

Tengiz

The mid-2008 completion by TCO of the second-generation plant and the sour gas injection (SGP/SGI) projects nearly doubled the Tengiz production rate, to over 550,000 b/d. Annual production rose from 17.3 MMt (376,000 b/d) in 2008 to 25.9 MMt (564,000 b/d) in 2010; project output declined slightly in 2011 and 2012 (due to maintenance work), falling to 24.2 MMt (527,000 b/d) before rebounding in 2013 to 27.1 MMt (590,000 b/d). In 2014 TCO produced 26.7 MMt (582,000 b/d) (see Figure 7.2.9.).

Under the base scenario, output is expected to remain relatively flat in the next few years, with scheduled maintenance dictating specific output fluctuations. Production growth is expected to resume in 2021. This is due to a new phase of expansion, the Future Growth Project (FGP), which includes construction of a third Tengiz crude processing plant, and is designed to add another 12 MMt per year (260,000 b/d) to the overall production capacity of the field. After considerable discussion, this expansion was finally approved by the responsible government entity in early October 2013, and Kazakhstan's Energy Minister confirmed that the government agreed "in principle" to the project in October 2014. But the cost of the project has now ballooned to about $40 billion compared with the initial estimate of $23 billion submitted the year before. The government has initiated negotiations with TCO in an attempt to reduce the overall cost of the project. Assuming a final investment decision (FID) for the FGP project is made in 2015, the first oil from the expansion project is expected only after 2021.

Under the base-case scenario, TCO production expands from 27.5 MMt (599,000 b/d) in 2020 to reach 37.9 MMt (825,000 b/d) in 2025 and a maximum of 42.0 MMt (915,000 b/d) in 2030 before gradually declining to 32 MMt (697,000b/d) over the next decade (some debottlenecking is assumed over this period). In a high scenario, TCO production reaches a higher maximum, of 45.0 MMt (980,000 b/d) in 2030, followed by a decline over the following decade, to 35 MMt (762,000 b/d) by 2040. In an alternative low scenario, a smaller contribution by FGP and other debottlenecking projects is envisioned, so that TCO production rises to a maximum of only 35.0 MMt (762,000 b/d) in 2025 before declining to 24.0 MMt (523,000 b/d) in 2040. TCO production is not projected to drop sharply after reaching peak production, but rather a gradual decline is projected. Economically, it is most sensible to maximize production potential available as quickly as possible following investment into the field.

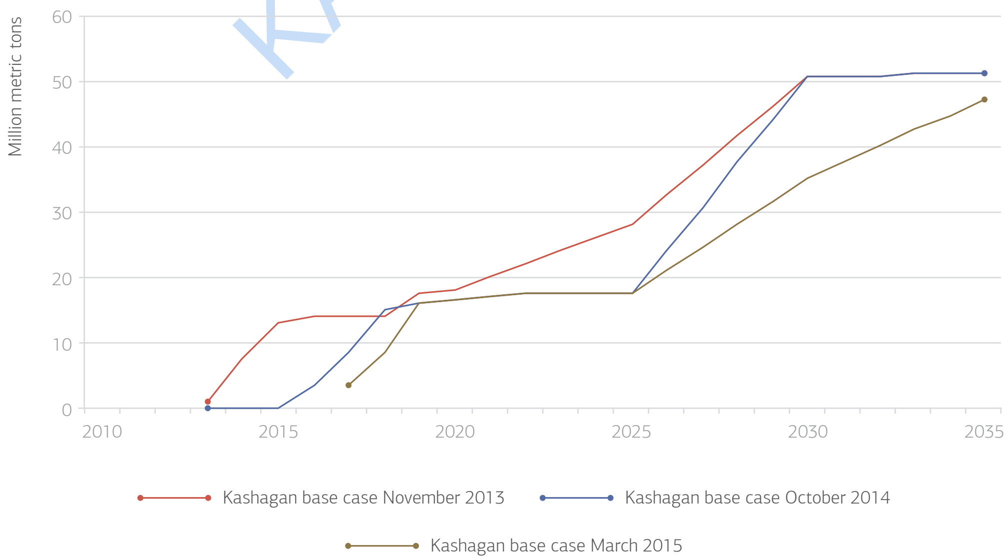
Karachaganak

Karachaganak's annual production has been basically flat since 2007, fluctuating in a range between 11.4 MMt (260,000 b/d) and 12.2 MMt (279,000 b/d); (gross) output in 2014 was 12.2 MMt (279,000 b/d). Karachaganak's fourth stabilization train (part of the project's second expansion phase), installed in 2010, increased the project's export capacity to international markets to 10.3 MMt (234,000 b/d) of liquids. Several years ago, the partners developing the project decided to postpone the launch of the third phase, which was originally slated to be completed by the end of 2012. A new concept for the third phase of the project is being developed following the entry of KMG into the project (acquiring a 10% stake in June 2012). It should be pointed out that Karachaganak condensate loses approximately 18–19% of its extracted volume in the process of stabilization undertaken at the field (or at Russia's Orenburg gas processing plant). This significantly reduces the liquids volumes available to flow into pipelines or other export systems (see the section "Karachaganak-Orenburg Gas Processing Plant Relationship" for more information). Stabilization is a crucial step in preparing condensate for pipeline transportation.

Kashagan

The restart of the offshore (Caspian Sea) Kashagan field, expected by end of 2016 - early 2017, is another factor supporting an overall increase in Kazakh oil production going forward. It is one of the 10 largest oil fields discovered in the world in recent years, and its development is one of the largest projects worldwide in investment and scope. The field is expected to be a major source of oil growth over the next two decades, not only in Kazakhstan but also within the CIS and globally as well. First oil at Kashagan was achieved in September 2013, and the field developers announced that "commercial" production was achieved in early October; but immediately thereafter, the field was shut down, owing to pipeline leaks. A subsequent investigation of the problem traced the leaks to pipeline cracks resulting from sulfide stress cracking. On account of extensive corrosion, the consortium is now in the process of replacing the oil and gas pipelines between the field and the onshore Bolashak processing plant, a total of about 190 kilometers (km) of pipe.

In February 2015 the NCOC consortium awarded a contract worth $1.8 billion to a Saipem-led joint venture for engineering and construction work to lay two 96-kilometer pipelines. The contract's estimated completion date is December 2016, although Kashagan is unlikely to resume operations in mid-winter, and would most likely wait for start-up until the following spring when the ice has melted. Hence the base-case outlook assumes that Kashagan production resumes in the first half of 2017, with a ramp-up to the design level for Phase 1 of about 17.2–17.6 MMt per year (365,000–370,000 b/d) by 2020–2021 (see Figure 7.2.12.). Kashagan's development involves the reinjection of much of the high-sulfur associated gas that is produced to support reservoir pressure and maximize liquids production. (On the importance and usefulness of gas reinjection, see the box on gas reinjection in the natural gas section.)



Source: *IHS Energy, EOEO*

Figure 7.2.12 Kashagan's production outlook: changing expectations

The key question for Kazakhstan's oil production profile longer term is the implementation of the second phase of the project (designed to drive production at the field to over 1 MMb/d, or 47 MMt per year). Phase 2 has not yet been sanctioned, and understandably any decision will be taken after Phase 1 re-starts and is operating smoothly. Economic analysis of the Kashagan project, which involves nearly $50 billion in capital expenditure for just the first phase, indicates that under IHS Energy's base-case expectation for global oil prices, longer-term project profitability is positive for the consortium, but quite low, so that Phase 2 faces considerable risk of not being sanctioned. Nevertheless once Phase 1 production begins, some type of compromise would appear to be possible on Phase 2, enabling it to go forward. This is because of its overall importance to both Kazakhstan and the companies involved. The key elements of such a compromise would likely involve an extension of the PSA, to allow the companies more time to recover the extra costs, and probably some compromises on fiscal issues as well.

In the IHS base-case, Phase 2 production is expected to start up after 2025, so that Kashagan's 2030 production amounts to 35.8 MMt (760,000 b/d), 2035 output is at 48.0 MMt (1.019 MMb/d), and 2040 output reaches 52.0 MMt (1.1 MMb/d). If Phase 2 is never sanctioned (i.e., a low scenario is assumed), then Kashagan production reaches only 17.5 MMt (372,000 b/d) in 2025 and stretches only to 18.5 MMt (393,000 MMb/d) through some debottlenecking. In the (optimistic) high production case, the buildup of Phase 2 is somewhat more rapid and brings production up to 42.5 MMt (0.9 MMb/d) in 2030 and 60.2 MMt (1.28 MMb/d) in 2040.

Turgay Basin producers

The Turgay Basin is a major oil-producing region in Kyzylorda Oblast in the south-central part of the country. There are a half-dozen or so significant discovered fields (of which Kumkol is the largest) and a number of prospective structures as well. The Turgay Basin crude tends to be high-quality in terms of density and sulfur content, although relatively high in paraffin content. The liquids produced at the Amangeldy gas field in southern Kazakhstan (Zhambyl Oblast) are also included within this category because of the field's general geographical location. This category of production includes 13 producing entities in the region (plus Amangeldy), the most important of which are:

- PetroKazakhstan Kumkol Resources (now a subsidiary of the state-owned China National Petroleum Corporation [CNPC], jointly owned with KMG following the acquisition of the Canadian-based company formerly known as Hurricane Hydrocarbons in autumn 2005)
- Turgay Petroleum (a JV between PetroKazakhstan and Russian oil major LUKOIL)
- KazGerMunay (now a 50:50 JV between PetroKazakhstan and KMG)
- CNPC-owned CNPC Ai-Dan Munay
- Small Kazakh independents Kuatamlonmunay, Sauts (South) Oil, KOR, and Kumkol Transervis.

Production in the Turgay Basin has been somewhat volatile over the past decade. It declined in 2005 because of the need to cut back oil production following both the enactment of a new law that restricted associated gas flaring and a legal dispute that erupted between PetroKazakhstan and one of its JV partners, LUKOIL. But these situations were apparently resolved with CNPC's acquisition of PetroKazakhstan in 2005. Regional production bounced back to 10.9 MMt (230,000 b/d) in 2012 but has declined slightly in 2013 and 2014. Production reached only 10.6 MMt (224,000 b/d) in 2013 and 9.9 MMt (209,000 b/d) in 2014. In the base-case, which assumes a moderately pessimistic geological position, the Turgay Basin production decline that began in 2013 continues, albeit slowly, and output falls to 6.0 MMt (127,000 b/d) by 2040.

Aktobe Oblast producers

Oil production in Aktobe Oblast traditionally comprised the output of just one company, CNPC-Aktobemunaygaz, based on the Kenkiyak and Zhanazhol fields. CNPC has owned and operated this company for nearly two decades, and its investment and development activity has more than doubled production from the low point in 1999. Another producer, Kazakhoil-Aktobe, went into operation in 2002, with others following in recent years, for a total of 17 producing companies by 2014. Kazakhoil-Aktobe was a JV between KMG and an international independent, Nelson Resources. But Nelson Resources was acquired by LUKOIL at the end of 2005. Production in Aktobe Oblast declined in 2006–2008, but rebounded slightly in 2009 and then rose more significantly in 2010–2013. However, output fell by 11% in 2014, to 7.4 MMt (156,000 b/d).

The base-case assumes some production decline in Aktobe Oblast from the 2014 level, but at a fairly slow rate. By 2035, production in the area declines to 5.0 MMt (105,000 b/d) and by 2040 it declines to 4.5 Mmt (95,000 b/d).

Legacy producers in western Kazakhstan

Production in western Kazakhstan (not to be confused with the Kazakh oblast of the same name) covers the output of five legacy producers: the Soviet-era producers UzenMunayGaz, MangistauMunayGaz, and EmbaMunayGaz plus CNPC International/Buzachi Operating (previously owned by Texaco and then Chevron but now jointly owned by CNPC and LUKOIL [through its acquisition of Nelson Resources]) and KarazhanbasMunay. These producers are grouped together because of their location (all are in Mangistau Oblast except for EmbaMunayGaz) and similar crude quality (basically heavy Mangyshlak or Buzachi crude) and general production dynamics as mature operations. In the base-case, output by this group will continue the general decline that began in 2006–2007 (with only a slight uptick seen in 2012–2013). Output in 2035 for the group is projected to fall from a 2014 production of 18.6 MMt (354,000 b/d) to 8.2 MMt (156,000 b/d) and by 2040 to decline further to 7.0 MMt (133,000 b/d).

Other producers (small producers and JVs)

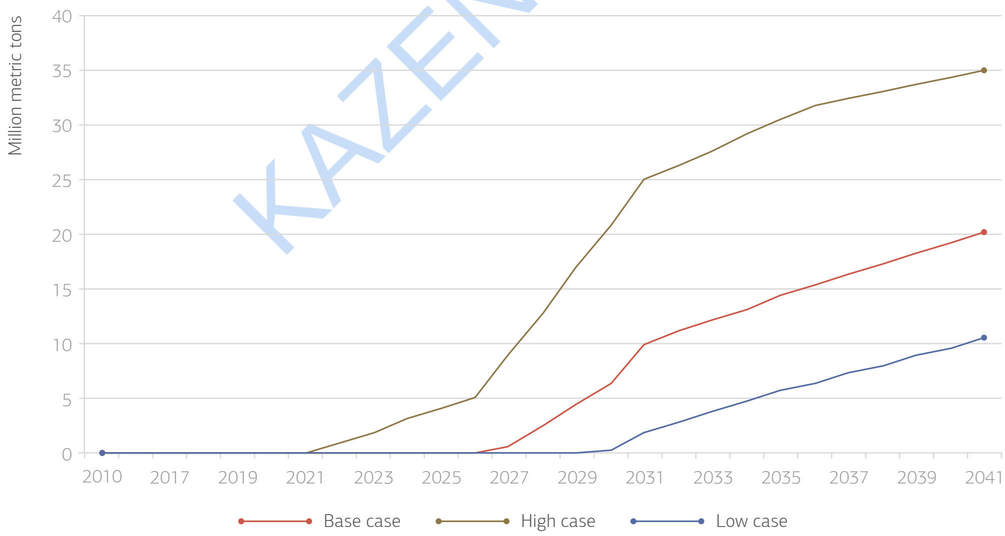
The remainder of onshore producers not mentioned above is included in a category of "other producers," which comprises projects run mainly by small JVs and other international independents. These projects are located predominantly in western Kazakhstan (mainly in Atyrau and Mangistau oblasts), such as Sazankurak, Emir Oil, and Arman. Their output declined slightly in 2012–2014, but going forward is expected to maintain moderate, steady growth, from 6.0 MMt (115,000 b/d) in 2014 to 13.5 MMt (259,000) by 2035 and 14.8 MMt (284,000 b/d) by 2040 in the base-case. This outlook is based largely on the strength of relatively conservative estimates of the reserve base and production growth potential of this diverse set of operations. Potential for this category to increase production is tied in part to policy decisions that could encourage small producers to flourish.

Other offshore producers (excluding the Kashagan field)

This category consists of all offshore production except for the Kashagan field itself. Kazakhstan's offshore area probably represents the country's greatest potential for significant oil discoveries. Since production from these fields will be driven largely by a combination of geology and investment conditions, the range of production possibilities is very broad. However, rather than exploring more extreme scenarios, three outlooks for new developments in the Kazakh offshore presented below fall within a relatively narrow band. The general outlook assumes some significant exploration success but also assumes that no new discoveries on the scale of Kashagan are made (see Figure 7.2.13.).

The "other offshore" category includes three types of offshore projects:

- Already-discovered fields within the North Caspian Operating Company license area (e.g., Kalmkas-More, Aktote, Kairan); movement on development of at least one of these other offshore fields has gotten under way, but obviously the timing and pace of development is going to be heavily influenced by larger Kashagan issues such as an extension of the production-sharing agreement.
- Joint 50:50 offshore projects between Russia and Kazakhstan (e.g., Tsentralnoye, Kurmangazy).
- Other projects involving prospective offshore blocks, usually being pursued as JVs between KMG and international investors (e.g., Nursultan, Abay, Satpayev, Isatay).



Source: IHS Energy, EOEO

Figure 7.2.13 Outlook for Kazakhstan's offshore oil production by scenario, excluding Kashagan

The most optimistic scenario for the production launch of at least one new field in the Kazakh offshore would be about five to six years after Kashagan, i.e., in 2021 (in the high scenario), although oil from two of the so-called 50:50 projects on the Russian side (in which half of output is shared with Kazakhstan) could possibly come slightly earlier. Thus production in the high scenario (including the contribution from 50:50 projects shared with Russia) begins in 2021, ramps up to 5 MMt (106,000 b/d) by 2025, and then reaches 32 MMt (679,000 b/d) by 2035 and 35 MMt (743,000 b/d) by 2040.

But a more likely scenario, a base-case, would be for production at these other offshore fields to begin no earlier than 2025 (including the 50:50 contribution), with an even slower ramp-up, reaching 15.5 MMt (329,000 b/d) by 2035 and 20.2 MMt (429,000 b/d) by 2040. Development of these other offshore fields in a low case would be even slower than in the base-case: first oil production is not until 2029, and output reaches only 6.5 MMt (138,000 b/d) by 2035 and 10.5 MMt (223,000 b/d) by 2040. These other two scenarios assume that post-Kashagan exploration and production in the Kazakh offshore moves more slowly than in the high case, owing both to challenges to reaching agreements over commercial terms and to a deficit of available equipment and services

Kazakhstan Upstream Oil and Gas Technology and R&D Roadmap

Because oil and gas is among the most capital and technology intensive of all industries, technological innovation is critical in supporting the discovery of economically viable new reserves and improving the efficiency of resource extraction. In order to help Kazakhstan focus its research and development (R&D) efforts and to contribute to the government's innovation agenda, in 2010 Shell undertook, in collaboration with more than 300 representatives across the entire oil and gas industry (including operators, service companies, and R&D personnel), to lead the development of the "Kazakhstan Upstream Oil and Gas Technology Roadmap." The Roadmap is designed to provide a coherent picture of the most urgent challenges facing the oil and gas sector in order to assign priorities for high-level decision making. More specifically, it identifies those measures that, when implemented, will yield the greatest economic benefit for the industry.

The Roadmap, presented in report form in 2013, identified 15 prime technology challenges in exploration and production confronting the upstream oil and gas industry in Kazakhstan. These challenges all reflect either subsurface characteristics (complex reservoirs, high temperatures and pressures, and high H_2S levels) or surface conditions (no direct sea access for transport, massive temperature swings, ice formation in offshore fields in winter). The 15 challenges were grouped into five technical target areas .

1. **Reservoir characterization** includes the challenges of: (1.1) seismic data acquisition; (1.2) reservoir description—geology, rock, and fluid interpretation; (1.3) well logging and in-well monitoring; (1.4) core analysis and data interpretation; and (1.5) fluid property analysis. Kazakhstan was found to have moderate overall capability in this target area, with strong geological knowledge, good subsurface modeling capabilities, and developing capabilities in core and fluid analysis. In contrast, there is little R&D focus on seismic data acquisition and some lack of awareness of issues surrounding the handling of high-H_2S streams.

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

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

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

5. **HSE and operations** incorporates the challenges of: (5.1) emergency response and disaster recovery; (5.2) operational HSE (health, safety, environment) risk reduction under sour production conditions; and (5.3) environmental impact. The Roadmap assessment found that little work was being done in the area of emergency response and disaster recovery or in operational risk reduction in sour conditions.

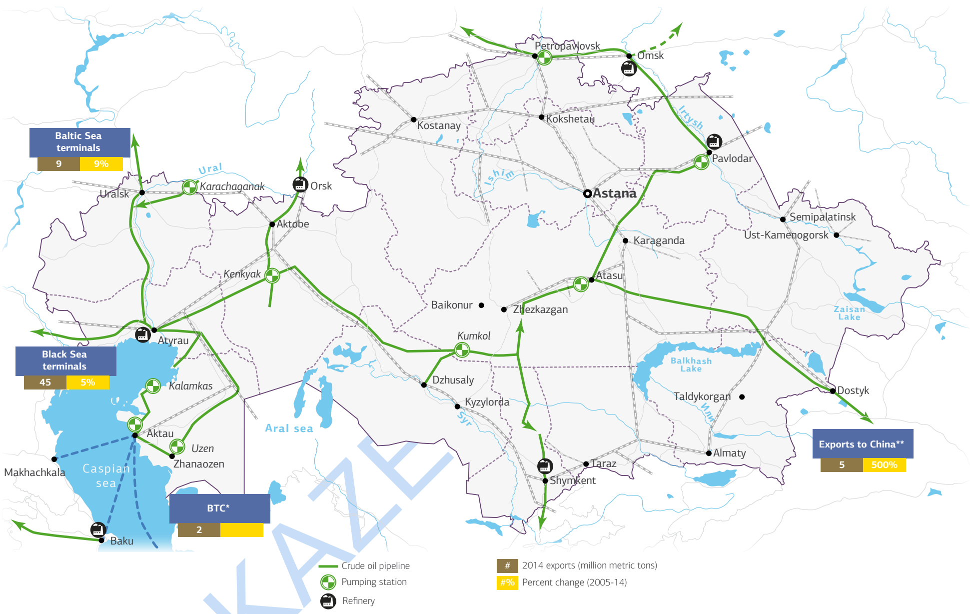
As part of the Roadmap analysis, the abovementioned challenges were ranked according to the benefits/savings for the industry as a whole in Kazakhstan. Improved and enhanced oil recovery (challenge 4.2), equipment and materials for sour service (2.1), and drilling and well costs (4.1) were judged to be the most pressing challenges, each yielding potential savings in excess of $5 billion. But what is also evident from the Roadmap's analyses of specific measures designed to address these challenges is that the costs of their implementation will be proportionately expensive.

7.2.5. Kazakhstan's crude oil transportation and exports

Exports of oil are of critical importance to Kazakhstan's economy. Revenues from hydrocarbon exports have increased tenfold since 2000 and now account for over half of the country's total export earnings (and nearly 20% of GDP).

Export capacity and routes remain one of the greatest challenges for oil producers in Kazakhstan, partly due to the country's landlocked location in the heart of the Eurasian continent. The combination of Kazakhstan's geopolitical position and its remote location relative to international markets represents an ongoing marketing and transportation challenge to ensure efficient future development of the country's hydrocarbon resources. The long distances involved in moving crude oil to markets mean relatively high costs for transportation, and export routes often involve transit through third countries. Therefore, concerns over the reliability of some of these export routes have driven Kazakhstan to embrace a "multi-vectoral strategy" of multiple routes going north, south, east, and west (see Figure 7.2.14.).

Mangyshlak high-paraffin oil has a pour point of 25°C, so it must remain heated during transportation through trunk pipelines; this affects the internal cost of transportation (and therefore the tariff).



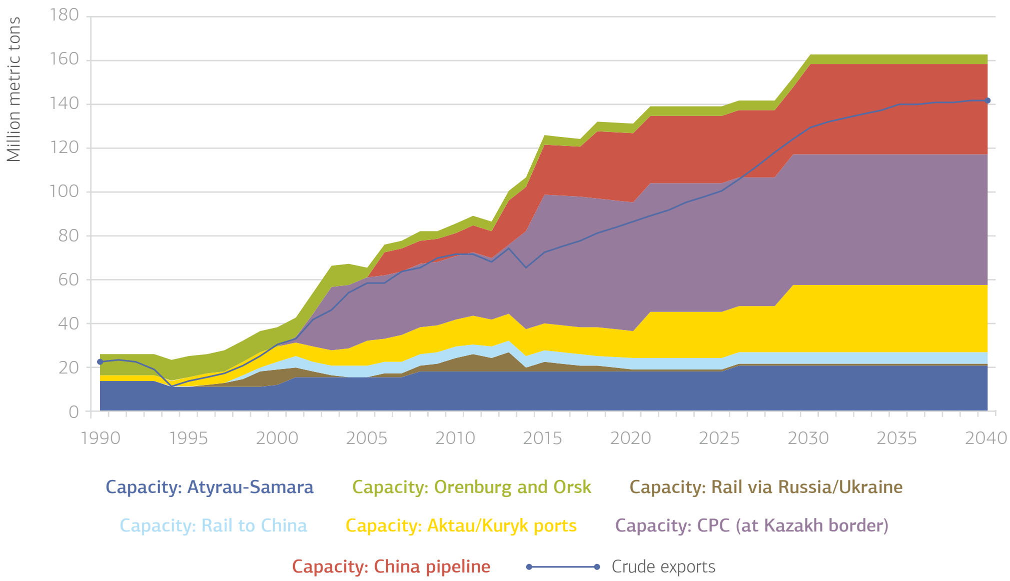
Source: IHS Energy, EOEO

** CPC: Caspian Pipeline Consortium route*
** BTC: Baku-Tbilisi-Ceyhan Pipeline; no Kazakhs exports via this route prior to 2008*
*** Rail during 2005-09 and pipeline during 2009-2014 (Official high of 11.8 MMt in 2013 and in 2014)*

Figure 7.2.14 Oil export routes from Kazakhstan

For Kazakhstan, an important development has been the emergence of spare export capacity in all the major export routes in recent years: BTC from Azerbaijan, swap capacities via Iran, westward evacuation in the Transneft system, rail capacity, and also on the Kazakhstan-China pipeline. As the key source of oil production and export growth in CIS, this creates an opportunity for Kazakhstan's producers/shippers to negotiate competitive transportation tariffs (see Figure 7.2.15.).

KazTransOil (KTO), a specialized subsidiary of KMG, operates the country's oil pipeline network. Access to KTO's pipelines for transport beyond Kazakahstan's borders is an intrinsic aspect of an oil export quota system administered by the Ministry of Energy. Some years ago, overall export capacity was tight and Kazakh oil production was rising, so access was a greater problem, particularly on the main transportation route, the Atyrau-Samara pipeline. But because of capacity expansions and relatively flat oil production trends, transportation constraints are presently no longer such an issue.



Source: IHS Energy, EOEO

Figure 7.2.15 Kazakhstan's crude oil exports versus available export capacity at national borders (base case)

Tariff Policy for Oil Pipeline Transportation

Tariffs for Kazakhstan's national oil pipeline company, KazTransOil (KTO), have long been regulated as a "natural monopoly" by the Committee for Regulation of Natural Monopolies and Protection of Competition (KREMiZK, formerly known as AREM). The basic tariff methodology is for tariffs to be adjusted periodically (usually annually) based upon cost recovery, including investment. The tariff rates for the main system are set per ton-kilometer, based on the expected costs and expected shipment volumes. After considerable volatility and experimentation in the 1990s, economic conditions, including inflation and the tenge-dollar exchange rate, have become more stable, and so have oil pipeline tariffs. They have tended to be adjusted (usually annually) only when material conditions changed significantly. Following KTO's initial public offering in 2012 as part of the program for "People's IPOs," a decision was made to harmonize the tariffs for oil exports and tariffs for domestic deliveries, with average tariff growth indexed to domestic inflation rates.[21] So in the regular tariff adjustment that took place in January 2014, tariffs on domestic routes were raised by 50% to bring them closer to export tariffs, which were increased by only 2.4%. In the previous tariff adjustment that was implemented (in December 2012), both tariffs were increased considerably (with domestic tariffs being hiked more substantially), mainly to cover KTO's planned 15.2 billion tenge ($99.6 million at the then-current exchange rate) capital investment program for 2013. However, the most recent tariff hike, which occurred in April 2014, contradicted the tariff harmonization policy, as pipeline tariffs for export shipments were raised by 20% (to 5,817.2 tenge [$31.94] per metric ton per thousand kilometers) to compensate for the tenge devaluation in February. Tariffs for shipments to domestic refineries remained unchanged.

Each of the joint-venture pipelines in Kazakhstan has its own individual tariff (e.g., Atasu-Alashankou, Kenkiyak-Atyrau) with tariffs also regulated by KREMiZK, although CPC is an exception: the tariff mechanism for CPC is set as part of its overall agreement, and is set internally. In an attempt to attract more oil transit volumes from Russia to China, a special "unit tariff" was established in September 2012, covering the entire route from the Russian border to the Chinese crossing point (i.e., over both KTO pipe as well as the JV section). It was initially established in tenge per ton (1,499.15 tenge per ton), but was changed to be paid in dollars in November 2014 (retroactively back to January 2014), effectively raising the tariff for Russian shippers because of the devaluation of the tenge.

This general policy has generally provided a fairly stable and understandable tariff structure for many years. But with changes to the law on natural monopolies enacted in May 2015, this may be changing. KTO's domestic tariff will remain regulated as before, while the export tariff, which applies to the bulk of shipments in the pipelines and generates the bulk of KTO's revenues, will no longer be directly regulated, but will be shifted

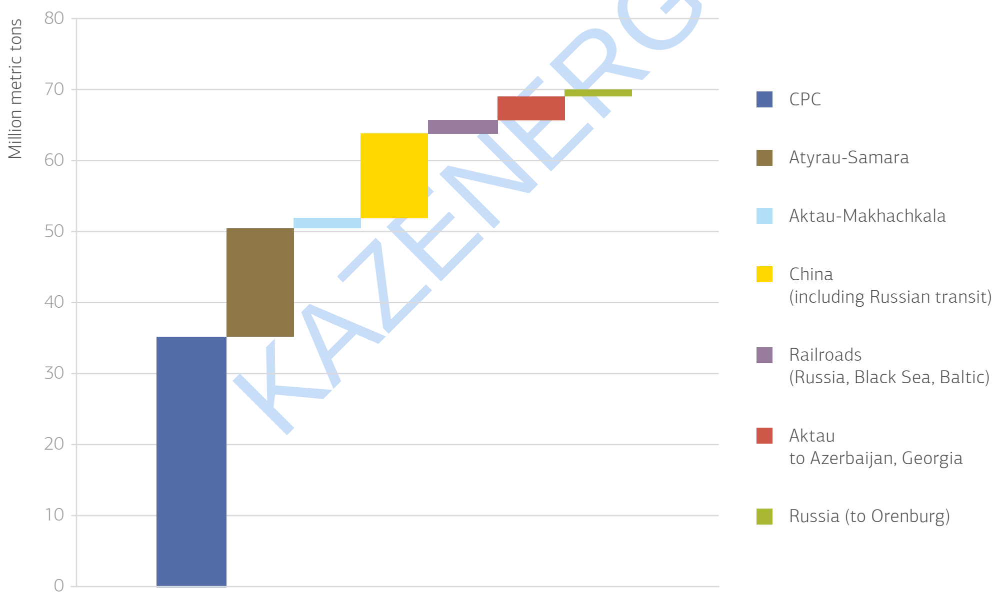
[21] The government of Kazakhstan established the People's IPO and planned to transfer ownership of 5% to 15% of the shares in national companies to the population and pension funds. This was done for so-called "first-tier" companies in 2012, including KazTransOil, KEGOC, and Air Astana, with "second-tier" companies to follow in 2013, and then third-tier companies.

to be part of KTO's own business decisions. The only direction will be from longer-term (five-year) guidelines regarding inflation expectations, which will continue to drive the domestic tariff. It remains unclear exactly how this new arrangement will work in practice.

Historical trends

Kazakhstan has always exported the bulk of its crude production (78% in 2014 excluding Russian transit volumes). Its total crude exports have increased from 20.3 MMt (425,000 b/d) in 1992 to 70 MMt (1.47 Mb/d) in 2014 (including 7 MMt of Russian transit crude), a more than threefold increase (see Table 7.2.3.).[22] In 2014, 68.6 MMt (1.44 Mmb/d) of the 70 MMt (1.47 Mmb/d) reached international (non-CIS) markets. Historically, most of Kazakhstan's crude has exited via Russia, and currently about 76% of Kazakhstan's international crude exports still transit Russia by pipeline or rail. This relationship remains very important to both Kazakhstan and Russia. Most of Kazakhstan's pipeline exports via Russia move either through the CPC or via the Russian pipeline system operated by Transneft.[23]

The principal export routes were as follows in 2014: 35.2 MMt (767,000 b/d) via CPC; 17.3 MMt (360,000 b/d) via Transneft, of which 15.3 MMt (306,000 b/d) went via the Atyrau-Samara pipeline (14.6 MMt to international markets and 0.7 MMt to Russia), and 11.8 MMt (247,000 b/d) via pipeline to China (including Russian swap volumes); no crude went to Iran via Aktau. According to Kazakh data, 2.3 MMt (50,000 b/d) went by rail (via Russia to the Black Sea or Baltic ports), another 5.2 MMt (108,000 b/d) transited via Aktau to Azerbaijan and Georgia after crossing the Caspian Sea, 0.72 MMt (16,000 b/d) went to Russia (from Karachaganak to Orenburg), and 2.7 MMt (55,000 b/d) went via Aktau to Makhachkala. But the sum of these figures exceeds total Kazakh crude exports, and cannot be reconciled with shipment data reported by pipelines and ports. Considering these sources, it appears that total shipments via Aktau were 5.2 MMt in 2014, including 1.7 MMt to Makhachkala and 3.5 MMt to Azerbaijan and Georgia, and that rail exports were only 1.8 MMt (see Figure 7.2.16.). A total of 45 MMt (0.943 MMb/d) of Kazakhstan's crude ended up being exported via the Black Sea in 2014, or 71% of Kazakhstan's exports (see Figure 7.2.17.).

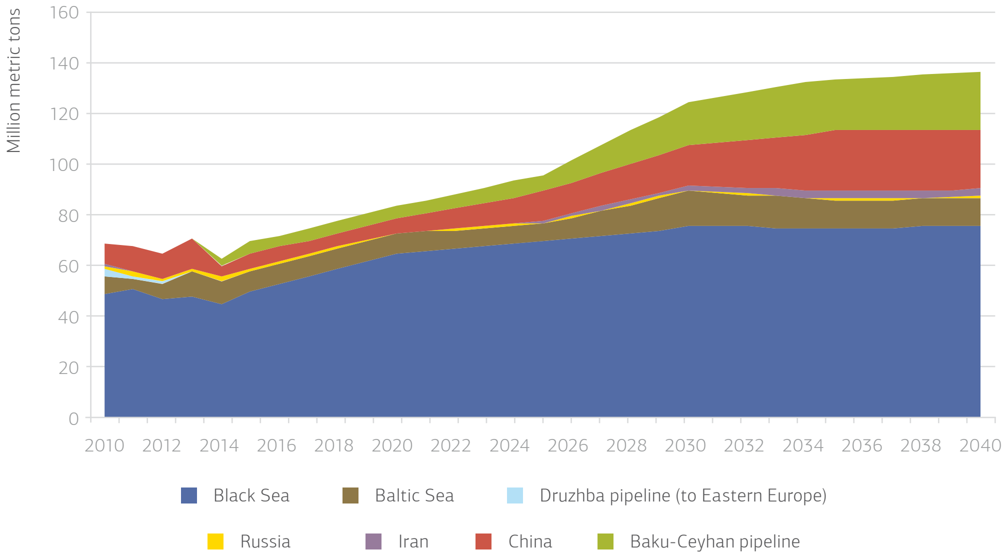


Source: IHS Energy
Note: Atyrau-Samara flow includes 14.6 MMt to international export markets and 0.7 MMt to Russia.

Figure 7.2.16 Distribution of Kazakhstan's crude oil exports by route, 2014

[22] During the Soviet period, all of Kazakhstan's exports fed into the Russian pipeline system, but it was not credited with supplying any exports to the international market. Exports in 2014 are presented on the same basis as in 2013, including the China swap flows with Rosneft.

[23] Kazakh crude enters the Transneft pipeline system either directly via the Atyrau-Samara pipeline or at Makhachkala after crossing the Caspian Sea from Aktau by tanker.



Source: IHS Energy

Figure 7.2.17 Kazakhstan's crude oil exports by destination

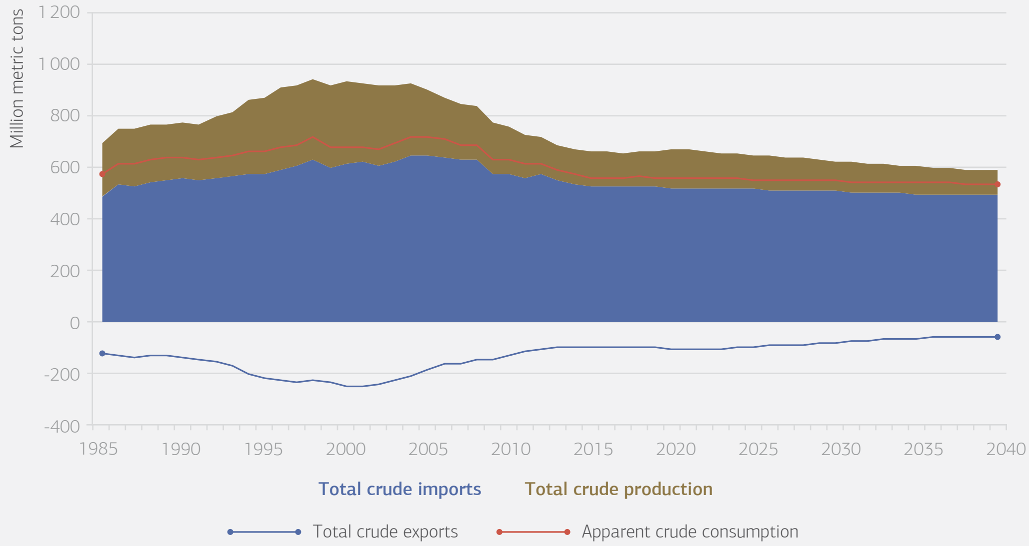
Traditionally, the bulk of Kazakh crude exports have been to countries in the Mediterranean (e.g., 79% in 2003, 73% in 2005). But that share has been dropping recently. In 2013 only 56% of Kazakh crude exports to the non-CIS went to Mediterranean countries; since 2005 there has been significant growth in exports to non-Mediterranean European countries (i.e., Northwest Europe) and especially to China. The largest individual recipients by country in 2013–2014 include Italy, China, France, Netherlands, Romania, Austria, and Switzerland.

European Oil and Product Demand Outlook

A key strategic question for Kazakhstan for its longer term oil exports is the oil demand outlook for Europe, as this has been the traditional market for the bulk of Kazakhstan's oil. In 2013, for example, European countries were the destination for 78% of Kazakhstan's non-CIS crude oil exports. Due to a combination of factors—slow economic growth, decarbonization and energy efficiency policies, social change, and economic restructuring—oil product demand growth has become negligible in Europe and is forecast to shrink slightly longer term. Furthermore, a rising share of available product demand in Europe has been captured by long-haul product imports, from Russia, the Middle East, and North America, among others, blunting the consumption of crude oil in regional refineries.

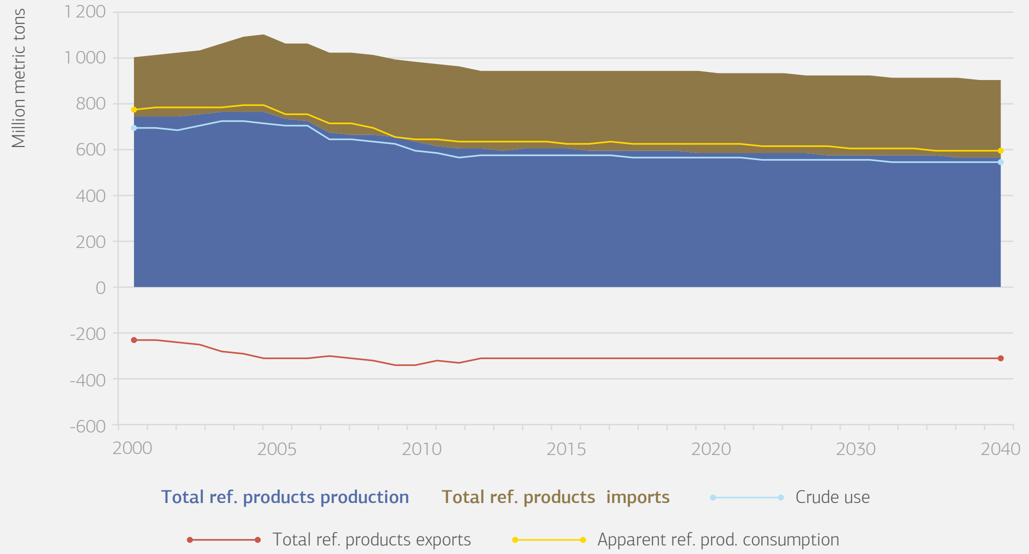
The IHS outlook expects demand for crude oil in Europe longer term to remain basically flat (albeit with a slight decline in the period to 2040). However, indigenous European crude oil production is expected to continue to decline longer term, at a 1.4% annual rate through 2040, and Europe's small amount of crude exports is expected to disappear. Importantly, European crude imports therefore are expected to also remain basically flat through 2040 (see Figure 7.2.18.). The main adjustment in European product supply is expected to be reduced imports of refined products. Thus, due to falling European crude production and relatively stable European crude demand, the European market is expected to remain relatively open to Kazakhstan's crude exports over the forecast period, for at least some incremental volumes.

This is despite the expectation of a flat or even slightly downward demand trajectory for refined products in Europe, which is due to a number of factors, including the impact of higher vehicle fuel economy standards and relatively mild economic growth longer term. Although refined product demand in Europe is expected to gradually contract (-0.4% annually to 2040), so do product imports (see Figure 7.2.19.).



Source: IHS Energy

Figure 7.2.18 Outlook for Europe's crude oil balance to 2040



Source: IHS Energy

Figure 7.2.19 Outlook for Europe's refined products balance to 2040

European product demand has been met by a combination of indigenous refining and product imports (the region has traditionally been long on some products, such as gasoline, which must be exported). The need for product imports arose when diesel demand began increasing at the expense of gasoline from the 1990s onward due to European policy shifts toward diesel,[24] while the majority of European refineries were outfitted in the 1970s and 1980s to meet gasoline demand. The imbalance between the domestic refinery product slate (with a surplus of gasoline) and demand (mostly diesel, which is in short supply) resulted in increasing volumes of gasoline being exported and increasing volumes of middle distillates (gasoil/diesel, as well as jet/kero) being imported into Europe. The main challenge for European refining is not so much absolute capacity but its configuration.

[24] The European policy bias toward diesel was initially based on its superior fuel economy, but subsequently this was based on diesel's supposedly lower carbon content. The overall policy has now been admitted to have been somewhat misguided (see the IHS CERA Private Report, Distillates in the Driver's Seat, October 2005; European Oil Demand: the Green Squeeze Begins, February 2010). Policy in Europe is now becoming anti-diesel because of the effect of diesel-fueled vehicles on air quality in Europe's largest cities, such as Paris and London; France announced that it will gradually phase out the use of diesel fuel for passenger vehicles, partly through raising excise taxes on diesel fuel.

As the strongest component of European demand is likely to remain the middle of the barrel, there will be a continued need for imported diesel (low-sulfur/road diesel) in Europe. Diesel demand is expected to peak around 2020 and then flatten by 2030, however, owning to increasing penetration of electric vehicles and increased natural gas use in trucking and ships longer term. Competition for market share is likely to intensify as gasoil/diesel imports from North America and Middle East compete with those from CIS, and with indigenous supply.

Gasoline demand is expected to remain in structural decline (falling by 2.5–3.0% per year), so that net gasoline export flows are expected to account for 50% of production in 2030, compared with 35% in 2013 and 9% in 2000. This poses an important challenge, as traditionally much of Europe's surplus gasoline was directed to North America, which is now becoming long on this product as well. This will probably mean shifting gasoline exports to Latin America and Africa.

As Europe will remain a major import market for crude oil over the longer term, the Black Sea can be expected to remain a major export direction for Kazakh crude, including some incremental volumes. Therefore, Kazakhstan can continue to rely heavily on the CPC system terminating in the Black Sea for its exports. Kazakh crude shipments in CPC rose by 22.6% in 2014, to 767,000 b/d (35.2 MMt). A planned $5 billion expansion of CPC capacity is underway, although it is running about a year behind schedule. Completion of a first phase of expansion is now expected in 2015, bringing total capacity to 1.3 MMb/d (67 MMt), and on Kazakhstan's territory throughput capacity will increase to 1.1 MMb/d (52.5 MMt). With drag-reducing agents total pipeline capacity can be expanded to 1.7 MMb/d (76 MMt) if needed, and on Kazakhstan's territory it would be 1.3 MMb/d (60 MMt).

The use of rail has been a "next best" option during the last several years, increasingly used by Kazakhstan's oil producers when pipeline capacity has been tight. Rail offers more flexibility in terms of routes, and also preserves the quality premium for Kazakhstan's light crude. However, with CPC expansion underway and its throughput capacity already increasing, the use of rail has contracted again, and is expected to remain relatively small. In 2014, just the interim CPC expansion largely displaced TCO shipments via rail (to Taman). In fact, the year-on-year decline in rail transportation has been quite dramatic, with rail transport falling by 80% from 8.7 MMt (89,000b/d) in 2013 to just 1.8 MMt (39,000 b/d) in 2014 (see Table 7.2.3).[25]

The principal non-Russian crude oil export routes are via pipeline to China and exports west across the Caspian Sea to Azerbaijan (Iranian swaps via the ports of Aktau and Neka have not occurred since 2010, largely due to international sanctions, although this is likely to change with the July 2015 preliminary agreement to lift sanctions against Iran). From Azerbaijan, the oil either goes by rail to Georgian ports on the Black Sea or into the Baku-Tbilisi-Ceyhan (BTC) pipeline to Turkey's Ceyhan terminal on the Mediterranean Sea.

In December 2013, KTO expanded the capacity of the 965 km Atasu-Alashankou segment of the Kazakh-China pipeline to 400,000 b/d (20 MMt per year), following construction of two new pumping stations. Altogether, crude flows to China via Atasu-Alashankou rose by 14% in 2013, to 11.8 MMt (236,000 b/d), and remained flat in 2014. But the challenge of filling existing Kazakhstan-China pipeline capacity is becoming more acute, as production from the regions within Kazakhstan that supply the Kazakhstan-China oil pipeline (Aktobe and Kyzylorda oblasts) has been declining while refinery throughput at Shymkent, fed largely by Turgay Basin crude, has been slightly up, making less Kazakh crude available to fill the pipeline to China.

In December 2013 KTO finalized an oil transit deal with Rosneft for 140,000 b/d (7 MMt per year) of Russian oil in 2014–2018. Rosneft delivers the crude at the northern Kazakh border, and in exchange Kazakhstan delivers an equal volume of crude oil to China via the Atasu-Alashankou pipeline; Rosneft began delivering oil to China under this scheme on 15 January 2014. This enables Rosneft to deliver on a new oil sales contract concluded with CNPC in summer 2013. Thus, nearly 60% of total shipments in the pipeline last year were effectively comprised of Russian crude (although about 5 MMt of the Russian crude is actually delivered to the Pavlodar refinery on its way to Atasu).

Meanwhile, the reversal of the Kenkiyak-Atyrau pipeline segment, to enable oil from western Kazakhstan to flow into the Kazakhstan-China pipeline, has been planned for several years, but this remains delayed to later. Currently the main challenge for oil from western Kazakhstan to flow east is the price China currently offers at the Kazakh-Chinese border, which makes export netbacks not as competitive as those received by western Kazakhstan producers on their exports westward.

Following a preliminary agreement reached between Iran and the five permanent members of the United Nations Security Council (plus Germany) on lifting the international economic sanctions on Iran, the export route via Iran is likely become available again. The prior export arrangements were based on a swap, where Kazakhstan's crude was supplied to northern Iran at Neka, and Iran would then make the equivalent amount of crude available at its southern export terminal on the Persian Gulf. This trade was quite substantial some years ago when Kazakhstan's export capacity was constrained (the maximum annual volume was 2.9 MMt in 2007); but now there is ample export capacity in a variety of directions, so it remains to be determined how attractive this route might be for Kazakh shippers. The scale of the possible swap operations could be fairly significant, easily about 5–6 MMt per year. But revival of the swap arrangement depends on Iran's willingness to offer competitive netbacks to the Kazakh shippers and those shippers being able to provide crude according to the rather stringent specifications Iran requires.

[25] Kazakhstan's own national data indicate that rail-based exports declined from 9.0 MMt in 2013 to 2.3 MMt in 2014.

7.2.6. Outlook for Kazakhstan's crude oil exports

For Kazakhstan, crude exports are projected to rise over the outlook period, driven upward by a combination of rising production and fairly modest crude oil consumption growth. In the base-case scenario, Kazakhstan's crude exports are projected to expand to 135 MMt (2.83 MMb/d) by 2035 and reach 137.2 MMt (2.88 MMb/d) by 2040 (see Figure 7.2.17.). Kazakhstan's trans-Caspian and eastbound exports are expected to increase the most longer term, while Black Sea exports are expected to drift upward more slowly.

Once the Kenkiyak-Atyrau pipeline section is reversed, increased Kazakhstan-China export flows can be achieved, but this oil will have to be attracted from western Kazakhstan. To make a producer in western Kazakhstan willing to send crude east instead of west means offering both a competitive pipeline tariff and an attractive price at the border with China, so that the netback (realized sales price after transportation) is the same or higher as from westward exports. In the past, the price China was willing to offer at the border with Kazakhstan was a function of China's internal economic calculations, which was tied to capped domestic prices for oil products.[26] Essentially, Kazakh crude supplied to refineries in western China (e.g., Dushanzi, Urumchi, and Karamay) had to yield oil products at prices competitive in domestic markets in eastern China where the marginal product supply from these refineries was sold. But given changes in China's domestic pricing policies, China may be more open to offering a better price on the Kazakh border to attract more crude.

Key Recommendations

- Hydrocarbon policy reform does not mean Kazakh authorities need to minimize legitimate national security, budgetary, and other concerns that may have played a role in the shifts of recent years, but it does imply a general rebalancing of state and oil industry interests. In order to re-incentivize investment by oil companies of all sizes, a number of mid-course corrections, spanning a number of major policy areas need to be implemented, some of them longer term. Top priorities include:

- Revise current domestic content requirements, especially in cases where these impede raising capital during early stages of exploration and production activity or requirements that significantly jeopardize timely implementation of upstream project schedules.

- Rationalize and streamline the regulatory apparatus in instances where multiple layers of government bureaucracy and excessive paperwork requirements complicate routine company operations.

- Longer term, reduce the importance of export taxes in favor of direct upstream taxes that more closely reflect the cost conditions faced by individual producers. This may raise the price of oil on the domestic market, but it will also more closely reflect investment costs.

- Liberalize domestic oil markets, including freeing wholesale and retail prices from direct government control and allowing free export and import of all refined products. This will also bring the price of crude oil on the domestic market to align with export parity levels (export price net of transportation costs and export duties and taxes).

- Balance the current tendency in environmental policy for punitive measures with implementation of some incentives as well. One of these might be compensation of oil companies' associated gas processing costs (along the lines indicated in existing legislation).

- Given that the contracts for the three "mega" projects—Tengiz, Karachaganak, and Kashagan—expire in 2033, 2037, and 2041, respectively, to ensure that the long-term productive potential of these projects is realized, policy needs to include provisions for continued investments and effective operation. This may include contract extensions to provide sufficient payback period or other contract adjustments.

- Consider the work done within the framework of the Upstream Oil and Gas Technology and R&D Roadmap (Shell Roadmap) in future policy. The roadmap identifies key challenges to the oil and gas industry and key measures that, if implemented, will yield the greatest economic benefit for the oil and gas industry and the country.

7.3. Natural Gas

7.3.1. Key points

- Natural gas production plays a secondary role in Kazakhstan to oil output. The bulk of natural gas is produced together with oil (either as associated gas or condensate-related gas), and commercial volumes remain secondary to the need for large volumes of gas for re-injection so as to maximize oil production and utilize associated gas.[27]

[26] Currently the China DAF [delivered at frontier] price is tied to Brent, but with a considerable lag. Historically it has been lower than prices that Kazakhstan's producers earned in western markets, such as the Mediterranean.

[27] For the purposes of this report, commercial gas volumes are defined as gross gas production minus reinjection volumes; therefore commercial production still includes any volumes that disappear as other upstream usage and losses (shrinkage with the removal of other gases and impurities). This is not the same as the volume of "sales gas" production (tovarnoye proizvodstvo) reported in some Kazakh statistical sources, which appears to exclude reinjection and other upstream usage and losses.

Kazakhstan re-injects about 40% of its associated gas output to maintain reservoir pressure so only about 60% of its gross gas output is potentially available as commercial volumes for distribution to consumers.

- Nonetheless, gas is likely to become increasingly important for domestic consumption; currently gas consumption remains relatively small (coal provides the majority of the country's primary energy supply), but it is expected to grow robustly going forward. Gas consumption ("end-of-pipe" deliveries to consumers) still remains below Soviet-era levels but is expected to more than double over the next two decades.

- To expand domestic gas consumption, promote "greener" energy, and boost the economy's international competitiveness, the government of Kazakhstan has placed responsibility for development of the domestic gas market with state-owned KazTransGaz (KTG), as the designated "national operator" for the county's single-buyer model. KTG, a specialized subsidiary of the national oil company JSC NC KazMunayGaz (KMG), manages a centralized infrastructure for commercial gas transportation through trunk pipelines and gas distribution networks, provides international transit as well as develops, finances, builds, and operates pipelines and gas storage facilities; and is also a small gas producer. KTG also sells gas in domestic and foreign markets and has a pre-emptive right to purchase processed associated gas from producers.

- Although Kazakhstan has significant gas reserves, gas is not likely to become a significant export commodity, although some modest amounts of gas will be exported to its nearest neighbors (mainly Russia and China); this is due to Kazakhstan's location in the heart of the Eurasian landmass, far from global markets, so the relatively high cost of gas transportation makes it challenging economically to develop a material export business; also the nature of its gas production (being mainly associated gas) makes it difficult to scale gas output in response to demand. But Kazakhstan possesses the potential to retain a key role in gas transit because of its geographic location.

- A large gap between natural gas and oil prices has been the primary driver for increased use of natural gas in transportation globally; as a result, consumption has been growing over the last decade, but especially in China. The main areas of growth have been in heavy vehicle use (trucks hauling freight), with significant potential in ships and urban vehicle fleets.

- Kazakhstan's gap between oil and gas prices is also significant, and Kazakhstan has the additional incentive of using gas to offset insufficient domestic production of light refined products to meet demand.

- Kazakhstan also has considerable gas supply potential, as it has significant reserves and relatively low recovery costs (although sulfur removal costs are high). Gas use in transport may help Kazakhstan achieve important policy goals, including reducing dependency on oil products imports, alleviation of product shortages, lowering fuel costs for consumers, utilizing local resources and monetizing stranded gas resources, and mitigating the environmental impacts of transportation on air quality.

7.3.2. Natural gas reserves in Kazakhstan

As of 1 January 2014, Kazakhstan's State Commission on Reserves (GKS) listed the country's gas reserve base (state balance) at 4.03 trillion cubic meters (Tcm), about the same as it has been for the past several years.[28] Of this, 2.27 Tcm is "solution" gas (held in solution with liquid hydrocarbons in the reservoir) and 1.76 Tcm is "free" gas.[29] Most of the country's reserves—3.72 Tcm—are concentrated in the North Caspian Basin. Approximately 98% of the country's gas reserves are located in western Kazakhstan (Mangistau, Atyrau, West Kazakhstan, and Aktobe oblasts), and about 85% is found in just a few large fields (e.g., Tengiz, Kashagan, Karachaganak, Zhanazhol, Imashevskoye). Most of these are subsalt deposits, characterized by considerable depths (up to 5 kilometers), multi-component composition, and high sulfur content, all of which greatly complicate development and production. The official state balance for 2014 lists gas reserves for 228 fields, of which 68 are reportedly in production.

A more thorough accounting of the reserve base is publicly available for 2009, which reported 3.7 Tcm of "confirmed" reserves (evidently A+B+C) onshore (dispersed across 172 fields) in the state balance, plus confirmed reserves of another 1.3 Tcm offshore in the Kashagan project, which was considered separately in 2009 (see Table 7.3.1). Thus, the total "confirmed" gas reserves for the country were 5 Tcm (A+B+C). The lower graded "preliminary" category includes an estimated 817 Bcm (dispersed over 16 offshore structures), but about 70% of this is found in just two structures—Khvalyn and Atash (see Table 7.3.1). At the time, other "prospective and prognosticated" resources amounted to another 8 Tcm of gas, found mainly in the offshore Caspian.

The twelve largest onshore reserve holders have more than half of Kazakhstan's estimated reserve base within their fields alone, with 1.8 Tcm. There are another 141 fields in the hands of other operators that contain 1.8 Tcm of gas. This includes only one very large field (Imashevskoye [180 Bcm]), two large fields Chinarevskoye [43 Bcm] and Amangeldy [33 Bcm]), and 16 medium-sized fields, which in aggregate hold 129 Bcm. The other 122 fields are small (1-3 Bcm) or very small (less than 1 Bcm) and together contain the remaining 1.4 Tcm.

In terms of operatorship, the three biggest holders of gas reserves are NCOC, TCO, and KPO (see Figure 7.3.1). The only other significant reserve holder—CNPC-AktobeMunayGaz—has its most important gas reserves in the Zhanazhol field,

[28] This is reported according to the domestic definition (in categories A+B+C1+C2). This appears to roughly correspond to the international equivalent of proven + probable ("2P") reserves. IHS Energy estimates Kazakhstan's remaining 2P gas reserves at 134 trillion cubic feet (3.8 Tcm).

[29] By international definitions for just "proven" (1P) reserves, Kazakhstan is considered to possess 1.5 Tcm as of the end of 2014, or 0.8% of the global total (BP Statistical Review of World Energy, June 2015). By this measure Kazakhstan ranks third among CIS countries (after Russia and Turkmenistan) and 23rd in the world, on par with Libya.

which accounts for about 2.5% of Kazakhstan's total.

Kazakhstan's simpler gas fields (those with shallower depths or without sulfur), contain only rather small gas reserves, and tend to be of only local importance for supply to nearby customers. However, these types of fields have been developed, mostly in areas other than western Kazakhstan, such as in Kyzylorda, Zhambyl, South Kazakhstan, and East Kazakhstan oblasts.

	Total	Solution	"Free"
Total confirmed reserves by GKS	5,004	3,643	1,361
Total confirmed GKS reserves: onshore	3,705	2,344	1,361
Fields of the largest 12 companies	1,872	944	928
Karachaganak (KPO)	810	151	659
TengizChevroil (TCO)	703	703	—
CNPC-Aktobemunaygaz	154	46	108
Tokynneftegaz	32	1	31
KazGPZ	8	—	8
KazGerMunay	13	7	5
Mangistaumunaygaz	53	12	41
KazMunayGaz E&P	40	1	40
PetroKazakhstan Kumkol Resources	6	6	—
AmangeldyGaz	32	—	32
Kazakhoil-Aktobe	20	16	4
Turgay Petroleum	1	1	—
Other fields	1,833	1,400	433
Confirmed reserves: offshore	1,299	1,299	—
Kashagan project (NCOC) **	1,299	1,299	—
Preliminary estimated reserves in offshore structures (GKS)	817	817	—
Khvalyn*	332	332	—
Atash	249	249	—
Mertvyy Kultuk	85	85	—
Total, confirmed and preliminary estimated reserves	5,821	4,460	1,361

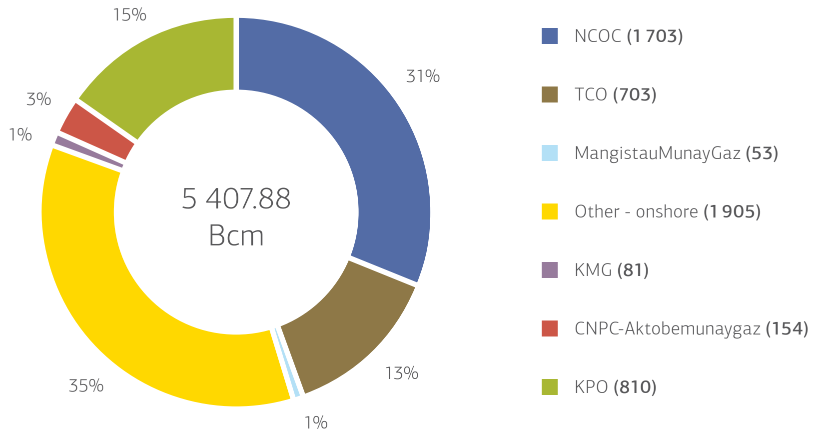
** 50% of reserves listed are credited to Russia.*
***This refers to Kashagan field reserves only, not all of NCOC acreage.*
Source: GKS; State Geology Committee; Ministry of Energy

Table 7.3.1 Confirmed and preliminary estimated gas reserves in Kazakhstan (January 2009), (billion cubic meters)

A distinctive feature of gas reserves in Kazakhstan is that most are in the form of associated gas, and consequently, gas production is mainly connected with the production of liquid hydrocarbons. A significant amount of the raw gas extracted is reinjected into the formation for pressure maintenance and primary extraction of liquid hydrocarbons.[30] These same fields also tend to have high concentrations of hydrogen sulfide. For example, the Tengiz and Kashagan fields' sulfur content is about 18–19%. Hence, a major problem for gas development in the country is high costs of processing the gas to remove sulfur and other impurities, and then the further utilization of the large amounts of recovered sulfur.

[30] Kazakhstan reinjects about 40% of its total gas output to maintain reservoir pressure.

Inferred or prospective gas resources in Kazakhstan are believed to be quite substantial: they are estimated at another 8 Tcm (or even as much as 17.5 Tcm). These prospective resources are mainly associated with the Caspian Sea shelf. But certain onshore areas, particularly parts of the North Caspian Basin and the North Ustyurt Basin in the area of the Aral Sea,[31] are also believed to have high probability for future gas discoveries.



Source: IHS Energy

Figure 7.3.1 Kazakhstan's 2P gas reserves in 2014 by operator (Bcm)

7.3.3. Natural gas production

In 2014, Kazakhstan's gross gas production was reported as 43.2 Bcm, compared to 42.4 Bcm in 2013; this volume is five times what it was in 1992, Kazakhstan's first year of independence. However, volumes of "commercial" gas, excluding reinjected volumes (consistent with usual international statistical practice), amount to only about half of gross output, or about 24.8 Bcm in 2014 (see Table 7.3.2. Kazakhstan's Gas Balance).[32] (See Text Box on "Gas Reinjection")

	1990	1991	1992	1993	1994	1995	1996	1997	1998	1999	2000	2001	2002	2003	2004	2005	2006	2007	2008	2009	2010	2011	2012	2013	2014
Production (total as reported; gross volumes)	7.1	7.9	8.1	6.7	4.5	5.9	6.5	8.1	7.9	9.9	11.5	11.6	14.1	16.2	22.1	25.0	26.4	29.6	32.9	35.9	37.1	39.5	40.1	42.4	43.2
Production (excluding reinjected volumes)	7.1	7.9	8.1	6.7	4.5	5.9	6.5	8.1	7.9	9.9	11.5	11.6	14.1	16.2	19.9	18.9	18.2	21.6	22.2	24.7	24.1	24.7	24.4	24.6	24.8
Reinjected volumes	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	2.2	6.0	8.2	8.0	10.6	11.3	13.0	14.9	15.8	17.8	18.4
Exports**	4.1	4.2	3.9	3.5	1.6	2.6	2.3	2.4	2.3	4.2	5.2	5.5	10.4	11.0	17.3	15.4	15.1	15.2	17.4	17.7	14.5	22.3	20.5	20.6	10.6

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[31] Also referred to locally as the Aral Basin.

[32] Gross production includes total volumes extracted from the reservoir, so it also includes all non-methane components, including hydrogen sulfide, carbon dioxide, nitrogen etc. It also includes reinjected volumes. In standard international statistical practice, reported production does not include reinjected volumes, but only "commercial" output available for project use and distribution to consumers. In Kazakhstan, a total of about 18.4 Bcm in 2014, or nearly 43% of gross gas production, is reinjected. All gas volumes in this report are quoted in the measure employed in countries of the former Soviet Union of 8,200 kilocalories (kc) per cubic meter (i.e., volumes are measured at 20°Centigrade (C) and 760 millimeters [mm] of mercury) instead of the usual international standard of 9,500 kc per cubic meter (at 15°C at a pressure of one atmosphere [760 mm of mercury]). To convert Soviet/Russian volumes to international standard gas volumes, multiply by 0.935.

	1990	1991	1992	1993	1994	1995	1996	1997	1998	1999	2000	2001	2002	2003	2004	2005	2006	2007	2008	2009	2010	2011	2012	2013	2014
Imports**	11.4	9.1	14.3	11.8	8.0	8.5	5.5	3.0	3.1	2.8	4.2	4.3	8.2	8.7	11.7	11.2	11.1	7.2	6.7	3.7	4.0	3.7	3.8	5.2	2.2
Consumption (apparent; gross)***	14.4	12.8	18.5	15.1	10.9	11.8	9.7	8.7	8.7	8.5	10.5	10.4	11.8	13.9	16.5	20.8	22.4	21.5	22.2	22.0	26.7	20.9	23.4	26.9	34.8
Consumption (apparent; excluding re-injection)***	14.4	12.8	18.5	15.1	10.9	11.8	9.7	8.7	8.7	8.5	10.5	10.4	11.8	13.9	14.3	14.7	14.2	13.5	11.5	10.8	13.7	6.0	7.6	9.2	16.4
Reported deliveries*	13.7	10.8	11.9	n.a.	n.a.	8.3	n.a.	n.a.	n.a.	n.a.	n.a.	4.8	5.0	6.0	6.5	7.3	8.0	8.4	9.0	8.4	9.0	10.1	10.5	10.9	12.4

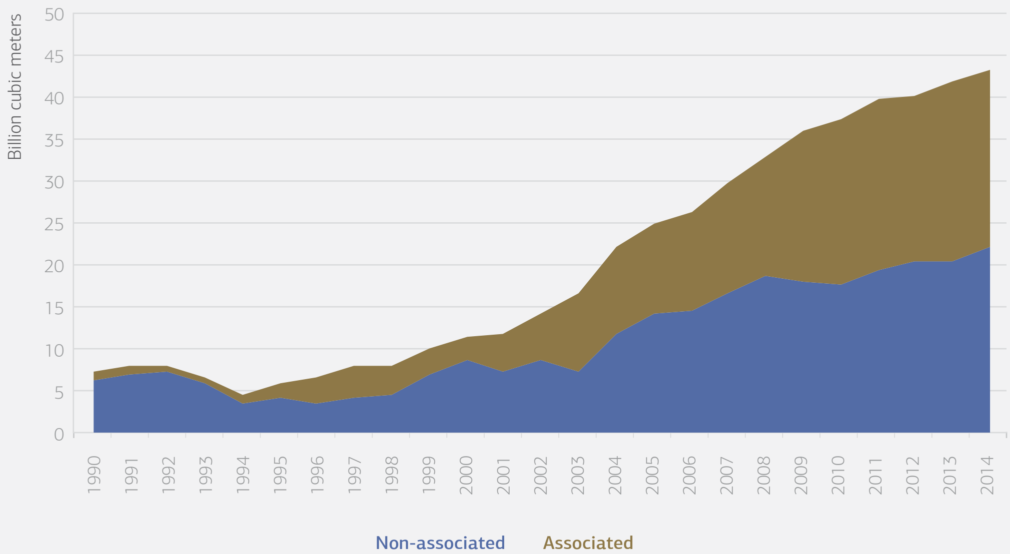
n.a. not available.
** Amount reported as consumption (end-of-pipe deliveries) by the Ministry of Energy or Kazakh statistical sources.*
*** Amount reported by Kazakhstan's foreign trade statistics; actual "operational" export volumes (derived from reporting from pipeline operations) are much lower ("operational" volumes shown for 2014).*
**** Apparent consumption is calculated as production - (exports-imports); thus it includes field use, shrinkage, lossses, and changes in stock.*

Source: Ministry of Energy; Kazakhstan statistical agency; IHS Energy

Table 7.3.2 Kazakhstan's historical gas balance (billion cubic meters)

Gas Reinjection

Kazakhstan is a relatively large producer of associated gas, which is hardly surprising given its sizable oil production. Out of 43.2 Bcm of gas extracted (in total) in Kazakhstan in 2014, 21.3 Bcm (49.3%) was associated gas (see Figure 7.3.2). Associated gas, which is extracted together in the same reservoir with crude oil, has a fairly complex structure: in addition to methane, it contains sizable proportions of heavier hydrocarbons such as ethane, propane, and butane, plus heavier liquid fractions as well as non-hydrocarbons, such as hydrogen sulfide, carbon dioxide, and nitrogen. The share of non-methane components in its total volume can be quite high, varying between 15% and 85%; in comparison, non-associated ("free" or "natural" gas) is predominantly comprised of methane, with the non-methane content often being 10% or less, although obviously this varies considerably from field to field.



Source: Kazakhstan statistical agency; Ministry of Energy
Note: Gross production, including reinjected volumes. Data presented as reported by official entities.

Figure 7.3.2 Historical (gross) gas production in Kazakhstan: associated versus non-associated

Besides the amount of non-methane materials present in associated gas, the overall "gas factor" (the gas-to-oil ratio [GOR] in total extraction) also varies considerably. Often a key variable in this in the depth of the producing horizon, with the higher heat and pressures present at greater depths resulting in generally higher gas factors and a higher proportion of heavier hydrocarbons as well. But because of its relatively high liquids content, associated gas is a valuable resource, especially for petrochemical feedstocks.

Conceptually, several options exist for associated gas utilization. As a means of enhanced oil recovery (EOR), associated gas can be used directly through reinjection back into reservoir to maintain pressure, or indirectly to produce steam and methanol on site for other types of EOR applications. In artificial gas lift, associated gas is injected under high pressure into the production conduit to lift the well fluids. On-site applications also include technological needs at the field itself, such as for electricity generation, or fuel for compressors. After processing and treatment, associated gas is transformed into dry pipeline-quality gas, a commercial product that can be sold to consumers such as electric power stations, industrial plants, or distribution companies for onward sale to households or commercial users. At the same time, processing and treatment also yield various by-products, including liquefied petroleum gas (LPG—propane and butane), ethane (for petrochemical feedstock), or heavier plant condensate (e.g., natural gasoline).

For an upstream producer, the economics of associated gas utilization depend on several factors. Perhaps the most important is the availability of infrastructure, including pipelines and processing plants near the oilfield. If these are already built, then together with an existing local gas market, these factors significantly improve the overall economic calculus. The stage of the field's production cycle also impacts the selection: gas reinjection installation for fields that are already in decline is typically more costly (and has less impact over the life of the project) than installation during the field's initial ramp up phase. Also, the total volume of associated gas production matters, as some utilization options are not feasible for small production volumes. Finally, the associated gas quality, including the concentration of hydrogen sulfide or mercaptan sulfur, also affects utilization options. Ultimately, if no other option seems economically feasible, associated gas can simply be flared, although this is often legally prohibited or heavily proscribed in most countries, including Kazakhstan.

In Kazakhstan, gas utilization options have been shaped by several factors. Two of the most important have been tightening regulations on flaring and the high content of hydrogen sulfide in much of the extracted gas. The latter not only makes processing expensive, but also necessary for many utilization options.

Until the late 1990s, upstream producers in Kazakhstan did not have specific obligations to utilize associated gas, so a sizable volume was flared. But the desire by the government to utilize more of the associated gas resource and to reduce atmospheric emissions has driven the development of a legislative and policy framework to accomplish this. In August 1999 amendments to Presidential Order No. 2350 "On Oil" (dating from June 1995) prohibited associated gas flaring, with certain exceptions. The next major step occurred in December 2004, when that Order became the core of the Law "On Oil." Under this legislation, subsoil users were obliged to "utilize" associated gas, which meant recovery of associated gas so that it could be used either for the technical needs of the producer or for further transformation into a commercial product. The Law "On Subsoil Use" (Kazakhstan Republic Law No. 291-IV from 24 June 2010) subsequently replaced the Law "On Oil" in this regard, providing additional specifications related to associated gas. This Law puts even more emphasis on utilizing associated gas by processing it into a saleable product; although processing gas is given priority, if this option is deemed "non-feasible" (with some uncertainty whether this means only from a technical standpoint or if it also means uneconomic), the Energy Ministry may allow the producer to utilize gas in one of three other alternatives:

- for the project's own technological needs;
- for reinjection back into the reservoir to increase liquids production over the life of the field;
- or for storage in underground gas storage facilities.

This requirement applies to all subsoil contracts concluded after 1 December 2004.

Because of the combination of these new regulations, the high cost of (sour) gas processing, and rudimentary gas market development (symbolized by low domestic producer prices), reinjection has become one of the most widespread gas utilization options in Kazakhstan, especially for projects with large amounts of sour gas. Of the 21.3 Bcm of associated gas extracted in Kazakhstan in 2014, 8.6 Bcm was reinjected (40%); another 9.8 Bcm of non-associated gas at Karachaganak was also reinjected last year, so a total of 18.4 Bcm of gas was reinjected out of total gas extraction of 43.2 Bcm (i.e., 42.6%) in Kazakhstan last year.

While this particular EOR method can increase the liquids recovery factor at a project by something like 4-8% or even significantly higher, it has its peculiarities, so each project must be evaluated on a case-by-case basis. Specifically, effectiveness depends on the reservoir geology and characteristics of the crude oil. For example, the method has a more pronounced effect in high permeability reservoirs with high dip and oil column height.

In terms of the field production lifecycle, this EOR method is actually more effective in adding incremental production during a project's decline phase; it tends to not alter the maximum oil production rate during the plateau phase. In contrast, gas reinjection does not work well in reservoirs with high water drives due to the risk of breaching the reservoir's seal and, consequently, a gas leakage. Finally, gas reinjection can be supplemented by water alternating gas (WAG) reinjection, which is becoming common globally and may in many cases provide better pressure maintenance support than reinjecting gas alone.

Karachaganak was Kazakhstan's first upstream project to introduce sour gas reinjection to enhance liquids production, beginning in 2004. Being a gas-and-condensate field, its gas-to-oil ratio (GOR) is relatively high, at about 1.4: that is, for each ton of condensate extracted, about 1,400 cubic meters of sour gas is also extracted. The project earns most of its revenues on sales of liquids (most of which are exported via the CPC pipeline), while the gas is disposed of by sending it across the border to the Orenburg gas plant to be processed through the KazRosGas joint venture (see below). Traditionally, this gas is sold at a substantial discount: average prices earned by KPO for its gas in recent years have been in the range of only $24-27 per thousand cubic meters (Mcm).[33] In comparison, the average price paid by Kazakhstan for its Russian natural gas imports was about $58-59 per Mcm. During this period, the value of the liquids being exported through the CPC was about $100 per barrel at the pipeline's entry point at Atyrau.[34]

The relative economics of reinjection for the upstream operator, KPO, can be illustrated by the proposal to process Karachaganak gas at a local plant that would be constructed, to provide an alternative marketing outlet and to make more gas available for domestic consumption (see below). A feasibility study was done for a plant with a processing capacity of 5 Bcm of gas per year. The alternative proposed by Eni would involve an estimated capital expenditure of $4.9 billion, while the one proposed by Petrofac was estimated to cost $2.5 billion. According to KMG's own estimation, the plant would have cost about $3.7 billion to build. Ultimately, this proposal was shelved because of its high costs: according to deputy energy minister Uzakbay Karabalin when announcing the decision, the plant would need to charge about $100 per Mcm for the dry gas to recover its costs.

At Tengiz, the planned expansion in oil production, which would also greatly increase the amount of sour associated gas extraction,[35] combined with the changes in regulations, also drove the project towards the reinjection option in the 2000s. For example, TCO flared about 2 Bcm per year in 1998-2001, but this had been reduced to only about 0.4 Bcm by 2004. Routine flaring at the project ended altogether in December 2009, following the completion of a long-term gas utilization project that involved $258 million in expenditure. But the key part of the program that would minimize the need for expensive (sour) gas processing and ease the project's sulfur storage problem, was sour gas reinjection. TCO's view is that injecting more gas into the reservoir helps to both partially offset the pressure drop and sweep the oil through the reservoir, both of which increase recoverable reserves. According to TCO's General Director at the time the reinjection project was being proposed, gas reinjection would ultimately add about 3 MMt of oil production per year during the field's eventual decline phase. The project's second-generation plant and sour gas injection (SGP/SGI) expansion (implemented in 2004-2008) involved a capital expenditure of around $5.5 billion; this increased oil production capacity for the project from about 335,000 b/d (15.5 MMt per year) to 585,000 b/d (27 MMt per year). This same element also figures prominently in Tengiz's next expansion phase that is expected to be completed in 2021; known as the Future Growth Project (FGP), it will add another 250,000 b/d (12 MMt per year) of capacity.

7.3.3.1. Foreign-partnered projects remain key producers

Kazakhstan's gas production comes mostly from its major international oil company–partnered projects, with the BG- and Eni-led Karachaganak Petroleum Operating B.V. (KPO) being the most important, followed by the Chevron-led TengizChevroil (TCO) joint venture (JV) (see Figure 7.3.3).[36] KPO and TCO together currently account for over 75% of Kazakhstan's gross gas production.

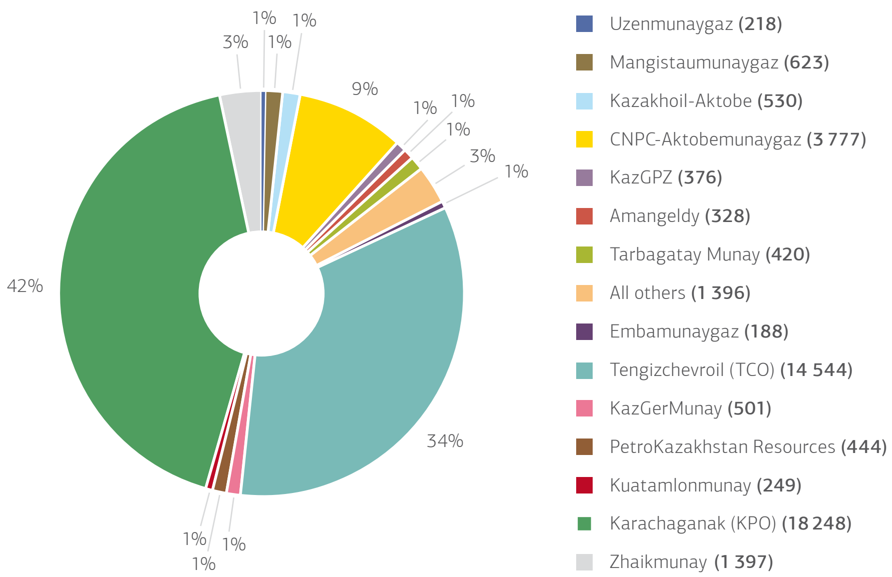
KPO—whose partners include Eni 29.25%, BG 29.25%, Chevron 18%, LUKOIL 13.50%, and KMG 10% in the Karachaganak field—is one of the largest gas reserve holders and the largest producer in Kazakhstan currently, with significant upside potential in the coming years. Karachaganak holds gross reserves estimated at over 325 million metric tons (MMt) of liquids and over 800 Bcm of gas. TCO—whose partners include Chevron 50%, KMG 20%, ExxonMobil 25%, and LUKOIL 5%—in the Tengiz and Korolevskoye fields—holds gross reserves of about 1 billion metric tons of liquids and over 700 Bcm of gas.

[33] The agreed upon-price that KRG receives for the dry processed gas is $85 per Mcm.

[34] That is, international prices for CPC Blend minus marine freight costs and the CPC pipeline tariff. The phase 2 expansion program at Karachaganak included the construction of a 635-km pipeline for stabilized condensate from the field to Atyrau, connecting to the CPC export trunk pipeline. This pipeline went into operation in 2001.

[35] The GOR for Tengiz, because it is an oilfield, is much lower than at Karachaganak, but it is still relatively high, at over 0.5. That is, each ton of oil extracted at the field results in over 0.5 Mcm of associated gas.

[36] BG is being acquired by Shell in a deal announced in March 2015 in a deal valued at $70-75 billion.



Source: IHS Energy, Ministry of Energy

Figure 7.3.3 Kazakhstan's (gross) natural gas production by largest producers in 2014 (MMcm)

While KPO in West Kazakhstan Oblast produced 18.2 Bcm in 2014 and 17.5 Bcm in 2013, over half of its sour gas (9.3 Bcm in 2013 and 9.8 Bcm in 2014) was reinjected, while nearly all the rest flowed to the Orenburg gas processing plant in Russia through dedicated pipelines built in the Soviet era.[37] The lack of local processing capacity at Karachaganak and the lack of alternative pipeline connections to other consuming centers limit the consortium's ability to market KPO's (sour) gas. With the plans for constructing a domestic processing plant now on indefinite hold (see below), the operators will continue to depend on swap agreements with Gazprom to market KPO gas.

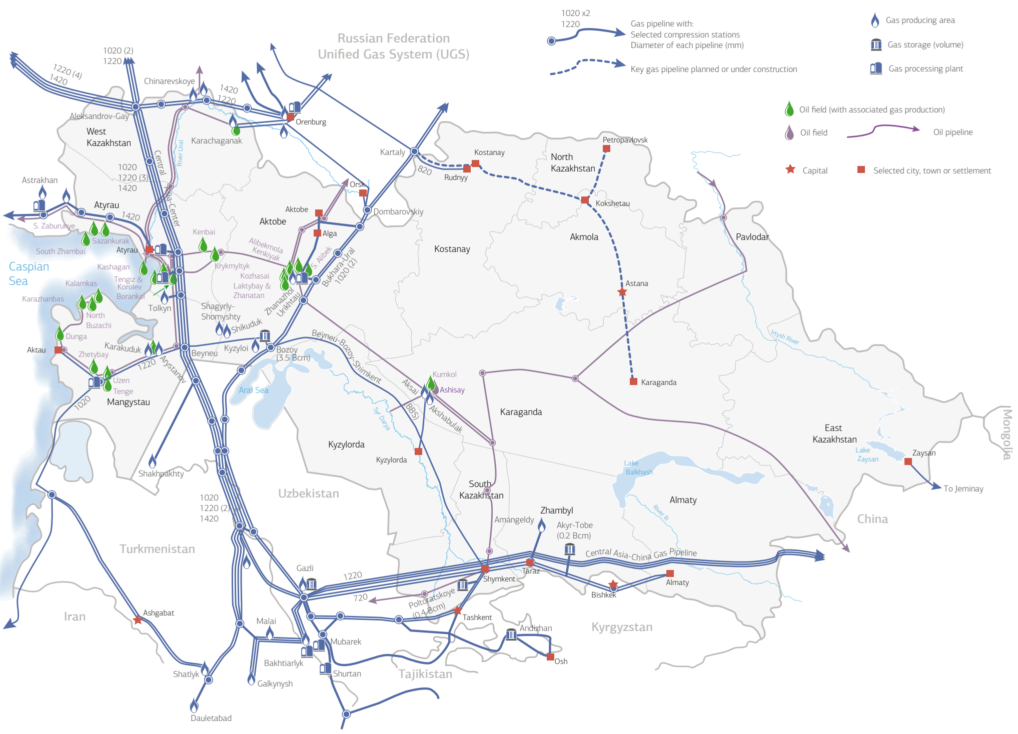
TCO, located in Atyrau Oblast, produced 14.5 Bcm in 2014 and 14.6 Bcm in 2013. In 2014, about 7.5 Bcm was reinjected. This left 7.0 Bcm of TCO gas in 2014 as "commercial" production.[38]

Other important gas producers include (see Figure 7.3.3; also Figure 7.3.4):

1. CNPC-AktobeMunayGaz, with total gas production of 3.8 Bcm in 2014 (in Aktobe Oblast),
2. private company Nostrum Oil and Gas (Zhaikmunay) with 1.4 Bcm (West Kazakhstan Oblast),
3. Sinopec-partnered Kazakhoil-Aktobe with 531 million cubic meters (MMcm) (in Aktobe Oblast),
4. CNPC-partnered MangistauMunayGaz (MMG) with 623 MMcm (Mangistau Oblast),
5. CNPC-partnered KazGerMunay with 501 MMcm (Kyzylorda Oblast),
6. CNPC-partnered PetroKazakhstan (PKZ) with 444 MMcm (Kyzylorda Oblast),
7. the KTG-operated Amangeldy field with 328 MMcm (Zhambyl Oblast).

[37] The initial project that launched large-scale (sour) gas reinjection in Kazakhstan was Karachaganak, beginning in 2003; reinjection scaled up starting in 2004.

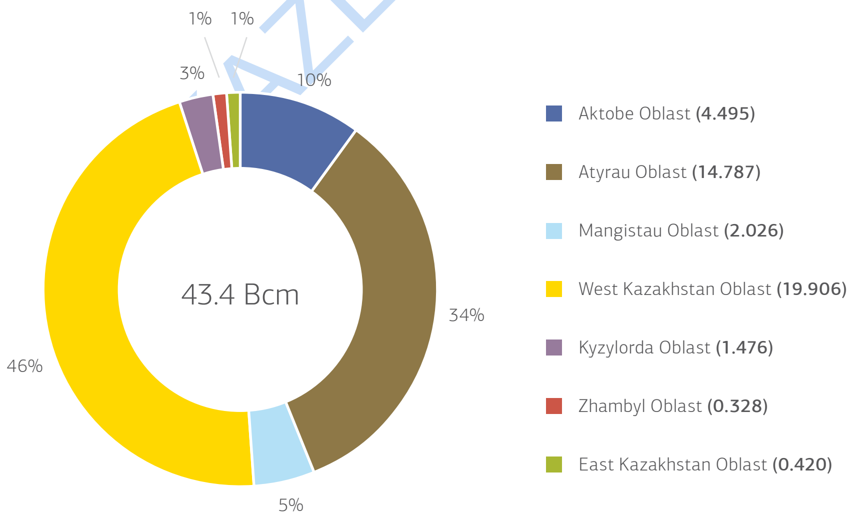
[38] The other field that currently employs reinjection is the Kozhasai field in Aktobe Oblast (since 2006), which is being developed together with the neighboring Alibekmola field. This project is part of a 50/50 joint venture between Caspian Investment Resources and KMG. In April 2014, LUKoil Overseas reached an agreement to sell its remaining stake in Caspian Investment Resources to Sinopec, but this arrangement was never completed. LUKoil had acquired the project stake when it acquired Caspian Investment Resources in 2005, when it bought Nelson Resources together with Sinopec.



Source: SEEPX Energy, IHS Energy

Figure 7.3.4 Map of Kazakhstan's major gas fields

Nearly 94% of Kazakhstan's gas production is in the oblasts of western Kazakhstan (see Figure 7.3.5). The largest producer among the oblasts is West Kazakhstan Oblast as the host of the Karachaganak project. The other large contributor is Atyrau Oblast.



Source: IHS Energy, Kazakhstan statistical agency
Note: Aktobe, Atyrau, Mangistau, and West Kazakhstan oblasts are in western Kazakhstan.

Figure 7.3.5 Kazakhstan's (gross) natural gas production by oblast in 2014 (Bcm)

7.3.4. Natural gas production outlook

KMG essentially reaffirmed Kazakhstan's oil-focused strategy in 2014 when it put off plans to construct a 5 Bcm per year domestic gas processing plant at Karachaganak—the country's largest gas field—that would have been part of a plan to increase gross gas output at the field considerably (see below). The KMG estimate of $3.7 billion for constructing the processing plant, on top of the total estimated cost of the third expansion phase at the field (ranging between $15 billion to over $30 billion, depending upon the precise scope, which remains a key point of discussion between the partners and the government), made the new plant's economics quite difficult.[39]

Gas production in the country is expected to remain tied to oil production trends longer term. It is unlikely that material upstream developments will be pursued aimed at producing natural gas alone. This is because the domestic gas market does not provide strong incentives for such development given relatively low gas prices on the domestic market. However, some dry gas producers, whose production costs are low and involve minimal gas processing, might still be able to make profit even with the current low gas prices.

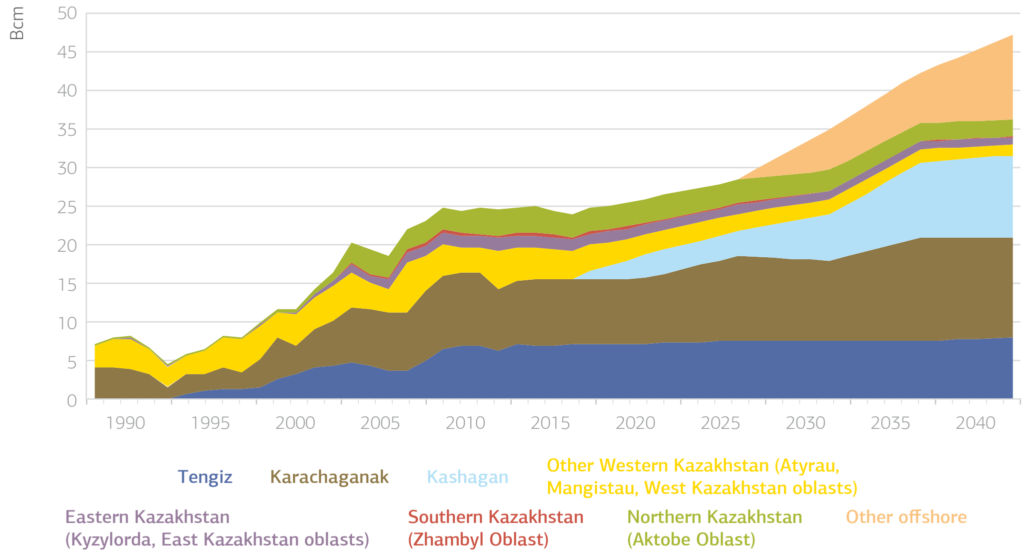
For much of its future increases in gas production, Kazakhstan will depend heavily on the development of the Kashagan field by the North Caspian Operating Company B.V. (NCOC), which partners KMG (16.88%), along with Eni, ExxonMobil, Shell, Total (with 16.81% each), CNPC (8.33%), and Inpex (7.56%). The Kashagan project (NCOC) has gross estimated reserves of 1.4 billion metric tons (11 billion barrels) of liquids and about 1.7 Tcm of gas. Kashagan's associated gas contains a lot of sulfur (about 18% H_2S and 4–5% CO_2). More than 50% of Kashagan's gas is planned to be reinjected, with the rest treated and marketed. High reservoir pressure necessitated the installation of powerful compressors (35 megawatts) specially built for the project. A total of 6.2 Bcm of processing capacity has been installed, so up to that amount of raw gas can be diverted to the onshore processing plant. Processing capacity was planned to expand to 9 Bcm eventually (under the second phase of the project). In August 2013, NCOC and KTG signed a long-term purchasing agreement where KTG would buy 2.5-3.0 Bcm of Phase 1 processed dry gas annually through 2041 (the current expiration of the PSA).

- For developing Kazakhstan's overall production outlook, we project gas production for several large regional groupings (not to be confused with Kazakh oblasts which have the same names) as well as the major individual projects: these categories are Tengiz, Karachaganak, Kashagan, Other offshore, Other West Kazakhstan (producers in Mangistau, West Kazakhstan, Aktobe, and Atyrau oblasts), East Kazakhstan (which includes producers in both Kyzylorda and East Kazakhstan oblasts), South Kazakhstan (Zhambyl Oblast), and North Kazakhstan (Aktobe Oblast) (see Figure 7.3.6).[40] The main sources of gas in 2030 are projected (in our base-case) to be Tengiz (23 Bcm of gross production and 7.5 Bcm of commercial gas), Karachaganak (22 Bcm of gross production and 10 Bcm of commercial gas), and Kashagan (13 Bcm of gross production and 6 Bcm of commercial gas). But the key factor is Kazakhstan's overall oil production outlook, as this is the principal driver for gas production as well. Commensurate with the base, low, and high scenarios for Kazakh oil production (see section above), the availability of commercial gas production volumes can also be quite different (see Figure 7.3.7). The base-case gas production outlook is consistent with the assumptions included in the IHS base-case oil production outlook, as detailed above in the crude oil production section.

According to the government's official outlook (prepared by the Ministry of Energy), gross gas production will increase to 62 Bcm of gas per year in 2020, and remain at about that level through 2030 (see Table 7.3.3). At the same time, the Ministry's definition of "commercial" gas (i.e., the amount available for distribution to consumers after taking out upstream and midstream usage) is expected to also remain relatively flat, at about 21-22 Bcm through 2030. IHS Energy's own outlooks envision that both gross gas production and commercial gas production will be slightly higher than this longer term. We project that gross output will reach about 48 Bcm per year in 2020 and 72 Bcm in 2030 in our base-case, while volumes of commercial gas are expected to increase to about 26 Bcm per year in 2020 and 35 Bcm in 2030 (see Table 7.3.4). The main factor that explains the difference with IHS's outlook is differing views on the overall outlook for oil production in Kazakhstan, and a differing composition among the different producers; these key differences were discussed above in the oil production section.

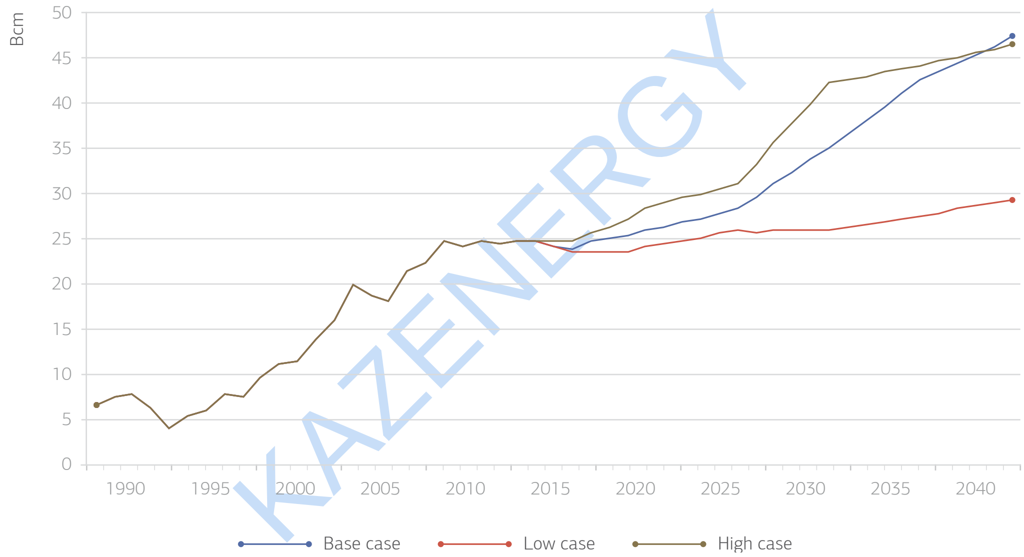
[39] Initially, the third stage was projected to increase production of liquids to 15 MMt per year and raw gas output to 38 Bcm per year. Other expansion concepts have liquids production holding steady at 11.0–11.5 MMt per year, with gas extraction increasing to as much as 40 Bcm per year.

[40] Kyzylorda Oblast is included in the eastern Kazakhstan category for gas production because it had no pipeline connections with other parts of Kazakhstan, so for the past two decades it was isolated, with consumption in the geographical area equaling production. It had to be considered in a separate category from southern Kazakhstan, which consumes mainly imported Central Asian gas. With the completion of the Bozoy-Shymkent pipeline segment, in 2013 this is no longer the case however: Kyzylorda's gas is now linked into southern Kazakhstan. Similarly, East Kazakhstan Oblast is not connected with the rest of Kazakhstan, although it has a small pipeline connection to China.



Source: IHS Energy

Figure 7.3.6 Outlook for Kazakhstan's gas production, base-case (commercial volumes)



Source: IHS Energy, EOEO

Figure 7.3.7 Outlook for Kazakhstan's gas production by scenario (commercial volumes)

						Forecast			
	2010	2011	2012	2013	2014	2015	2020	2025	2030
Total gas production (gross volumes)	37.4	39.5	40.3	42.4	43.2	44.2	62.0	61.0	59.8
Gas reinjection	13.0	14.9	15.8	17.8	18.4	12.5	22.8	24.8	25.1
Other upstream use for processing and internal needs (including flared volumes) *	11.1	9.8	8.6	6.8	6.4	5.6	5.9	5.5	5.3
Total commercial gas production	24.1	24.7	24.4	24.6	24.8	26.1	33.3	30.7	29.4
Fuel gas for pipeline use. including gas turbines*	2.7	2.9	3.0	2.9	1.8	3.9	8.6	8.5	8.4
Commerical gas for distribution (to consumers. export. etc.)	21.4	21.7	21.4	21.7	23.0	22.2	24.7	22.3	21.0

** The Ministy of Energy presents the own and internal use data breakdown in this fashion: Other Upstream use and separately fuel for gas pipeline use, including gas turbines.*

Source: Ministry of Energy report, Republic of Kazakhstan Gas Supply to 2030, 5 December 2014.

Data for 2010-2014 compiled by IHS Energy from various sources, including reports from the Ministry of Energy.

Table 7.3.3 Gas supply forecast for Kazakhstan: Ministry of Energy (billion cubic meters)

	2005	2010	2015	2020	2025	2030	2035	2040
Production (total as reported; gross volumes)	25.0	37.1	42.8	47.6	57.8	71.8	75.4	76.7
Production (excluding reinjected volumes)	18.9	24.1	24.1	25.8	28.2	34.7	42.0	46.7
Reinjected volumes	6.0	13.0	18.7	21.8	29.6	37.1	33.4	30.0
Exports**	15.4	14.5	11.7	10.1	7.8	11.8	14.3	16.0
Imports**	11.2	4.0	6.0	6.3	6.3	6.0	6.0	6.0
Consumption (apparent; gross)	20.8	26.7	37.1	43.8	56.3	66.0	67.1	66.7
Consumption (apparent; excluding reinjection)	14.7	13.7	18.4	22.0	26.7	28.9	33.7	36.7
Reported deliveries*	7.3	9.0	13.4	16.8	20.6	22.3	27.2	30.8
Other consumption***	7.5	4.7	5.0	5.2	6.1	6.6	6.5	5.9

** Amount reported as consumption (end-of-pipe deliveries) by the Ministry of Energy or Kazakh statistical sources.*
*** Amount reported by Kazakh statistical authorities; actual "operatonal" export volumes are much lower ("operational" volumes shown for 2015 and after).*
**** Other domestic disappearance: includes upstream losses and shrinkage, use and losses in the pipeline system, and any changes in stocks.*
Source: Ministry of Energy; Kazakhstan Statistical Agency; IHS Energy (Eurasian Gas Export Outlook)

Table 7.3.4 Kazakhstan's gas balance: outlook to 2040 (IHS base-case) (billion cubic meters)

7.3.5. Gas processing

Kazakhstan has three major gas processing plants (GPZs) as well as an arrangement for Karachaganak gas processing across the border at Russia's Orenburg gas processing plant (see below).[41] These three plants now have a processing capacity of 19.8 Bcm per year, up from 12.3 Bcm in 2008. These include the Kazakh, Tengiz, and Zhanazhol plants. The Kazakh plant, in Mangistau Oblast, processes associated gas from the Uzen and Zhetybay fields; it has a capacity of 2.9 Bcm per year. The Tengiz plant has a capacity of 7.9 Bcm per year. The Zhanazhol plant (in Aktobe Oblast) belongs to the field operator, CNPC-Aktobemunaygaz. The Zhanazhol plant has three trains, with a total capacity that has now reached 9 Bcm per year a result of recent additions in mid-2014. The main addition that is forthcoming to bolster the country's processing capability is the 6 Bcm plant at Kashagan (see above). In aggregate, together with the availability of Russian capacity at Orenburg, this amount appears adequate to handle the bulk of Kazakhstan's expected volumes of commercial gas for the next decade or so.

[41] There are other (smaller) field-type gas processing/preparation facilities for associated gas operated by other producers. These include facilities at Karakuduk, which went into operation in December 2008, or the gas plant at Zhaikmunay's (now Nostrum Oil and Gas) Chinarevskoye field, which came fully on line in 2012. There is also a plant at KMG's Amangeldy gas field, which produces mainly liquids.

7.3.5.1. Karachaganak-Orenburg gas processing plant relationship

In 2014, about 8.4 Bcm of Karachaganak sour gas was sent to the Orenburg gas processing plant across the Russian border for processing, an arrangement which has traditionally been handled by a Kazakh-Russian joint venture, KazRosGas (KRG), which was set up in 2002 between KMG and Gazprom (see text box). While the KRG joint venture has controlled export (and domestic) sales from Karachaganak, this role was supposed to eventually shift to KazTransGaz as a result of the 2012 Law on Gas and Gas Supply (see below). In June 2015 KMG's 50% share in KazRosGas was transferred to the trust management of KazTransGaz. KRG still manages exports and domestic sales from Karachaganak. Some Karachaganak gas is used domestically, although nearly all the raw gas is exported to neighboring Russia for processing at the Orenburg facility.

The arrangement with Gazprom also figures critically in domestic supply as well as Kazakhstan's gas exports. The gist of the swap operation is that Gazprom supplies Uzbek gas to the southern oblasts of Kazakhstan and its own gas to northern Kazakhstan, in exchange for the gas that is delivered from the Karachaganak field at the Russian-Kazakh border. Nearly half (48%) of Kazakhstan's actual end-of-pipe consumption in 2013 was met with imports (either from Russia or Central Asia), as current gas infrastructure in Kazakhstan does not connect many production areas to demand centers yet.

KazRosGas

The KazRosGas (KRG) joint venture was established under an intergovernmental agreement between Russia and Kazakhstan in November 2001, ostensibly for jointly marketing Kazakh (and other) gas to Europe. Although the entity was established with a broad mandate for activity in production, marketing, and transport of Kazakh and Russian gas, its main focus has been as the intermediary handling of Karachaganak gas being processed at Russia's Orenburg plant. But it has also handled some gas offtake from TCO.

The volumes of gas handled by KRG have increased over the years, as Karachaganak production has expanded. In 2012, KRG purchased 8.0 Bcm of Karachaganak raw gas for processing at the Orenburg processing plant, from which it received 6.9 Bcm of processed dry gas, as well as other products, including sulfur, LPG, ethane, and stable condensate. This compares with 5.5 Bcm of raw gas delivered in 2003, from which it obtained 4.8 Bcm of dry gas. It delivers some of the processed dry gas directly to consumers in West Kazakhstan Oblast and swaps the remaining volume for gas delivered by Gazprom to Kostanay Oblast (Russian gas) and southern Kazakhstan (Uzbek gas). KRG delivered 4.0 Bcm to customers in Kazakhstan and sold 2.9 Bcm as "exports" outside Kazakhstan in 2012. The distribution of KRG's domestic sales is approximately one quarter each to West Kazakhstan and Kostanay oblasts and about half to southern Kazakhstan. In 2013, KRG sent 8.2 Bcm to Orenburg and received 6.3 Bcm of network-quality gas in return.

A 2008 intergovernmental agreement (IGA) between Russia and Kazakhstan for sour gas shipments from Karachaganak envisaged a deeper relationship between the two countries, with Kazakhstan taking part ownership of the Orenburg processing plant. But the IGA was never implemented because it would have required an up-front investment by KMG of about $350 million in the Orenburg processing enterprise, along with a long-term delivery commitment of gas from Karachaganak. However, the trade relationship continues because of its usefulness for both sides. The agreement has now been extended. In June 2015, KPO and KazRosGas extended their arrangement through 2038. The annual amount going to Orenburg was slated to rise to 16 Bcm under the previous contract. The new contract reduced the annual deliveries to no more than 9 Bcm. Thus the new deal appears to indicate that the third phase expansion, which was going to increase raw gas production considerably, appears to be on hold indefinitely or that plans for an indigenous processing plant at Karachaganak might be resurrected to handle any expanded output. But the contract extension secures an outlet for the bulk of KPO's current gas production for the remaining period of the production-sharing agreement for the field.

7.3.6. Gas transportation in Kazakhstan

Kazakhstan does not really have a unified national gas transmission system, partially owing to the legacy of central planning, when trunk pipelines were constructed for transit purposes. Furthermore, Kazakhstan's local pipeline distribution networks are very sparsely developed. Most piped gas is consumed in large population centers along the sparse trunk pipeline routes rather than being widely distributed among smaller cities, towns, and settlements. But activities are under way to expand these networks and to increase the overall level of gasification. The length of distribution pipelines in the country reached 25,601 kilometers (km) in 2014, with about 11,698 km added to the network since 2007 (see Table 7.3.5).[42] The largest distribution networks are in South Kazakhstan, West Kazakhstan, and Atyrau oblasts. These pipelines delivered 8.6 Bcm in 2014, which was actually higher than in any year since in 2007 (see Table 7.3.6).

Oblast	2007	2008	2009	2010	2011	2012	2013	2014	Change 2007-14	Regional Share
Total for Kazakhstan	13 903	14 695	16 260	17 773	20 249	21 525	23 525	25 601	11 698.3	100.0
Akmola	-	-	-	-	-	-	-	-		
Astana city	-	-	-	-	-	-	-	-		
Aktobe	748	747	867	927	938	1 002	1 088	1 100	352.0	3.0
Almaty	363	417	476	504	518	725	947	1243	880.0	7.5
Almaty city	406	444	602	648	664	664	798	934	528.7	4.5
Atyrau	1 944	2224	2 882	3 432	3 803	3 838	4 229	4 695	2 751.6	23.5
West Kazakhstan	2 904	2 921	2 941	2 972	3 070	3 192	3 334	3 571	667.2	5.7
Zhambyl	543	545	748	755	772	1 003	1 199	1 529	985.8	8.4
Karaganda	-	-	-	-	-	-	-	-		
Kostanay	1 872	1 898	1 901	2 096	2 186	2 281	2 328	2 394	521.5	4.5
Kyzylorda	144	159	159	339	823	1 049	1 072	1 109	964.6	8.2
Mangistau	1 285	1 447	1 560	1 646	1 681	1 681	1 681	1 681	395.5	3.4
South Kazakhstan	3 693	3 893	4 124	4 455	5 794	6 090	6 848	7 407	3 713.4	31.7
North Kazakhstan	-	-	-	-	-	-	-	-		
East Kazakhstan	-	-	-	-	-	-	-	38	38.0	0.3

Source: Kazakhstan Statistical Agency (Housing and Communal Economy).

Table 7.3.5 Length of gas distribution pipelines in Kazakhstan (kilometers)

[42] Different data from the Ministry of Energy available for 2013 indicate slightly higher length for the gas distribution system of Kazakhstan.

Region	Length, km
Almaty city and Almaty oblast	3,690.00
Aktyubinsk oblast	2,110.03
Atyrau oblast	3,771.04
Zhambyl oblast	3,388.20
Western Kazakhstan	3,723.72

Region	Length, km
Kyzylorda oblast	1,049.70
Kostanay oblast	1,970.59
Mangystau oblast	2,477.22
Southern Kazakhstan	5,928.68
TOTAL for Kazakhstan	**28,109.18**

Source: The Ministry of Energy of the Republic of Kazakhstan

Oblast	2007	2008	2009	2010	2011	2012	2013	2014
Total for Kazakhstan	**7 615**	**6 891**	**6 206**	**6 064**	**7 131**	**7 478**	**7 303**	**8 639**
to population	1 498	1 680	1 822	1 981	2 380	2 620	2 608	3 220
for communal needs	431	488	398	407	504	448	580	600
other consumers	5 685	4 723	3 987	3 676	4 247	4 411	4 116	4 819
Aktobe (total)	980	982	1 015	1 138	1 223	1 222	1 237	1 422
to population	197	205	230	249	298	312	315	375
for communal needs	59	54	69	35	82	43	43	49
other consumers	723	724	715	854	843	868	880	998
Almaty (total)	139	101	120	134	169	213	293	364
to population	45	55	57	59	89	113	154	226
for communal needs	8	4	7	13	11	19	53	36
other consumers	86	42	57	62	69	81	86	102
Almaty city (total)	1 140	1 075	1 166	943	1 034	1 157	1 183	1 297
to population	272	274	303	380	402	436	402	432
for communal needs	104	96	-	-	-	-	36	2
other consumers	763	705	863	563	633	722	746	864
Atyrau (total)	712	764	598	441	561	614	575	667
to population	156	201	233	237	311	330	311	369
for communal needs	35	51	48	39	48	47	91	99
other consumers	521	511	317	166	202	237	174	199
West Kazakhstan (total)	553	561	593	615	705	662	655	730
to population	159	173	177	194	234	231	230	292
for communal needs	83	124	122	152	184	146	144	190
other consumers	311	264	294	270	287	285	281	247
Zhambyl (total)	1 060	1 517	835	801	1 277	1 399	1 048	1 359
to population	174	204	213	236	292	320	251	332
for communal needs	7	9	15	16	21	25	27	33
other consumers	879	1 304	607	549	965	1 054	770	995
Kostanay (total)	176	186	187	196	222	223	237	556
to population	104	109	107	116	131	140	151	144
for communal needs	59	61	62	65	73	69	72	71
other consumers	13	16	18	16	19	15	14	342
Kyzylorda (total)	133	120	199	217	231	261	261	423
to population	4	32	46	26	63	86	66	117
for communal needs	1	3	10	11	15	19	43	35
other consumers	128	85	143	180	153	157	152	271
Mangistau (total)	2 221	1 091	1 018	1 041	1 061	995	1 113	920
to population	182	180	211	220	203	230	325	388
for communal needs	53	64	37	48	29	33	22	17
other consumers	1 986	848	769	773	829	732	766	516

Oblast	2007	2008	2009	2010	2011	2012	2013	2014
South Kazakhstan (total)	501	494	476	537	647	733	700	902
to population	206	247	244	266	359	423	405	547
for communal needs	21	23	29	29	41	48	49	69
other consumers	274	224	204	242	248	261	247	286
Akmola (total)	-	-	-	-	-	-	-	-
Astana city (total)	-	-	-	-	-	-	-	-
Karaganda (total)	-	-	-	-	-	-	-	-
North Kazakhstan (total)	-	-	-	-	-	-	-	-
East Kazakhstan (total)	-	-	-	-	-	-	-	0.1
to population								0.0
for communal needs								0.1
other consumers								
Rounding Error	0.1	0.8	0.1	0.0	0.3	–0.1	0.1	0.1

Source: Kazakhstan Statistical Agency (Housing and Communal Economy)

Table 7.3.6 Gas delivered via distribution pipelines in Kazakhstan (million cubic meters)

The government has long held ambitious plans to expand domestic gas consumption by creating a unified national pipeline transportation network, partly to become more "green" (gas has a much lower carbon footprint compared to coal and oil, which currently dominate primary energy consumption). This is also viewed as making the economy more competitive internationally (because of gas's lower total costs and greater efficiency in domestic use).

Improving and developing the country's gas infrastructure is the responsibility of KazTransGaz (KTG). In addition to domestic deliveries, KTG has assumed the responsibility of supplying northern Kyrgyzstan with gas that is delivered from Uzbekistan through a pipeline that transits southern Kazakhstan (Shymkent and Taraz), and then heads to the Kyrgyz capital of Bishkek before ending at Almaty, in Kazakhstan. This is via a long-term contract between KTG and Kyrgyzgaz to supply northern Kyrgyzstan with up to 0.5 Bcm of gas per year.

7.3.6.1. Kazakhstan's existing trunk gas pipelines

Kazakhstan's trunk pipeline system, reported to consist of 16,042 km of trunk pipelines in total, has a transport capacity to handle up to 180 Bcm per year (see Table 7.3.7). Owned and operated through its subsidiaries, by KTG, the system includes 28 compressor stations, with a total capacity over 2,000 megawatts (MW).

Pipeline	Length (km)	Current capacity (Bcm/year)	Year entered operation
Central Asia-Center (CAC)	4 163	60	1966-1970
Soyuz*	424	25	1976
Orenburg-Novopskov	382	15	1975
Kazakhstan-China	2 610	30	2009-2013
Makat-North Caucasus	372	22	1987
Bukhara-Urals	1 577	8	1964
Okarem-Beyneu*	547	7	1972-1974
Bukhara-Tashkent-Bishkek-Almaty	1 639	6	1966; 1999
Gazli-Shymkent	309	4	1988
Beyneu-Bozoy-Shymkent**	1 477	3	2013-2015

** Length includes loop line.*
*** In 2014, only the Bozoy-Shymkent segment was in operation (1,110 km).*
Source: Ministry of Energy

Table 7.3.7 Kazakhstan's principal trunk gas pipelines, 2014

Because most of Kazakhstan's gas in the Soviet period was (and remains) associated gas that is derived as a byproduct of oil, the country's gas output remained insignificant when compared to that of its neighbors to the south, Uzbekistan and Turkmenistan. The latter two have substantial volumes of non-associated gas production. Kazakhstan has served largely as a transit corridor for Turkmen and Uzbek gas being shipped north to Russia, and it has remained a major transit country in the post-Soviet period. However, its transit role has been increasingly shifting to Central Asian gas heading east to China rather than north to Russia in recent years (see text box). A sizable volume of Russian gas has also transited Kazakh territory, mainly on the pipeline segment between Orenburg and Aleksandrov-Gay (Soyuz pipeline).

The principal trunk gas pipelines in Kazakhstan are part of the Central Asia–Center (CAC) transit system, comprising several strings (see Figure 7.3.8). The system was built in the 1960s and 1970s to move Central Asian gas to Central Russia.

Source: SEEPX Energy, IHS Energy

Figure 7.3.8 Kazakhstan's gas trunk pipelines

The CAC extends for over 4,000 km on Kazakh territory, connecting into the Russian pipeline system at Aleksandrov-Gay. CAC also feeds a spur pipeline that extends around the northern Caspian Sea into the North Caucasus. At one time, the plan was to restore the annual capacity of the CAC system to 70–80 Bcm per year (under an agreement signed in May 2007 between Russia, Turkmenistan, Uzbekistan, and Kazakhstan). This did not happen. Instead, with the installation of a new compressor station at Opornaya (Mangistau Oblast) and replacement of 271 km of a 1,420 mm line in 2008, the capacity of the system was increased from 54.6 Bcm to 60 Bcm per year, where it remains today. Plans for further expansion have been shelved because of the dramatic reduction in Central Asian gas transit to Russia after the 2008–2009 global recession, which left Russia awash in its own gas and reduced its need for imports (see text box).

Intergas Central Asia, now a subsidiary of KTG, directly manages most of the company's gas trunk pipelines and is responsible for transportation and storage services. It was established in 1997 when the pipeline system was privatized, being turned over to Belgium's Tractebel. But in 2000, control of the company was transferred to KTG (when that entity was officially established). The main trunk pipelines are:

- **Kazakh section of CAC.** CAC, comprised of five parallel pipelines running from either the Kazakh-Uzbek border or the Kazakh-Turkmen border to Aleksandrov-Gay on the Russian-Kazakh border, has been the main transit route to Russia for Central Asian gas.

- **Orenburg-Novopskov and Soyuz pipelines.** These reach northwestern Kazakhstan from the Orenburg gas processing plant through Aleksandrov-Gay. The Soyuz (export) pipeline extends all the way from northwestern Kazakhstan across southern Russia to the Ukrainian-Slovak border near Uzhgorod. The parallel Orenburg-Novopskov pipeline ends in Ukraine. The original design capacity of the two parallel pipelines was 43 Bcm per year, which is now about 40 Bcm; in 2014 these pipelines reportedly carried 16.9 Bcm.

- **Bukhara-Urals pipeline.** This system consists of two parallel pipelines that were laid in 1963–1964 to transport gas from Uzbekistan to industrial centers in the Russian Urals. The system's capacity has dropped from 14.5 Bcm to about 8 Bcm per year. The northward flow on this pipeline in 2014 was about 3.5 Bcm. In the Soviet period, following the advent of West Siberian gas production in the 1970s, the northern section of the pipeline was reversed, allowing Russian gas to be carried south into Kazakhstan, supplying Kostanay Oblast and Aktobe Oblast.

- **Bukhara (Gazli) –Shymkent–Tashkent–Almaty pipeline.** This pipeline delivers Uzbek gas to southern Kazakhstan. It also transits Uzbek gas to northern Kyrgyzstan (Bishkek). It carried 4.5 Bcm in 2014.

- **Akshabulak–Kyzylorda and the Amangeldy–Compressor Station No.** 5 pipelines. These are newer pipelines (constructed since independence) that move gas from new fields developed in the post-Soviet period in southern and eastern Kazakhstan to regional consumers. Akshabulak is a field developed by the KazGerMunay (KGM) joint venture in the Turgay Basin, while Amangeldy is a new field developed by KTG in Zhambyl Oblast. In 2004, Amangeldy began producing gas, which moves by pipeline connection into the main Bukhara-Shymkent-Almaty pipeline at Compressor Station No. 5.

- **Central Asia–China gas pipeline system.** The Central Asia–China gas pipeline system (CAGP) begins in Turkmenistan. On Kazakhstan's territory this pipeline is operated by a joint venture between CNPC and KTG known as Asia Gas Pipeline LLP (AGP). The pipeline now consists of three operating strings (lines A, B, and C), with a fourth (line D) under construction. It provides an alternate eastward export route for Central Asian gas (to China) in addition to the traditional flow northward on CAC (to Russia). The three operating strings of the CAGP can carry 55 Bcm per year to China (planned to be 40 Bcm from Turkmenistan, 10 Bcm from Uzbekistan, and 5 Bcm from Kazakhstan), following the launch of Line C. Line D will be able to carry an additional 25 Bcm from Turkmenistan across Tajikistan and Kyrgyzstan (rather than through Kazakhstan) to China sometime after 2020, and with envisioned incremental expansion of the other three lines, total Central Asian gas delivery capacity to the Chinese market will be up to 85 Bcm per year, matching the current contracted volumes (see Figure 7.3.8).

In 2008, Kazakhstan's trunk pipeline system carried a total of 116.7 Bcm, but in 2009 the amount had dropped significantly to 91.1 Bcm, owing mainly to a dramatic contraction in the transit of Central Asian gas to Russia as a result of gas oversupply in the market. Since then, total transported volumes of gas began to recover, partially due to increasing transshipments of Turkmen gas to China (see Table 7.3.8). In 2014, the Kazakh gas pipeline system carried a total of 111.7 Bcm, with the bulk of this being transit gas.[43]

[43] KTG's Intergas Central Asia subsidiary is responsible for transporting most of the gas in Kazakhstan, but not all. In 2013 it transported 93.7 Bcm of gas, which included 10.4 Bcm for the domestic market, 12.0 Bcm of exports, and 71.3 Bcm of transit gas.

	2006	2007	2008	2009	2010	2011	2012	2013	2014
Total	121.9	114.2	116.7	91.1	101.7	109.5	109.2	110.2	111.7
Transit shipments	107.6	97.9	97.7	73.2	79.7	89.0	84.7	85.3	88.7
Shipments of Kazakh gas for export*	7.8	8.3	9.6	10.0	13.5	11.9	11.9	12.0	10.6
Shipments for internal consumption	6.5	8.0	9.4	7.9	8.5	8.6	12.6	12.9	12.4

** Operational volumes.*
Source: KMG Annual Report.

Table 7.3.8 Gas transportation by trunk pipelines in Kazakhstan (billion cubic meters)

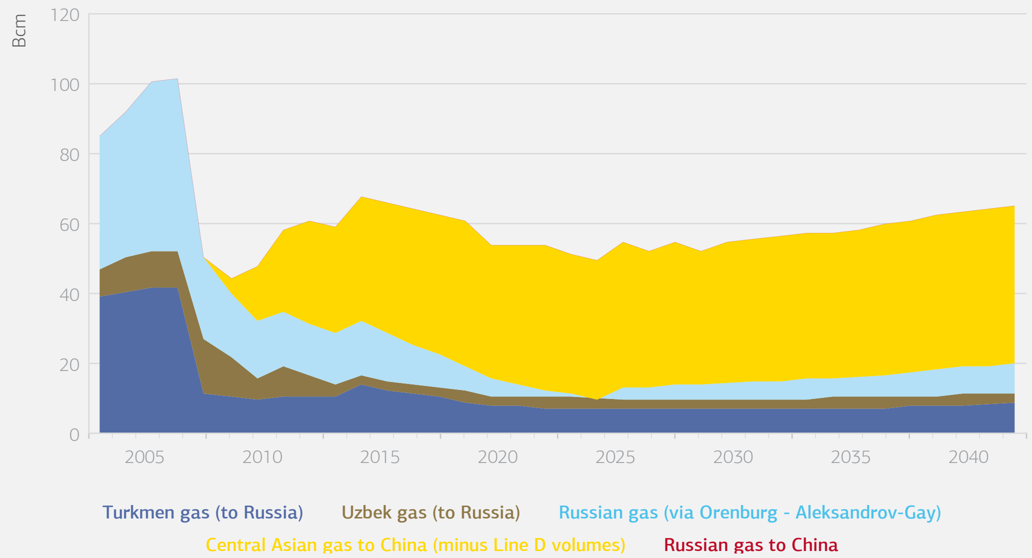
Transit gas has always taken up the largest share of the gas moved through the country's trunk pipeline system. In the years immediately prior to 2008, the pipeline system moved over 100 Bcm per year of transit gas, including about 55 Bcm of Central Asian gas and about 50 Bcm of Russian gas. In 2008, for example, the pipeline system transported 9 Bcm of gas for domestic consumption, which was less than 8% of total flow in the system. Transit amounted to 97.7 Bcm that year, of which 46.1 Bcm was Russian gas, 40.3 Bcm was Turkmen gas, and 11.3 Bcm was Uzbek gas. Going forward, transit flows will remain the largest component of gas flowing in Kazakhstan's pipeline system. However, the volumes flowing north via CAC and Bukhara-Urals are likely to contract, with the bulk of Central Asian transit volumes flowing eastward across Kazakhstan to China via the CAGP system.

But as Kazakhstan's own oil and gas production has increased since the mid-1990s, the country has begun to focus on connecting its own new centers of gas production, such as the Akshabulak and Amangeldy fields, with its demand centers. So Kazakh gas is also expected to become a larger component of overall shipments.

Outlook for Gas Transit Through Kazakhstan

Central Asian Gas. Kazakhstan's transit role for Central Asian gas has shifted over time from carrying gas north to Russia to increasingly carrying gas east to China. The volume of gas carried going north to Russia reached about 53 Bcm in 2007-08, but had dropped to less than 15 Bcm by 2014. At the same time, Central Asian gas going east to China went from zero a few years ago to 31 Bcm in 2014 (see Figure 7.3.9). The volume of Central Asia going to China is expected to increase over time, although some of the total flow between Turkmenistan and China is going to be carried by Line D, which goes through Tajikistan and Kyrzyzstan and not Kazakhstan. This transit volume across Kazakhstan, in our base-case, is expected to reach about 45 Bcm by 2040, which would account for over 60% of total Kazakh transit in that year in our base-case scenario (see Figure 7.3.9). Conversely, flows going north to Russia are expected to continue (although Russia has threatened to end them altogether), but at a level of only about 10 Bcm per year.[44]

[44] See the IHS Energy Insight, Russia's Need for Central Asian Gas Diminishing, but Has It Disappeared?, November 2014.



Source: IHS Energy, Statistics Committee of Kazakhstan
Note: Russian transit volumes are derived as residual (total reported transit minus Central Asian volumes): this figure cannot be reconciled with reported Russian shipments via the Orenburg-Novopskov and Soyuz pipelines.

Figure 7.3.9 Outlook for gas transit in Kazakhstan (base case)

Russian Gas from Orenburg. Transit of Russia gas through northwestern Kazakhstan has traditionally been as large, if not more so, than Central Asian transit flows in the period since 2000. The main flow of Russian gas across Kazakh territory is between Orenburg and Aleksandrov-Gay on the Orenburg-Novopskov and Soyuz pipelines. But volumes have been dropping for this route over time, and amounted to less than 20 Bcm in 2014. Given the ongoing shift in Russian gas production within West Siberia, from the Nadym-Pur-Taz region to the Yamal Peninsula longer term, this likely means a further gradual reduction of gas flows in southern Russia of West Siberian gas. Therefore, we project a gradual decline in flows of Russian gas between Orenburg and Aleksandrov-Gay, and therefore in overall Russian transit (see Figure 7.3.9).

Russian Gas to China. Another prospect for Kazakhstan is to attract Russian gas exports destined for China to transit Kazakh territory. In 2014, Kazakhstan's Energy Ministry proposed that Russia use a pipeline route through Kazakh territory (between West Siberia and the main border crossing into China at Alashankou or even further south at Khorgos) instead of the more challenging Altay pipeline route directly between West Siberia and western China. Most likely, the proposed Kazakh route would involve constructing a pipeline between Ishim and Astana via Petropavlovsk, and then from Astana to Atasu and Alashankou, a distance of about 1550 kilometers, of which less than 100 kilometers would be on Russian territory; a pipeline extending south to Khorgos (to join the flow in the existing Central Asia-China pipeline system, near Almaty, would involve an additional distance of about 750 kilometers.[45] But at this juncture, the prospects for this project happening are quite low, as the emergence of a second ("western") route for Russian gas to China is far from a done deal, and both sides appear determined to avoid transit through other states should the project eventually go ahead.

For the time being, Russian gas exports to China are focused mostly on the "eastern route" that involves constructing a new pipeline ("Power of Siberia") from new fields in East Siberia to northeast China.[46] Work on both field development and pipeline construction is now in full swing to meet the delivery date of first gas to China in 2019. But Russia has continued to press China to sign a second deal, to also take gas through a "western route" from existing West Siberian fields. After a decade of negotiations with China National Petroleum Corporation (CNPC), Gazprom appears to have broken through Chinese resistance to its preferred gas supply option for the Chinese market, the Altay pipeline, with a second preliminary memorandum of understanding being signed between the Russian and Chinese presidents on 8 May 2015, reiterating what was agreed in an initial agreement reached in 2014.[47] This is still a long way from having a final contract, as it took several years of further negotiations on the "eastern pipeline route" between when the same type of memorandum

[45] Since nearly all the pipelines that flow south within West Siberia are full, most likely the route would have to include construction of a trunk pipeline all the way from the producing area in the Nadym-Pur-Taz region in northern West Siberia rather than just an extension from the southernmost sections of the trunk pipeline system. For example, the Tyumen-Ishim-Omsk pipeline, the feeder for the proposed new trunk line through Kazakhstan, is itself only a small-diameter (530 mm), low-capacity pipeline.

[46] See the IHS Energy Insight, Russia-China Gas Deal: The Winding Road to an Agreement, May 2014.

[47] See the IHS Energy Insight, Framework Agreement Signed for Additional Russian Gas Deliveries to China via Western (Altay) Pipeline. But Is China Really Ready to Agree?, November 2014.

was struck and the conclusion of a final contract in May 2014. For Gazprom, relying on already developed gas fields in West Siberia, which can also supply European export markets, is highly desirable. But the Altay pipeline is less attractive for CNPC, which will have to invest in the construction of expensive new infrastructure in China through an area already receiving large volumes of Central Asian gas. The initial framework agreement for the Altay pipeline, signed in Beijing on 9 November 2014, calls for the delivery of 30 Bcm per year for 30 years from West Siberian fields to China's Xinjiang Uyghur Autonomous Region, via a pipeline that would cross through the narrow area in the Altay region where Russia and China share a common border.

Gazprom currently has excess productive capacity of 150 Bcm per year in West Siberia, so it would not have to expand upstream investments to have sufficient gas available for Chinese exports. With domestic demand flat, increasing gas exports remains key for Gazprom to monetize its available West Siberian resources. To supply the route, Gazprom plans to construct an entirely new export pipeline, although the route essentially parallels an existing (small-diameter) pipeline that already extends from the Middle Ob oil-producing region of West Siberia (Samotlor) all the way to the Altay Republic (Gorno-Altaysk). The new pipeline would extend about 2,600 kilometers from the main gas-producing area in northern West Siberia (Purpeyskaya compressor station) to the Chinese border. It would cross the rugged Altay Mountains into China via the Ukok Plateau, and would transit the Kanas Pass (at 2,712 meters in elevation). According to Gazprom, the new pipeline would begin some 200 kilometers south of the Arctic Circle at the Purpeyskaya compressor station in the Yamal-Nenets Okrug in West Siberia and run south, requiring a major crossing of the Ob River and at least a dozen smaller rivers, with construction in the final sections at altitudes of up to 2,600 meters.

In addition to the difficult terrain, the Altay pipeline faces a major hurdle on the Russian side. The Ukok Plateau is a UNESCO World Heritage Site, mainly because of archeological sites, but also due to its pristine environment. This will undoubtedly lead to opposition from environmental and other groups, with UNESCO already issuing a statement that building a pipeline through the area is "highly inappropriate." The general region also is seismically active, with a 7.3 magnitude earthquake occurring in September 2003, resulting in significant damage in inhabited areas in Altay Kray. Gazprom insists that the pipeline can be constructed through the Altay's nature preserve where economic activities are allowed without significant environmental disruption.

In China, the challenges are also high for this route. The northern parts of Xinjiang, where the Altay pipeline enters China, are completely lacking in infrastructure. In order to join China's West-East Pipeline (WEP) system, the route from Kanas Pass to Karamay would traverse two more mountain ranges, several rivers, and parts of China's second largest desert. From there, the gas would transit 4,000 km to the east through the WEP system before reaching China's major consuming coastal markets. To accommodate these supplies, a fifth branch of the WEP would need to be built.

Xinjiang is already one of China's biggest gas producing regions and already hosts four WEP pipelines to transport indigenous and Central Asian gas, largely from Turkmenistan, but also from Kazakhstan and Uzbekistan. Central Asian gas imports are expected to eventually reach 85 Bcm per year.

According to Gazprom, a final commercial agreement with pricing and technical details for gas shipments via the Altay pipeline is projected to be reached by the end of 2015, while an intergovernmental agreement covering the legal aspects of the project and details on the financing would come after. However, the pricing terms for the Altay pipeline may prove difficult to hammer out. Gazprom will not want to concede a price discount for China on the same gas that can be sold in Europe, and would want to establish the same netback value at the wellhead in West Siberia between the two markets. Given the cost of constructing a pipeline from West Siberia to the Chinese border in the Altay region, the delivered price at the Chinese border therefore would have to be relatively high. But it is doubtful that China would accept a border price for Russian gas that is higher than Central Asian gas, even if the pipeline costs made this necessary to provide the same wellhead netback as for European gas exports. Gazprom would like to establish a direct link between exports to China and gas supplies to Europe as a signal to Europe that it has other export options for its gas.

Because of its entry point, Russian gas piped through the Altay pipeline will have less value for China than Russian gas supplied from East Siberia or Sakhalin into the northeast provinces. It is also unclear why China would want to enter into another long-term pipeline supply commitment at this time when it may now be poised to benefit from downward price pressure on more flexible LNG supplies.

7.3.6.2. Beyneu-Bozoy-Shymkent pipeline

KTG's flagship project, the Beyneu-Bozoy-Shymkent pipeline, currently under construction in a 50/50 joint venture between KTG and the China National Petroleum Corporation (CNPC) subsidiary Trans-Asia Gas Pipeline, is part of the larger Central Asia Gas Pipeline (CAGP) network for regional exports to China. It is a significant component of KMG's overall gas transportation strategy. Beyneu-Bozoy-Shymkent will supply oblasts in Kazakhstan's south, where the government seeks to reduce long-standing import dependence on Uzbekistan. Kazakhstan wants to eliminate its dependence on Uzbek gas imports, which are handled through a gas swap agreement between Uzbekistan, Russia, and Kazakhstan. Uzbek gas is delivered to Kazakhstan by Gazprom, and Kazakhstan in turn ships the same volume of gas to Russia, with up to 4 Bcm per year involved in this arrangement. The Beyneu-Bozoy-Shymkent pipeline will eventually link to Line C of the CAGP—also constructed in a JV with CNPC. This will allow China to access piped gas from Kazakhstan.

Construction of the Beyneu-Bozoy-Shymkent pipeline began in August 2012; its estimated cost is $3.8 billion (financed largely with loans from the China Development Bank). The long-term plan is for the pipeline to carry up to 15 Bcm per year (including 5 Bcm of Kazakh gas exported to China), but its initial designed capacity is 10 Bcm per year.[48] The portion of the pipeline between Bozoy and Shymkent (1,166 km) was completed in September 2013. This portion allows domestically produced gas to flow south, initially from Aktobe Oblast, following reversal of one of the strings of the Bukhara-Urals system. In 2013 about 300 MMcm of gas flowed via the new pipe into southern Kazakhstan, while in 2014 1.6 Bcm of gas flowed through the pipeline. The second stage of the pipeline, the 311 km segment between Beyneu and Bozoy, is planned to be completed in 2015–2016.

7.3.6.3. Kartaly-Astana pipeline

The other major gas pipeline that Kazakhstan has been seeking to develop is to the capital of Astana from Kartaly in Russia's Chelyabinsk Oblast in the southern Urals, also referred to as the West-North-Center gas trunkline. This project fits with the government's broader gasification goals for the country. Due to Soviet legacy logistics, Kazakhstan's northern Kostanay Oblast receives about 1 Bcm per year of Russian gas through an existing spur pipeline that extends from Kartaly via Tobol (in Kostanay Oblast) to Rudnyy. The main consumer is the local Rudnyy iron ore mining and processing complex. Other oblasts within this general region—Northern Kazakhstan, Akmola (including Kazakhstan's capital of Astana), and Karaganda—have continued to use coal and fuel oil for power generation and heating, as piped gas is not available. It is these areas that the government wants to gasify through the Kartaly-Astana pipeline, although the initially planned 6 Bcm per year capacity for the pipeline was subsequently reduced to only 3 Bcm per year, before the entire plan was subsequently put on hold. This planned pipeline would extend from Kartaly through Tobol and Kokshetau to reach Astana, with extensions possible to Petropavlovsk from Kokshetau and to Karaganda from Astana (see Figure 7.3.8).

Initially, the pipeline would carry Russian gas—perhaps supplied through a swap arrangement for Karachaganak gas—but ultimately, the plan was to build a pipeline from Karachaganak to tie in with the new pipeline at Tobol so that domestic gas could be substituted for Russian gas.

In his annual address to the nation on 27 January 2012, President Nazarbayev called on the government to design, construct, and implement this gas pipeline to ensure gasification of the country's north-central region, including the capital Astana. President Nazarbayev designated that the National Fund be tapped to fund the project.[49] But for now, both the Kartaly-Astana pipeline and the planned supply source, a new Karachaganak gas processing plant, have been put on hold—at least temporarily. This likely reflects the high costs of constructing the new processing plant and the pipeline connecting it with Astana—estimated at $3.7 billion and over $4.1 billion, respectively.

In terms of gasifying Astana, other options besides the Kartaly-Astana pipeline are being studied. In March 2014, KTG began a feasibility study of the potential for coal-bed methane (CBM) production in the coal basin of Karaganda oblast—with a decision on such projects to be taken in 2015. This has included the idea of constructing a local liquefaction plant that would convert the methane gas into LNG (liquefied natural gas), for transportation by either rail or truck to Astana and other cities in the region (see section 7.3.12.3 below). These plans would seem to be technologically and economically challenged to become real supply sources.[50] Therefore, it seems likely that the pipeline plans will re-emerge at some time in the future.

[48] With this amount of capital expenditure, shipping the gas south effectively almost doubles the delivered cost of the gas. An indicative cost recovery tariff given the reported capex for the pipeline ($3.8 billion), a cost of capital of 10%, and average shipments of 10 Bcm over 20 years, would be about $88 per Mcm. With typical gas procurement costs of around $50 per Mcm in Aktobe Oblast, delivered costs therefore would be about $140 per Mcm. Several years ago when Saut Mynbayev was Kazakhstan's Minister of Oil and Gas, he stated that wholesale prices in southern Kazakhstan would end up at about $120-150 per Mcm through the new pipeline, estimating that the transportation tariff would be about $62 per Mcm.

[49] However, the pipeline was not among the infrastructure projects included in the new Nurly Zhol (Bright Path) economic policy, announced by President Nazarbayev during his state-of-the-nation address on 11 November 2014. This policy calls for $3 billion annually in infrastructure investments to be funded from the National Fund over the period 2015–2017, as an economic stimulus to counter the effects of low oil and commodity prices and other economic pressures.

[50] As noted in Chapter 8, coal-bed methane in Kazakhstan does not have as high a heating value as natural gas, and thus appears to be better suited as a fuel for small boilers rather than larger applications. A study in the Karaganda Basin, for example, concluded that coal mine methane was not competitive in price with natural gas for delivery by pipeline or in the form of compressed natural gas (CNG) or liquefied natural gas (LNG), nor was the necessary infrastructure in place for practical applications in district heating and industrial use.

7.3.7. The Law on Gas and Gas Supply

Since passage of the Law on Gas and Gas Supply in January 2012, Kazakhstan's domestic gas market has been moved into the hands of KTG, as the designated "national operator" for the county's single-buyer model. KTG operates most of the gas infrastructure in the country, and under the legislation, has preferential rights to purchase associated gas from producers. KTG also sells gas on the local market and exports gas abroad. Two recent developments reflect KTG's enhanced role:

- Consolidation of all downstream distribution in all parts of the country that have piped gas available under the overall umbrella of KTG;
- Progress on the country's first major trunk gas pipeline project since independence: Beyneu-Bozoy-Shymkent.

The logic of the Law on Gas and Gas Supply appears to be that it puts Kazakhstan's gas production at the disposal of a single national operator through administrative means and specifically empowers KTG to develop the domestic market and pipeline infrastructure. This reflects the fact that the bulk of gas production in Kazakhstan occurs as a byproduct of liquids production (either associated gas or condensate-related gas), and thus gas supply does not respond to (gas) market conditions directly. Government policy also appears to be aimed at having the state-owned entity capture any upside from higher domestic end-user prices and export prices, while maintaining a single channel for exports so as to balance the near-monopoly conditions in two neighboring gas-purchasing countries, Russia and China.

While this type of market structure probably can work in Kazakhstan, where aggregate supply (associated gas) is not as strongly linked to actual conditions in the gas market, it probably means that Kazakhstan will likely forgo some natural gas development, since companies would have little incentive to pursue pure dry gas plays in their upstream endeavors (see below on gas market regulation). Of course, KTG could provide targeted incentives if needed to drive dry gas development in parts of the country where gas is needed or where dry gas plays dominate.[51]

In 2013, KTG and its subsidiaries delivered 99.9% of all piped gas that reached domestic consumers, with more than 95% of all gas delivered to domestic consumers traveling through KTG's trunk pipelines. KTG delivers piped gas to consumers through its two subsidiary distribution companies, KazTransGaz-Aymak and KazTransGaz-Almaty. Previously, these two distributors supplied gas to only seven of the ten provinces that receive natural gas by pipe, but this has now changed to encompass all ten.[52] These subsidiaries traditionally did not operate in Mangistau Oblast or Atyrau Oblast, but KazTransGaz-Aymak started deliveries to consumers in Atyrau Oblast in 2012, and it became the sole supplier in Mangistau Oblast in September 2011. KazTransGaz-Almaty is responsible only for Almaty Oblast and Almaty City, while KazTransGaz-Aymak now operates in the other nine provinces and is responsible for the majority of all domestic sales.[53] KTG has displaced the private gas trading companies that previously operated in various parts of Kazakhstan, buying gas from producers and selling it directly to consumers.

7.3.8. Kazakhstan's gas consumption

Unlike the other large energy-consuming countries in the CIS, Kazakhstan is not a significant consumer of gas. This is because domestically produced coal provides the majority of Kazakhstan's primary energy consumption, accounting for 62% of the total of the 76 million metric tons of oil equivalent (MMtoe) of primary energy consumed in 2014. The share of gas was over 17%, ranking third in importance after coal (62%) and oil (19%). The remaining 2% or so of primary consumption came from primary electricity (mainly hydropower) and other minor fuels.

Kazakhstan has long pursued a strategy to increase utilization of associated gas, aimed partly at reducing its reliance on imported gas and partly to further its goals for a "green" economy. This strategy involves increasing sales of domestically produced associated gas, expanding the country's domestic pipeline infrastructure, and severely restricting gas flaring.

In 2014, total apparent consumption of natural gas in Kazakhstan (defined as commercial production minus exports plus imports) came to 16.4 Bcm, but of that only 12.4 Bcm was reported as "end-of-pipe" deliveries (or sales) to consumers (see Table 7.3.2).[54] The difference represents other

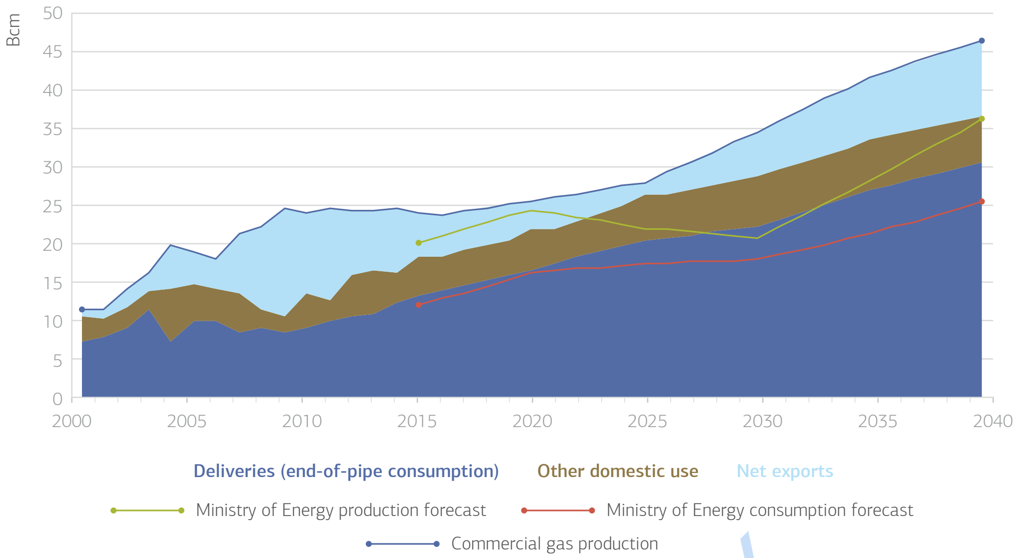
[51] An example of this is KTG's offtake contract with Tethys Petroleum for its (shallow, dry) gas production in Aktobe Oblast. In December 2014, a new gas sales contract with KTG was announced, which increased the purchase price of gas by 42% to $75 per Mcm, which is more than double the national average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

[52] Historically, only nine oblasts received piped gas, but this became ten in 2015 with the launch of deliveries in East Kazakhstan Oblast.

[53] Prior to May 2013, KazTransGaz-Aymak only sold gas wholesale to energy, industrial, and metallurgical companies in Kostanay Oblast in northern Kazakhstan, while gas for households and communal consumption was supplied by a different entity, GKP Kostanaygaz. But in May 2013, KazTransGaz-Aymak became the sole gas operator in Kostanay Oblast. KazTransGaz-Aymak also supplies gas to consumers in Kyzylorda Oblast, following the launch of piped gas supplies there. In Aktobe Oblast gas is mainly supplied from the Zhanazhol field, which is operated by the Chinese-owned company CNPC-AktobeMunayGaz. Other local producers also supply gas to the local market, with some imported gas also being delivered to consumers in the oblast.

[54] A major issue in the calculation of apparent consumption is the volume of exports. National customs statistics report exports as exceeding 20 Bcm in 2011-13, an amount nearly as large as total commercial volumes available (see Table 7.3.2). Nearly all of Kazakhstan's gas exports go north, to Russia, but Russia reports that it receives only 12-13 Bcm from Kazakhstan at its southern border. According to operational data reported by Kazakhstan's Energy Ministry (based on shipments reported by the pipeline operators), only 10-11 Bcm of gas is exported from Kazakhstan. The reason for these sizable discrepancies in reported export volumes remains unknown, but it may stem from the statistical treatment of Karachaganak gas flowing to Orenburg, which may be recorded once as

domestic disappearance, including field and processing losses (gross extraction includes the non-hydrocarbon volumes which are removed during processing), pipeline use, changes in stocks, etc. Actual gas consumption (end-of-pipe deliveries), as opposed to apparent consumption (or total domestic disappearance), is still slightly lower than the levels recorded at the end of the Soviet period (13.7 Bcm in 1990 and 11.9 Bcm in 1992). But Kazakhstan's actual (end-of-pipe) gas consumption has more than doubled from the low levels of the early 2000s (see Figure 7.3.10).



Source: IHS Energy, Ministry of Energy
Note: Other domestic use includes: field use and losses, processing losses, pipeline use, changes in stocks.

Figure 7.3.10 Outlook for Kazakhstan's natural gas balance

Concomitant with the relatively small absolute volume of gas actually consumed in Kazakhstan, the structure of consumption among the various sectors has tended to shift considerably from year to year. Of the amount of gas sold to consumers in 2013 (10.9 Bcm), about 2.8 Bcm (25.5%) was used by industry, 4.9 Bcm (45.2%) was used in the electric power sector to produce electricity and heat, and 3.2 Bcm (29%) was used by a combination of residential and commercial/communal consumers.[55] Comparative statistics for 2008, when a total of 9.0 Bcm of natural gas was sold to consumers in Kazakhstan, reports that nearly 5.2 Bcm (58%) of gas was used by power plants to produce electricity and heat, 2.0 Bcm (22%) was used by industrial enterprises and another 1.6 Bcm (17%) by households, and 0.3 Bcm (3.4%) was used by the communal/commercial sector (e.g., hospitals, schools, restaurants, hotels).

7.3.8.1. Regional gas markets

There are effectively several regional submarkets or consuming centers in Kazakhstan, some of which depend on imports from Russia and Uzbekistan, rather than domestic production. This is due to the geographic disjuncture of production (found mainly in the western part of the country), the transport system (built mainly to transit Central Asian gas to Russia), and domestic consumption. Piped gas is, in fact, provided to only 10 of the 14 oblasts in Kazakhstan. The other four oblasts—found in the north and central sections of the country—must rely on bottled liquefied petroleum gas (LPG) for their gas needs for the time being. Kazakhstan still does not have a unified national gas transmission system.

Much of the domestically produced gas is consumed in the western region of Kazakhstan, where the principal gas reserves (and the bulk of national production) are found. This region (comprising three oblasts: Atyrau, Mangistau, and West Kazakhstan) accounts for over 40% of the national consumption total (see Table 7.3.9). Among all of Kazakhstan's provinces, Mangistau Oblast consumes the largest volume and it also leads in the rate of demand growth: in the course of the previous decade, gas consumption in the oblast more than tripled. Mangistau also has a relatively high level of gasification (i.e., the percentage of settlements and towns with piped gas available), at 96%.

raw gas when it leaves Kazakhstan and then included again when it reenters Russia after being processed under the existing swap arrangements with Gazprom. Along the route between Orenburg and Aleksandrov-Gay, the pipeline actually dips in and out of Kazakh territory twice. This discrepancy means that apparent consumption in these years is smaller than reported deliveries to consumers.

55 This is according to data provided by the Ministry of Energy. According to the Agency of the Republic of Kazakhstan on Statistics, which is probably based on activity by sector rather than specific entities, 1.6 Bcm (15%) was consumed by industry as fuel in 2013, 3.7 Bcm (34%) was consumed in electric power, and 3.6 Bcm (33%) was consumed by households and the commercial-municipal sector.

						Plan				
	2003	2004	2007	2008	2012	2020	2025	2030	Gasification level in 2008 (in pct)	Gasification level in 2013 (in pct)
Total	**5 524**	**5 330**	**8 658**	**8 992**	**9 920**	**16 288**	**17 591**	**18 086**		
Western Kazakhstan	1 687	2 300	3 518	3 727	4 280	6 015	6 423	6 290	91%	96%
Mangistau Oblast	661	1 200	2 096	2 241	2 310	2 634	2 766	2 590	67%	87%
West Kazakhstan Oblast	595	500	513	504	700	1 121	1 159	1 165	56%	93%
Atyrau Oblast	431	600	909	982	1 270	2 260	2 498	2 535		
Southern Kazakhstan	2 309	1 100	2 872	3 099	3 160	5 752	6 309	6 735	41.5%	
South Kazakhstan Oblast	499	100	712	762	940	1 304	1 444	1 544	24%	
Zhambyl Oblast	784	300	1 197	1 434	1 010	2 696	2 794	2 894	5.7% for oblast; 81% for city	
Almaty Oblast and City	1 027	700	963	903	1 210	1 752	2 071	2 297	58.3%	79.9%
Northern Kazakhstan	1 311	1 900	2 135	2 046	2 230	3 811	4 076	4 203	58,3%	79,9%
Aktobe Oblast	1 123	1 100	1 273	1 236	1 360	2 086	2 187	2 217	16%	
Kostanay Oblast	187	800	862	810	870	987	1 006	1 025		
Akmola Oblast	—	—	—	—	—	137	162	169		
Astana City	—	—	—	—	—	601	721	792	44.5%	
Eastern Kazakhstan	216	30	133	120	250	710	783	858	44,5%	
Kyzylorda Oblast	216	30	133	120	250	695	763	838		
East Kazakhstan Oblast	—	—	—	—	—	15	20	20		

Source: Oil and Gas Kazakhstan, No. 9 (2009), p. 99; Kazakhstan's Gasification Program, 2014.

Table 7.3.9 Natural gas consumption by oblast in Kazakhstan (million cubic meters)

In the south, which accounts for 23% of national consumption, South Kazakhstan Oblast has the most developed distribution network, with a gasification level of over 40%, while Almaty Oblast is significantly less developed, with less than 6% gasification. Gas supply for southern Kazakhstan is met mainly from Uzbek imports, although the city of Taraz and other areas of Zhambyl Oblast also receive a small amount of gas from the Amangeldy field (and now the new Zharkum field since November 2014). South Kazakhstan Oblast now receives gas from Aktobe oblast following the completion of the Bozoy-Shymkent pipeline as well.

Gas consumption among the oblasts varies considerably, not only in the amount of gas consumed but also in the composition of consumption. Oblasts with more mature markets generally have a more diversified mix of consumers. Industrial areas, such as Kostanay and South Kazakhstan, tend to have high shares of gas consumed in the industrial sector, whereas ones with a major power plant (e.g., Zhambyl) have a high share of consumption by the power sector. Because it is a large urban center, Almaty tends to have a higher percentage of consumption by the residential-commercial sector.

7.3.8.2. Gas market regulation

Gas producers in Kazakhstan must contend with three key issues in the domestic gas market: flaring regulations, market structure, and low domestic prices:

- **Flaring legislation.** Producers in Kazakhstan have been adjusting to changes in gas flaring legislation since 2005, when Kazakhstan prohibited gas flaring for all subsoil contracts signed after 1 December 2004. Since then, regional and local agencies have increased monitoring and fines for gas flaring. The Subsoil Law passed in 2010 goes one step further by prohibiting commercial development of a field without a plan for utilization and processing of the gas. The law defines utilization as including reinjection; however, there is clearly a preference for commercial use over reinjection. The amount of flaring has been reduced dramatically in Kazakhstan since the legislation was introduced.
- **Market structure.** Kazakhstan's domestic gas market has used a single-buyer model for some time, and this structure was reinforced by the Law on Gas and Gas Supply passed in January 2012 (see above). This role is transitioning to KTG as the "national operator" under the new legislation. KTG, as the operator of most of the gas infrastructure in the country, also has preferential rights to purchase associated gas from producers and sell it on

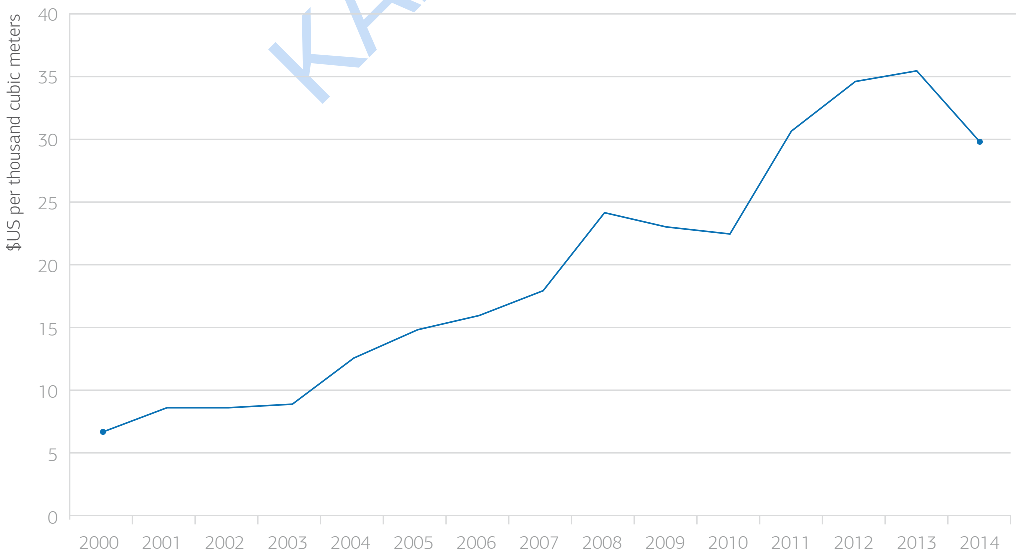
the local market as well as for export. Furthermore, the 2010 Subsoil Law stipulates that for contracts executed after the law took effect, associated gas belongs to the state (unless otherwise specified in the subsoil contract), though the investor bears the responsibility and cost for gathering and processing this gas while the state is obliged to cover these costs when buying the gas. The subsequent 2012 Law on Gas and Gas Supply clarifies this issue by stipulating that the government has the right to acquire raw and dry gas (processed from associated gas) from producers, and the national operator will be the government entity fulfilling this role (e.g., KTG).

- **Gas prices for producers remain low.** Historically, this single-buyer market model has left producers little room to negotiate price, and the price at which they sold to intermediaries such as KRG, KTG, or independent traders was usually quite low, barely recovering costs. The Law on Gas and Gas Supply states that the price at which the national operator buys this gas from the producer will include the cost of producing and processing (in the case of commercial gas) and of transporting the gas to the point where the national operator takes title, and a profit margin no higher than 10%, indicating that producer prices in Kazakhstan will be on some type of cost-plus basis. However, there has been some concern that it will be hard to ensure that these costs are in fact covered by the purchase price, since the state-owned buyer holds the much stronger bargaining position. At the end of 2014, the average price received by producers in Kazakhstan for their gas was $29.6 per thousand cubic meters (Mcm) (see Figure 7.3.11), although varying considerably within the country from as little as $21.9 per Mcm in West Kazakhstan Oblast to $82.0 per Mcm in Zhambyl Oblast. And this is a dramatic improvement: the average price paid to producers a decade ago, in December 2000, was only $6.6 per Mcm. For small producers of dry gas, which requires minimal processing, current prices may still allow a positive margin. However, for higher-cost producers, especially those with associated gas requiring extensive gathering and processing, the gas has at best no value, or even a negative value if extensive processing is required, as the low prices paid do not cover costs. This is an important consideration that factors into the economics of any new developments.

- **Domestic gas prices in Kazakhstan are regulated at the consumer level.** The State Committee for Regulating Natural Monopolies and Competition Protection (KREMiZK), previously known as the State Agency for the Regulation of Natural Monopolies (AREM), sets consumer prices for natural gas; it also regulates domestic gas storage and transport tariffs.

- **Several factors affect the formation of tariffs and consumer prices in Kazakhstan's domestic gas market.** The most important factor is the acquisition cost of natural gas, but others include geographic distances between consumers and domestic hydrocarbon resources, import dependence, and the state of gas distribution within a given province. As a result, prices vary significantly within the country. Besides being differentiated by consumer categories, mainly between industry and households, gas prices in Kazakhstan are differentiated by region as well. This is because transportation costs and gas procurement costs vary greatly within the country.

- **In regions that are supplied with domestic gas, lower end-user prices generally prevail.** This is because acquisition costs for the gas are much less than for imported gas. There also tends to be a strong differentiation between prices for households and industry in such provinces, with household prices being much lower than for industry (similar to the practice in Russia) (see Figure 7.3.12). In provinces that depend on imported gas, end-user prices tend to be higher (reflecting the higher acquisition costs for the imported gas), and prices are less strongly differentiated between households and industry, with households sometimes paying higher prices than industry.



Source: IHS Energy, Kazakhstan statistical agency

Figure 7.3.11 Average producer price for natural gas in Kazakhstan (in December each year)

- **Rising procurement costs for imported gas have been a difficult challenge for the regulator.** The average price for imported gas was $33.9 per Mcm in 2005 and was still fairly reasonable at $55 per Mcm in 2008. But then the average annual price paid for imported gas increased considerably—to $76.4 per Mcm in 2010, and was about $95 per Mcm in 2012–2014. As a result, end-user prices in areas that depend on imported gas have risen sharply as well.

Source: IHS Energy, Kazakhstan statistical agency

Figure 7.3.12 Trends in domestic gas prices in Kazakhstan (reported at year-end)

7.3.9. State gasification program

Kazakhstan's government approved an official gasification program in late 2014 ("General Plan for Gas Infrastructure Development in the Republic of Kazakhstan in 2015–2030"), codifying its long-held plans to increase domestic gas consumption. This program calls for the extension of piped gas supply to 13 oblasts from the current 10 by 2030. It calls for domestic deliveries to rise to 18 Bcm by 2030 under its "realistic" scenario.

The objective of the program is to create conditions for phased development of the gas transportation system and to meet rising domestic gas demand as an environmentally clean fuel, mainly using domestic natural gas resources. The key tasks of the program are:

- to formulate the strategic directions for future gas infrastructure development;
- determination of the specific gas infrastructure that will create a unified gas supply system;
- to allow the share of gas in Kazakhstan's overall fuel and energy balance to increase;
- to manage and achieve efficient cooperation between the National Operator and local authorities in the implementation of gas infrastructure development and gas supply;
- to take steps to modernize gas transportation system facilities to ensure technological and environmental safety in their operation, and to build new gas pipelines and develop (new) export routes for gas transportation to foreign markets.

As part of the key trunkline projects that are underway—Beyneu-Bozoy-Shymkent, Sarybulak-Maykapshagay, Turkmenistan-Kazakhstan-China, and Almaty-Taldykorgan, and the proposed West-North-Center gas trunkline—measures are being taken to refurbish, upgrade, and build new gas distribution infrastructure. Areas of such major activity (which already has been ongoing for several years) include South Kazakhstan, Zhambyl, and Kyzylorda oblasts, now complemented by expansion of gas supply to residential areas in Zaysan district in East Kazakhstan Oblast.

What is referred to as the government's "realistic" scenario contains the following key assumptions:

- "reasonable" prices at both the consumer and producer level that incentivize both consumption and production (recovery of associated gas), as well as "stable and reasonable" tariffs for gas transportation and storage;
- sufficient regional gas supply to meet the announced needs of major industrial and energy facilities, although some gas demand by major industrial consumers remains uncovered by domestic resources, which is assumed to be covered by imports at market prices;
- completion of construction of the Turkmenistan-Kazakhstan-China and Beyneu-Bozoy-Shymkent gas trunklines in southern Kazakhstan;
- construction of key gas pipeline branches from these major trunklines in Almaty, Zhambyl, and South Kazakhstan oblasts, together with expansion and upgrade of gas distribution networks;

- construction of the Sarybulak-Maykapshagay gas pipeline in East Kazakhstan Oblast and the beginning of gas infrastructure development in residential areas in Zaysan district;

- continued expansion of gas distribution networks in Aktobe Oblast.

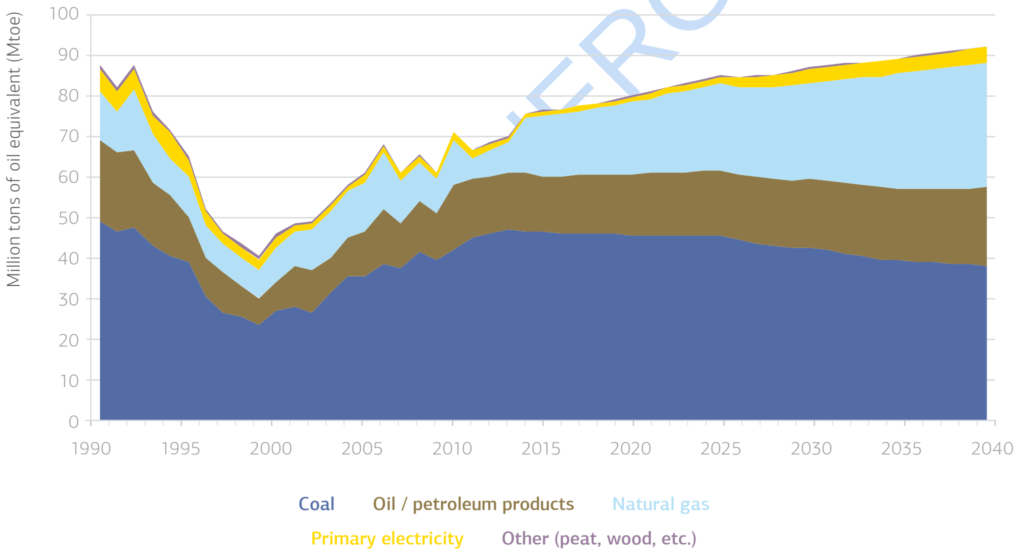
This scenario also includes construction of the postponed West-North-Center gas trunk pipeline together with the extension of gas supply to the city of Astana and surrounding residential areas in Akmola Oblast. But the scenario does not include expansion of pipeline infrastructure to Karaganda Oblast, North Kazakhstan Oblast, or the Tarbagatay district of East Kazakhstan Oblast.

The forecast volume of investments under this "realistic" scenario for gas infrastructure development is more than 656 billion tenge (in 2012 prices, or the equivalent of about $4.4 billion).[56] The highest share of this total, over 45%, is in construction of gas distribution networks within towns and cities rather than connector pipelines. According to calculations, the total length of distribution pipeline to be constructed would be about 28,300 km (i.e., about the same amount as the existing network), of which more than 18,000 km will be gas distribution pipelines inside towns and cities.

Implementation of this program is expected to make piped gas available to 56% of Kazakhstan's population, with gas being supplied to roughly 1,600 communities.

7.3.10. Kazakhstan's natural gas consumption outlook

IHS Energy expects natural gas consumption to grow and to become more prominent in Kazakhstan's energy balance going forward, increasing its share of national primary energy consumption, rising to about 22% by 2020, and to nearly 28% by 2030 (see Figure 7.3.13).[57] Actual gas consumption (end-of-pipe deliveries) is projected to increase quite robustly, rising at an average annual average of 3.5% between 2015 and 2040, to reach 22.3 Bcm in 2030 and 30.8 Bcm in 2040 (see Figure 7.3.14; and Table 7.3.4).[58] The key areas of expanded gas consumption are electric power, residential-commercial, and industry. We project that in 2030 electric power will account for about 44% of actual gas consumption (deliveries), residential-commercial users about 31%, and industry about 25%. In addition, there is another component of domestic use that includes upstream and processing losses as well as midstream uses (pipelines and changes in stocks) (see Figure 7.3.10).



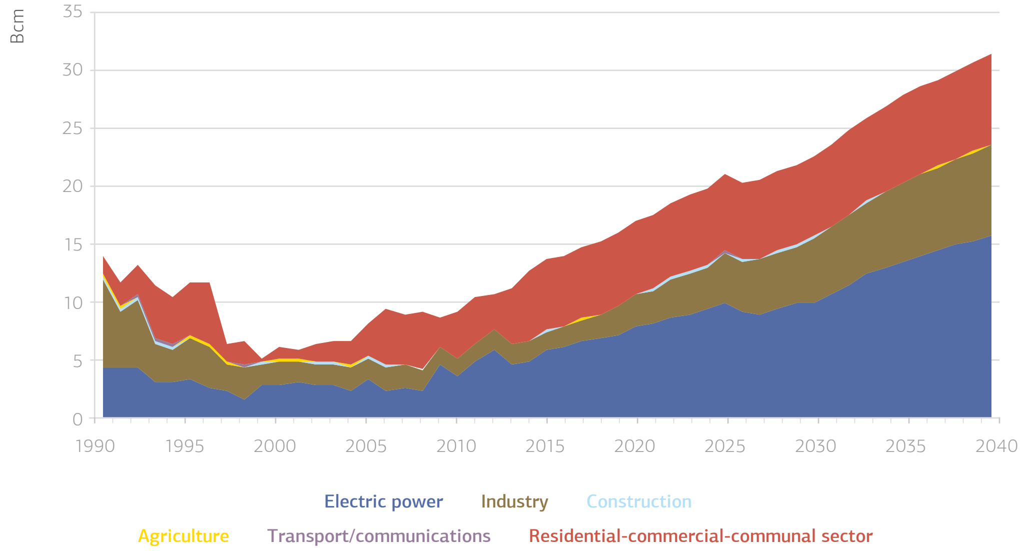
Source: IHS Energy

Figure 7.3.13 Kazakhstan's primary energy consumption

[56] The investment costs included only the distribution network's costs and did not include trunklines, such as Beyneu-Bozoy-Shymkent.

[57] Following standard international statistical practice, this calculation excludes the "disappearance" of gas into the overall economy through reinjection.

[58] Apparent consumption (domestic disappearance) of commercial volumes of gas, which includes a residual category of other consumption comprised of pipeline use, changes in stocks, and upstream losses, is projected to reach about 22 Bcm in 2020 and 29 Bcm in 2030.



Source: IHS Energy, Kazakhstan statistical agency
Note: Sectoral composition based on the historical breakdown provided by Kazakhstan statistical agency.

Figure 7.3.14 Outlook for actual gas consumption (deliveries) in Kazakhstan

But a key challenge will be the disparity between the location of domestic gas production, mainly in western Kazakhstan, and growing demand in areas such as southern Kazakhstan. While there is adequate domestic supply in aggregate, gas imports will likely continue, not only in the north from Russia, but also in the south (despite Beyneu-Bozoy-Shymkent). Kazakhstan is still going to remain a net exporter of gas (see below), but the choice is between constructing more pipelines to move more gas long distances between sources of production and consumption or to increase imports. Because Russia is long on gas, this should pose no particular problem in the north. However, in the south, Uzbekistan's gas balance is becoming increasingly tight, so in the south the main supplier is likely to become Turkmenistan rather than Uzbekistan. Kazakhstan already imports a small amount of Turkmen gas, mainly to meet its supply commitment to Kyrgyzstan.

Natural Gas in Petrochemical Production

One of the reasons for relatively modest growth in industrial gas consumption in Kazakhstan is that the country does not have a major nitrogenous fertilizer sector nor does it produce other chemicals that use methane as a feedstock, such as methanol and carbon black. Kazakhstan produces only a very small amount of ammonia and nitrogenous fertilizers.

Current plans to establish a major gas-based petrochemical industry in Kazakhstan will actually use relatively little methane. Petrochemical 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—rather than oil. Higher-than-average levels of ethane in Kazakh associated gas also make it an attractive input for petrochemical production: Kazakh associated gas contains about 13–16% of ethane.

The government is proceeding with plans to build a gas-chemical complex consisting of two plants initially, at Karabatan in Atyrau Oblast, close to the Tengiz oil field. The new complex will produce polypropylene and polyethylene at first, but plans call for other related products, such as ethyl benzene, ethylene glycol, polyethylene terephthalate, and polyvinyl chloride, to be added eventually.

Steps have been taken to secure feedstock gas from local producers. In March 2008, TCO signed an agreement pledging a supply of 6–7 Bcm of gas annually for the second-phase facility. The gas will be run through a separation plant to extract ethane and other natural gas liquids for petrochemical use, while the methane will be returned to be available for other uses.

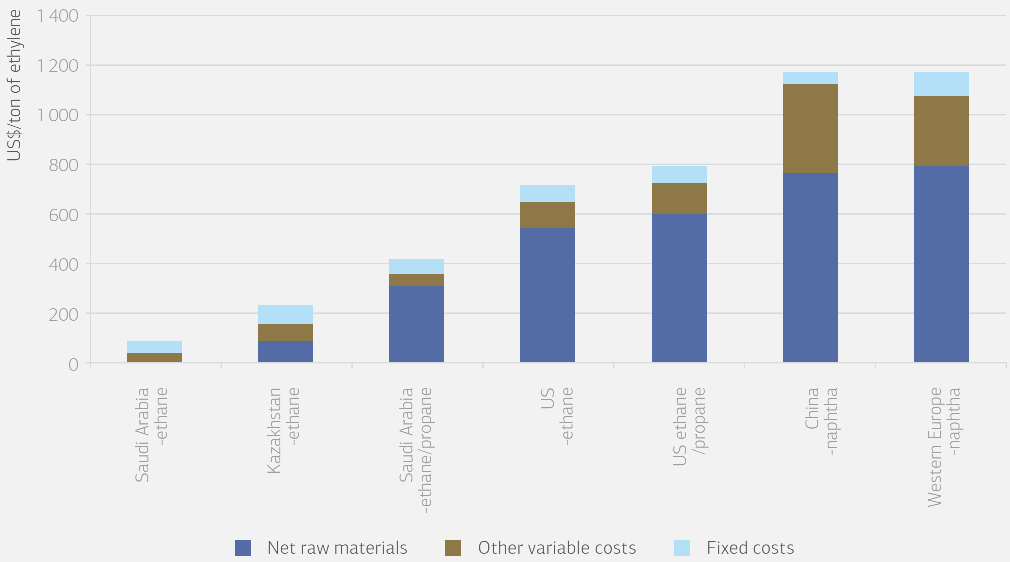
Cash cost of olefins production from an existing plant. A cost competitive analysis on the key units of the proposed petrochemical plants, assessing the cash cost of production for the Karabatan site relative to likely competitors (a key point of comparison for chemical operations globally), indicates that the plants in Kazakhstan are quite competitive. The cash costs of production are comprised of three components: net feedstock costs; other variable costs; and fixed costs. They specifically exclude corporate costs, depreciation, amortization, and any other financing costs, which can vary significantly from country to country. Cash costs are defined as follows:

Net feedstock costs include:
- Raw materials
- Co-product credits (where applicable)

Other variable costs include:
- Utilities costs
- Cost of catalyst and chemicals
- Packaging (where applicable)

Fixed costs include:
- Direct: labor, maintenance, direct overheads
- Indirect: general overheads, local insurance, and taxes

Analyzing the gas separation unit (GSU), steam cracker unit (SCU, or pyrolysis plant), and downstream units on an integrated basis shows that the proposed Kazakh plants are quite low for production costs in a global comparison of other "next generation" plants (see Figure 7.3.15).[59] This is due, above all, to low-cost feedstock. Kazakhstan's low-cost feedstock more than offsets the much higher transportation costs incurred for the final product of these same "next generation" plants in reaching global markets from such a deep inland location.



Source: IHS Energy

Figure 7.3.15 Comparative cash cost of ethylene production for new steam cracker units

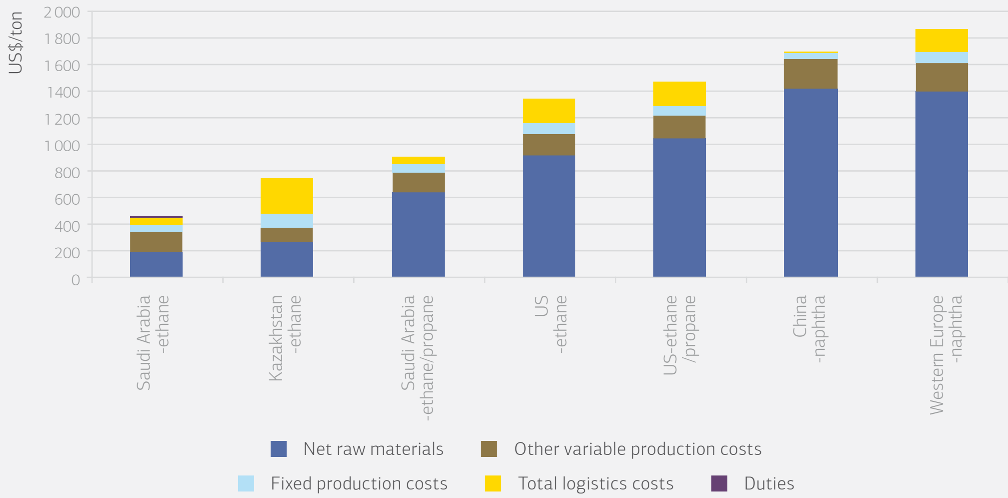
The proposed steam cracker (olefin plant) at Karabatan is estimated to have the second lowest total cash costs for olefins of the "next generation" cracker units shown (see Figure 7.3.15). This is achieved through the low-cost ethane feedstock produced by the gas separation unit in Tengiz and delivered to the plant in Karabatan. Because of the pricing arrangement for the raw gas, essentially the capital and operating costs associated with the construction and operation of the new units, along with a notional return on investment of 15%, become the main determinant of the effective input price for the ethane. These are factored into an implied (or indicative) ethane feedstock procurement cost of only about $107 per ton (in 2020 dollars) longer term. The additional revenue the gas separation unit generates through co-product sale of propane to the neighboring facility is also accounted for in the effective feedstock cost for the steam cracker.

As indicated above in Chapter 4 on global trends, the main element determining the cash costs of integrated polyolefin production globally is actually the cost of the feedstock. Technology differences for integrated polyolefin do not tend to make a significant change to the cash costs of production. As a result, the cost competitiveness of the main commercial products, high-density polyethylene and low-density polyethylene,

[59] This analysis, which was done in 2013, uses an assumption of long-term crude prices averaging about $100 per barrel over the lifetime of the projects. It also assumes that relative product prices and feedstock costs reflect this level. Since relative supply and demand for natural gas liquids indicate that these have less relative scarcity compared to crude oil longer term, NGL prices are likely to be at a discount relative to crude oil longer term compared to where they have been historically, so these calculations probably understate the advantage of low-cost feedstocks in the overall economics.

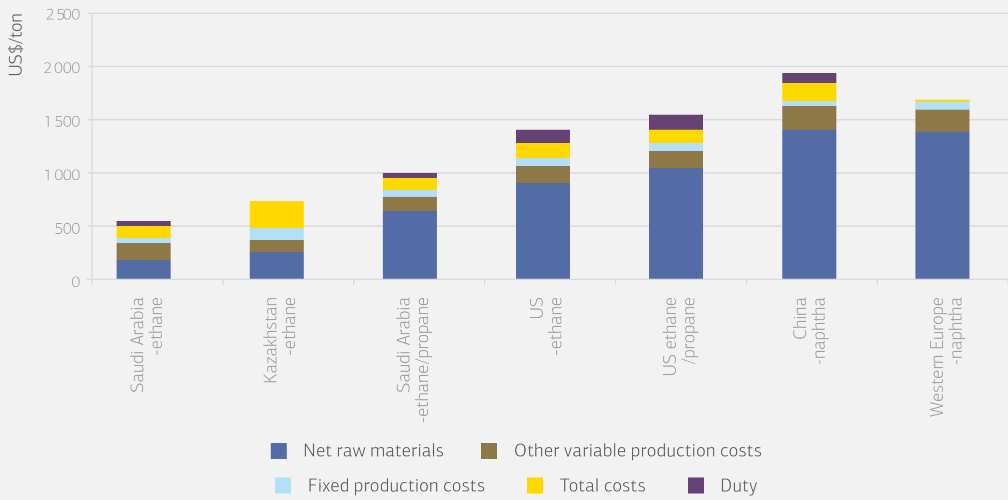
essentially mirror the results of the olefins cost competitiveness analysis. Therefore the low-cost feedstock available to the Kazakh plants make them highly competitive on a delivered cash cost basis (i.e., including transportation costs), either to European markets or to Asian markets, for high-density polyethylene and low-density polyethylene over nearly all the other producing regions analyzed globally; the sole exception is ethane-based manufacture in Saudi Arabia. Comparative delivered costs of a key final product (low-density polyethylene) to two key global markets, Western Europe and China, are estimated for a number of the "next generation" plants; Kazakhstan's new plants are the lowest cost except for ethane-based manufacture in Saudi Arabia (see Figure 7.3.16 and Figure 7.3.17).

It is important to note, however, that this cash cost analysis does not reflect differences in investment costs (especially actual construction costs as the equipment units tend to be very similar) between regions and countries, and that such costs are likely to be relatively higher in Kazakhstan due to the country's remote location and limited availability of local equipment manufacturing capability and ancillary services. Nor does this view reflect the more intangible regulatory and fiscal risks of doing business in Kazakhstan that we explore more fully elsewhere in this report. These differences will also play into investment decisions in the petrochemical sector, particularly for external investors and financial institutions.



Source: IHS Energy, IHS Chemicals
Note: Chinese import duty is 0%.
Assumes average long-term oil price of ~$100 per barrel and related product pricing.

Figure 7.3.16 Comparison of delivered costs of low-density polyethylene to China for selected "next generation" plants



Source: IHS Energy, IHS Chemicals
Note: Assumes average long-term oil price of ~$100 per barrel and related product pricing.

Figure 7.3.17 Comparison of delivered costs of low-density polyethylene to Western Europe for selected "next generation" plants

In the country's official gasification program, 18.1 Bcm is projected to be the amount of gas consumed in Kazakhstan in 2030 under the "realistic" scenario (see Table 7.3.9). Of this, 12.9 Bcm is projected to be consumed by industrial and energy plants (7.2 Bcm by power and 5.7 Bcm by industry) and 5.2 Bcm by residential-commercial users. Geographically, 35% of consumption in 2030 is forecast for western Kazakhstan, 42% in southern and eastern Kazakhstan, and 23% in northern Kazakhstan.

The Gas Value Chain of KazTransGaz and Infrastructure Investment

Under Kazakhstan's single-buyer model, KazTransGaz (KTG) is administratively empowered to develop the domestic gas market and the necessary pipeline infrastructure. Essentially, this must be financed through KTG's margin on gas sales. It appears that KTG should have the financial means to implement Kazakhstan's "realistic" gasification scenario given the sizable difference that is likely to continue to prevail between its acquisition costs for gas from producers and average sales prices to consumers (see below), as well as its regulated pipeline revenues. Currently, this price difference is about $60/Mcm, generating a total margin of about $665 million on annual gas sales of about 11-12 Bcm, and KTG's capex in 2013 was commensurate with this, at about $565 million. This general price differential seems likely to remain at about this same level going forward (since both purchase and sales prices are effectively tied to costs), so the total margin would reach about $1.1 billion on projected annual sales of 18 Bcm in 2030. Total investment outlays for the gasification program are estimated as $4.4 billion over this period.

7.3.11. Outlook for gas prices in Kazakhstan

Back in 2009, Kazakhstan's Ministry of Oil and Gas proposed that by 2020 the Kazakh internal gas market should reflect European gas prices as a general principle.[60] This was similar to Russia's general plan, proposed in 2006–07, that its own domestic market price should close the gap with European price levels through an aggressive program of hikes in regulated domestic prices. At the time, in Kazakhstan, it was proposed that changes in domestic gas pricing would take place in two stages. In the first stage (then envisaged as running through 2015), internal market prices would gradually move toward a level that reflected the European price level (discounted by 20–25% and also subtracting transportation costs). In the second stage, by 2020, a full conversion to European prices would be realized, with the only difference being transportation costs.

The formation of the Customs Union in early 2010 between Russia, Kazakhstan, and Belarus (and the subsequent Eurasian Economic Union) pushed this general concept further, as it has led to a broad understanding between the governments that natural gas prices should be harmonized across the member states for end users. Because gas production, trade, and the overall size of the domestic market are much larger in Russia than in Kazakhstan or Belarus, this harmonization essentially means that domestic gas prices in Kazakhstan are to converge with Russian domestic market prices.

An agreement to this effect was ratified by the Majilis, the lower chamber of the Kazakh parliament, on 30 March 2011. This agreement—"On the Rules for Granting Access to the Services of the Natural Monopolies in the Gas Transportation Sector and on the Pricing and Tariff Policies in the Countries Participating in the Common Economic Space"—called for domestic gas prices in Kazakhstan to be raised so that they will be brought into line with Russia's domestic gas prices.

7.3.11.1. General background on Russia's domestic gas pricing policy

Beginning in 2006–07, Russia officially promulgated plans to have its domestic gas prices converge with export netback parity (i.e., average export prices paid by European consumers for Russian gas, minus the 30% export duty and transportation costs from Russia to Europe). This broad change in overall policy direction for Russian domestic gas prices (which had long been kept quite low to keep Russian export-oriented manufacturing profitable and competitive internationally) was driven by rising domestic demand against a declining production base for low-cost Soviet-legacy gas, so that a (higher cost) generation of "new" Russian gas could be developed. Initially the plan was to have domestic prices for industrial consumers achieve export netback parity as early as 2011. But this proved impossible to achieve because high oil prices drove (oil-linked) export gas prices to very high levels, which are only now coming down in 2015 after the oil price crash in 2014.

Faced with this problem, Russia put off its price parity goal to 2015, but set in motion a series of ~15% annual hikes in domestic regulated prices, to allow domestic prices to significantly close the gap. These programmed increases in regulated prices were designed to lift Russia's average price for industrial consumers up to around $160 per Mcm by the

[60] This was officially proposed by the former Minister of Oil and Gas, Sauat Mynbayev, at a government meeting. Mynbayev had been Minister of Oil and Gas since August 2007, but in July 2013 he changed positions, becoming head of KMG.

end of 2015. At the same time, the government promulgated a plan to capture the bulk of the increase in domestic prices for the Russian budget through much higher taxes on Russian gas production.

But then the government decided to take a second look at the longer-term impact of these sizable gas price and tax hikes on Russia's gas sector and the overall economy. A series of alternatives were put forward: for example, Sergey Novikov, then Head of the Federal Tariff Service (which regulates gas prices in Russia), suggested that reducing gas price growth so that it is only in line with inflation (~6.5% per year) might be more sensible, even though it would delay domestic-export gas price parity. Some officials suggested limiting domestic price growth to about 5% per year, while others called for including US domestic prices into the export parity formula in some manner, and proposals were made for an outright freeze on tariff growth for the "natural monopolies," including gas. Beginning about 2014, as the domestic economy began showing signs of strain, Russia effectively changed policy from a goal of attaining netback parity to a slower growth path for domestic gas prices through lower indexation. IHS Energy now expects the average gas price in Russia to grow at around the rate of inflation, staying between a floor set by the long-term marginal cost of supply from next-generation fields under development or coming onstream and a ceiling determined by the economics of Russia's largest gas consumers, metals and fertilizers producers.[61] Therefore, domestic gas prices and transportation tariffs in Russia will likely remain heavily regulated for the foreseeable future, as there is little incentive to tie domestic prices to the higher-priced European market, and no large-scale gas-on-gas competition is likely to emerge.

The regulator has laid out a series of annual hikes in prices of 6-8% at mid-year (reflecting the rate of inflation) out through 2018. This will increase the average domestic price back up to about $90 per Mcm by the end of 2018, which will mean that the domestic price will remain roughly at around 60% of export parity (based on our base-case expectations for oil prices, the ruble exchange rate, and oil-linked gas prices in Europe).

7.3.11.2. Kazakhstan's domestic price convergence with Russia

Both Kazakhstan and Russia have internal regional price differences based on a variety of factors, including transport costs from centers of production to centers of consumption. This means that gas prices for industrial consumers located in gas-producing regions of both countries are much lower than prices for industries in more distant, non-producing regions. Thus, Russian industrial consumers in the gas-producing area of Yamal-Nenets Okrug in West Siberia paid $68 per Mcm in mid-2014, compared with an industrial price of $119 per Mcm in Saratov Oblast, a gas-consuming province in European Russia that neighbors Kazakhstan to the northwest—a difference of about 75%. Such regional disparities around the average within Russia are expected to continue going forward.

In the gas-producing areas in western Kazakhstan, domestic Kazakh prices paid by industrial consumers are roughly equivalent to the prices paid by industrial consumers in the gas-producing Russian price zones: for example, prices in Atyrau Oblast at the end of 2013 were $55.4 per Mcm, compared with $53.3 per Mcm in Yamal-Nenets.

For Kazakhstan the key question is, to which Russian pricing zone should Kazakhstan's domestic prices be harmonized (especially in western Kazakhstan)? Former Oil and Gas Minister Mynbayev suggested that Kazakhstan should take advantage of Russia's zone-based price disparities and harmonize its prices with the lower industrial prices found in gas-producing zones in West Siberia and not with the higher prices found in consuming regions in European Russia. He argued that this would allow Kazakh industry to remain more competitive than Russia's and would be a less painful transition for consumers.

IHS considers this as the most likely scenario for domestic gas developments in Kazakhstan—that is, where western Kazakhstan is considered a gas-producing region, and prices for industrial consumers follow essentially the same trajectory as Yamal-Nenets Okrug in Russia, with prices moving upward basically at the rate of domestic (Russian) inflation.

In contrast, if western Kazakhstan is considered in the same pricing zone as neighboring Saratov Oblast, it would require much higher annual price increases for average industrial prices in Atyrau Oblast to converge on those in Saratov Oblast. Despite this region's geographic proximity to Russia's southern non-producing oblasts, harmonization with these higher prices would be a greater stretch for Kazakhstan, and more expensive gas would make industrial development in Kazakhstan, despite its local resource base, no more attractive than that in any other gas-consuming region in European Russia.

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

7.3.12.1. Global trends in use of natural gas in transportation

Over past decade the use of natural gas as a motor fuel has been gaining momentum globally. A large gap between relatively high oil prices and natural gas prices has been a key driver of this development, particularly in North America. At the same time, the use of cleaner alternative transportation fuels, including natural gas, has been promoted by many governments, as concerns of pollution and human impact on the environment became more prominent in public discourse. Use of natural gas in transportation also answers a key strategic policy goal for the leadership of many countries, as it increases energy security by both diversifying transportation fuel supply and increasing use of domestic resources.

Use of natural gas in motor vehicles was tried during the early days of the automobile industry and was still being experimented with in the 1930s. However, abundant oil discoveries

[61] See the IHS CERA Private Report, Russian Domestic Gas Prices: How High Can They Go?, February 2012.

in the United States and later in the Middle East made oil widely available as a motor fuel. Use of oil products in motor vehicles and aviation during World War II firmly cemented oil's key role in transportation. Indeed, gasoline is a remarkable fuel for transportation: it is easy to transport and relatively small volumes provide sufficient torque for a light vehicle to move relatively long distances.

In addition to liquefied petroleum gases (LPGs; i.e., propane and butane), which already are used widely in automobiles in Kazakhstan, there are two forms in which natural gas (methane) has been used in motor vehicles globally: compressed natural gas (CNG) and liquefied natural gas (LNG). Due to fuel density and on-board storage issues, CNG/LNG use is challenging in light-duty vehicles (passenger cars), as the fuel tank would occupy much of the useful space and the car still would not be able to travel more than 100–200 km without refueling. But the switch to CNG/LNG can be more easily made for medium- and heavy-duty vehicles (trucks and buses). CNG, for example, is widely used in urban fleets that have only a short range and return to the same base each day, such as garbage trucks and city buses. These types of vehicles have a predictable and relatively short route that makes both of the key challenges for CNG use in transportation—storage/fueling infrastructure and travel distance—quite manageable. LNG, on the other hand, has found its widest use in long-haul trucking. This is because an LNG tank holds more fuel than a CNG tank, as the natural gas is held in a denser, liquefied form.

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

Nonetheless, tightening fuel and emissions standards in China have helped retain the relative competitiveness of natural gas versus diesel in trucking. Another factor helping sustain gas competitiveness is that the Chinese government has raised oil taxes amid low oil prices, so the diesel price for end-consumers does not reflect the recent decrease in global oil prices. The increase of LNG-fired trucks in China is impressive: from essentially zero LNG-fueled vehicles in 2008, there were ~140,000 LNG trucks on the road in 2013, consuming 3.8 Bcm of natural gas. There were about 1,500 LNG fueling stations in China in 2014, supported by a sizable small-scale inland liquefaction capacity (i.e., in addition to the large coastal import facilities) of about 16.9 MMt per year, a 50% year-on-year increase. Strong liquefaction capacity growth is expected to continue, with an additional 14.1 MMt per year of capacity currently under construction and 6.8 MMt in the planning phase. However, the utilization of this capacity has been somewhat low; in 2014 the utilization rate was around 56%. In 2014, gas production from small LNG plants in China constituted only 4.3% of total gas consumption in the country.

If before 2008 most of China's small LNG supply came from "stranded gas" in small fields, at present an increasing number of new LNG plants are using unconventional gas as feedstock. Many plants are using coalbed methane (CBM), taking advantage of CBM volumes that have struggled to find pipeline access to the market. The construction of the first liquefaction facility to use shale gas as a feedstock started in July 2015 and is projected to come online in 2016. A few plants also use coking gas as feedstock.

The importance of state policy in shaping gas use in China's transportation sector is not an anomaly. Government subsidies and policies have been a prime reason for the adoption of CNG and LNG as a transport fuel worldwide. Although nowhere else has the scale of conversion matched that of China, other countries have seen some shift to natural gas in transportation as well. In the United States, lack of fueling infrastructure is inhibiting sales of LNG trucks, despite the wide price differential in fuels, although limited LNG infrastructure is now in place as a launching pad for further development. LNG is facing a major new challenge in the US from CNG "long-range solutions," where CNG can be used in long-haul trucking. Some developers see greater potential in CNG and are thus expanding the number of CNG fueling stations along major trucking routes; but use of CNG in municipal public transport is already fairly widespread in the US, where legislation requires all state-funded organizations to purchase gas-powered vehicles when renewing their fleet.

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

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

In Russia, natural gas has been used for transportation since the 1980s, mostly as CNG, although its use dropped sharply in the 1990s. In recent years, interest in CNG and LNG has revived, especially from Gazprom, as the company is looking at various ways to monetize its gas by expanding domestic gas consumption. Gazprom has launched a special-purpose company "Gazomotornoye Toplivo" and plans to step up CNG infrastructure investments. This initiative has found strong political support as well, with the government promulgating plans for expansion of CNG for urban fleets.[62]

One key aspect of the proliferation of gas as a transportation fuel is the consumer's willingness to buy gas-fueled vehicles. However, this only happens if there is infrastructure to support them. At the same time, infrastructure build-up does not occur until the investor feels confident that there is sufficient demand from consumers to cover the costs and the risks of investment. In China, the initial development of infrastructure and retrofitting of trucks occurred simultaneously when such companies as Guanghui Investments acted as both investors and consumers in the market. This jump-started the development of LNG use and infrastructure, and is the main reason why China has been more successful than other countries in switching to LNG.

7.3.12.2. Potential use of natural gas in transportation in Kazakhstan

Although many countries have not been able to replicate China's dramatic rise in LNG use in trucking, mostly due to their existing infrastructure, Kazakhstan is well positioned to quite effectively build up its gas-fueled transportation fleet, as it can more easily coordinate the development both of infrastructure and of the vehicle fleet. In addition, Kazakhstan has large supplies of associated gas and a relatively low cost of recovery for that gas (although sulfur removal costs are high) to supply the market.

Use of natural gas as a motor fuel in Kazakhstan may help achieve a number of important policy goals. First, it may help alleviate a shortage of refined products for transportation.[63] Second, it would help utilize local resources, increasing energy independence and supporting the local economy. Third, it could help monetize stranded gas resources that are not connected to the main gas pipelines. And finally, it would mitigate the environmental impacts of transportation on air quality. Formulation of a general policy that links these four policy goals in order to promote their coordinated development is critical to enabling CNG/LNG use to progress beyond the "niche" stage. Otherwise progress in one area that is not tied to advances in another may inhibit overall development.

Kazakhstan has begun to use natural gas in transport, although activity remains quite limited at present. Currently there are 11 CNG fueling gas stations in the country, three of which were built in Soviet times and the remainder constructed since 2010. There are about 1,015 vehicles operating on natural gas in the country, including 520 buses, 83 trucks, and about 500 light-duty vehicles.[64]

KazTransGaz Onimderi—a specialized subsidiary of KazTransGaz (KTG)—is responsible for the construction, operation, and maintenance of CNG filling stations and related infrastructure in the country. KazTransGaz Onimderi's subsidiary AvtoGazAlmaty, in collaboration with the South Korean company Kor-KazCNG Investment Limited, has built four CNG fueling stations in Almaty, of which two were completed in September 2014.[65] There are a total of five CNG stations in Almaty that serve 450 buses, 33 street-cleaning vehicles, and about 500 passenger vehicles that run on natural gas. According to KTG, since the beginning of operation of CNG stations in Almaty (i.e., during 2011–2014), over 30,000 metric tons of diesel have been replaced by 40 MMcm (million cubic meters) of gas.

Expansion of CNG networks in other cities is also going forward. In 2015 KTG is planning to open three CNG stations in Kyzylorda, Aktobe, and Shymkent, respectively. In 2014, several operators of filling station chains in Kazakhstan signed a memorandum to help expand the number of gas filling stations in the country. Within the scope of this agreement, KazMunayGas Onimderi plans to retrofit 21 existing filling stations in six regions with one CNG unit each.

The government is working on a detailed gas motor fuel marketing plan, which envisages that consumption of natural gas as a motor fuel by public, road servicing, and utility transport will reach at least 30% in Almaty and Astana and at least 10% in cities that are oblast centers by 2020. Gas consumption in transportation by these consumers by 2030 is expected to be at least at 50% in Almaty and Astana and at least at 30% in the oblast centers. A network of CNG fueling stations is planned to be developed along the Kazakh section of the planned western Europe – western China transit corridor.

A Chinese company with a wide network of LNG trucks, fueling stations, and liquefaction plants intends to build a pilot mini-LNG plant in Kostanay Oblast in 2016, Kazakhstan's first.[66] If this pilot project is successful, it is likely that Kazakhstan will be looking to expand this technology more broadly across the country.

In Kazakhstan, the gas–oil price gap may enable LNG-fueled transportation to proceed, although much depends on the cost of the sourced natural gas. Prices for both oil products

[62] In 2014, KazTransGaz and Gazprom Gazomotornoye Toplivo signed a memorandum of understanding on cooperation and advancement of natural gas use in transportation, including creation of a unified technical policy between the two countries and increasing personnel training in this area.

[63] Kazakhstan's demand for gasoline and kerosene has been growing since the 2000s, and has been met by increasing imports, mostly from Russia.

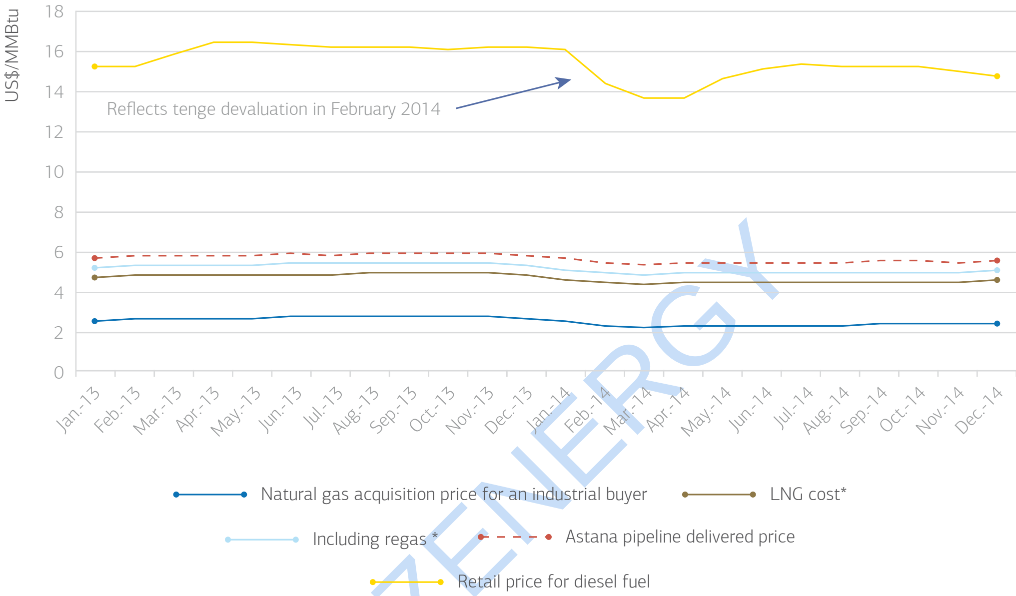
[64] These data are from the Gas Industry Development Concept to 2030.

[65] Kor-KazCNG Investment Limited was formed in 2011 by two South Korean companies—Kolon and Kogas-Tech—for implementation of joint Kazakh-Korean projects for construction and operation of CNG filling stations in the Republic of Kazakhstan.

[66] Guanghui Energy purchased a 49% interest in an upstream entity, Tarbagatay Munay LLP, in 2009 for $41 million to develop an upstream production license in East Kazakhstan Oblast. This project offers a unique way to monetize otherwise stranded gas for the local partner, and also benefits the local population, as Tarbagatay Munay LLP provides half of its production to the town of Zaysan and nine other villages in the area.

and natural gas are regulated in Kazakhstan, but a significant gap still exists.[67] In December 2014, the average retail diesel price was the equivalent of $14.68 per MMBtu, while the average natural gas price paid by households was only $2.61 per MMBtu. For an industrial consumer, such as a small liquefaction plant, the acquisition price it would pay for gas would be higher than for households, but still was only $3.02 per MMBtu in December 2014. This was significantly lower than the diesel equivalent (see Figure 7.3.18).[68] Growing diesel consumption in Kazakhstan, especially in transportation, represents an opportunity for LNG sales to substitute for some of the diesel consumption in trucks. Kazakhstan's diesel demand has been growing and is already the largest component of Kazakhstan's product demand balance (5.6 MMt in 2014), with trucks accounting for the largest share of diesel consumption (~40%).

By our estimates, even a liquefaction plant based on more expensive imported Russian gas (as would be the case in Kostanay Oblast) would seem to have strong economic prospects, at least when the product can be sold as a refined product. Adding on announced capex and estimated opex costs of the facility to industrial acquisition costs for gas still results in total costs of $4.71 per MMBtu, which provides considerable room to compete with diesel fuel in the local market (see Figure 7.3.19).[69] These costs reflect the LNG supplier costs only, which include the cost of feedstock gas and cost of conversion into LNG. The costs associated with using LNG at the consumer level, including costs to retrofit an LNG truck, also need to be considered, of course.



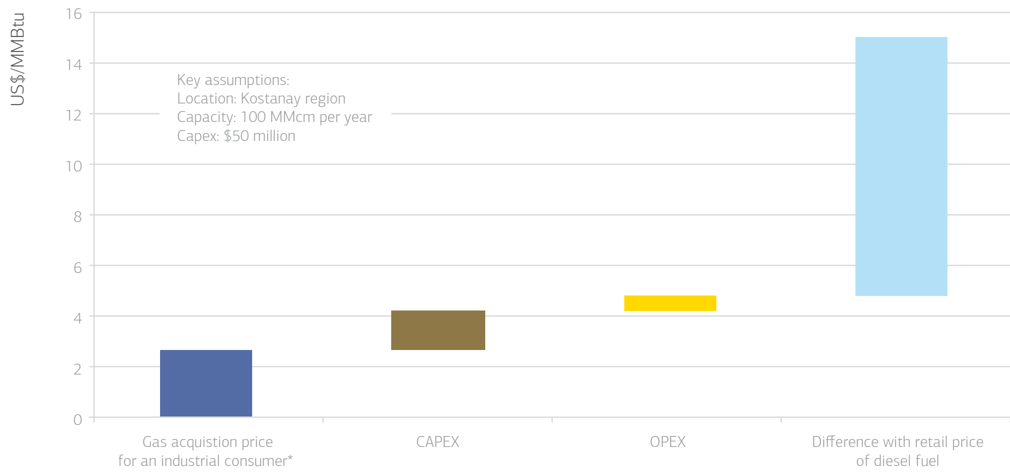
Source: IHS Energy
**For LNG cost and regas ex-plant; transportation costs from the plant to Astana (or other markets) not included.*

Figure 7.3.18 Natural gas–diesel fuel price differential: potential for LNG-fueled transportation

[67] In September 2015, the Kazakh government suspended regulation of domestic prices for AI-92/93 gasoline (the most popular grade)— to prevent fuel shortages following the August 2015 tenge free float, given the higher procurement prices for imports of Russian gasoline after the decline in value of the tenge in relation to the ruble.

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

[69] This cost does not include transportation of LNG to a different consumption point; delivery to a customer ex-plant is assumed.



Source: IHS Energy
**Source gas is assumed to be imported Russian gas to Kostanay.*

Figure 7.3.19 Comparative economics of a small-scale LNG plant in Kazakhstan versus diesel fuel in 2014

7.3.12.3. Other uses for small LNG in Kazakhstan

Use of small-scale LNG for gasification of households and small industries is less likely to be as economically attractive, however, but could potentially be still workable in small quantities. LNG prices would need to reflect the additional costs involved in liquefaction, re-gasification, and delivery to end-consumers from the liquefaction plant. The only instance in which this would appear to be possible is when the end-consumers are willing to pay gas prices high enough to cover these additional costs (e.g., remote locations where the competing fuel for heating is refined products, such as gasoil or fuel oil). But in this case, another obvious competitor would be LPGs, a typical situation where piped gas supplies are unavailable.

Trucking small-scale LNG to industrial and commercial users for production of high value-added products or services, for peak-shaving needs, and even for selected residential consumers is a niche market. These categories of consumers are willing to pay premium prices for additional volumes of the cleaner fuel that is natural gas. Meanwhile the sector that consumes the largest share of small LNG output in China is transportation, in particular trucks. However, there are a number of uncertainties to the further growth of this sector in China stemming from the ongoing price reforms and other factors discussed above.

An idea to help begin the gasification of Astana, beginning with small LNG, is being currently considered. There are instances in China, Spain, Turkey, and other countries where isolated consumers that do not have pipeline coverage in their area receive LNG that is trucked. The scale of the mini-LNG plants that would supplying such markets would still likely to be quite small, but this could provide gas to targeted consumers willing to pay a higher premium for natural gas.

7.3.12.4. Mini-GTL: a possible solution for gas monetization and flaring

Despite current legislative requirements, the amount of associated petroleum gas (APG) that is still flared remains significant. Official statistics on associated gas flaring based largely on data obtained indirectly—by estimation—rather than by direct metering. As a result, it is very likely that the amounts being flared are understated. The sizable gap between official statistics and those gathered by satellite monitoring by the World Bank's Global Gas Flaring Reduction program has long been noted. According to these GPS surveys, the volume of gas being flared in Kazakhstan remains sizable, and contrary to official statistics, ostensibly has been actually increasing in recent years, along with the USA, Russia, and Venezuela.

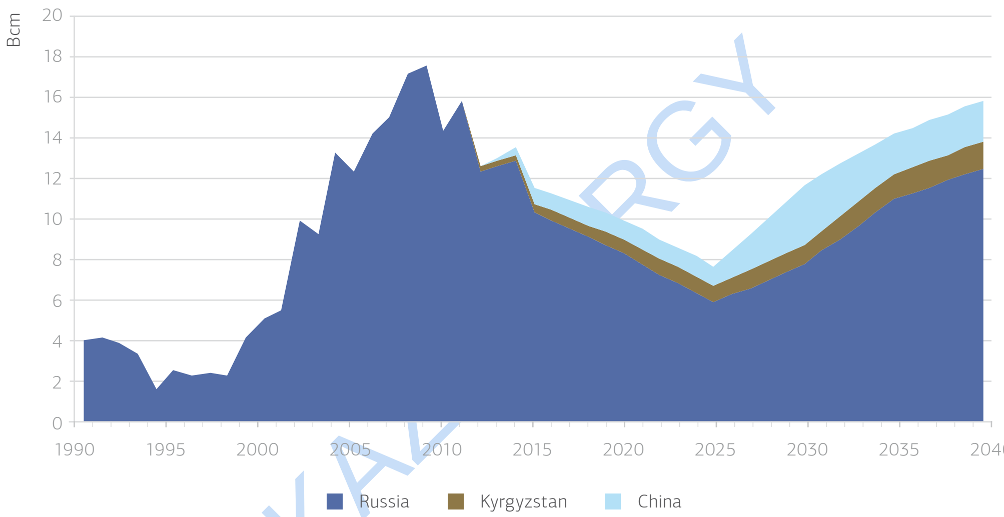
As indicated elsewhere in this chapter, the problem of APG processing and utilization in Kazakhstan stems from several factors, including the low level of development of the domestic gas market, the remoteness of many of the fields from trunk pipelines, and the need for investments in gas processing. APG also is used by the upstream projects themselves for their own in-field needs, including reinjection to maintain reservoir pressure as well as for heat and electricity generation. But some gas is still flared, and the unified accounting system for APG flaring, planned to be introduced by the government by 2020, seeks to drive new directions of APG utilization. One new direction under consideration is producing refined products from associated gas, such as ultra-clean diesel fuel using gas-to-liquids (GTL) technology, or methanol manufacture.

GTL technology is used in a number of large-scale plants globally (e.g., Shell Pearl, Sasol). This technology, based on the Fischer-Tropsch process, is associated with high capital expenditures per ton of finished product and relatively large feedstock requirements for gas. However, in recent years new technologies are emerging for small-scale "mini"-GTL – modular units that use small amounts of gas (e.g., from 5 million cubic meters per year) and a wide range of gas compositions. These plants also reduce the marketing problem for product since it is possible to deliver the end product, diesel fuel, directly to consumers by truck. Depending upon feedstock characteristics and the particular catalysts that are used, in addition to diesel fuel, the GTL technology can also yield various byproducts such as paraffins, heavy petroleum fractions, etc.

Initial research by the Kazakh Institute of Oil and Gas (KING) shows (based on the Kumkol group of fields in Kzylorda Oblast that were analyzed) that given current capital and operating costs, an acceptable payback period (3-4 years) can be achieved, mainly due to current low APG acquisition costs at the field. The advantage is that such plants can produce high-quality refined products in short supply in Kazakhstan, helping to reduce imports, essentially from an input that might otherwise be wasted (flared APG). However, a danger would be pressures to maintain low acquisition prices for APG to preserve the economics of mini-GTL once an investment had taken place, which could actually backfire by failing to incentivize long-term recovery of APG.

7.3.13. Natural gas export outlook

Kazakhstan is not a major gas exporter, as much of its available gas production is used domestically, particularly for reinjection at the oil fields. But the country is, in fact, a net exporter of gas. Its exports mainly flow north, into Russia, as part of the established relationship with the Orenburg gas processing plant (see above). We expect this to remain the case for the bulk of Kazakh exports going forward, but modest amounts of gas are expected to also be exported to China. Kazakhstan has an agreement to deliver up to 10 Bcm per year to China, but this much gas is unlikely to be available for export in the period to 2030. In our base-case, total exports shrink to about 8 Bcm in 2025, but rise thereafter, reaching about 16 Bcm in 2040. Russia remains the major destination, with Chinese exports reaching a maximum of about 3 Bcm in 2030 (see Figure 7.3.20).



Source: IHS Energy
Note: Exports are aggregated only to those countries for which there is a contractual relationship (e.g., Russia, Kyrgyzstan, China), rather than those for which exports are reported by trade statistics.

Figure 7.3.20 Outlook for gas exports from Kazakhstan

7.3.14. Liquefied petroleum gas (LPG)

7.3.14.1. Key points

- Kazakhstan has become a significant producer of liquefied petroleum gas (LPG), with most output coming from gas processing (of associated gas), and with oil refining contributing a much smaller amount. TCO is the largest producer by far, accounting for over half of national output. Kazakhstan's production appears set to increase in concert with expanded upstream operations, especially the recovery of associated gas, and deeper refining.

- About two-thirds of LPG production is exported, with the rest consumed domestically, mostly by households and the commercial sector for cooking and heating; sizable amounts also are used by industry and in transportation (motor vehicles). A new area of consumption that is set to grow substantially is LPG use as a petrochemical feedstock. But even so, it appears likely that most LPG production will continue to be exported.

- The domestic LPG market in Kazakhstan is highly regulated, both in terms of pricing and market operations; wholesale prices are set based on LPG quotations at the Belarus-Poland border adjusted for transportation costs from Kazakhstan and for a coefficient based upon the prior year's ratio of gasified population in the country to total population of Kazakhstan.

- Global balances for LPG are shifting, with supply increasing significantly in many regions of the world (Middle East, North America, Russia) due to changes in upstream operations, while demand has been concentrated in two key sectors—petrochemicals and households—that are already saturated. Prices in international markets are under pressure from oversupply, threatening to cause prices to collapse to their value as a gas-based fuel instead of the traditional premium earned by LPG as a specialty refined product.

7.3.14.2. LPG production

Kazakhstan is a significant producer of liquefied petroleum gas (LPG); i.e., propane and butane. This is a fuel source that spans an overlap between oil and gas operations. LPG production in Kazakhstan comes from two main sources: gas processing (of associated gas) and oil refining. LPG derived from gas processing accounts for about 85% of total output. The production of LPG in Kazakhstan has grown substantially in the previous decade largely as a function of increased associated gas production from the country's large upstream projects. The trend of growing LPG production intensified after December 2004 when Kazakhstan amended the 1995 Law on Petroleum to prohibit the flaring of associated gas, except in specific situations.

LPG is produced at four gas processing plants (GPZs) in Kazakhstan: the Tengiz GPZ that belongs to TCO, the Zhanazhol GPZ at CNPC-Aktobemunaygaz's Zhanazol field, the Kaz GPZ at KMG E&P's Uzen field, and at KTG's Amangeldy gas field. LPG is also produced at four gas treatment units (GTUs) from associated gas: the Akshabulak GTU by KazGerMunay, Turgay GTU by Turgay Petroleum, the Aktau GTU, and the Chinarevskaya GTU of Nostrum Oil and Gas (formerly Zhaikmunay).[70] LPG is also produced at the three main oil refineries—Atyrau, Pavlodar, and Shymkent.[71]

LPG output in Kazakhstan reached about 2.52 million metric tons (MMt) in 2014. Of this, 404,000 tons (16%) came from the refineries, with the rest from gas processing operations. About two-thirds of LPG production is exported (66% in 2014), with the rest consumed domestically, mostly by the residential-commercial sector for cooking and heating (~45%), with some also being used by industry for fuel (~23%) and in transportation (motor vehicles) (~13%).

7.3.14.2.1. TCO Is the Leading LPG Producer and Marketer

The leading producer in Kazakhstan is the Tengizchevroil (TCO) joint venture, which is Kazakhstan's largest oil producer, developing the Tengiz and Korolev fields in western Atyrau Oblast. TCO also produces sizeable volumes of associated gas, which when processed yields dry, network-quality gas as well as LPG and other byproducts. Its LPG output has risen steadily, both due to reduced flaring since 2005 as well as expanded oil (and associated gas) production. While the Future Growth Project (FGP) is slated to expand TCO oil production capacity to 40 MMt (867,000 b/d) by 2027, up from 26.7 MMt (581,000 b/d) in 2014, all incremental gas production derived from the FGP is planned to be reinjected, so future increases in (marketable) LPG output will remain far more modest than the growth in hydrocarbon extraction.[72] The goal for TCO is to maximize oil production and exports.

TCO's gross output of associated gas in 2014 was about 14.5 Bcm, of which 7.5 Bcm was reinjected. This left 7.0 Bcm of TCO gas in 2014 for commercial sales, which when processed also yields LPG (propane and butane). In 2014, TCO produced 1.3 MMt of LPG, slightly lower than the 1.4 (1.353) MMt of output in 2013.

TCO sells LPG into the wholesale market in Kazakhstan, but not on a retail level. It delivers the LPG to buyers by truck and rail using a loading terminal at Kulsary. But the bulk of its LPG output is exported, both overland to European and CIS countries as well as via seaborne transport from Black Sea terminals, mainly to countries bordering the Black Sea and the Mediterranean. TCO's Black Sea exports now largely move through the port of Taman in Russia, rather than from Odessa in Ukraine, initially because the port of Taman offered competitive tariffs, and later due to the conflict in eastern Ukraine.[73]

[70] The difference between a GPZ and a GTU is really the size, with the GPZ being the larger of the two in terms of processing capacity. Both types of facilities treat or process away raw gas from the contaminants and natural gas liquids contained within it, before the gas reaches pipeline quality and can be safely delivered to consumers. Contaminants in natural gas are often non-hydrocarbon gases such as water vapor, carbon dioxide, hydrogen sulfide, nitrogen, oxygen, and helium; sulfur is another serious contaminant in natural gas. Natural gas liquids (NGLs) are hydrocarbons such as ethane, propane, and butane (primary heavy hydrocarbons [liquids]) and isobutane, pentanes, normal gasoline, etc. (lighter hydrocarbons).

[71] Raw sour gas from Karachaganak flows to the Orenburg GPZ in Russia for processing. It yields dry gas as well as other products, including sulfur, LPG, ethane, and stable condensate. Since LPGs from Karachaganak are not produced on the territory of Kazakhstan, they are not included in the official LPG production numbers for Kazakhstan.

[72] However, TCO will provide the raw gas that will be used in a new gas separation unit at the field that will provide ethane and propane for the two olefin plants that are planned at Karabatan. The separation unit will provide about 1.3 MMt of ethane to run one of the plants and up to 2 MMt of propane for the other. One plant is planned to run exclusively on ethane; if the second plant uses a mix of both ethane and propane, then only about 1.2 MMt of propane would be needed.

[73] With the CPC pipeline expansion, much of the lucrative transport of crude oil by rail has begun to shift away into the oil pipeline. Taman has been pressed to offer increasingly competitive fees to attract any incremental shipments.

7.3.14.2.2. Other Upstream Producers

Other important LPG producers include CNPC–AktobeMunayGaz (Aktobe Oblast), which in 2013 had gas production of 3.5 Bcm and LPG output of 233,000 tons; Nostrum Oil and Gas (formerly Zhaikmunay), with 1.4 Bcm of gas and 131,000 tons of LPG; Kazakhoil-Aktobe with 565 million cubic meters (MMcm) of gas and 5,900 tons of LPG; KazGerMunay with 520 MMcm of gas and 124,000 tons of LPG; KMG E&P with 405 MMcm of gas from its Uzen and Emba fields and 152,900 tons of LPG; Turgay Petroleum with 158,500 MMcm of gas and 57,800 tons of LPG; and KTG's Amangeldy field with 322 MMcm of gas in 2013 and 5,100 tons of LPG.[74]

The total output of these other upstream producers in Kazakhstan is about 710,000 tons, equal to about 29% of total LPG output in 2013. The future outlook for their LPG production is largely dependent upon their oil production prospects.

7.3.14.2.3. Oil Refineries

Another source of LPG in Kazakhstan comes from the three main refineries, which currently process about 15 MMt of crude per year. Total LPG from the three refineries in 2014 was 404,000 tons, versus 383,000 tons in 2013. LPG output from the refineries is dependent upon both the overall amount of crude runs and the depth of refining. Each of the three refineries now processes roughly the same amount of crude annually, but Pavlodar's greater depth (deeper cuts) yields substantially more LPG. In 2013, the Pavlodar refinery produced 215,400 thousand tons of LPG; Shymkent produced 148,300 tons; and Atyrau produced only 19,600 tons of LPG.

Modernization at all three refineries will raise total refining capacity, and also deepen their refining processes. Therefore, LPG production from the refineries can be expected to increase moderately as well going forward (see section 7.4.3 for more detail on refinery modernization).

7.3.14.3. LPG consumption

The domestic LPG market in Kazakhstan is highly regulated, with its pricing subject to regulation by the Ministry of Energy and the Ministry of Economy. The Energy Ministry has developed a methodology for calculating the LPG wholesale price ceiling based on LPG quotations at the Belarus-Poland border (DAF Brest) adjusted for transportation costs from Kazakhstan and for a coefficient based upon the ratio of gasified population in Kazakhstan to the total population in Kazakhstan for the prior year. Specific prices are set each quarter and need to be approved by both the Energy and Economy ministries.

The Energy Ministry has primary authority for the LPG market: it tracks LPG balances, develops templates of LPG retail sales contracts to be used by market players, specifies monthly LPG supply volumes that must be sold domestically by each local LPG producer, and specifies gas network organizations (GNOs) to which the gas must be sold. Retail prices are regulated by the Economy Ministry's Committee for Regulation of Natural Monopolies and Protection of Competition (KREMiZK, formerly known as AREM) for dominant market players. Wholesale prices in the domestic market generally are not as attractive for LPG producers as global market prices for exports. Hence producers will continue have a higher share of exports in total sales, even after satisfying mandatory supply quotas to the domestic market. But ironically, retail prices in Kazakhstan are sometimes higher than those found in major consuming countries in Europe or in Turkey. Domestic LPG prices are lowest in western Kazakhstan near the major production centers and highest in the east and south because of transportation costs.

The 2012 Law on Gas and Gas Supply restricts the number of intermediaries operating in the market. Specifically, it prohibits the resale of LPG to another wholesaler. It also requires that LPG retail sales be carried out only by certain types of companies—GNOs, the owners of retail gas stations, or LPG producers if they sell LPG directly to industrial consumers.

Use of LPG in the transport sector is reasonably established in Kazakhstan, although this still remains somewhat of a niche fuel. Currently, there are 466 filling stations in Kazakhstan that provide LPG fueling services, with the majority of these in Mangistau Oblast (122), followed by North Kazakhstan (70), Karaganda (47), South Kazakhstan (34), Kyzylorda (32), Almaty (28), Atyrau (23), Akmola (22), West Kazakhstan (32), Aktobe (18), Pavlodar (14), Zhambyl (9), Kostanay (8), and East Kazakhstan (7). These filling stations dispensed a total of 131,500 tons of LPG fuel in 2013, which represented about 23% of reported domestic consumption that year.

For EXPO 2017 in Astana, the government is aiming to create a taxi fleet of 500 LPG-fueled cars. The liquefied gas will be a propane-butane mixture and will be available at a network of gas stations— currently at least 18 gas stations in Astana can serve these "eco-friendly" taxis.

7.3.14.4. Global LPG production and consumption outlook

Until the mid-2000s, the world supply/demand balance for LPG was relatively tight. However, after 2004, increments to supply began to outstrip increases in demand, albeit with a brief interruption (2008–2010) due to the global recession. World production increased from roughly 200 MMt in 2000 to over 280 MMt in 2013, whereas demand increased to 265 MMt. A wave of new production and export sources has thus now decisively tipped the balance toward oversupply, with internationally traded LPG expanding to about 94 MMt. The growth in output thus far has come primarily from two key sources: the Middle East (United Arab Emirates, Qatar, Saudi Arabia) and unconventional oil and gas development in North

[74] Raw sour gas from Karachaganak flows to the Orenburg GPZ in Russia for processing. It yields dry gas as well as other products, including sulfur, LPG, ethane, and stable condensate. In 2013, Karachaganak sour gas yielded 167,200 tons of LPG that was returned to KazRosGas by the Orenburg GPZ. It appears that these LPGs are exported for the most part.

America (where LPG output increased by 8% in 2012 alone). Russia also is expected to become an additional major source of exported LPG, as natural gas producers shift their efforts from relatively shallow (dry) Cenomanian horizons to deeper and wetter (Neocomian, Valanginian) formations.[75]

As a result, global LPG supply is projected to increase by another 40–50 MMt by 2020. Growth in base demand will be slower, as lackluster economic growth in many parts of the world is expected to exert a drag on consumption in the two main end-use sectors—residential/commercial and chemicals—which together account for roughly 75% of world LPG consumption.[76] In the absence of strong new demand growth in other sectors (e.g., LPG as a motor vehicle fuel), this weak economic environment and soft crude oil prices are expected to continue to exert downward pressure on LPG prices. More specifically, oversupply potentially could lead to a collapse of LPG prices. Traditionally, LPG has been priced as a specialty refined product rather than as a gas-based fuel. But these pricing arrangements have been coming under increased pressure, particularly in North America.

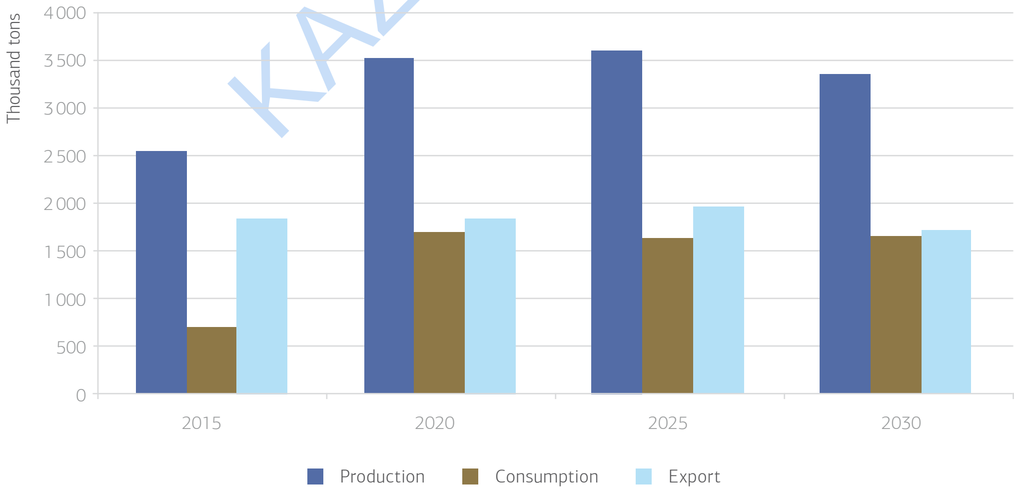
Such a repricing of LPG in the European export market would have important consequences for Kazakhstan. The expected expansion of crude oil output in Kazakhstan not only raises the issue of the disposal of increasing amounts of associated gas, but of the LPG within that gas. As noted above, Kazakhstan presently is able to absorb only a limited amount of the LPG it produces (exporting two-thirds of its total output). A further issue is that many of these exports are destined for Europe, a region where for demographic and economic reasons LPG demand growth in the medium term (to 2020) is going to be increasingly challenged. LPG demand in Europe is projected to grow at ~1% annually between 2010 and 2020, which is only half the average rate for the world at a whole (over 2%).[77] Europe is also expected to be a region where U.S. and Middle East exports will compete strongly for markets, which could further weaken LPG pricing for all but the most specialized uses.

7.3.14.5. LPG production and consumption outlook for Kazakhstan

Since LPG is a by product of petroleum refining and gas processing, its volumes will directly depend on commercial gas and petroleum production. In the oil refining industry of Kazakhstan, three refineries are to be modernized, and with the expansion of associated gas recovery, especially at Kashagan, "marketable" LPG production will probably expand by about 1 MMt over the forecast period, with another 1.3-2.0 MMt produced as "captive" output for petrochemical operations.

It would appear that most of the incremental marketable output will be exported, but not all. In terms of consumption, LPG will be gradually substituted with piped gas, first of all in households and the commercial sector as well as public utility enterprises, and eventually also in industry for its fuel needs. But there are still many parts of Kazakhstan that will remain without piped gas, and their demand will grow over time. Also, autogas (LPG use in vehicles) will continue to grow as well. So it appears that demand for LPG outside of petrochemicals is likely to remain fairly flat. There are other possibilities to increase domestic consumption of LPGs, such as exploring the feasibility of LPG-based electric power generation, especially near sites of LPG production.

Of course, the largest incremental source in domestic demand will be in the petrochemical sector, as LPGs will be one of the main raw materials for one of the two olefin plants that will form the basis of the integrated gas chemical complex in Atyrau Oblast, amounting to between 1.3 and 2.0 MMt per year.



Source: The Ministry of Energy of the Republic of Kazakhstan

Figure 7.3.21 LPG production and use forecast in Kazakhstan by 2030

[75] Matthew J. Sagers and Vitaly Yermakov, A Rising Tide: Significant Growth Expected in Russian LPG Production, Consumption, and Exports, CERA Private Report, 2008.

[76] The split between residential/commercial and chemicals consumption is about 40% and 35%, respectively, for about a 75% total share.

[77] IHS, World LPG Market Outlook, Volume 1, 2012, p. II-3.

According to the Ministry of Energy, total LPG production in Kazakhstan will be around 3.5 MMt after 2020. In their view, LPG consumption will be about 1.7 MMt annually during this period. Consequently, LPG exports will be relatively stable as well, at about 1.8 MMt per year (See Figure 7.3.21).

Given the discussion above, however, it would appear that domestic demand will increase to between 1.9 and 2.6 MMt, depending upon the mix of feedstocks used in the petrochemical complex. Production would be in the range of 4.7 to 5.5 MMt. This would put exports about a million tons higher than currently, at about 2.8–2.9 MMt per year.

7.3.15. Sulfur production and utilization

In Kazakhstan, byproduct sulfur from oil and gas production has been a challenge in terms of disposal and utilization. Whereas previously sulfur was legally considered a production waste, due to its many potential uses in the economy it is now officially designated as a raw material. For many years, sales were less than recovery, leading to a sizable build-up of sulfur inventories in open-air storage. Total output of elemental sulfur in Kazakhstan in 2014 was reported as 2.455 million metric tons (MMt) by the state statistical agency, essentially the same amount as in 2013 (2.443 MMt) (see Table 7.3.10). The dynamics of sulfur production largely reflects trends in oil production in the country, as hydrocarbon extraction is the key source, although a significant amount also can be derived from smelting of nonferrous metallic ores.

	Utilization Rate	Capacity	Production	Imports	Exports	Apparent consumption — IHS Chemical	Stocks	Stock changes, Tengiz
2000	92%	1 353	1 238	0	0	1 238	n.a.	n.a.
2001	105%	1 361	1 427	2	2	1 427	n.a.	n.a.
2002	119%	1 361	1 625	0	44	1 581	n.a.	n.a.
2003	73%	2 185	1 585	0	261	1 324	8 100	n.a.
2004	74%	2 185	1 625	1	972	654	8 800	700
2005	73%	2 185	1 590	4	1 356	238	9 000	200
2006	73%	2 185	1 600	2	1 844	-242	8 900	-100
2007	73%	2 192	1 600	0	2 721	-1 121	8 500	-400
2008	74%	2 367	1 750	0	2 864	-1 114	7 900	-600
2009	81%	2 779	2 250	0	3 614	-1 364	6 900	-1 000
2010	86%	2 779	2 400	1	3 884	-1 483	5 600	-1 300
2011	83%	2 779	2 311	1	3 594	-1 282	4 100	-1 500
2012	74%	2 909	2 150	1	3 196	-1 045	2 640	-1 460
2013	76%	3 229	2 443	1	3 657	-1 213	1 150	-1 490
2014	76%	3 229	2 455	0	3 850	-1 395	265	-885

Source: IHS Chemicals

Table 7.3.10 Supply/demand for sulfur in Kazakhstan (thousand metric tons)

TengizChevrOil (TCO) is the largest sulfur producer by far in the Kazakhstan. In fact, it appears that nearly all of Kazakhstan's elemental sulfur production now comes from TCO. TCO's crude oil contains mercaptans (a type of hydrogen sulfide), which is removed at the field, and its associated gas has a very high sulfur content (H_2S at 16%).[78] As production of oil at the project increased, so too did production of sulfur, particularly after the expansion commensurate with the launch of the second-generation plant in 2009. Output was 2.4 MMt in 2014, about the same amount it has been since 2010 (see Table 7.3.11); in contrast, TCO output in 2005–2007 was about 1.6–1.7 MMt per year.

[78] TCO's crude is a light sweet crude with a density of about 790 kilograms per cubic meter (46.4° API) and a low sulfur content (about 0.51%) following field treatment.

	Production (MMt)	Sales (MMt)	Inventory at year-end (MMt)
2004	1.7	0.4	8.7
2005	1.7	1.4	9.0
2006	1.6	1.6	9.4
2007	1.6	2.0	8.9
2010	2.4	3.6	5.6
2011	2.3	3.8	4.1
2012	2.1	3.6	2.6
2013	2.4	3.9	1.2
2014	2.4	3.8	0.3

Source: TCO

Table 7.3.11 TCO sulfur operations

For many years TCO was not able to market all the sulfur it produced, resulting in a growing volume of inventory that had already reached about 5 MMt at the end of 2001 and reached a maximum of 9.4 MMt at the end of 2006.[79] Since then, sales have exceeded annual production, resulting in a drawdown of inventory. In 2013, sales were 4 MMt, and in 2014, TCO sold over 3.8 MMt of sulfur, which was 162% of the 2.4 MMt produced. TCO's sales success has resulted in the reduction of volumes of sulfur stored in Tengiz's inventory to less than 265,000 tons as of December 31, 2014. TCO's sulfur is sold in four different forms—liquid, granulated, flaked, and blocked—to over 130 customers in 38 countries, including Kazakhstan, Russia, Ukraine, and China as well as countries in the Mediterranean and Central Asia regions. Kazakhstan's largest export markets for sulfur include China (1,750,000 tons in 2013), the countries of the Middle East as a group (440,000 tons), and Morocco (600,000 tons).

Sulfur Treatment at TCO

TCO constructed treatment facilities in 2002–2003 with a capacity of approximately 2,000 tons per day in order to treat its sulfur and sell it in Kazakhstan and abroad. In 2002, sulfur sales were only 57,000 tons, but by 2006 had reached over 1.6 MMt. In 2007, TCO expanded its sulfur granulation capacity by 800,000 tons, allowing total sulfur sales to exceed 2 MMt per year. The sulfur moves by rail within Kazakhstan to export points. Export markets for TCO sulfur include:

- CIS markets for liquid sulfur. Third party liquid sulfur rail cars are used to move the liquid sulfur to market from the field.
- Foreign and CIS markets for GX granulated sulfur.
- Foreign and CIS markets for crushed block sulfur.
- China for granulated sulfur. Sulfur from TCO is sold to buyers in China either as flaked sulfur in 50 kg bags or as GX granulated sulfur in 50 kg bags. The sulfur is moved by rail across Kazakhstan to China.

The launch of TCO's Sour Gas Injection–Second Generation Project (SGI-SGP) in 2009 is another key component of the sulfur disposal strategy. The SGI-SGP project boosted the project's oil production capacity to 540,000 b/d (27 MMt per year) by reinjecting "H_2S enriched" gas, thus reducing the need to treat the gas and strip out the sulfur.

Domestically, the key sector that generates demand for sulfur is the mining sector, and particularly production of uranium. Kazakhstan's expanding uranium and gold production greatly increased domestic demand for sulfuric acid, which is used in the in-situ leaching production process. About 550,000 tons of sulfuric acid was required to produce 5,000 tons of uranium in 2006, and 2 MMt was required to produce 20,000 tons of uranium in 2013. There are several sulfuric acid production facilities in Kazakhstan. Four facilities are owned by metal companies and use sulfur recovered from their smelter operations to produce sulfuric acid: the Balkhash and Zhezkazgan smelters owned by KazakhMys, with annual production capacities of 1.2 MMt and 270 Mt, respectively; and the Ridder and Ust-Kamenogorsk (Oskemen) plants owned by

[79] TCO's first sulfur sales did not occur until 2001, when 16,000 tons were sold.

KazZinc, with capacities of 250 Mt and 400 Mt, respectively. Three plants use sulfur from TCO to produce sulfuric acid: a 600 Mt plant in Zhambyl Oblast belonging to KazFosfat; and KazAtomProm's Zhanakorgan and most recently launched Stepnogorsk facilities, with capacities of 500 Mt and 180 Mt, respectively. KazMunayGaz's Pavlodar refinery also can produce up to 180,000 tons of sulfuric acid per year

7.3.15.1. Sulfur as a global commodity

Sulfur is an important resource used in the chemical industry. While historically sulfur was primarily derived from mine production from salt domes and other evaporitic rocks, this has shifted so that about 97% of global sulfur production now is sourced from hydrogen sulfide (H_2S), which is a byproduct of oil and gas operations, including gas processing and petroleum refining, as well as nonferrous metallurgy. About 2% of elemental sulfur worldwide is produced at nonferrous metallurgical smelters during the processing of sulfide ores for metals such as nickel, zinc, and copper, as well as from pyrites (FeS_2). Environmental issues are an important driver of sulfur production from smelters and petroleum refining. Air pollution concerns have led to the tightening of emissions standards globally, requiring reductions of the sulfur content in motor fuels, leading to expanded volumes of elemental sulfur production at oil refineries. But the major source of elemental sulfur globally is the processing of sour (high-sulfur) natural gas.

Up to 95% of the global elemental sulfur output is used to produce sulfuric acid (H_2SO_4). About half of the produced sulfuric acid is used to make mineral fertilizers, including phosphoric acid, superphosphate, and ammonium sulfate. Other important uses of sulfuric acid include mining, using the leaching process, which is applied in uranium and gold production.

Global production of elemental sulfur reached 59 MMt in 2014—a 24% increase from the 2009 level of 48 MMt. North America remains the largest sulfur production region, although its share of global production has been declining, falling from 31% in 2009 to 24% in 2014 (see Table 7.3.12). The United States has been the world's largest producer of sulfur, reaching output levels of 9 MMt (15% of the world's total) in 2014. At the same time, Canada's production decreased from 7 MMt in 2009 to 6 MMt in 2014. A key reason for the decline in output has been the build-up of sulfur inventories to an estimated level of 11.2 MMt by the end of 2013. China's sulfur production rose dramatically from 2 MMt (4% of the world's total) in 2009 to 6 MMt (10%) in 2014. China's growth in production has been the result of adding sulfur recovery capacities at oil refineries processing imported crude oil, although natural gas and domestic coal also provide significant volumes. Within the CIS, Russia remains the largest sulfur producer, with an output of 7 MMt in 2014, followed by Kazakhstan, which produced about 2.4 MMt. Turkmenistan appears to be on the verge of displacing Uzbekistan as the third-largest producer in the CIS, as its (sour) gas production is growing, while Uzbekistan's is declining.

	2009		2014		2019	
	Thousand metric tons	Percent of total	Thousand metric tons	Percent of total	Thousand metric tons	Percent of total
Middle East	8 418	18	12 508	21	18 110	24
Eastern Europe*	8 413	18	10 780	18	14 340	19
United States	8 200	17	8 920	15	9 550	13
China	1 700	4	5 700	10	8 850	12
Canada	6 581	14	5 500	9	5 998	8
Western Europe	4 631	10	3 934	7	4 114	6
Northeast Asia	1 870	4	2 255	4	2 200	3
Southwest Asia	1 516	3	1 975	3	2 400	3
Japan	1 863	4	1 760	3	1 600	2
Africa	500	1	1 586	3	2 069	3
Central Europe	697	1	1 304	2	1 542	2
Oceania	1 024	2	965	2	990	1
Mexico	1 112	2	825	1	922	1
Southeast Asia	690	1	775	1	900	1
Central and South America	906	2	700	1	742	1
Total	**48 121**	**100.0%**	**59 487**	**100.0%**	**74 327**	**100.0%**

**In the given regional and country breakdown, Kazakhstan is included in the category of "Eastern Europe"*

Source: IHS Chemicals.

Table 7.3.12 Global production of sulfur

On the demand side, sulfur consumption is expected to grow from 59 MMt in 2014 to 72 MMt in 2019, or at about 3% on average annually. While consumption of phosphatic fertilizers in developed economies is growing only incrementally, consumption in developing regions will drive the overall growth, both due to increasing population (and thus higher demand for food) and higher use of phosphatic fertilizers relative to nitrogen fertilizers. China has been, and will remain, the largest global consumer of sulfur: China's demand grew from 15 MMt (32% of the world's total) in 2009 to 18 MMt (29%) in 2014 and is projected to grow to 21 MMt (30%) in 2019. Consumption by the United States—the world's second largest sulfur consumer—was 10 MMt in 2014, up from 8 MMt in 2009; thus, its share of global consumption remained at about 17%. Morocco, which holds 75% of the world's reserves of phosphate rocks—the key source for making phosphoric acid and phosphatic fertilizers—is the world's biggest exporter of phosphoric acid and other types of phosphates. So it is a major destination globally for sulfur.

In terms of international trade flows, China continues to be the world's largest importer of sulfur, followed by Morocco; in 2014 the two countries imported 12 MMt and 4 MMt of sulfur, respectively. The US is the world's third largest sulfur importer, bringing in 3 MMt to its market in 2014. China and Morocco will remain the largest importers of sulfur; however, as the US continues losing its share of the global phosphate fertilizers' market due to the rise of lower-cost producers, its share of global sulfur imports is projected to decrease, to 2 MMt in 2019.

Canada is the world's largest sulfur exporter, delivering 5 MMt to the global market in 2014. Russia and Kazakhstan exported about 4 MMt each of sulfur each last year. Saudi Arabia and UAE are also important exporters, sending about 3 MMt and 2 MMt, respectively, into the global market in 2013. In the future, exports from the Middle East are set to substantially increase as sulfur production is projected to ramp up in UAE, Kuwait, Oman, Qatar, Saudi Arabia, and Iraq, adding another 6 MMt by 2019. In the same period, increases in sulfur production from Russia, Kazakhstan, and Turkmenistan are expected to be about 4 MMt in aggregate, which will go mostly into the export market.

7.3.15.2. Anticipated increase in Kazakhstan's sulfur production as oil and gas output grows at Tengiz and Kashagan

In addition to the TCO operations, a second major source of elemental sulfur production that is expected to come on line in 2017, with the restart of oil and gas production at Kashagan, is from the North Caspian Operating Company (NCOC). Once designed full first-phase capacity at Kashagan is achieved, NCOC is expected to be producing 1.2 MMt of sulfur annually. Thus forecasts of oil output growth[80] at the two mega-projects, Tengiz and Kashagan, while not providing a comprehensive accounting of sulfur production in Kazakhstan,[81] nonetheless are a good indicator of relative magnitudes of future sulfur production volumes that could be expected in the country.

Table 7.3.13 shows the aggregate volumes of sulfur that could be expected from the two fields under two IHS forecasts for oil output presented earlier in this chapter (Chapter 7.2.5)—the base- and low-case scenarios. The base-case scenario projects that Tengiz oil production will expand to 27.5 MMt in 2020, to a peak of 42.0 MMt in 2030 before declining to 32 MMt by 2040; for Kashagan the base-case projects output increasing from 17.2–17.6 MMt at maximum Phase 1 capacity in 2020–2021 to 35.8 MMt in 2030 (assuming a Phase 2 production start-up in about 2025) and 52.0 MMt in 2040. A low case-scenario assumes a smaller contribution to output from the Future Growth Project at Tengiz and that Phase 2 is not sanctioned for Kashagan. Under this scenario Tengiz's oil output rises only to 35.0 MMt in 2025 before declining more rapidly, to 24.0 MMt in 2040; Kashagan produces at roughly the 2020 level in 2025 (17.5 MMt), and increases only to 18.5 MMt through some debottlenecking. The table extrapolates sulfur production at current rates of oil output at Tengiz to the projected future levels of oil production at that field, and extrapolates expected sulfur production at full first-phase capacity at Kashagan forward to projected oil production levels (it is assumed at both fields that sufficient sulfur production capacity is available to accommodate the higher volumes of oil output).

	Base-case scenario			Low-case scenario		
Year	Tengiz	Kashagan	Total	Tengiz	Kashagan	Total
2014	2.4	0	2.4	2.4	0	2.4
2020	2.4	1.2	3.6	2.4	1.2	3.6
2025	3.4	1.2	4.6	3.1	1.2	4.3
2030	3.7	2.4	6.1	2.8	1.2	4.1
2040	2.8	3.6	6.4	2.1	1.3	3.4

Source: IHS Energy
Note: Based upon scenarios for oil production at the two fields.

Table 7.3.13 Kazakhstan's projected sulfur production at the Tengiz and Kashagan fields, base- and low-case scenarios, 2014–2040

[80] We focus on oil output rather than associated gas for the obvious reason that oil is the primary commodity driving production decisions at these deposits.

[81] Karachaganak's sulfur is extracted at the Orenburg processing plant, and is technically Russian output, whereas additional small quantities are produced at smaller oil and gas fields in the country as well as in nonferrous metallurgical facilities.

As is evident from the table, the amounts of sulfur produced at the two fields under the two different scenarios begin to diverge widely after 2025. By 2040 Kazakhstan is producing almost twice the amount of sulfur under the base-case (6.4 MMt) as in the low case (3.4 MMt). Given the healthy demand growth for sulfur projected globally over the near term (as well as in the Chinese markets that Kazakh producers already serve), it appears that Kazakhstan has the opportunity to export its growing volumes of sulfur production.

Key Recommendations

- To better assess and analyze Kazakhstan's gas balance, the country needs to make changes in its statistical reporting to provide production and consumption figures consistent with international norms and practices. This should include presenting a consistent historical series on gas production that excludes reinjected volumes, but includes all useful volumes, including those used for internal needs by the producers themselves. Similarly, reporting on exports should focus upon figures consistent with actual cross-border flows.

- To provide for an adequate supply response, ensure that upstream procurement prices are high enough to fully cover costs involved in producing, processing, and delivering natural gas by the producers;

- Consider special exemptions to allow associated gas flaring by small, remote producers, if there is no other economically viable solution for disposing of their relatively small gas volumes; an alternative integrated utilization solution, which involves pooling their gas, may be a possibility if several small producers are in close proximity to each other.

- Gasification of the domestic economy along the general lines currently being discussed, especially in areas of existing trunk pipelines, should continue to be pursued, as it provides significant economic and environmental benefits to consumers and the nation as a whole.

- Given the pending harmonization with consumer gas prices in Russia, prices in Kazakhstan should be viewed as being in a gas-producing region rather than a gas-consuming region; this will help maintain Kazakhstan's economic competitiveness within the emerging Eurasian Economic Union.

- Enabling CNG/LNG use in transportation to progress beyond the "niche" stage needs to be encouraged where economic versus alternative fuels by a formulation of a general policy that coordinates development of four key policy goals: (1) alleviation of refined products shortage for transportation; (2) utilization of local resources, increasing energy independence and supporting the local economy; (3) monetizing stranded gas resources that are not connected to the main gas pipelines; (4) and mitigating the environmental impacts of transportation on air quality.

- In response to impending oversupply of LPG on world markets, it would seem advisable for Kazakh energy planners to consider additional measures for increasing consumption domestically where possible. These might include, but not be limited to, further expanding its use in the transport sector, extending its availability to residential/commercial consumers in areas where piped gas is unavailable, and most importantly, establishing a petrochemical industry in sectors that utilize LPG as a feedstock. Another possibility is exploring the feasibility of LPG-based electric power generation, especially near sites of LPG production.

7.4. Oil Refining and Downstream Oil Issues

7.4.1. Key points

- **Kazakhstan has three main oil refineries as well as a number of mini-plants; total primary distillation capacity for the country as a whole is reported as 18.3 million metric tons (MMt) per year (366,000 barrels per day [b/d]).** All three of the main refineries were built during the Soviet period, and have seen very limited modernization since independence. Although the plants have some conversion capacity, the refining system is relatively unsophisticated and, as a result, the output structure of the refining sector remains heavily skewed towards mazut (residual fuel oil), which does not match the country's refined product needs.

- **In aggregate, Kazakhstan's refineries currently cover only about 78% of domestic product consumption,** with imports covering about 22%.[82] This is because Kazakhstan exports a large proportion of its own output (comprised mostly of mazut), while it must import light products (motor fuels), mostly from Russia, to meet domestic demand.

- **Kazakhstan has now launched a major refinery modernization program,** which when completed will significantly alter the product slate towards light products (motor fuels). Because of the lack of refining depth, the country's refineries still turn out a significant amount of mazut, while demand has shifted decisively toward light products—gasoline, diesel fuel, and jet kerosene—with the ongoing modernization of its economy. The resulting mismatch has led to an increasing dependence upon im-

[82] Throughput (considered equivalent to gross output) was 14.3 MMt in 2013, exports were 5.3 MMt, and imports amounted to 2.5 MMt, so apparent consumption (including refining losses and fuel use) was 11.5 MMt. In aggregate, 9.0 MMt of this was covered by domestic production.

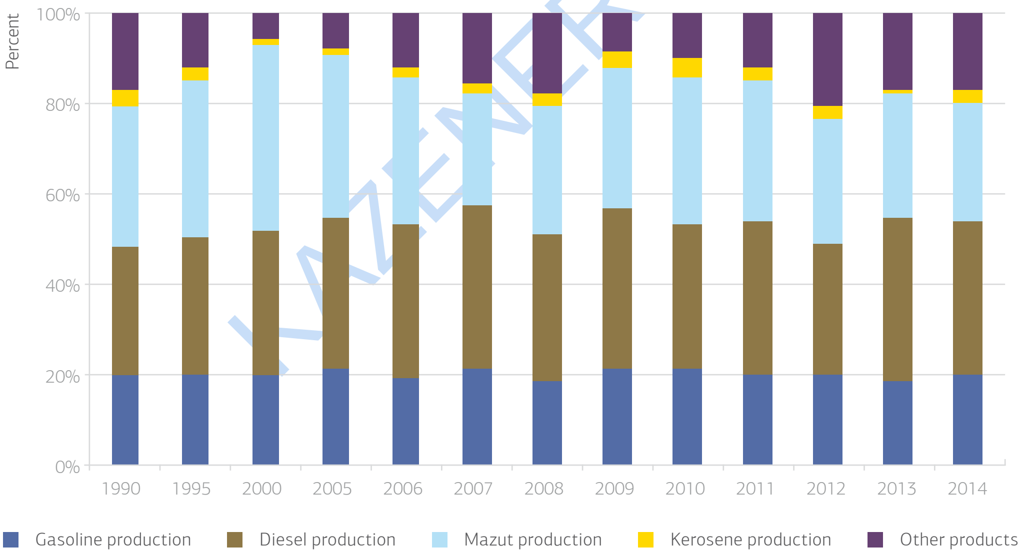
ported products, especially of high-octane gasoline and jet kerosene. However, refinery modernization, when completed, should eventually help correct the mismatch and significantly reduce the need for imports of light products.

- **Another major downstream project is the planned construction of a fourth major refinery in Kazakhstan, aimed at eliminating the need for imports.** Several options have been discussed in terms of its location, market position, and feedstock source. In Kazakhstan, we project that aggregate refinery throughput needs to only expand to about 17–18 MMt per year by 2030, the amount sufficient to cover gasoline and diesel consumption, following refinery modernization. A sizable increase in the output of gasoline and diesel during this period is expected from the existing refineries, while the production of mazut is expected to contract longer term. Because of the expectation of relatively modest growth in aggregate consumption of light products, the construction of a fourth major refinery in Kazakhstan would result in significant excess capacity for domestic needs. There also are only fairly limited possibilities for refined product exports given the country's inland location.

7.4.2. Kazakhstan's oil refineries: capacities and capabilities

The country has three main refineries, all of which were built during the Soviet period. They have seen only very limited modernization and other upgrades since independence. There are also a considerable number (over 30) of small mini-plants that individually produce very small amounts of (low-quality or semi-finished) products, and so contribute little to domestic supply. The mini-plants processed about 1.5 MMt of feedstock in 2014.

The three main plants are located at Atyrau in Kazakhstan's northwest near the Caspian coast; at Shymkent in southern Kazakhstan; and at Pavlodar in northern Kazakhstan. Total primary distillation capacity for the country as a whole is reported as 18.3 million metric tons (MMt) per year, so capacity utilization in 2014 was 81%, as runs amounted to 14.9 MMt. Although Pavlodar has a coking unit and a catalytic cracker, and Atyrau has a small coker, the refining system is relatively unsophisticated, with relatively little conversion capacity.[83] But plant upgrades with several conversion units are underway or planned (see below). Since independence, Kazakhstan's refined product demand structure has undergone a profound structural shift from heavy fuels to light products, while the output structure of the refining sector has hardly changed, and is still dominated by heavy products (mainly residual fuel oil [mazut]) (see Figure 7.4.1).



Source: IHS Energy
Note: Other products include refinery fuel and losses.

Figure 7.4.1 Structure of Kazakhstan's refined product output

[83] Oil refining processes include: primary distillation, which separates crude oil into its constituent fractions; conversion capacity such as crackers and cokers, which convert heavy fractions into light fractions (e.g., gasoline, diesel); and upgrading capacity, which improves the quality of products (e.g., reformers to increase octane or hydro-treaters to remove sulfur). In addition, vacuum units are often added to the distillation process to allow the pressure above the liquid mixture that is being distilled to be reduced to less than its vapor pressure, causing evaporation of the most volatile liquids. This allows a "deeper" cut to be made (for extracting heavier vacuum gas-oil), reducing the overall amount of residuum.

All three of the main refineries now are effectively owned and operated by the national oil company, KazMunayGaz (KMG), although the Shymkent refinery is actually a joint venture between KMG and Chinese company CNPC following the latter's acquisition of privately held PetroKazakhstan Resources in 2005.[84] The consolidation of the key refining assets in the country into KMG's hands occurred through several ownership changes during the 2000s; during the 1990s the refineries were privatized or partly privatized.[85]

While the Atyrau refinery has long processed only indigenous Kazakh crude, as it is located in the country's main oil-producing area, the two other refineries, at Pavlodar and Shymkent, were designed to be supplied with crude oil by pipeline from West Siberia in Russia. But with the expansion of local crude production in the Turgay Basin in south-central Kazakhstan (Kyzylorda Oblast), the Shymkent refinery shifted predominantly to processing indigenous crude, both from the Kumkol producing area (in Kyzylorda Oblast), delivered by pipeline and, for a time, from Aktobe Oblast, delivered by rail. Pavlodar still refines mostly Russian crude delivered by pipe from West Siberia. Currently, its crude supplies are being delivered via a swap arrangement with Rosneft.

The three refineries vary in their basic characteristics and production profile:

- **Atyrau:** Built in the 1940s, this is Kazakhstan's oldest refinery, and with secondary processes (excluding vacuum distillation) amounting to only 54% of the plant's assessed distillation capacity of 4.5 MMt in 2013 (see Table 7.4.1), the plant has a hydroskimming profile. The refinery is designed to process locally sourced crude, delivered mainly by pipeline. In 2014, its crude throughput amounted to 4.9 MMt (indicating that its crude distillation capacity had been debottlenecked to about 5.0 MMt), the highest it has ever been.[86] Mazut comprised the largest portion of the plant's output, at 31% of the total in 2014 (see Figure 7.4.2a). Diesel fuel, at 27% of total output, was second. The plant has experienced several modest renovations and upgrades over the years, including a $370 million modernization scheme with Marubeni, completed in 2006. Atyrau's sizable mazut production is surplus in the regional market, and so is largely exported.

		Kazakhstan (total)	Atyrau	Pavlodar	Shymkent
A. Thousand Metric Tons	Crude Distillation Capacity (MMt)	18.3*	4.5	6.0	5.3
	Vacuum Distillation	8 440	3 000	4 000	1 440
	All Secondary Processes (sum)	17 377	2 440	10 507	4 430
	Catalytic Cracking	2 000	0	2 000	0
	Thermal Cracking	0	0	0	0
	Visbreaking	2 500	0	1 500	1 000
	Hydro-Cracking	0	0	0	0
	Coking	1 360	720	640	0
	Catalytic Reforming	2 420	420	1 000	1 000
	Hydro-Treating	8 730	1 300	5 000	2 430
	Bitumen Production	367	0	367	0

[84] PetroKazakhstan Resources had initially been only an upstream company, acquiring its producing assets in the Turgay Basin in Kazakhstan's initial privatization process in the 1990s. These assets supplied crude to the Shymkent refinery; the company subsequently acquired the Shymkent refinery in 2000. KMG's ownership stake in the Shymkent refinery has been 49.7% since 2007.

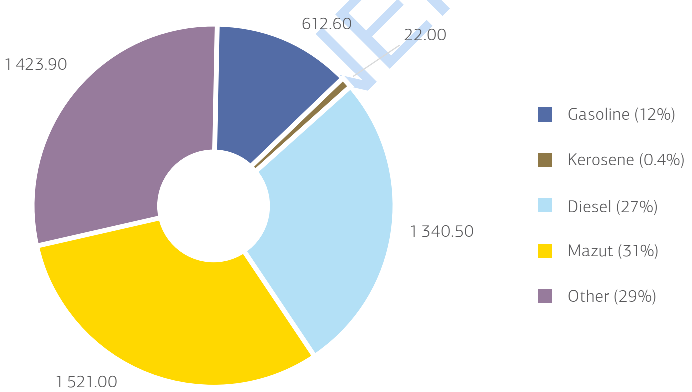
[85] KMG currently holds 99.5% of the ownership of the Atyrau refinery, reclaiming a majority shareholding in 1999, and took over the operatorship (and majority ownership) of the Pavlodar refinery in 2009; by the end of 2013, KMG's ownership stake in Pavlodar was 100%.

[86] The previous maximum was 4.8 MMt, achieved in 1994.

		Kazakhstan (total)	Atyrau	Pavlodar	Shymkent
B. Percent of Crude Distillation Capacity	Crude Distillation (%)	100.0	100.0	100.0	100.0
	Vacuum Distillation	46.1	66.7	66.7	27.4
	All Secondary Processes (sum)	95.0	54.2	175.1	84.4
	Catalytic Cracking	10.9	0.0	33.3	0.0
	Thermal Cracking	0.0	0.0	0.0	0.0
	Visbreaking	13.7	0.0	25.0	19.0
	Hydro-Cracking	0.0	0.0	0.0	0.0
	Coking	7.4	16.0	10.7	0.0
	Catalytic Reforming	13.2	9.3	16.7	19.0
	Hydro-Treating	47.7	28.9	83.3	46.3
	Bitumen Production	2.0	0.0	6.1	0.0

**Note: 18.3 MMt (million metric tons) is reported as the primary distillation capacity for the country as a whole, including all mini-refineries.*
Source: KMG: Refinery reports.

Table 7.4.1 Secondary processing capacities of Kazakhstan's main refineries in 2013



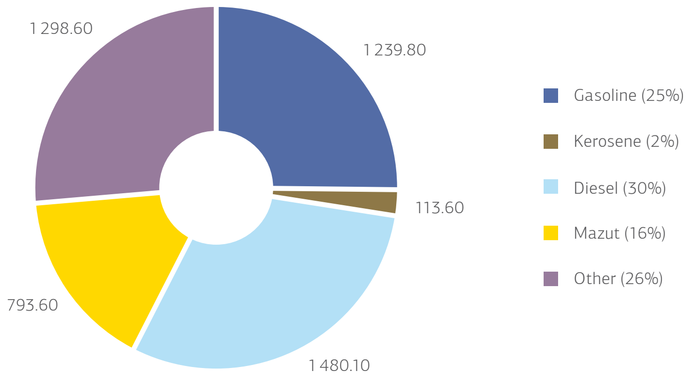
Source: IHS Energy; Ministry of Energy

Figure 7.4.2a Output profile in 2014 - Atyrau (thousand metric tons)

- **Pavlodar:** This refinery, situated in northeast Kazakhstan, opened in 1978 and was designed to process mainly Russian crude. In 2014, Pavlodar processed 4.9 MMt of crude oil. Effective operable capacity at the plant is currently assessed at 6.0 MMt per year (see Table 7.4.1). The facility has the most significant secondary processing capacity of any of the three main plants in Kazakhstan, including conversion units (coker and catalytic cracker). Secondary capacity represents 175% of its distillation capacity, giving it the greatest refining depth of the three Kazakh refineries.[87] Therefore, unlike Atyrau, mazut does not comprise the largest share of its production. Instead, diesel accounts for 30% of total output, with gasoline making up 25% (see Figure 7.4.2b). Pavlodar's refined

[87] Secondary refining processes are those that operate on the fractions that come from primary distillation. These either upgrade the fractions (e.g., remove sulfur, add octane, remove wax, or improve other properties) or in the case of less desirable heavier fractions, convert them into additional light product streams. The fractions may go through several secondary processes to become finished fuels. These secondary processes also include specialized extraction or finishing processes that produce special additives or

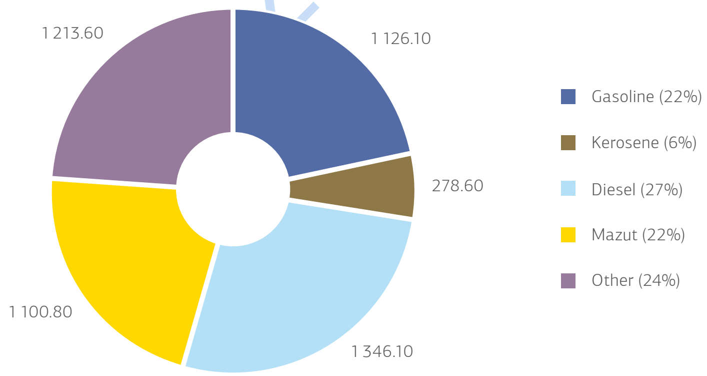
products mainly supply the needs of the agricultural and mining sectors in northern Kazakhstan as well as the capital city of Astana.



Source: IHS Energy; Ministry of Energy

Figure 7.4.2b Output profile in 2014 - Pavlodar (thousand metric tons)

- **Shymkent:** Shymkent was completed in 1980. The plant is less sophisticated than Pavlodar, as it is a basic hydro-skimming plant. Its secondary capacity is equivalent to 84% of its assessed distillation capacity of 5.25 MMt. Shymkent's crude runs in 2014 amounted to 5.1 MMt, with an output mix comprised of diesel (27%), with mazut and gasoline production amounting to about 22% each (see Figure 7.4.2c). Originally, West Siberian crude from Russia supplied the Shymkent refinery, but the expansion of production in the Turgay Basin post-independence provided a local crude feedstock source for the plant. This Kumkol crude is now the dominant feedstock for the plant, although it nominally was receiving some Russian crude in recent years. Shymkent's principal market area includes the large Almaty metropolis and southern Kazakhstan.



Source: IHS Energy; Ministry of Energy

Figure 7.4.2c Output profile in 2014 - Shymkent (thousand metric tons)

specialized products such as bitumen or lubricants. Secondary capacity percentage is calculated as the total amount of secondary processing capacity divided by primary distillation capacity. Sophisticated refineries typically have considerably more secondary capacity than primary distillation capacity, so that all the derivatives can be fully (thoroughly) processed.

7.4.3. Refinery production and modernization program

Kazakhstan's refineries have received very little investment since independence by industry standards (in aggregate, amounting to the equivalent of only about $3.8 billion in total since 2000). This has meant that the refineries' output mixes have not changed much, and therefore they have not adapted to shifting domestic consumption patterns. The only significant new units added to Kazakhstan's refineries since 2000 were vacuum distillation and a visbreaker at Shymkent.

This has led to a significant mismatch between domestic demand and the available refinery slate. As a result, in 2009 the Kazakh government officially launched a program for modernizing the three main refineries, to be completed by 2015 initially, involving a total capital outlay of about $6.0–6.5 billion. The overall objectives were to increase aggregate distillation capacity to 19.5 MMt,[88] to deepen refining (to increase production of light refined products to 12.5 MMt per year and, at the same time, to reduce heavy refined products to 0.6 MMt per year), and to upgrade product quality (to Euro-4 and Euro-5 specifications).[89] Delays in individual components of the program, however, already have extended the expected completion date well beyond the initial timeline.

The most significant investments are occurring at the older Atyrau plant: KMG, with contracts that include Japanese and Chinese firms, is installing a heavy product conversion unit, initially estimated to cost $1.7 billion, but total costs have risen to $2.9 billion. The unit, which includes a catalytic cracker, a coker, and a vacuum unit, would be able to convert some 2.4 MMt of heavy products into gasoline, kerosene, and diesel (see Table 7.4.2). Ultimately, it will allow Atyrau to boost production of diesel to 1.64 MMt per year, gasoline to 1.75 MMt per year, and jet fuel to 244,000 tons per year. Just as important, it will allow products of Euro-5 specification to be produced. Another new unit being installed at the plant will produce aromatic hydrocarbons. This aromatics unit started up in mid-2015.

Type of unit	Company	Refinery	Capacity (thousand metric tons per year)	Expected date of completion
Hydrocracker	KMG	Atyrau	979	2016
Reformer-CCR	KMG	Atyrau	1 115	2016
Hydrogen-Steam Methane (MMcm per year)	KMG	Atyrau	207	2016
Aromatics-BTX	KMG	Atyrau	629	2016
Benzene			496	
Para-xylene			133	

Source: KMG

Table 7.4.2. Projects underway at Kazakhstan's refineries

Although Atyrau's modernization is expected to be the most extensive, the other two plants will also be upgraded and expanded. In May 2014, CNPC and Kazakhstan agreed to modernize the Shymkent plant, extending a $1 billion line of credit to be used for the project. The extent of the modernization so far is expected to include construction of a catalytic cracker that would permit more premium product to be produced. A new isomerization unit is close to completion, to provide high-octane components for gasoline blending. Other planned units include more vacuum distillation capacity; hydro-treating capacity for naphtha/gasoline, diesel, kerosene, and vacuum gasoil; and catalytic reforming. Plans to outfit Pavlodar include six new processing units, including a reformer, a gasoline hydro-treater, and another catalytic cracker, but much of the work is planned to involve upgrades to the existing facilities, including reconstruction of the existing catalytic cracker.

Like most countries, Kazakhstan has been moving toward tighter fuel specifications to improve air quality. Kazakhstan's fuel specifications are now determined via its Customs Union/Eurasian Economic Union agreements with Russia and Belarus. However, these agreements provide a more relaxed timeline for Kazakhstan, given its delayed refinery modernization program, with the transition to more stringent specifications in Kazakhstan lagging well behind Russia and Belarus. As of 1 January 2013, the regulations correspond to Russia's "class" benchmarks rather than Euro standards, although

[88] The current program calls for debottlenecking at the three major plants, to allow expansion of distillation capacity at Atyrau to 5.0 MMt, Shymkent to 6.0 MMt, and Pavlodar to 7.5 MMt, which totals 18.5 MMt. Distillation capacity is difficult to define precisely, as it depends upon a variety of factors, including the type of crude being run, the expected number of days of operation annually, and others.

[89] During the Soviet times, Kazakhstan's refineries produced mostly low-octane gasoline (A-80) used for trucks and buses. While the share of motor gasoline in total refinery output remains about the same because of limited refinery modernization to alter the overall refinery slate, the share of gasoline output represented by higher octane fuels (AI-92) used by cars has been increasing. The available gasoline pool has been upgraded without installing expensive new catalytic reformers through the use of octane additives via isomerization and alkalylation processes as well as oxygenates.

these classes are nearly identical to Euro specifications (the difference being that the Russian class benchmarks allow for lower octane fuels).

The Euro-3 standard was only introduced in Kazakhstan from 1 January 2012, replacing Euro-2 which had become effective on 15 July 2009. The date for the shift to Euro-3 was delayed twice: initially it was pushed back to 1 July 2011 from the original date of 1 January 2011, and then to 1 January 2012. However, a requirement for foreign cars imported into Kazakhstan or cars manufactured within the country to meet the Euro-4 standard became effective as of 1 July 2013, although for the refineries the introduction of Euro-4, which had been planned for 1 January 2014, has been pushed back to 2016.[90]

7.4.4. Domestic crude oil consumption

The fall and subsequent rebound of domestic refined products consumption since independence (see below) was mirrored by a similar decline and recovery in domestic crude consumption and refinery operations. Crude oil consumption dropped from 18.0 MMt in 1991 to a low point of 6.8 MMt in 1999, before slowly rebounding through the 2000s. National apparent consumption of crude oil reached 16.7 MMt in 2013 and was 20.8 MMt in 2014.[91] This amounted to about 26% of national crude oil production last year; the bulk of national output (over 80%) has traditionally been exported.

KMG is the primary refinery owner in Kazakhstan, and it is also the dominant supplier of crude oil feedstock to the Kazakh refineries.[92] However, KMG's main production assets are mature, and are now in decline; the key sources of growth in Kazakh oil production are the projects of international consortia and foreign producers. Crude oil production by KMG's 100%-owned entities has declined by 14.5% since 2005–2006, when it was 9.6 MMt, to about 8.2 MMt in 2014 (see Table 7.4.3).[93] Because production of KMG's 100% owned entities is expected to continue to contract longer term, this has generated considerable concern about the availability of crude supplies to meet the country's refinery demand after about 2020. This concern is compounded by a general decline in the key areas of legacy production that provide supplies for the domestic refineries (e.g., essentially Atyrau Oblast, Mangistau Oblast, and Kumkol production other than the three "mega" projects— operated by TCO, KPO, and NCOC).

	2000	2001	2002	2003	2004	2005	2006	2007	2008	2009	2010	2011	2012	2013	2014
KMG (100% ownership)	5 937	6 600	7 397	7 915	8 939	9 392	9 575	9 575	9 512	9 004	8 804	7 931	7 798	8 080	8 181
KMG E&P	5 937	6 600	7 397	7 915	8 919	9 364	9 551	9 548	9 470	8 962	8 766	7 898	7 766	8 049	8 151
Uzenmunaygaz	3 645	4 200	4 883	5 283	6 206	6 571	6 750	6 742	6 646	6 251	5 966	5 082	4 950	5 208	5 328
Embamunaygaz	2 292	2 400	2 514	2 632	2 713	2 793	2 801	2 806	2 824	2 711	2 800	2 816	2 816	2 841	2 823
AmangeldyGaz (KTG)	0	0	0	0	20	28	25	26	26	26	24	22	21	22	21
KazGPZ	0	0	0	0	0	0	0	0	16	15	14	11	10	9	9

Source: Ministry of Energy

Table 7.4.3 Crude oil (and condensate) production by KazMunayGaz (KMG) (thousand metric tons)

[90] In January 2016, Kazakhstan's cars have to meet the Euro-5 standard, and the production of the A-80 ("normal") gasoline grade will be phased out. Although Russian refinery production changes to Euro-5 specifications in January 2016, there does not yet appear to be a specific timetable for Kazakhstan's refineries to produce only Euro-5 fuels.

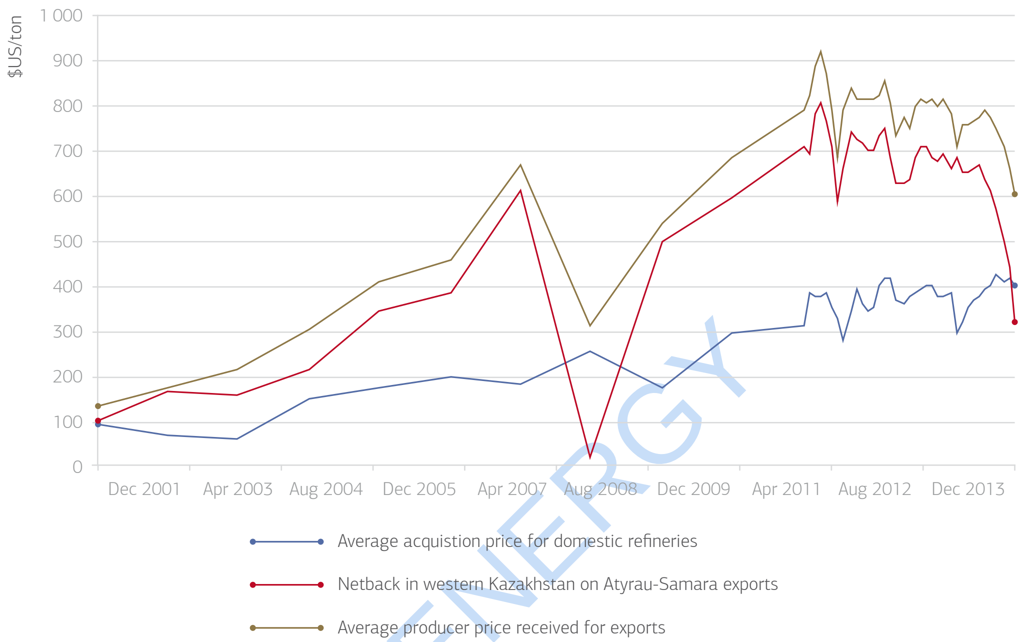
[91] This is calculated as crude (and condensate) production minus exports plus imports. This includes field losses as well as any changes in stocks.

[92] KMG also owns the Petromedia refinery in Romania, located on the Black Sea coast. KMG acquired the plant in 2007 for $2.7 billion. This refinery, formerly known as Rompetrol, has a distillation capacity of 5 MMt per year (100,000 b/d) after an upgrade in 2012. It ran 5.05 MMt of crude in 2014. Petromedia accounts for about 40% of Romania's refinery capacity and has been the key asset of KMG International (the new name of Rompetrol). KMG spent $380 million on an upgrade at the plant in 2012, and plans to spend about $100 million on an overhaul and other work at the plant in 2015. KMG also owns a refining plant in Ploesti and a small petrochemical facility, but the Ploesti plant uses feedstocks from Petromedia, finishing them into products such as hexane, solvents, and bitumen. It also owns over a thousand filling stations across Europe.

[93] KMG's equity production (the aggregate of all entities in which it holds a stake, weighted by KMG's ownership share in each) is much higher, and has been rising: the calculated amount was 22.3 MMt in 2014, representing 27.7% of Kazakhstan's total national production last year.

Therefore, it may be that Kazakhstan's refineries will need to attract some of the crude output of other producers, including the three big export-oriented projects. Theoretically, this should not pose an insurmountable problem as long as the domestic market offers a price commensurate with the export options available for this crude. That is, the domestic price would have to be at export parity (i.e., quoted international prices minus marine freight, pipeline and other transport costs, and any applicable export tax).

However, until recently oil product prices have been completely regulated in Kazakhstan; currently only diesel fuel and gasoline AI-80 prices are regulated.[94] The government has long set retail product prices in the country, and effectively determines most margins back through the value chain. So these regulations effectively determine wholesale (ex-refinery) product prices as well as what the refineries can offer producers for their crude.[95] Domestic crude oil prices (average acquisition prices paid by the refineries) were about 50% of the average prices earned on exports by producers in 2013 and 2014 (see Figure 7.4.3). In terms of average export netbacks,[96] the average acquisition prices paid were about 60% of export netback parity in 2013 and about 70% in 2014 (see Figure 7.4.3). Therefore, most oil producers in Kazakhstan prefer to export than to sell to the domestic refineries.



Source: IHS Energy, Kazakhstan statistical agency

Figure 7.4.3 Crude oil prices in Kazakhstan

Therefore, a key recommendation to assure domestic crude supplies is to relax current domestic pricing regulations and allow domestic crude prices to rise to export netback parity. Another option that the Ministry of Energy has proposed is that special incentives be provided for producers that would sell oil domestically. One such incentive would be to extend exploration and production rights to oil companies on condition that priority be given to domestic crude supplies over exports.

With Kazakhstan's available export capacity for crude oil, and with the CPC expansion being completed, 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). In turn, domestic product prices at the refinery gate would then have to reflect the resulting domestic price of crude, with retail prices also reflecting the price of competing fuels, such as natural gas.

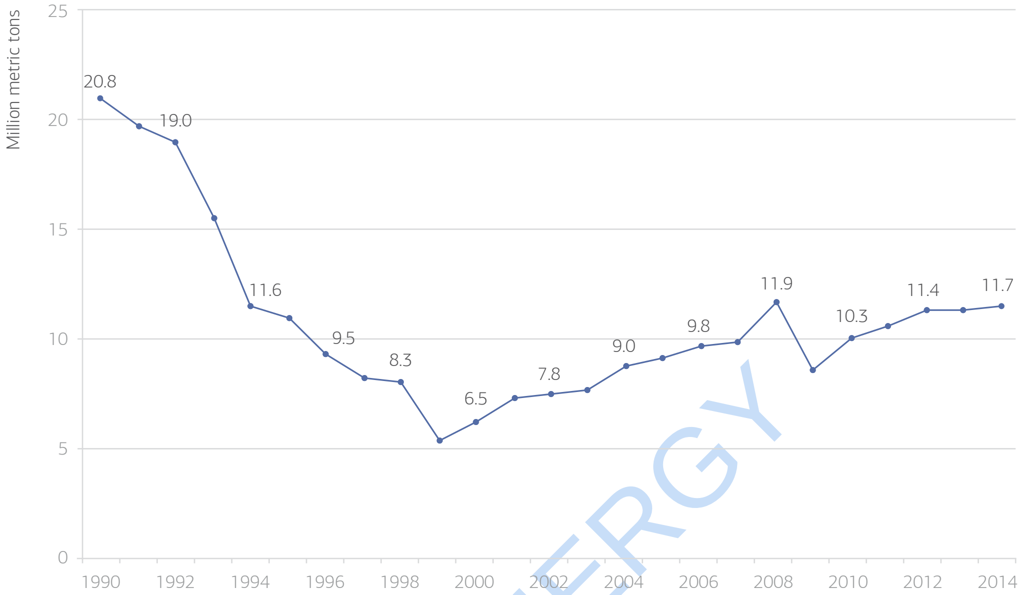
[94] In September 2015, the Kazakh government suspended regulation of domestic prices for AI-92/93 gasoline (the most popular grade)— to prevent fuel shortages following the August 2015 tenge free float, given the higher procurement prices for imports of Russian gasoline after the decline in value of the tenge in relation to the ruble.

[95] The State Committee for Regulation of Natural Monopolies and Protection of Competition (KREMiZK, formerly known as AREM) announced on 1 March 2013 that it would also begin regulating wholesale prices once the relevant legislation was passed.

[96] Calculated as quoted prices in the Mediterranean minus both transportation (pipeline and marine) costs for the Atyrau-Samara export route and export duties.

7.4.5. Domestic refined products consumption

Domestic consumption of refined products suffered greatly after the collapse of the Soviet Union: in addition to the economic recession experienced upon the collapse of the USSR, all the newly independent states, including Kazakhstan, dealt with painful shocks tied to global market entry and the transition to a market economy. As a result, Kazakhstan's aggregate (apparent) domestic consumption of refined products dropped from 19.6 MMt in 1991 to 5.7 MMt in 1999, before slowly rebounding throughout the 2000s. By 2014, apparent consumption had reached 11.7 MMt (see Figure 7.4.4). Average annual demand growth between 2000 and 2014 was a rather robust 4.3%. During this period, GDP growth averaged 7.5% per year, and the national car fleet expanded rapidly, averaging 10.4% growth each year. Much of this was due to "catch-up" as demand had been suppressed during both the Soviet period as well as the immediate transition period in the 1990s.

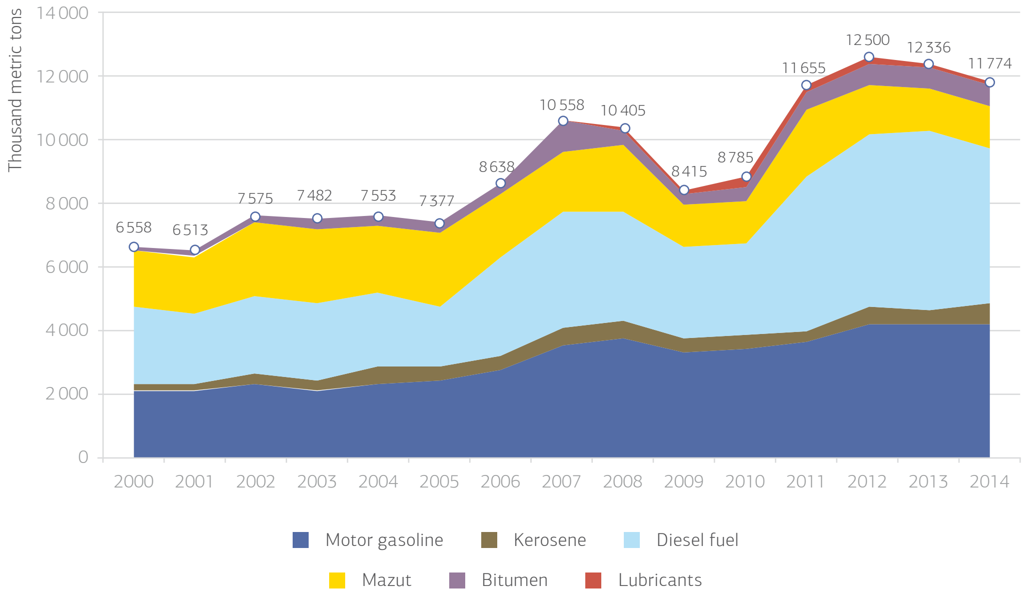


Source: IHS Energy
Note: Apparent consumption equals production (refinery throughput) minus exports plus imports.

Figure 7.4.4 Kazakhstan's apparent consumption of refined products

But the expansion of the economy will be at a much slower pace going forward, and so will the growth of the car fleet. We project that GDP growth will average only about 3.3% annually between 2015 and 2040, while growth in the car fleet will be much slower as well, at only 2.3% per year. As a result, aggregate apparent consumption of refined products is projected to reach 11.9 MMt by 2020, 13.5 MMt by 2030, and 15.2 MMt by 2040, registering an average growth of only about 1.2% per year over the entire period.

In contrast to apparent consumption, actual (reported) consumption of refined products (calculated as a sum reported for all individual products) amounted to 12.5 MMt in 2012, 12.3 MMt in 2013, and only 11.8 MMt in 2014 (see Figure 7.4.5). But the figures still show the same general trends, with a slight decline in consumption in recent years (see text box).



Source: Kazakhstan statistical agency

Figure 7.4.5 Reported consumption of refined products in Kazakhstan

Apparent Consumption versus Reported Consumption of Refined Products

Apparent consumption is the difference between production and net trade (exports minus imports). In many cases, the figures differ substantially from those reported in various statistical sources for actual consumption. Measures of apparent consumption are believed to be superior to other measures of consumption in this region of the world because data and statistical reporting on trade flows (imports and exports), together with production data, are much stronger, more reliable, and more comprehensive than those on actual fuel consumption. Also, data on energy production and trade flows are more routinely available and on a far more regular basis than actual consumption data.

Because apparent aggregate refined product consumption is defined as total refinery throughput minus product exports plus product imports, it includes refinery fuel and losses; these are essentially viewed as a specific type of use of oil/oil products. This convention is followed in part to simplify analysis over time, where detailed data on refinery use and losses are not always available for each period of a time series, whereas refinery throughput is routinely reported. The Kazakh refineries differ greatly in terms of their refinery use and losses—for the country as a whole, aggregate output of refined products (residual products plus distillates) has been reported annually since 2009. In 2013, this figure was 13.8 MMt, and in 2014, 14.3 MMt. Therefore aggregate refinery fuel use and losses were 3.2% of crude runs in 2013 and 3.8% in 2014.

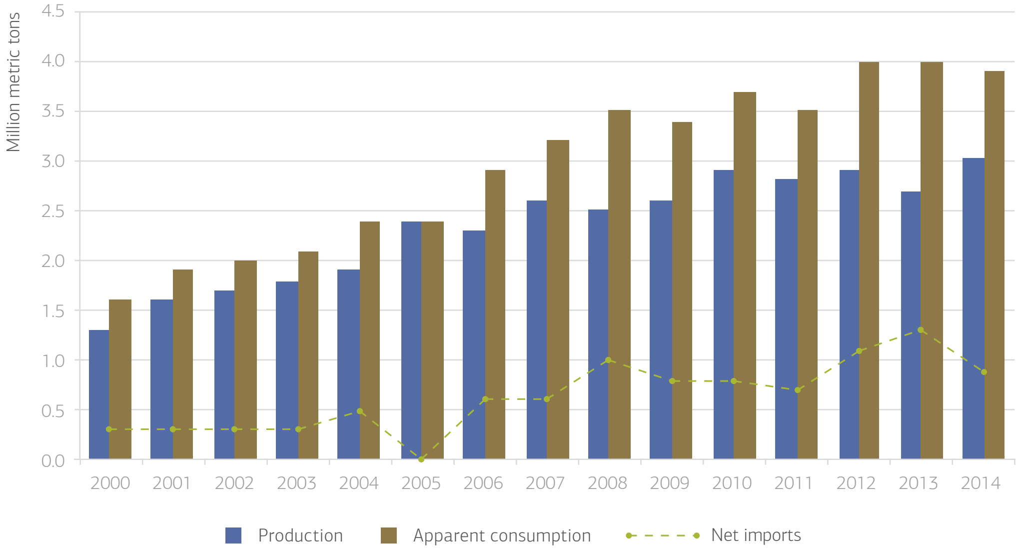
The composition of Kazakhstan's consumption of refined products has changed considerably over the years. There has been a substantial decline in mazut usage, as the country has gradually begun to switch to natural gas for power production, and the industrial sector has switched from mazut as well. Thus, reported mazut consumption declined from 6.4 MMt in 1990 to 1.7 MMt in 2000, and to 1.3 MMt in 2013–2014 (see Figure 7.4.5). Mazut's share of product consumption in Kazakhstan has declined from 34.6% in 1990 to 26.1% in 2000 and to 10.5% in 2014, and is expected to gradually decline going forward as well.

The decline in mazut has been accompanied by a decisive shift in consumption to light products, particularly motor fuels. With economic growth and the rise in personal incomes, Kazakhstan's fleet of personal automobiles has grown rapidly, reaching 4.0 million by the end of 2014. And although new automobiles are more gasoline-efficient than previous models (constraining incremental growth in gasoline consumption somewhat), gasoline consumption, particularly of high-octane grades needed by modern automobiles, has also expanded. Gasoline consumption had dropped to 2.1 MMt in 2000, but then reached 4.2 MMt in 2013–2014. Of this, 69.3% in 2014 was comprised of "regular" grade (A-92), 24.5% was the "normal" (A-80) or low-octane grade used by trucks and buses, and the remainder (about 6.2%) was comprised of "premium" grades (A-95, A-98).[97]

[97] The letter A stands for automobile (motor) gasoline, while the numbers refer to the octane rating of the particular grade measured by the research method.

The country's growing domestic demand for high-octane gasoline has long been met with incremental imports. Kazakhstan typically has imported between 300,000 tons and 1.3 MMt of gasoline annually since 2000 (see Figure 7.4.6).

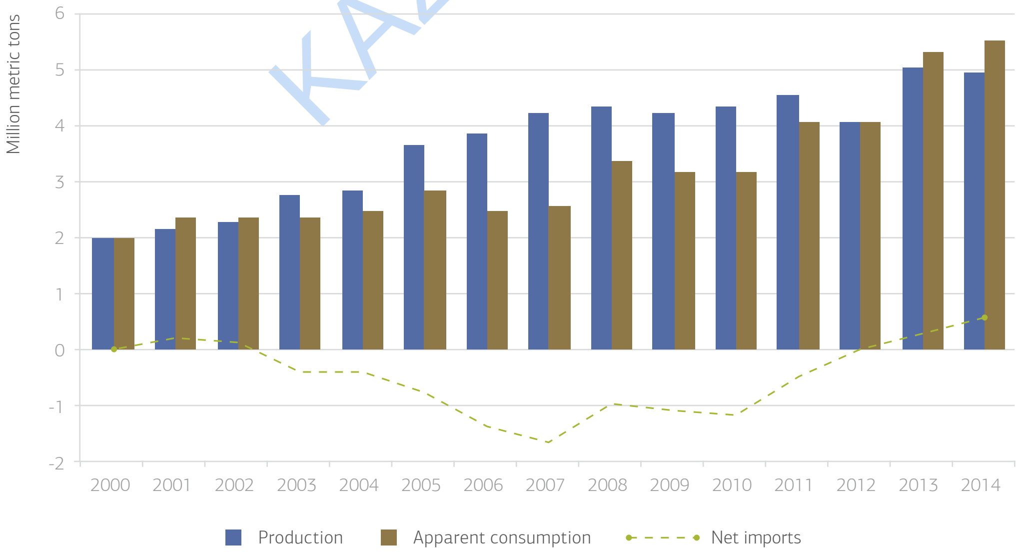
Kazakhstan will likely have to continue to import a sizable share of its gasoline supply until refinery modernization and expansion provides sufficient refinery output.



Source: IHS Energy, Kazakhstan statistical agency, Ministry of Energy

Figure 7.4.6 Kazakhstan's gasoline balance

Another key shift in the composition of demand is dieselization: trucking activity has rebounded with the overall economy, and gasoline-powered trucks and buses are being phased out in favor of diesel-powered vehicles. Other major consumers of diesel include railroad transportation, agriculture, and some industrial use. After contracting from 7.2 MMt in 1990 to 2.2 MMt in 2001, diesel consumption has expanded to reach 5.6 MMt in 2013 (but only 4.9 MMt in 2014). Diesel's share of the product mix has grown from 33.1% in 2001 to 45% in 2013. Historically, domestic demand for diesel was met with domestic production; however, apparent diesel consumption in 2012–2014 exceeded domestic production, making Kazakhstan a net importer of diesel as well as gasoline (see Figure 7.4.7).



Source: IHS Energy, Kazakhstan statistical agency, Ministry of Energy

Figure 7.4.7 Kazakhstan's diesel balance

7.4.6. Refined products trade

Both imports and exports of refined products in Kazakhstan have grown significantly since 2000. Kazakhstan exports low value-added (heavy) products while importing premium products, a function of its increasingly mismatched refined product slate.

Imports of refined products have grown from 1.2 MMt in 2000 to 2.5 MMt in 2013, although declining to 2.0 MMt in 2014. Imports in 2013 included 1.3 MMt of gasoline, 600,000 tons of diesel, 300,000 tons of mazut, and 400,000 tons of other refined products (mostly jet kerosene).[98] Gasoline's share of total Kazakh imports of refined products has been rising, from 33% of total imports in 2000 to 55% in 2014.

Russian products account for the bulk of Kazakhstan's total product imports (75–95% in recent years). Russia has delivered between 1.2 and 2.3 MMt of refined products to Kazakhstan annually as part of its existing bilateral trade relationship since 2005, with the amount tending to rise over time. Russia delivered 1.7 MMt of products to Kazakhstan in 2014 (versus 2.3 MMt in 2013), including only 967,700 metric tons of gasoline (versus 1.1 MMt in 2012 and 2013). KazMunayGaz Onimderi, a subsidiary of the national oil company KMG, is the designated operator on the Kazakh side for handling these import volumes.

Russian imported products account for a substantial share of total Kazakh consumption, about 20% in recent years. But for gasoline and jet kerosene, the share of Russian imports is typically much higher, meeting about 30% of Kazakh gasoline consumption and about one-third of (jet) kerosene consumption. Just as important, the bulk of these imports are destined for north-central Kazakhstan and the national capital, Astana. These products are mainly sourced from Gazprom Neft's major refinery at Omsk, in West Siberia.

The ongoing economic integration process (Customs Union, Eurasian Economic Union [EEU]) has led to differing views between Russia and Kazakhstan regarding the mutual trade in oil and oil products, largely because of the different conditions that Russia applies to member states' export duties. For example, Russia's arrangement with Belarus following the formation of the Customs Union provided crude oil to the country duty-free, but obliged Belarus to turn over to Russia the export duties generated by its refined products exports derived from the imported crude. But as part of the new agreement reached in May 2014 for the EEU (which launched on 1 January 2015), this stipulation was removed, allowing Belarus to retain all export duties on its product exports. For other new members joining the Customs Union/EEU, such as Armenia and Kyrgyzstan, export duties on Russian refined products have been waived altogether. But for Kazakhstan, which imports both Russian crude and refined products to supply domestic demand, Russia has insisted that Kazakhstan provide compensation for the loss of export duty revenue on its oil deliveries to Kazakhstan.

Under the terms of a bilateral agreement signed in June 2012, Kazakhstan agreed to supply 1.5 MMt of crude oil annually to compensate Russia for duty-free deliveries of 1.3–1.4 MMt of petroleum products; any imports above that would carry export duties. At that time, Moscow claimed that it would lose the equivalent of about $780 million annually by supplying duty-free products to Kazakhstan. These bilateral agreements also explicitly prohibit re-exports of duty-free oil and products, and also call for Kazakhstan and Russia to eventually harmonize their export duties.

To stay within the targeted volumes of compensation oil that Kazakhstan must provide (amid rising worries about the overall dependence of Kazakhstan on Russian product supplies), initially in spring 2014, Kazakhstan imposed strict limits on Russian refined product imports. These restrictions were subsequently lifted at the end of July as shortages of motor fuels developed across Kazakhstan and were particularly acute in some regions. As a result, the country began to look for additional supplies from a variety of sources, including more from Russian companies. Other measures to ease the shortages, such as a crackdown on gasoline smuggling across the border to Russia (where the product could be sold at much higher prices—see below) also were stepped up.

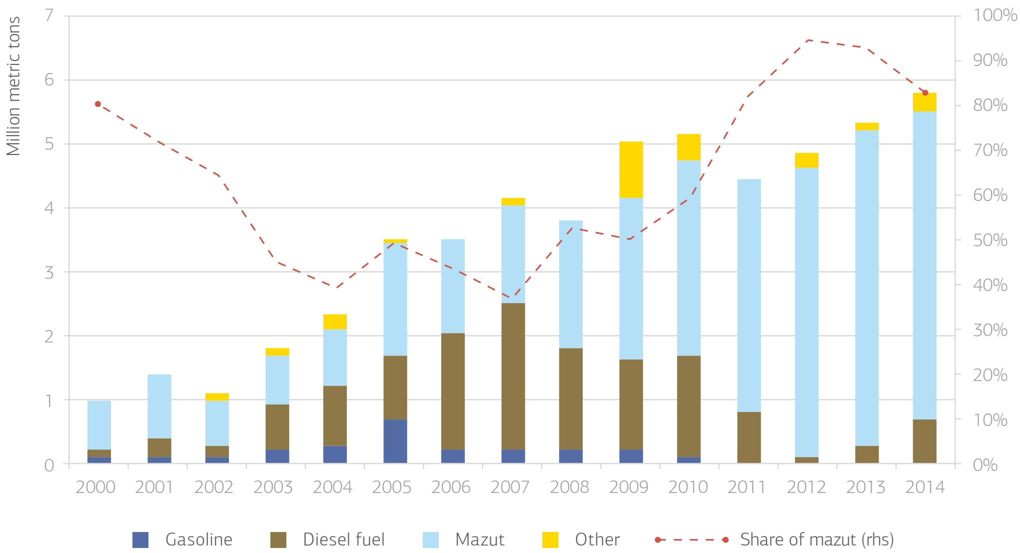
Kazakhstan also established tolling agreements with Chinese refineries, in which Kazakhstan delivers crude to Chinese refineries and brings refined products back into Kazakhstan. This arrangement provided only small volumes,[99] and these also ended up being relatively expensive because of the extra logistics involved.

Kazakhstan exported a total of 5.3 MMt of refined products in 2013, of which 4.9 MMt (92%) was comprised of mazut; the share in 2014 was slightly lower (see Figure 7.4.8).[100] Kazakhstan's product exports have grown significantly since 2000, reflecting the surplus volumes of mazut.

[98] With mazut supply being long domestically, it may seem surprising that Kazakhstan imports any mazut at all. However, Kazakhstan is a large country, and for some consumers in certain areas it is more attractive to import from refineries in neighboring countries than buy from more remote domestic refineries.

[99] In 2012–2013, Kazakhstan dispatched 339,000 metric tons of crude to China under this tolling arrangement, taking back only about 150,000 metric tons of gasoline.

[100] This export category actually comprises all heavy liquid fuels, so it includes a sizable amount of vacuum gasoil (VGO).



Source: IHS Energy, Kazakhstan statistical agency, Ministry of Energy
Note: Exports of mazut include vacuum-gasoil.

Figure 7.4.8 Kazakhstan's refined products exports

The main destination for Kazakhstan's mazut exports has become Europe. European countries received about 92% of Kazakhstan's total mazut exports in 2013 and 80% in 2014 (see Table 7.4.4). At the same time, the share of mazut going to CIS countries, or to other countries, such as China, has tended to decline. Europe's consumers do not actually consume much mazut directly, preferring cleaner fuels such as heating oil or natural gas for boiler fuel needs. Most of the mazut imported by Europe is actually used as an intermediate product by its refining sector, for conversion into lighter, cleaner products. As a result, the major importing countries tend to be those with major refining sectors, such as Italy and the Netherlands.

	2009	2010	2011	2012	2013	2014
Total	**2 453.4**	**3 184.8**	**3 376.8**	**4 511.7**	**4 959.0**	**4 845.2**
CIS countries	294.0	508.4	351.3	326.0	47.1	1 154.7
Kyrgyzstan	116.3	128.0	43.9	4.9	4.4	6.2
Tajikistan	36.2	12.6	5.8	26.0	13.1	13.1
Uzbekistan	20.8	1.1	10.8	6.3	0.9	—
Ukraine	120.3	49.9	255.6	286.5	28.7	12.5
Other	0.4	316.8	35.2	2.2	0.0	1 122.9
Non-CIS countries	2 159.4	2 676.4	3 025.6	4 185.7	4 912.0	3 690.4
Europe	960.8	1 648.7	1 171.2	3 599.0	4 558.1	3 480.1
Austria	—	—	0.2	—	—	—
Bulgaria	—	—	1.5	—	—	—
Germany	—	0.2	1.0	8.7	5.0	—
Denmark	—	49.1	0.4	—	—	1.1
Italy	205.5	393.9	503.9	606.2	380.5	35.3
Cyprus	—	—	20.0	—	—	—
Latvia	6.6	61.4	167.9	166.4	432.5	553.8
Lithuania	1.0	4.4	0.3	26.1	47.5	14.5
Netherlands	217.1	365.0	115.6	540.4	3 132.1	1 906.1
Poland	3.9	—	0.7	0.8	—	—
Romania	6.3	8.1	1.9	—	—	—
United Kingdom	162.6	494.0	14.7	48.8	65.8	13.4
Finland	341.6	232.3	333.2	235.0	375.3	1.7
France	—	1.7	—	—	—	—

	2009	2010	2011	2012	2013	2014
Switzerland	0.2	—	—	1 962.0	119.4	—
Sweden	14.3	33.3	—	—	—	—
Estonia	1.6	5.4	10.0	4.5	—	954.2
Other	1 198.7	1 027.7	1 854.4	586.7	353.9	210.4
Hong Kong	—	5.3	—	—	—	—
Georgia	—	1.5	0.9	0.2	4.3	—
Iran	156.0	0.6	4.6	—	—	—
Canada	—	—	2.7	—	—	—
China	1 042.8	509.4	1 846.1	565.4	291.2	209.3
USA	—	504.4	—	10.0	4.6	—
Turkey	—	6.5	—	11.1	41.9	1.1

Source: Kazakhstan's foreign trade statistics.
** Exports of heavy liquid fuels; includes vacuum gasoil.*

Table 7.4.4 Kazakhstan's exports of mazut by country* (thousand metric tons)

7.4.6.1. Product export bans and other administrative controls

One method the government has used extensively to influence domestic markets and prices is periodic administrative bans on exports of selected refined products. These typically apply to light and middle distillates. Originally intended to ensure supply for the agricultural sector during its peak demand seasons (spring planting and fall harvest), these bans have persisted year after year, and have now become practically year-round, with only limited amounts of diesel allowed for export during off-peak demand seasons. The export bans are now viewed as a tool for achieving broader objectives than merely ensuring sufficient light products for agriculture. More specifically, they are seen as a means of preventing: (1) shortages of oil products in the overall domestic market; and (2) any resulting spikes in domestic prices.

For example, an export ban applying to light and middle distillates began on 1 January 2013 and was to last for six months, but was extended several times, including another six months from 1 January 2014.[101] The most recent extension was for another six months banning exports of gasoline, kerosene, and diesel fuel from 1 January 2015. These periodic bans are likely to remain a feature of Kazakhstan's domestic refined product market until Kazakhstan's refinery modernization projects are completed.

Kazakhstan also imposes export duties on both light and heavy products, although these do not apply to trade with fellow Customs Union/Eurasian Economic Union members. There are no import duties on oil products levied by Kazakhstan.

7.4.6.2. Domestic refined product pricing

Oil product prices have remained regulated in Kazakhstan, by the Committee for Regulation of Natural Monopolies and Protection of Competition (KREMiZK, formerly known as AREM).[102] The government has long set retail prices in the country. The key piece of applicable legislation is the Law "On Public Regulation of Production and Circulation of Certain Oil Products," adopted in July 2011. The law's key features include:

- Setting maximum allowable retail prices for certain oil products at filling stations. These are set by KREMiZK according to a formula that relates prices of individual products to international quotations, with changes in prices to occur when certain thresholds have been breached;
- Introduction of the principle of regional distribution of fuels and lubricants rather than just a single national market;
- Provision for equal access of oil suppliers/producers to domestic refineries;

[101] These periodic bans no longer apply to trade within the Customs Union/Eurasian Economic Union, as Kazakhstan cannot regulate inter-union trade with Russia and Belarus.

[102] Crude oil prices were theoretically liberalized in Kazakhstan in December 1994, following a similar government decision on refined products in November 1994; however, oil prices, in fact, remained regulated through various means, such as the periodic use of special prices for favored consumer groups (especially agriculture) and the introduction of various pricing rules or mechanisms on refineries or other entities considered "monopoly" suppliers.

- Legislative recognition of a value chain for products that extends from upstream production through refining to wholesale and retail;[103]

- Regulatory approval of investment programs and inclusion of the resulting "investment component" into the established cost base for oil products at the refineries.

However, KREMiZK does not always fully comply with the legislated requirements for setting maximum retail prices. It often does not adjust prices when the threshold values for oil prices in the international market have changed, exercising judgment about particular conditions that arise in the Kazakh domestic market, such as domestic inflation. For example, in 2013, maximum prices were eligible to be changed six times due to changes in world prices exceeding the established threshold values. However, the ceiling prices for regular (A-92) and normal (A-80) gasolines were not revised, causing their actual prices to diverge substantially from the values set in the regulations.

One chronic problem is that Pavlodar, which processes Russian crude oil (for which import prices essentially vary with world market quotations), often incurs direct losses from the sale of oil products. A similar situation has occurred periodically for product importers. This is because the procurement prices paid for Russian crude or products are not synchronized with the regulations that set domestic prices for refined products. This serves as a major impediment to investment in upgrading and expanding the Pavlodar refinery or other infrastructure.

Regulating domestic wholesale and retail prices will become increasingly problematic on several fronts going forward for Kazakhstan. One is ensuring domestic crude supply for the refineries: as the KMG-controlled legacy oil production declines, the national oil company may be unable to completely supply domestic crude oil demand as it did before. Therefore, domestic crude prices will need to increasingly reflect those prevailing in international markets in order to attract crude from other suppliers. Another issue is securing sufficient imported products to meet domestic demand, at least in the medium term during refinery modernization. This becomes quite difficult if domestic prices continue to be set below those available in surrounding markets (especially in Russia): suppliers naturally would prefer to export their products and importers have no incentive to bring products in. Finally, it affects the incentives for refining investment and modernization because it distorts domestic price signals. One key reason for the rather late start for Kazakhstan's refinery modernization program is very weak market forces and contradictory price signals for domestic refined products. Because price regulation essentially established ceilings for high-demand light products while keeping a price floor under mazut, market signals did not reflect relative scarcities.

Kazakhstan's issues in the domestic refined product market have been brought into much sharper relief by the launch of the Customs Union, and now Eurasian Economic Union. These arrangements imply free trade and market-determined prices. But because these elements remain weak, Kazakhstan and Russia have disagreed over the customs and duty arrangements for crude oil and refined products flowing from Russia into Kazakhstan, and administrative measures have been routinely invoked in their refined product trade.

A more sensible arrangement for the longer term would be for full domestic price liberalization, which would mean that domestic oil prices would gravitate toward export parity netback, as they have in Russia (see text box).

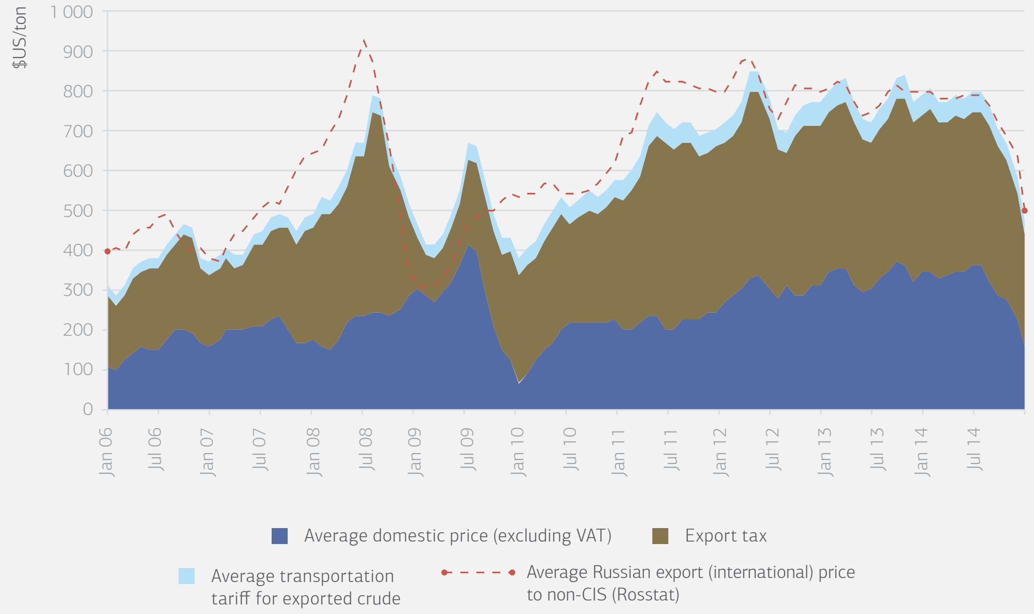
Russia's Key Principle for Domestic Product Prices: Export Netback Parity

Since the mid-1990s, when the Russian government abandoned direct price controls for crude and petroleum products and largely liberalized the domestic oil market, export price parity has provided the main mechanism in the formation of petroleum product prices in the domestic market. This is because a relatively large amount of products is exported, which essentially clears the domestic market at export parity; i.e., at this price level refiners are indifferent between selling their products in the domestic market or exporting them. By definition export price parity occurs when domestic prices are equal to international export prices minus the export tax and the cost of transportation. In other words, three principal elements determine domestic prices for petroleum products: international (export) prices, export duties, and transportation costs. An additional important element is the ruble-dollar exchange rate.

As a result, domestic prices for petroleum products in Russia have tended to fluctuate in line with international prices, separated by a "wedge" comprising export duties and transportation costs. Export duties have constituted the principal component of this wedge over the past several years, but this is changing now with the ongoing "tax maneuver" that involves the progressive reduction of export duties. As international prices increased, export duties increased more than proportionately, expanding the size of the wedge. Likewise, the collapse of international crude prices in 2008 and 2014 reduced the relative size of the wedge (see Figure 7.4.9 and Figure 7.4.10).[104]

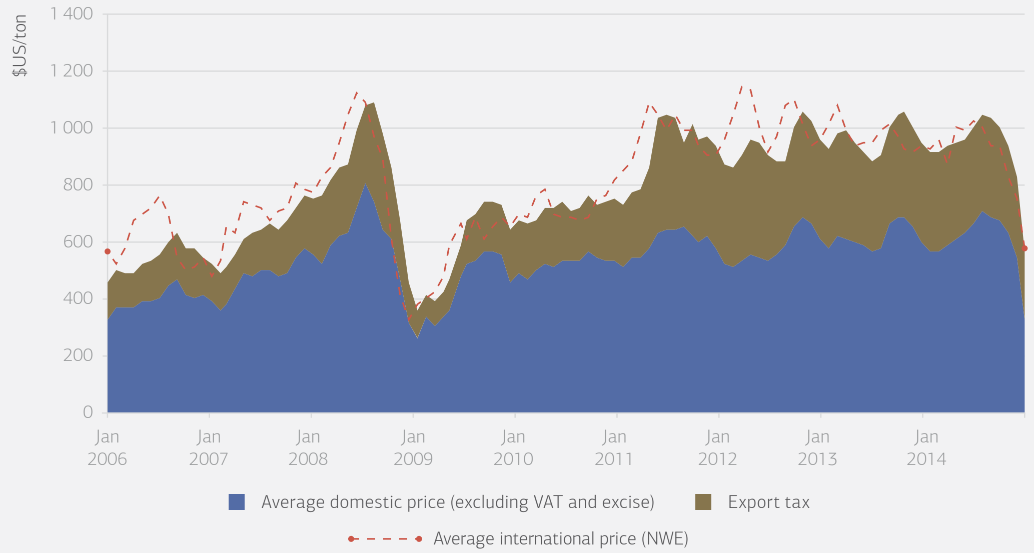
[103] This law also requires accreditation for wholesalers (it sets qualification requirements for access to the oil product wholesale market), bans sales from one wholesaler to another, and limits any retailer's market share to no more 35% in any given region. A region in the context of this legislation is defined by the size of the population, so any town or administrative district with over 10,000 residents falls under the 35% rule of this legislation.

[104] Transportation costs for gasoline are not displayed in Figure 7.4.10. While a "typical" transportation cost can be derived for crude oil exports because the of dominance of West Siberia in production and pipeline transportation, the situation for refined products is not as straightforward due to the number of refineries and the variety of export routes employed for individual products.



Source: IHS Energy

Figure 7.4.9 International versus domestic prices for Russian crude oil



Source: IHS Energy

Figure 7.4.10 International versus domestic prices for Russian gasoline

Transportation tariffs also contribute to the wedge between Russia's domestic prices and international prices. However, their magnitude compared to international prices has declined in recent years because growth in prices outstripped growth in transportation tariffs. Thus, their contribution to the wedge has become less significant over time.

As part of its responsibility to ensure competition, Russia's Federal Anti-Monopoly Service (FAS) monitors wholesale and retail prices for petroleum products in Russia. The FAS has become increasingly assertive in regulating Russia's petroleum products market in recent years. Both segments of the value chain are largely controlled by Russia's large vertically integrated companies (VICs), and only a tiny fraction (perhaps about 1-2%) of petroleum products is actually traded at exchanges on a competitive basis.[105] Also many regional product

105 The FAS has been urging oil companies to trade a larger portion of their petroleum products at exchanges, and at one time was considering a proposal that would require oil companies to trade a certain portion of their products at bourses. Even so, most Russian oil majors have been recently increasing their involvement at the bourses as a means of self-defense against allegations of "excessive" prices.

markets within Russia are considered to be dominated by one of the VICs, usually with a market share of over 35%. From FAS's perspective these facts have justified its repeated attempts to intervene in the domestic products market.

Additionally, some of the deviations in the wholesale price of petroleum products can be explained through the specific dynamics of the Russian crude and products market. In essence, maintaining product prices close to export parity is not always under the complete control of Russian refineries (and the VICs overall). This is because:

- The acquisition cost for crude has also deviated substantially from export parity. A refinery that faces sudden fluctuations in the price of crude oil would likely reflect this in its price offers on its products. This is particularly the case if the crude prices exceed the export parity level for a certain period. Such a situation occurred in late 2008, when export duties for crude failed to decline fast enough relative to the drop in international crude prices. For instance, in November 2008 domestic crude prices were nearly four times the export parity level. Thus refiners reflected their crude acquisition costs in their own product prices.

- Predicting export price parity is not simple. Refineries choose between selling to either domestic or foreign markets on the basis of relative netbacks (export price parity). The practice is for crude and products to be sold one or two months in advance, and Russian refiners have to predict what export parity will be when making their contract offers to either sell products or buy crude. Thus volatility in export prices or exchange rates as well as other fluctuations, such as in transportation costs, can result in substantial deviations from expected export parity levels.

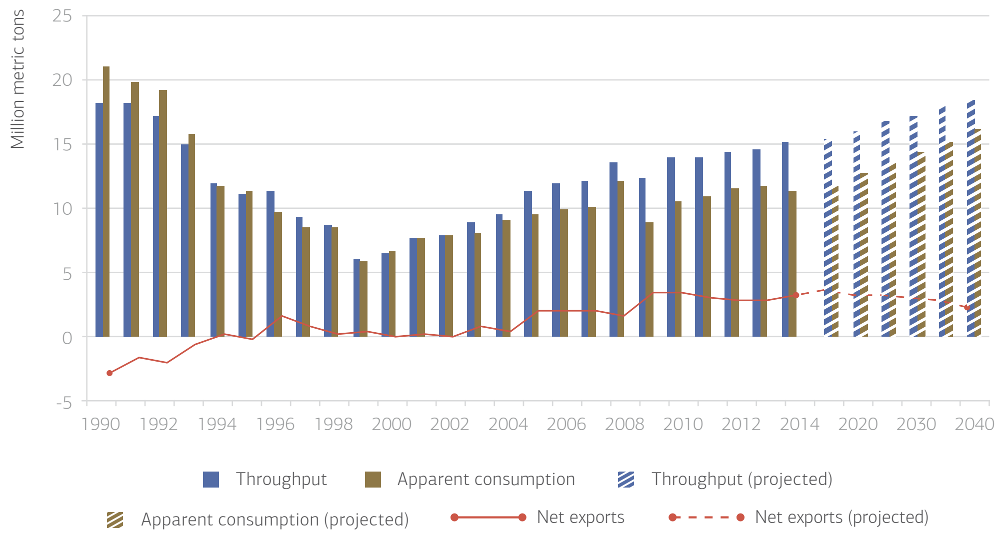
- Export duties affect prices, but with a lag. Export duties do not fluctuate simultaneously with international crude and product prices: they are adjusted only with a lag; duties are now set on the basis of price data for the preceding month (it had been on a two-month period until late in 2008). Since the export parity level is equivalent to "current" international prices minus export duties (and transport costs, also set with a time lag), conditions can change rapidly.

- Cutting export duties has a "reverse effect" on domestic prices. By reducing the size of the "wedge," it allows domestic prices to close the gap with international prices. Given the lag in the adjustment of export duties to international prices, this has resulted in situations where international prices are declining (along with export duties), while domestic prices are rising.

- Excise taxes may slow the reduction in wholesale prices. Two types of taxes directly affect wholesale prices of petroleum products: value-added tax (VAT) and excise. As the VAT is set on a percentage basis, it varies automatically with the ex-refinery price. But the excise tax is a specific tax, set per ton.

7.4.7. Refinery operation and refined product consumption outlook

IHS consumption forecasts show that gasoline and diesel demand will continue to grow in Kazakhstan, driving up aggregate product demand. In the base-case, apparent gasoline consumption will grow from 4.1 MMt in 2014 to 6.0 MMt in 2040, and diesel consumption will increase from 5.6 MMt (2014) to 8.0 MMt in 2040. Aggregate product demand is expected to reach about 14.1 MMt by 2030 and 15.9 MMt by 2040 (see Figure 7.4.11). These projections are based on the IHS base-case macroeconomic assumptions that envision average annual GDP growth in Kazakhstan to 2040 at 3.3%, with a general assumption of gradually slowing growth over time, reflecting the larger economic base.



Source: IHS Energy

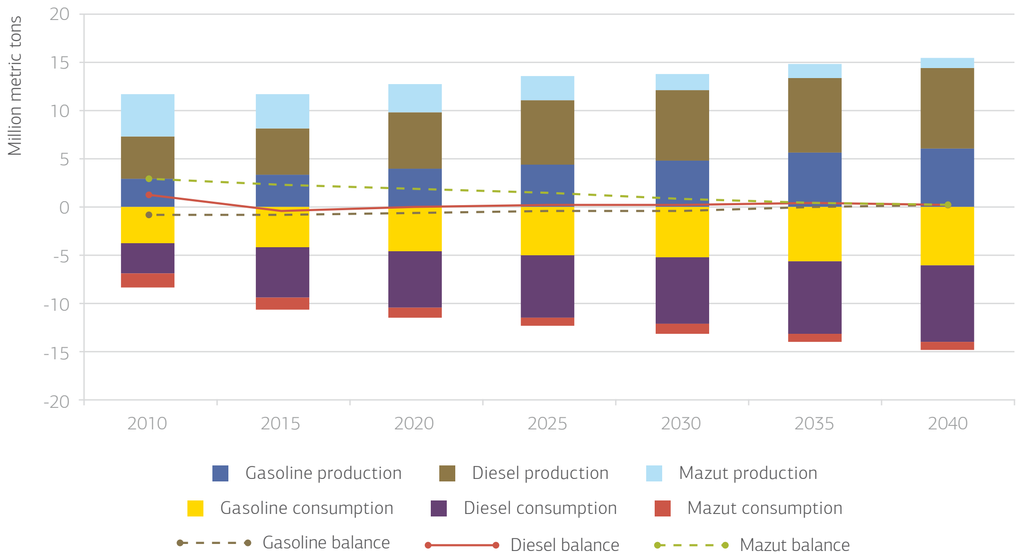
Figure 7.4.11 Kazakhstan's aggregate refined product balance

Although aggregate consumption is expected to increase, demand growth is projected to be much slower than in 2000–2014 (about 1.2% per year on average for 2015–2040). This flattening of gasoline demand is the result of slowing growth in Kazakhstan's car park, which grew to 4,001,000 in 2014 from 1,058,000 in 2000. The slightly higher growth in diesel consumption vis-à-vis gasoline (1.5% versus 1.4%) is due to two factors: (1) expanding economic activity that drives growth in truck shipments; and (2) the eventual retirement of Soviet-era gasoline-fired buses and trucks in favor of newer diesel-powered vehicles. At the same time, mazut consumption will continue to decline gradually—while mazut is essential to Kazakhstan's mining and heavy industries, demand by these industries is forecast to contract (with some substitution by gas or coal), with apparent mazut consumption dropping to about 0.8 MMt in 2040.

In Kazakhstan, crude consumption and refinery throughput are expected to remain closely tied to developments in aggregate domestic demand for refined products because of fairly limited possibilities for refined product exports. Thus, our methodology for projecting crude demand begins with projections of consumption for the four key products of gasoline, diesel fuel, mazut, and kerosene. In Kazakhstan, gasoline has traditionally been the "bottleneck" product upon which crude runs are balanced nationally. For purposes of projecting crude consumption (refinery operations), we assume that enough crude oil is delivered to domestic refineries such that gasoline demand (which also usually means total demand) can be met without resorting to imports, although the country still exports and imports some products because demand for the overall product slate is never perfectly balanced by refinery production.

IHS forecasts predict that refinery throughput will expand to only 17.0 MMt by 2030 and 18.1 MMt by 2040 (see Figure 7.4.11), mainly because of modernization programs instituted in the country's three refineries. This modest expansion in crude runs is expected to be commensurate with an increasing share of gasoline and diesel fuel in total production, even as the production of mazut—currently a major Kazakh refined product—declines. In this scenario of limited growth in domestic demand, the construction of a fourth refinery would lead to aggregate oversupply and low national refining capacity utilization. The lack of any substantive export markets for potential Kazakh refined products also must be considered.

Gasoline production in the country is set to expand from 3.0 MMt of production in 2014 to 4.8 MMt by 2030 and 6.2 MMt by 2040, with its share of the output mix rising from 20.3% in 2014 to 28.5% in 2030 and 34% in 2040. Diesel fuel production is also slated to increase with modernization, growing from 5.0 MMt in 2014 to 7.3 MMt in 2030 and 8.2 MMt in 2040. Simultaneously, mazut production will contract from 4.0 MMt in 2014 to 1.7 MMt in 2030 and 1.1 MMt in 2040. Despite this, mazut will still show a slight surplus even in 2040 (see Figure 7.4.12).



Source: IHS Energy

Figure 7.4.12 Outlook for Kazakhstan's production-consumption balance for the main refined products

7.4.8. Distribution of refined products

Each of the three major refineries essentially serves a surrounding regional market comprised of several oblasts. Most primary distribution of products from the refineries (i.e, to regional fuel depots [neftebazy]) is via rail, although distribution to immediate surrounding consumers is directly by truck.

Kazakhstan makes only limited use of product pipelines, with most existing product pipelines being non-operational because they were built to deliver refined products from Russian refineries or to neighboring republics when it was all one country without international boundaries. The main refined product pipelines include:

- **Travniki-Kostanay-Armankaragay:** This 445-km pipeline is a spur off the main Russian trunk pipeline system operated by Transnefteprodukt that connects Ufa and Omsk. It moved diesel, but is no longer operational.
- **Ufa-Petropavlovsk-Astana:** Petropavlovsk (in North Kazakhstan Oblast) is on the main Russian trunk pipeline system between Ufa and Omsk where it crosses Kazakh territory; some products are offloaded from the main trunk in North Kazakhstan Oblast after the pipeline reopened in 2012 after being closed in 2010 due to issues involving measuring flow; a 142-km spur pipeline that moved diesel south to Astana from Petropavlovsk is no longer working.
- **Samara-Uralsk:** This 175-km pipeline, which moved products from the Samara refineries in Russia, has not been in operation since the end of the Soviet period; some consideration was given to converting it to move crude/condensate from Karachaganak at one time.
- **Shymkent-Tashkent:** This 179-km pipeline was constructed in the late Soviet period to serve the large Tashkent metropolitan area. It also has not been in operation since the end of the Soviet period.

Not surprisingly given KMG's ownership of the three main refineries, Kazakhstan's wholesale products market is dominated by the national company through its specialized marketing subsidiary. There are some other players though, although handling mostly imported products. Much of Kazakhstan's wholesale market is comprised of diesel due to the country's large agricultural sector.

However, most gasoline is sold retail to consumers through the filling station network. Kazakhstan has over 4,400 filling stations that dispensed 3.3 MMt of gasoline in 2014; the aggregate number of stations has not changed much in the past decade, although the number of container-type stations has given way to more permanent stations (see Table 7.4.5). The average number of stations per thousand vehicles has dropped considerably in Kazakhstan since the early 2000s, mainly due to the expansion of the car fleet. The operator of the largest network of filling stations in Kazakhstan is KMG, although a number of companies are present in the market, including several foreign operators.

	2002	2003	2004	2005	2006	2007	2008	2009	2010	2011	2012	2013	2014
Number of stations*	4 186	4 373	4 562	4 583	4 433	4 370	4 308	4 333	4 283	4 174	4 217	4 170	4 425
Stationary	3 163	3 498	3 783	3 904	3 840	3 839	3 843	3 872	3 838	3 747	3 838	3 850	4 045
Container	825	686	587	504	452	399	355	312	286	259	235	211	243
Mobile	198	189	192	175	141	132	110	149	159	168	144	109	137
Stations per thousand vehicles	3.9	3.8	3.8	3.3	2.5	2.0	1.7	1.6	1.4	1.2	1.2	1.1	1.1
Car park (thousands)	1 062.6	1 148.8	1 204.1	1 405.3	1 745.1	2 183.1	2 576.6	2 656.8	3 087.6	3 553.8	3 642.8	3 678.3	4 000.1
Retail sales of motor fuels:**													
Gasoline (thousand tons)								2 573.4	2 714.5	2 558.3	3 444.9	3 526.6	3 345.8
Diesel (thousand tons)								898.7	977.2	840.4	1 399.6	1 473.1	1 380.0
LPG (thousand tons)								86.9	109.5	90.1	117.3	131.5	131.3

** Including gas filling stations for LPG.*
*** Includes retail sales to both individuals and businesses.*

Source: Kazakhstan statistical agency

Table 7.4.5 Filling station operations in Kazakhstan

Key Recommendations

- Completion of modernization of the three main refineries in Kazakhstan is critical; during this current downcycle for the oil industry and KMG, with greatly reduced revenues, this area of investment must be recognized as one of the company's highest priorities for capital expenditure.

- Undertake a phased relaxation of current domestic pricing regulations to allow domestic crude prices to rise to export netback parity. In time, this will provide sufficient incentive for crude producers to supply domestic refineries.

  — Other special incentives being considered to get producers to supply domestic refineries over imports, such as extending exploration and production rights, are likely to be less effective; they also tend to distort the domestic oil market.

- With Kazakhstan's available export capacity for crude oil, and with the CPC expansion being completed, 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). In turn, domestic product prices should be de-regulated, allowing them to reflect the resulting domestic price of crude and also the price of competing fuels, such as natural gas.

- To allow domestic market forces to operate effectively, the government needs to end the practice of periodic bans of refined product exports; after refinery modernization is completed, it should also completely liberalize product imports within the larger integrated economic space of the EEU.

7.5. Hydrocarbon Taxation in Kazakhstan

7.5.1. Key points

- Kazakhstan's Tax Code (introduced in January 2009) employs an approach that includes multiple tax instruments as opposed to just one or two; it also includes levies on both sales and profits. This combination has the potential to provide a greater balance of interests between the producers and the government over the life of a project. Major taxes that apply in the fiscal regime include corporate income tax, rent tax on exports, bonuses, a mineral extraction tax, excess profit tax, and an export duty. This regular fiscal regime is in force for almost all existing subsurface users, with the few exceptions being those production-sharing or similar long-term agreements that came into effect prior to January 2009.

- But there are a number of problematic aspects to Kazakhstan's existing tax regime. Kazakhstan's overall tax take for upstream projects is relatively high by international standards. The tax instruments also are structured to ensure early revenue for the government before profitability has been assured for the producer. This means that the tax burden is not proportional to the risks born by the investor, particularly at different stages of the project cycle.

- Although new PSAs are no longer allowed under the new Tax Code, offering a versatile stable contractual framework can be attractive to both the contractor and government since it can be adjusted to suit particular project circumstances without changing the overall fiscal framework for the country. Kazakhstan should, in particular, consider establishing a stable long-term contractual framework for large, high-risk projects with long gestation periods for investment, such as for offshore blocks.

7.5.2. Overview of developments in hydrocarbon tax legislation

Since independence, Kazakhstan has sought to improve its hydrocarbon tax legislation to help provide a stable and competitive business climate to attract a diversity of international investors needed to develop its hydrocarbon resources. At the same time it has sought to ensure that the state, as resource owner, receives an appropriate share of the economic rent generated from extraction of oil and gas. Kazakhstan has generally been cautious when introducing tax changes. But after a decade of rising oil prices in global markets and with oil prices reaching unprecedented levels in the period before 2008, the government decided to introduce a new Tax Code that would increase budget revenues by significantly increasing the tax burden on the oil and gas industry. The new Tax Code went into effect on 1 January 2009.[106] A more predictable taxation regime certainly can foster a more stable operating environment, which is important in terms of the challenging situation currently facing investors in Kazakhstan. The Tax Code also was introduced to foster other national goals, such as the development of an oil service and support industry.

Kazakhstan's 2009 Tax Code was a major step in establishing a clearer framework for taxation of the energy sector, leading to greater certainty and transparency in Kazakhstan's taxation structure. But the timing of such a major change in hydrocarbon taxation was somewhat inauspicious, coming during the great global recession and financial crisis, with global oil prices falling from highs of about $130 per barrel in mid-2008 to only about $40 per barrel in early 2009.

As an investment destination, Kazakhstan is characterized by significant resource commercialization risks that other world-class hydrocarbon resource holders do not face. In particular, Kazakhstan's land-locked geography makes it dependent on either Russian-owned pipelines or on its ability to secure investment to build alternative transportation routes (usually trans-national) in order to ship its oil and gas to international markets. Such sizable transportation outlays naturally erode the availability of some of the petroleum sector rents, leaving less to be collected by the Kazakh government.

Major Milestones in the Evolution of Kazakhstan's Hydrocarbon Taxation

- **1991:** Even before the end of the Soviet period and Kazakhstan's official independence, the country's first main contract with a major international oil company was negotiated by the Kazakh government. The contract established three types of payments: a fixed bonus-type payment ($20 million the first year, $30 million the second year, and $40 million the third and fourth years); a base royalty-type payment (18% after four years applicable on gross revenues at the wellhead net of transportation and marketing costs, non-well associated operation costs, and depreciation of non-well facilities); and an additional profit-based payment (at a rate of 25% of the same adjusted gross revenues) if the nominal rate of return exceeds 17%.

- **1991:** Three types of bonuses were established for oil and gas contracts (signing, commercial discovery, and mining), and a maximum corporate income tax of 30% was introduced.

[106] The Tax Code is Law No. 99-IV of the Republic of Kazakhstan, dated 10 December 2008.

- **1995:** A Tax Decree was issued that introduced an excess profits tax (which included four different rates applicable to specific thresholds stipulated in individual contracts, applicable when the project has an internal rate of return exceeding 20%); ring fencing for upstream projects also was introduced.
- **1996:** The Petroleum Law was issued, which included a tax stability clause.
- **1997:** Amendments to the (1995) Tax Decree were issued: royalties and the signature bonus became deductible from corporate income tax and the excess profits tax; the commercial discovery bonus and the mining bonus were repealed; also the tax stability provision was repealed (with certain exceptions related to international treaties).
- **2002:** Kazakhstan's first Tax Code was issued, which codified much of previous tax developments but repealed in its entirety the tax stability clause for contracts signed after 31 December 2001.
- **2009:** New Tax Code issued.

7.5.3. Kazakhstan's subsurface use legislation

The new Tax Code is one of several major laws that govern the economic terms established in a subsurface use contract in Kazakhstan. The other is the Subsoil (Subsurface) Use Law, which contains the basic legal framework for granting, using, and assigning or terminating rights to a subsurface user.[107]

Oil, gas, and other mining companies in Kazakhstan are referred to as "subsoil users" and enter into "subsoil use contracts" to acquire rights to exploit the mineral resources of the country, including oil and gas. There are two types of subsoil use contracts in Kazakhstan: production-sharing agreements (PSAs) or the regular contract regime. There were only a limited number of PSAs (or similar long-term agreements) concluded prior to 2009, and these were essentially "grandfathered" under the new Tax Code.[108] But since 2009, PSAs are no longer possible. Furthermore, the Tax Code states that the Code alone may establish provisions concerning the payment of taxes and levies relating to subsoil operations in Kazakhstan; separate agreements with the government of this type are no longer allowed. Other than the tax provisions established in the Tax Code, there are no special tax holidays in Kazakhstan's legislation for oil and gas producers (subsoil users).

Overview of Key Legislation Affecting Kazakhstan's Oil and Gas Industry

The legislation passed in the late 1990s as Kazakhstan attempted to attract foreign investment into the oil and gas sector has been gradually replaced over the past decade by tougher legislation governing taxes, subsurface licenses, gas flaring, asset sales, local content, transfer pricing, and other areas.

- In January 2009, a Tax Code was introduced which contained stricter provisions than the previous tax legislation. License holders, including projects operating under PSAs, were pressured to amend their tax provisions in accordance with the 2009 Tax Code. Producers challenged the policy as an erosion of tax stability, though many producers (largely those without PSAs) eventually were forced to comply.
- In July 2010, the new Law on Subsurface and Subsurface Use took effect, replacing three previous pieces of legislation: the Petroleum Law of 1995, the Subsurface Law of 1996, and the PSA Law of 2005. The producers' reactions to the new legislation were mixed:
  - — The new subsurface law provides better integration of laws and regulations and clarifies the authority of different state agencies.
  - — But the new legislation allows combined exploration and production (E&P) contracts to be granted only in a few instances. The new procedure is to grant just an exploration contract and then producers need to re-apply for a production contract post-discovery (which may not be granted); this provision

[107] That is, Law No. 291-IV of the Republic of Kazakhstan on Subsurface and Subsurface Use, dated 24 June 2010. Law No. 2350 of the Republic of Kazakhstan on Petroleum (of 28 June 1995), that had been in force previously, was superseded.

[108] According to the former Minister of Energy, Saut Mynbayev, Kazakhstan had concluded 16 production-sharing contracts before the new Tax Code went into effect, out of a total of over 600 subsurface use contracts.

was amended in December 2014 in an update to the Subsoil Law, where the subsoil user is granted an exclusive right to transition from exploration to a production license.

  — The new law also severely limits the use of PSAs.

  — The Subsurface Law reinforces the state's priority right regarding asset transfers and imposed stricter procedures.

- In early 2012, the Law on Gas and Gas Supply was passed, which sets forth details on gas utilization and processing.

7.5.4. Tax stability in Kazakhstan

The tax regimes for the small number of existing PSAs are stable under the provisions of the Tax Code provided that they have undergone a "tax expert evaluation"—essentially a review by the tax authorities to ensure that the tax terms in the PSA comply with the law in force at the time the PSA became effective. The tax regimes established in other types of contracts are not stabilized except for cases where such contracts were approved by the President of the Republic of Kazakhstan (meaning essentially the unusual joint venture contract for the Tengiz project). Stabilized contracts can be changed by mutual agreement between the parties, however, if current terms should become more favorable than the earlier established ones.

7.5.5. Other tax-related issues: ring-fencing, accounting rules, and transfer pricing

Oil and gas production activities are ring-fenced from downstream activities and from each other (i.e., segregated contract by contract) for tax purposes. That is, the tax regime of a subsurface use contract applies to activities that are carried out within the framework of the contract and that meet the definition of subsurface use in the Subsurface Use Law. The Tax Code implies that the tax boundary occurs after the extraction and primary processing stages, i.e., initial stabilization.

The Tax Code contains detailed requirements for tax policy and a set of tax registers that provide the bridge from the underlying accounting records to the tax returns. Accounting records are maintained in accordance with the Law on Accounting and Financial Reporting, which requires most companies to prepare their financial statements under the rules of the International Financial Reporting System (IFRS).

Through transfer pricing, a taxpayer seeks to minimize income and maximize deductible expenditures in high-tax jurisdictions or sectors, such as by moving revenue from upstream to downstream activities when selling crude oil at reduced prices to affiliated trading intermediaries or refineries. A prior transfer pricing law proved difficult to apply to transactions involving products for which market price quotes were not available, and was even more difficult to apply to service transactions. To remedy the situation, Kazakhstan adopted a new transfer pricing law, which entered into force in 2009.[109]

Kazakhstan's current transfer pricing legislation has wide applicability for all businesses, but the impact for subsurface users is particularly broad. The transfer pricing rules potentially apply to all cross-border transactions, and in the case of subsurface users, it also applies to domestic transactions.

7.5.6. Taxes applicable to subsurface users

Governments can collect revenue from the oil and gas sector through a number of tax and non-tax instruments. Most countries collect the government's share either through production-based or profit-based instruments. In some countries, the government also participates more directly in projects through an equity interest.

Because each of the various tax instruments has different advantages and disadvantages, multiple fiscal instruments are often employed in an effort to achieve a balance of interests between the producers and the government over the life of the project. For example, production-based instruments, such as a royalty applied per ton or per barrel, can ensure that the government receives at least a minimum payment for its mineral resources. They also provide up-front or early revenues for the government (because revenue is received as soon as production begins). They also have the advantage of being relatively simple to administer. But they have the disadvantage of raising the marginal cost of production, so they may discourage development of marginal reserves and can lead to early abandonment of still-producing assets, particularly if the royalty is set relatively high. An additional drawback is that royalties are often only a deductible expense in determining taxable income in the home country for investors and are not allowed as a foreign tax credit against the home country's income tax. On the other hand, while profit-based instruments allow the government to share in the upside of highly profitable projects, they also increase the government's risk

[109] The Law of the Republic of Kazakhstan, No. 67-IV on Transfer Pricing, of 5 July 2008, regulates transfer pricing. Transfer pricing in Kazakhstan also is regulated by several subordinate legal acts or instructions.

by deferring revenue to later in the project, and there may not be any revenue at all if the project ends up being unprofitable.

Kazakhstan employs an approach that utilizes several different tax instruments. The generally applicable fiscal regime in Kazakhstan for exploration and production contracts in the petroleum industry consists of a combination of corporate income tax, rent tax on exports, bonuses, and a mineral extraction tax (see Table 7.5.1). The regular fiscal regime is in force for almost all existing subsurface users. The exceptions are those PSAs that came into effect prior to 1 January 2009 and special contracts specifically approved by the President of Kazakhstan.

Applicable tax	Rate/taxable base
Bonuses (signing and commercial discovery)	Variable
Mineral resource extraction tax (MRET)	0.5% to 18%
Excess profit tax (EPT)	0% to 60%
Rent tax on exports	0% to 32%
Payment for compensation of historical costs	Variable
Excise tax on crude and gas condensate	0 tenge per ton
Value-added tax (VAT)	12%
Crude oil export duty	Levied per ton; currently at $60 per ton (from March 2015)
Land tax	Usually immaterial for oil and gas producers
Property tax	1.5%
Environmental fees	Variable
Other fees (e.g., fee for use of radio frequencies, fee for use of navigable waterways)	Variable
Other taxes and payments	Variable

Source: Kazakhstan Tax Code

Table 7.5.1 Taxes applicable to subsurface users in Kazakhstan

7.5.6.1. Mineral resource extraction tax

The mineral resource extraction tax (MRET) was introduced as part of the new Tax Code in January 2009, replacing the previous royalty system. MRET is a royalty-type tax applicable to crude oil, gas condensate, and natural gas production. Kazakhstan uses ad valorem rates that escalate based upon the annual production volume of the subsurface user, varying between 5% and 18% of sales revenues (see Table 7.5.2). Different rates also apply depending on whether the output is exported or sold domestically. Since the royalty rates that previously applied varied only between 2% and 6% of revenues, the overall level of taxation is much higher under the new MRET.[110]

[110] The Tax Code allows the government to administratively lower the MRET for selected high-cost or "hard-to-recover" fields or projects on a case-by-case basis. Initially, applications for relief were accepted only from companies where production was unprofitable. A special commission exists to review each individual application. For example, the Karazhanbas field (in Mangistau Oblast) was recently reclassified as a low-profitability, high-viscosity, high water-cut, marginal, and worked-out field. Under a resolution signed by the Prime Minister (18 June 2014), the MRET for the field was set at only 0.5%.

Volume of annual production (thousand metric tons)*	MRET rate**
Up to 250	5%
251-500	7%
501-1000	8%
1001-2000	9%
2001-3000	10%
3001-4000	11%
4001-5000	12%
5001-7000	13%
7001-10,000	15%
Over 10,000	18%

* *For crude oil or gas condensate.*
** *Applicable rate since 1 January 2011.*

Source: Kazakhstan Tax Code

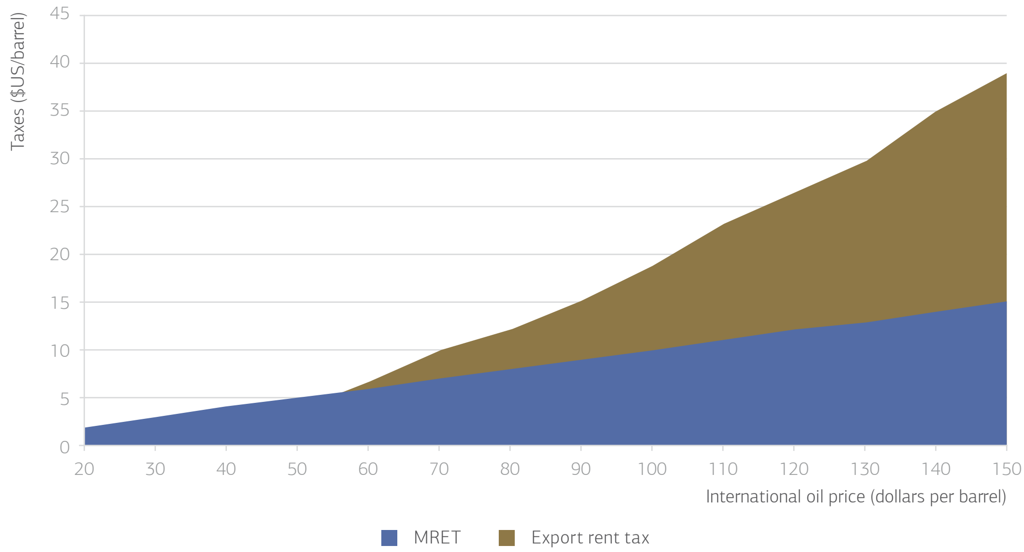
Table 7.5.2 Ad valorem rates for the mineral resource extraction tax in Kazakhstan

The taxable base for MRET is the value of production. On export sales, the value is based on world prices without adjustments (i.e., for transportation costs or quality differences). The export value of crude oil (and gas condensate) is determined as the arithmetic mean of daily quotations for each of the Urals Blend Mediterranean or Dated Brent prices for the tax period in question.[111] Therefore, the MRET increases for any given producer with international oil prices (see Figure 7.5.1). The export price for natural gas is determined as the arithmetic mean of daily quotations as well.[112] For natural gas that is exported, a flat rate of 10% applies.

The ad valorem rates (in Table 7.5.2) are reduced by 50% if the production is sold (and refined/processed) domestically in Kazakhstan either by the producer or by a purchaser. There are special rules for the calculation of the domestic value in such cases. If the gas is sold in the domestic market, then rates are reduced to between 0.5% and 1.5%, depending on the level of annual production by the subsoil user.

[111] These prices are determined on the basis of information published in the Platts Crude Oil Marketwire, or if that source does not provide the necessary price information, then the Argus Crude source is used.

[112] The quotations are to be taken from Zeebrugge Day-Ahead for the tax period in question on the basis of information published in Platts European Gas Daily. If that source does not provide the necessary price information, then Argus European Natural Gas is to be used.



Source: IHS Energy (calculations)

Figure 7.5.1 Illustrative export rent tax and MRET in Kazakhstan for a typical oil producer

7.5.6.2. Bonuses

Bonuses are perhaps the most troublesome fiscal instrument for investors because the payment is made up front, well before production even begins, and in many cases even before a discovery has been made. Because of the timing of the payment, bonuses can have a deleterious effect upon project economics, particularly if they are sizable. But they have the advantage of ensuring some up-front revenue for the government and may incentivize companies to explore and develop contact areas more rapidly. But in general, sizable up-front bonuses are usually suitable only in highly prospective areas where there is strong competition among investors for petroleum rights.

The Tax Code includes two types of bonuses that subsurface users are expected to pay in Kazakhstan: a signature bonus and a commercial discovery bonus.

The signature bonus is a lump-sum payment paid by a subsurface user for the right to use the subsurface. For oil exploration contracts where reserves have been officially estimated and approved, the bonus is a fixed amount of 2,800 MCI (equivalent to approximately 5,549,600 tenge or $20,400 at the current exchange rate).[113] For oil production contracts where reserves have not been approved, the bonus is a fixed amount of 3,000 MCI (5,946,000 tenge or $21,860). If reserves have been approved for the tract above a certain threshold size, the bonus is calculated by a formula that applies a rate of 0.04% to the approved reserves and 0.01% to the provisionally approved reserves, but not less than 3,000 MCI.

The commercial discovery bonus is a one-off payment paid by subsurface users when a commercial discovery is made on the contract territory. The base for calculation of the commercial discovery bonus is defined as the value of the extractable minerals subsequently approved by the competent state authorities. The value of the mineral resources is determined using the market price established at the International (London) Petroleum Exchange in Platts Crude Oil Marketwire. The rate of the commercial discovery bonus is fixed at 0.1% of the value of proven extractable resources.

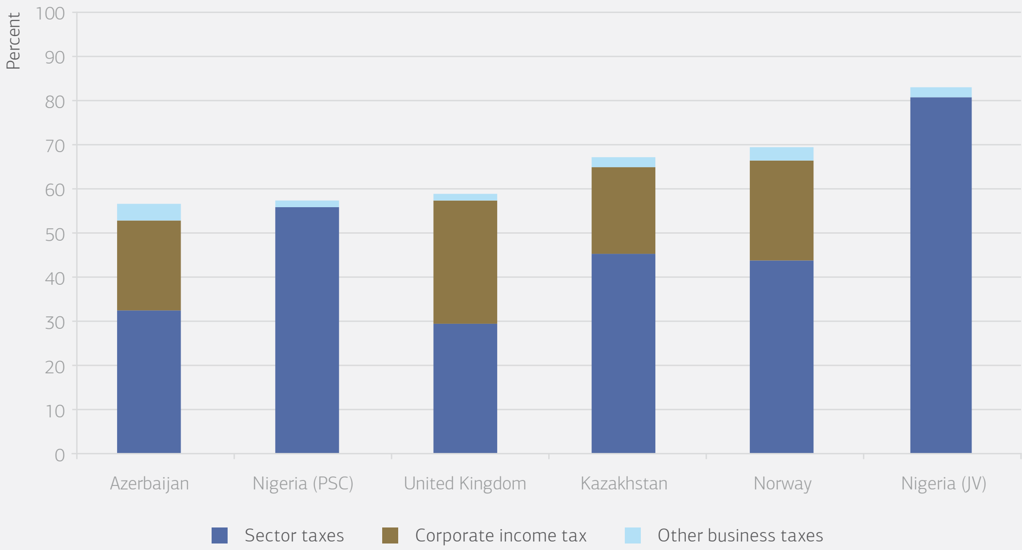
7.5.6.3. Excess profit tax (EPT)

EPT is calculated and paid on an annual basis rather than pay-as-you-go like most other upstream taxes. The tax is paid at progressive rates applicable to the portion of net income that exceeds 25% of relevant expenses. The taxable tranches are derived by applying ratios to the deductible expenses. The EPT becomes significant for most Kazakh producers only in a high oil price environment (about $100 per barrel or higher).

[113] MCI (or Monthly Calculation Index) is established in Kazakhstan's budget law. Since 1 January 2015 it was established in the Law on the Republican Budget for 2014–2016 No. 149-V, dated 3 December 2013, at 1,982 tenge.

Relative Tax Burden for Producers in Kazakhstan

Calculation of the tax burden on the oil industry is naturally a complex issue. It varies over the life cycle of any given project, usually with limited tax payments during the exploration phase compared to more substantial payments when in full production. Different rates of tax depreciation also affect the tax burden. While relief will generally be available under all the regimes, there will be important timing differences. To measure the relative tax burden between countries, for example, PwC uses the approach of a "model company" that is employed in each tax jurisdiction to give a snapshot of the tax burden in a particular year. This same model company is used to provide a comparison between countries and over time.[114] The specific measure employed by PwC is what is known as the Total Tax Rate, a measure of the cost of all taxes borne by a company in relation to its profit before all those taxes.[115] According to this indicator, Kazakhstan ranks third highest within a peer group of major oil producers, at over 67%, with only Norway and Nigeria's joint venture regime showing a higher Total Tax Rate (see Figure 7.5.2).



Source: PwC

Figure 7.5.2 Total tax rate for a model company in selected countries (December 2013)

[114] PwC's model company is an abstract derived as an average of large global E&P companies. It has the following general characteristics:

- Gross profit margin 75%
- Net profit margin before taxes 54%
- Annual production of 9.6 million barrels (1.3 MMt) of oil in the country in question.
- Net book value of assets at 60% of revenues
- Fixed asset additions (upstream) of 16% of net book value.

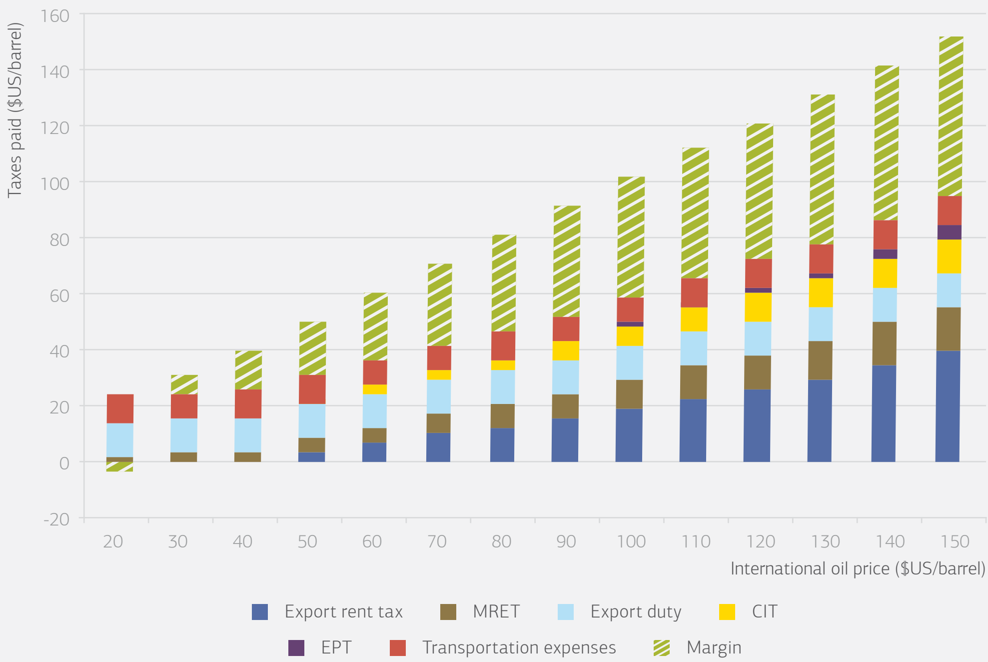
These data were sourced from annual reports, with the relevant averages calculated. There are several limitations to this particular approach. These include:

- The model company does not reflect specific characteristics typical for a company operating in any particular country, such as Kazakhstan, or for a company at the exploration phase.
- The size of the company may be considered large in some countries and modest in others.
- The model company reflects operations measured for only one year, assumed at full production. Tax depreciation is a snapshot in a single year and does not take account of the fact that a country with a lower tax burden as a result of tax depreciation in the year in question will have a higher tax burden in subsequent years.
- The output does not provide a definitive assessment of the cost of paying taxes in any particular country. However, it allows the tax burden in the selected countries to be compared on a like-for-like basis.

[115] See PwC, KazEnergy: A Comparative Study of Oil Tax Regimes, October 2014.

Alternatively, KMG E&P can be used as a more specific example of the relative tax burden on an upstream producer in Kazakhstan subject to the regular tax regime (see Figure 7.5.3). When international oil prices are between $60 and $110 per barrel, the overall tax burden on the company is only on the order of 45–50%. But KMG E&P's main producing assets, UzenMunayGaz and EmbaMunayGaz, are relatively mature, and the company's tax burden reflects this. Oil production has been underway for several decades, with output expected to remain in long-term secular decline going forward. The company spends about $700 million per year in capital expenditures (capex), of which it spends about $100 million on exploration at its core assets, which it funds out of its existing cashflow.

The picture for a "new" project, which Kazakhstan would like to see developed in its upstream industry, would be quite different. A new producer would likely have additional tax outlays, such as compensation for historical expenditures by the state and various bonus payments, none of which would be applicable to KMG E&P. Hence, for a new project in Kazakhstan, the tax burden would be much higher, about 85%, which is among the highest in the world (see Chapter 5).



Source: KMG, IHS Energy
Notes: Assumes export duty rate of $80 per ton. Calculations based on varying oil prices and 2013 KMG E&P cost structures (excluding non-operating income/expenses and unusual/extraordinary items). Transportation costs calculated for June 2014 as average of Atyrau-Samara pipeline and Aktau-Makhachkala-Novorossiysk combined costs plus marine freight Novorossiysk-Augusta.

Figure 7.5.3 Hypothetical tax burden in Kazakhstan at different international oil prices for KMG

The net income is calculated as aggregate annual income less relevant expenses and corporate income tax (CIT) (plus Kazakhstan's special profit tax that applies to branch offices). For the purposes of EPT, the relevant deductions are the same as those deductible for CIT purposes plus additional deductions such as accelerated depreciation for fixed assets. The tax is calculated by applying specific rates to the tranches of excess income, each tranche being allocated the marginal net income determined as a percentage of deductions until total net income is allocated (see Table 7.5.3).

Net income allocation schedule for EPT, pct. of deductions	Pct. for calculating marginal net income allocation for EPT	Excess profit tax rate (%)
Less than or equal to 25	25%	Not set
From 25 to 30	5%	10%
From 31 to 40	10%	20%
From 41 to 50	10%	30%
From 51 to 60	10%	40%
From 61 to 70	10%	50%
Over 70	Any excess	60%

Source: Kazakhstan Tax Code

Table 7.5.3 Calculation of excess profits tax in Kazakhstan

Special rules apply to determine the taxable object if the hydrocarbons are processed prior to sale, such as refining crude oil into gasoline, or raw natural gas into dry, pipeline-quality gas. In such cases, though, it is unlikely that an EPT liability would actually arise.

7.5.6.4. Rent tax on exports

The rent tax on exports is paid by legal entities and individuals that accrue sales from the export of crude oil, gas condensate, and coal. The tax base is determined as the value of the exported crude oil and gas condensate based on the same tax valuation standard as for MRET upon export. The tax rate ranges from 7% to 32% and is applied once the world price for crude oil and gas condensate exceeds $40 per barrel (see Table 7.5.4).[116] It also increases with higher international oil prices (see Figure 7.5.1).

Market price of crude	Rate
Up to US$20 per barrel	0%
Up to US$30 per barrel	0%
Up to US$40 per barrel	0%
Up to US$50 per barrel	7%
Up to US$60 per barrel	11%
Up to US$70 per barrel	14%
Up to US$80 per barrel	15%
Up to US$90 per barrel	17%
Up to US$100 per barrel	19%
Up to US$110 per barrel	21%
Up to US$120 per barrel	22%
Up to US$130 per barrel	23%
Up to US$140 per barrel	25%
Up to US$150 per barrel	26%
Up to US$160 per barrel	27%
Up to US$170 per barrel	29%
Up to US$180 per barrel	30%
Up to US$190 per barrel	32%
Up to US$200 per barrel and above	32%

Source: Kazakhstan Tax Code

Table 7.5.4 Rent tax rates on exported crude and condensate from Kazakhstan

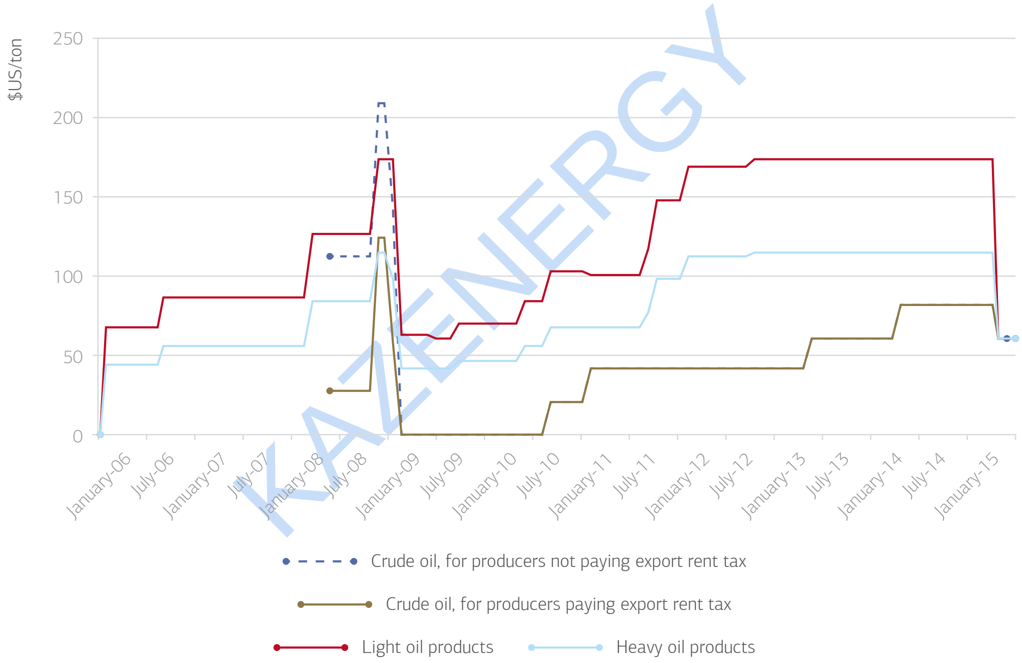
[116] The tax base of the rent tax on export for coal is the actual volume of exported coal, and the tax rate is 2.1%.

7.5.6.4.1. Crude Oil Export Duty

Russia has used export duties since the end of the Soviet period as a fiscal tool, maintaining a wedge between international (export) prices and domestic prices (creating an incentive to process raw materials before export), and allowing the increasing margin from high oil prices to accrue to state coffers rather than to producers. Kazakhstan already had an existing levy (since 2003) that specifically applied to oil exports, in the export rent tax. But as oil prices continued to rise in 2007–2008, Kazakhstan also decided to introduce an export duty as well. Export duties apply to 206 items, mainly crude oil, petroleum products, and nonferrous and ferrous metals, but also to wool and hides.

In April 2008, as Brent reached $104.8 per barrel, the government approved an export duty of $15.81 per barrel ($109.91 per ton).[117] The introduction of the export duty was apparently driven by several elements of state policy beyond simply collecting more revenue. First, by creating a wedge between export and domestic prices, the duty could potentially divert more crude oil into the domestic market than would otherwise be the case. This also represented an attempt to hold down rising prices for refined products in the domestic market.

It was not immediately clear which producing companies had to pay the export duty. Also, in 2008, before the Tax Code went into effect, producers were entitled to reduce the amount of export duty they paid by the amount of the rent tax on exports that they paid (see Figure 7.5.4). The government indicated that companies operating under subsoil use contracts with certain exemptions (i.e., PSAs with tax stabilization clauses) were not obliged to pay it at all. Then the government indicated that companies operating under production-sharing agreements were exempt from the export duty at least until the January 2009 Tax Code was enacted. A total of 38 crude oil producers ended up being liable to pay the new tax in 2008. In effect, however, the export duty fell primarily on KMG E&P as well as on smaller producers not covered by PSAs but operating under the regular tax-and-royalty regime. Some of the smaller producers were even forced to shut in production because the export duty was so large as to make production unprofitable. However, in response to producers' complaints as oil prices fell but costs remained high, the government ultimately reduced the level of duty to avoid an overall decline in production.



Source: Announcements from Government of Republic of Kazakhstan

Figure 7.5.4 Oil export duties in Kazakhstan

The subsequent collapse in oil prices in international markets in the second half of 2008 ultimately led to the suspension of the export duty altogether. The duty was subsequently reinstated in 2010, but at a much lower level of $20 per ton, and was raised to $40 per ton in January 2011. Also, from 2010, producers paid both types of taxes on oil exports, with the export duty being the same rate for all (see Figure 7.5.3). The duty applies to all oil exporters, except those producers with a tax stabilization clause. These are mostly those operating under a PSA executed before 1 January 2009, but there are a few producers operating under normal subsoil use contracts that also have exemptions from paying export duties.

From April 2013 the rate was $60 per ton of crude oil, which was raised to $80 per ton in March 2014. In March 2015 the export duty was reduced to $60 per ton. The export duty rate mechanism is not set in the Tax Code, but is set directly by the government. The Ministry of National Economy of the

[117] The term "export duty" is used interchangeably with tax; however, the two terms differ. Duty is another name for an excise, which is levied either ad valorem (per value) or per physical unit.

Republic of Kazakhstan revisits the level of export duties on a quarterly basis, evaluating oil prices in global markets, particularly trends in domestic prices for refined products.

7.5.6.5. Payment for compensation of historical costs

Since 2009, the payment for compensation of historical costs has been included in the list of obligatory payments to be made by a subsurface user to the state budget. Previously, this was probably a negotiable item applicable to certain projects. It is a fixed payment to compensate the state for geological survey, exploration, and development costs of the contract territory incurred before the subsurface use contract was concluded. The obligation is based upon the date when the agreement is concluded between the subsurface user and authorized state body on subsurface usage.

7.5.6.6. Corporate income tax (CIT)

Corporate income tax currently is set at a rate of 20% for all companies in Kazakhstan on their taxable income. Taxable income is calculated as the difference between aggregate annual income (after certain adjustments) and statutory deductions.

7.5.6.6.1. Deductions

All expenses incurred by a taxpayer and related to conducting activities aimed at generation of income are deductible for CIT purposes. Examples of expenses that are allowable deductions are:

- Interest expenses (within limits).
- Contributions to the decommissioning fund. The procedure for making such contributions and the amount are established in the subsurface use contract.
- Expenditure on geological studies, and exploration and preparatory operations for extraction of mineral resources.
- Expenditures on research and development, scientific, and technological works.
- Expenses incurred under a joint operating agreement (based on information provided by the operator).
- Business trips and representative expenses.
- Foreign exchange losses (when foreign exchange losses exceed foreign exchange gains).
- Insurance premiums (except for those paid according to accumulative insurance contracts).
- Amounts paid to redeem questionable payables previously written off as income.
- Questionable receivables not redeemed within three years.
- Taxes paid (except for the taxes already excluded prior to determining aggregate annual income, income tax paid in Kazakhstan and in other countries, and EPT).
- Fines and penalties, except for those payable to the state budget.
- Maintenance or current repair expenses.
- Capital repair (within the statutory limits).
- Expenditures actually incurred by a subsurface user with respect to training Kazakh personnel and the development of the social sphere (within the amounts stipulated in subsurface use contracts).

Geological studies, exploration, and preparatory operations for production of useful minerals incurred prior to the start of production following the commercial discovery include the following: appraisal, preparatory work, general and administrative expenses, and costs associated with the payment of bonuses. These costs, together with expenditures on purchases of fixed assets and intangible assets (i.e., expenditures incurred while acquiring rights to geological exploration, development, or extraction of mineral resources), form a separate depreciation group. These costs may be deducted by declining balance depreciation at a rate not exceeding 25% after production begins following the commercial discovery. Expenses incurred after production starts are included in the same group to increase its residual value if under IFRS such expenses are capitalized into the value of assets already included.

In the case of a farm-in, the cost of acquiring a subsurface use right should be capitalized. Upon farm-out, the subsurface user is liable for tax on any capital gains.

The Tax Code also provides for certain expenses to be deducted directly from taxable income up to 3% of the taxable income, such as sponsorship aid and charitable contributions (subject to certain conditions).

7.5.6.6.2. Dividends

Dividends distributed by a local subsidiary to a local parent company are tax exempt for companies. Dividends distributed abroad by subsurface users are subject to 15% withholding tax (usually reduced by international tax treaties with most countries to 5%). Branches of foreign legal entities are subject to an equivalent branch profit tax at the same rates, but applied to undistributed profit after deduction of CIT.

7.5.6.6.3. Capital Allowances

Allowances are available for CIT and EPT. For tax depreciation purposes, fixed assets are split into four groups, which are depreciated at different rates (see Table 7.5.5). Fixed assets include:

- Fixed assets, investments in real estate, intangible assets, and biological assets recorded in accordance with IFRS and Kazakhstan accounting standards.
- Assets with a useful life exceeding one year, manufactured and/or acquired by concessionaries under concession agreements.
- Assets with a useful life exceeding one year that are social infrastructure.
- Assets with a useful life exceeding one year which are intended for use in activities that are directed at the receipt of income and were received by a fiduciary for fiduciary management purposes under a fiduciary management agreement.

Group	Type of fixed assets	Maximum depreciation rate (%)
I	Buildings, structures (except for oil and gas wells and transmission devices)	10%
II	Machinery and equipment, except for that used for oil and gas production	25%
III	Office machinery and computers	40%
IV	Fixed assets not included in other groups, including oil and gas wells, transmission devices, machinery and equipment of oil and gas production	15%

Source: Kazakhstan Tax Code.

Table 7.5.5 Capital allowances in Kazakhstan

7.5.6.6.4. Carry Forward of Losses

Tax losses relating to subsurface use contracts can be carried forward for up to 10 years.

7.5.6.7. Excise taxes

Excise taxes are levied on the sales of certain goods manufactured within the country or imported for use in the country. Fuels subject to excise tax in Kazakhstan include motor gasoline (excluding aviation gasoline), diesel fuel, and crude oil/gas condensate. Currently, crude oil and gas condensate have zero excise tax. Excise taxes are fixed in the Tax Code itself rather than set by the government as they were previously. Since January 2009, these have been set at 5,000 tenge per ton on gasoline and 600 tenge per ton on diesel fuel.[118] These are the total rates that apply to retail prices. Refineries pay excise taxes at a rate of 4,500 tenge per ton for gasoline and 540 tenge per ton for diesel on all their domestic sales. Retail sellers are responsible for excise of the remaining 500 tenge per ton for their gasoline sales and 60 tenge per ton for their diesel sales. If refineries engage in direct sales to consumers, then they pay the entire excise amount.

7.5.6.8. Indirect taxes: VAT

A European Union-style value-added tax (VAT) applies in Kazakhstan on all sales between companies. The VAT rate has been gradually reduced from 20% in the 1990s to 12% currently. Crude oil, natural gas, gas condensate, and refined products sold within the territory of Kazakhstan are subject to 12% VAT. Export sales of crude oil, natural gas, gas condensate, and refined products are not subject to VAT.

Under the Tax Code, international transportation services (including transportation of oil and gas via trunk pipelines) are subject to zero-rated VAT. But VAT is applicable on domestic transportation services (i.e., on oil and gas destined for the domestic market).

The applicability of Kazakhstan VAT is determined based on the deemed “place of supply.” If the place of supply is deemed to be outside of Kazakhstan, the underlying supply is not subject to Kazakhstan VAT. It is important to note that under this rule, a service may be physically performed outside of Kazakhstan, but deemed to be supplied inside Kazakhstan for VAT purposes. Examples of services taxed in this way include services related to immovable property located in Kazakhstan, or a consulting service performed outside of Kazakhstan for a customer inside Kazakhstan. The rules determining “the place of supply” that apply to goods are generally as follows:

[118] At the current exchange rate, this amounts to about $17 per ton for gasoline and $2 per ton for diesel. This would be the equivalent of about 3.4% of the current retail price of gasoline and 0.4% of the retail price of diesel fuel.

- The place where transportation commences, if goods are transported; or
- The place where goods are transferred to the purchaser (including a physical transfer or a transfer of rights).

For works and services the rules that apply are:

- The place where immovable property is located for works and services directly related to such property.
- The place where works and services are actually carried out for movable property.
- The place of business (or activity) of the customer for works and services that involve transfer of rights to use intellectual property, consulting services, audit services, engineering services, design services, marketing services, legal services, accounting services, advertising services, data provision and processing services, rental of movable property (except for rental of motor vehicles), supply of personnel (commonly referred to as "secondment"), and communication services.
- Otherwise, the place of business (or activity) of the service provider.
- Sales of goods or services that are merely auxiliary to a principal sale are deemed to take place wherever the principal sale takes place.

7.5.6.9. Import duties

Generally, equipment, spare parts, and materials used in oil and gas operations are subject to import customs duties. Some contracts concluded prior to creation of the Customs Union/Eurasian Economic Union may benefit from grandfathered customs exemptions. However, new contracts do not.

The customs legislation provides for a temporary import regime for goods that will be re-exported eventually. It either exempts goods and equipment from customs duties and import VAT or it allows for partial payment, provided the goods and equipment are re-exported.

7.5.6.10. Registration fees and other taxes

A number of other taxes, fees, and levies exist, most of which are economically insignificant for oil and gas operations. These include: (1) social tax (paid by employers for each employee at the rate of 11% on the total cost of employing the individual, including benefits in kind); (2) property tax (an asset tax is charged at the rate of 1.5%, applicable to immovable property); and (3) environmental fees (producers of mineral resources are liable for payment of certain environmental fees). There are two types of environmental fees. Some fees are levied for the use of certain natural resources, and other fees (penalties) are charged for unauthorized pollution of the environment.[119] Other types of fixed fees also apply in Kazakhstan, but these are relatively insignificant.

7.5.7. Production-sharing agreements

Production-sharing agreements are the most widely used types of contracts in the upstream industry. Introduced in their modern form in the 1960s, the underlying concept of the agreement has been employed for much longer. The main idea of a PSA contract is that the owner of the resource (a government) invites a foreign company to explore and produce the resource, taking on the associated exploratory and operating risk, and receiving a share of the oil output as a reward. Meanwhile the state retains the right to the resource and gets a share of the profits if the exploration and production are successful. This is very different from a concessionary contract, where the oil belongs to the oil company developing the field. PSAs are used in Indonesia, Egypt, Libya, Algeria, and many other oil-producing countries in Africa, Asia, and South and Central America. PSAs are not typically used in certain regions of the world, which are mostly developed countries in the OECD or in the Middle East, not because of rejection of the concept of PSAs, but because of specific market conditions (see below).

The key reasons that PSAs appeal to investors are long-term stability of the tax environment and cost recovery. OECD countries essentially already are able to guarantee these investor requirements. In the UK, for example, the exploration and production contracts are not called PSAs, but they in essence provide tax stability, and other guarantees, like PSAs. In the Middle East, the development of oil began with contracts similar to PSAs, but gradually domestic companies took over the producing areas. The government was able to provide an environment for the domestic companies sufficient to explore and produce oil, with relatively little need for foreign-company participation.

Elsewhere PSAs are widely used because they have features that are attractive to both private investors and governments. For private investors production sharing is attractive because it replaces energy-specific taxes and eliminates many uncertainties about future tax rates and rules. PSAs are often used for difficult, high-risk projects, eliminating some of the associated uncertainties, and making oil companies willing to take on the substantial exploration and production risks involved. The terms of the contract are negotiated to take into account the particular physical and economic characteristics of development and to share the risk arising from uncertain future prices. Typical contracts provide the government a minimum revenue from the start of production (as this helps protect its revenue against excessive deductions by the operating company); priority to the company for recovering

[119] As discussed in Chapter 13 on environmental issues, often these environmental fees are viewed as available sources of general budget revenue, particularly by local governments, and become another form of taxation.

its costs, including capital costs and an industry standard level of return; and a sliding scale for dividing the remaining profits between the government and the company, with the government's share increasing with the rate of profitability.

For the government, one of the attractions of production sharing or other types of concession contracts is that it does not incur any upfront costs while signing the contract. In fact, the government grants the exploration rights to an oil company, which then bears all the costs and risks of exploration (including the risk that oil production may never even occur) and production. Later on, the costs incurred by the oil company are recovered from what is called cost oil share of production. Very often this is an acceptable arrangement, because the government may not have the so called "risk capital" to provide to national oil companies to develop a high-risk resource.[120] Oil exploration and production is a long-term process, and the government needs to make choices about spending its available capital and using its natural resources that most closely match its goals.

International experience (for example in the UK North Sea licenses) has demonstrated that the relationship between a government and oil companies has its ebbs and flows. First comers to develop the UK North Sea blocks received very attractive contracts, but after successful discoveries the government sought to toughen the terms. Even when this was done without breaking the existing contracts, the effect of changing the rules caused both production and investment to decline. New companies that entered the sector after the changes received much less favorable contracts; it was only later, after terms were readjusted to be more attractive to the companies that a second wave of new comers arrived.[121]

But PSAs are not without risks. The major risks involved with PSAs are the uncertainty of the reserve base and particularly the costs involved in developing any reserves once they have been discovered. The latter (uncertain cost estimates) have been a major problem at Kashagan, where capital costs have ballooned to nearly $50 billion. But Kazakhstan arguably has gained considerable experience in understanding costs of difficult offshore developments and the major uncertainty of determining allowable costs.

Key considerations for Kazakhstan include:

- Does the government want to assume all the risk of bringing on production from new (perhaps difficult, offshore) fields?
- Does this align with its overall strategy, and is this the best use of its capital?
- Does it want oil production growth and corresponding economic benefits and growth of the National Wealth Fund?
- If so, is it willing to transfer that risk to oil companies, and how much is it willing to compensate them?

Some Misperceptions about PSAs

Investors regard the production-sharing agreement (PSA) as a workable mechanism upon which major investments can be based, especially during the period during which an overall legal and tax regime is being put into place and confidence in it is built. A common misperception is that PSAs reduce a government's sovereignty and control over mineral resources. This is not the case. The contract holder must meet the terms of the PSA agreement or the contract can be revoked. The PSA, however, does protect the investor against arbitrary unilateral decisions by the state. Moreover, it is misleading to compare government revenues from PSAs with revenues under the regular tax system. Many projects that could proceed under PSAs would not be realized at all under many regular tax regimes. Another common misconception is that PSAs do not have to be employed for all projects and licenses. They can be employed selectively to secure investments only in high-cost, high-risk projects with long gestation periods.

A versatile production-sharing framework can be appealing to both the contractor and government since it can be adjusted to suit particular project circumstances without changing the overall fiscal framework for the country. Most difficulties with PSAs relate to the determination of allowable costs.

Moreover, PSAs permit the conditions governing petroleum exploration and development to be consolidated in one document. They may be particularly helpful in two situations: (1) in new emerging areas that are only developing administration and regulatory systems for hydrocarbon exploitation; and (2) for new entrants, not familiar with the operating environment, since the necessary provisions (including fiscal stabilization) can be consolidated in the PSA and the way in which the law will be applied can be clarified. The PSA offers investors a straightforward way of codifying contractual assurances and additional statutory rights in one document.

[120] In cases when the government is interested in spending some of its risk capital, a joint venture or other arrangement is often made.

[121] See Kirsten Bindeman, Production-Sharing Agreements: An Economic Analysis, Oxford Institute for Energy Studies, WPM 25, October 1999.

7.5.8. Customs Union, Eurasian Economic Union, and taxation issues

In accordance with the agreement dated 6 October 2006 on formation of a single customs territory and customs union, the Customs Union was created among Belarus, Kazakhstan, and the Russian Federation. It began functioning on 6 July 2010, with the approval of the Customs Code of the Customs Union. The Customs Union was created in order to unify the customs territory of the three states, where the goods originating from member states of the Customs Union are exempt from customs duties and other economic constraints when moving to market in another. The establishment of the Customs Union, and subsequently the formation of the Eurasian Economic Union from January 2015, particularly affects VAT, export taxes, and import duties. Other countries have since joined the initial integration project, Armenia and Kyrgyzstan, and others may choose to join in the future.

Within the Eurasian Economic Union, all sales of goods to or from Kazakhstan are deemed import/export operations and are subject to VAT at 12% upon import and VAT of 0% upon export. Generally, equipment, spare parts, and materials used in oil and gas operations are subject to import customs duties as well, but some contracts concluded prior to creation of the Customs Union may benefit from grandfathered customs exemptions. The customs legislation provides for a temporary import regime for goods that will be re-exported eventually. It either exempts goods and equipment from customs duties and import VAT or it allows for partial payment, provided the goods and equipment are subsequently re-exported.

Recommendations

- Since Kazakhstan's total overall tax take for upstream projects is relatively high by international standards, to maintain the country's competitiveness to attract international capital, the government needs to reduce the rates set in several of the various tax instruments. In particular, reductions need to be made in the "early revenue" instruments to make the overall tax structure more profit-based, including signing and commercial bonuses, historical expenditures reimbursement, and perhaps even royalties (MRET).

- In fact, the government of Kazakhstan should consider abolishing the signing bonus and commercial discovery bonus altogether, for several reasons:

  — The payment amounts remain unclear

  — Because they essentially punish a company for success in exploration, they provide a totally wrong signal to market participants

  — These payments are paid in advance, making them problematic for an industry with long lead times before the actual start-up of production.

- At the prospecting and exploration phase, to effectively attract private capital, it is necessary to create appropriate economic incentives. (For example, Norway reimburses expenditures on prospecting and exploration, greatly diminishing the overall risk.) Effectively in Kazakhstan, this means that almost no tax burden should be applied during this phase because there is no income, only expenditures (taxes and fees at this stage should be limited to income taxes on workers' salaries and other income-type taxes). Also, at this stage, investment obligations (minimal work programs established in the contract) should also be kept to a minimum.

  — At the next phase of operation, exploration, the current tax structure does not create incentives for subsoil users to quickly and efficiently proceed with exploration following initial prospecting. The existing procedure for exploration involves the payment of land tax, property tax, signing bonus, social expenses, and other payments. It is recommended that a single rental charge be introduced to simply the procedure, established in the form of a dollar-denominated rate per unit of exploration area. This rental charge should be set so that it rises progressively each year, so that the investor/developer is incentivized to either move on quickly with the work program or to relinquish the contracted area.

  — Also during the exploration phase, a more effective way of treating these sizable costs is needed. It is recommended that an option be established to attribute 30% of expenditures incurred on prospecting and exploration for deductions under non-contractual activities. If no commercial discovery is made, the option to allow the remaining (70%) of actual expenditures on prospecting and exploration to also be deducted should be considered. In the case of a commercial discovery and signing of a subsoil contract, it is recommended that the subsoil user be allowed to deduct all the incurred expenditures on prospecting and exploration evenly over the next five years as non-contractual activities. Currently, these expenditures are deductible as contractual activities (Article 111 of the Tax Code).[122]

- During the production phase for hydrocarbon development, taxation should be as transparent as possible, reflective of costs (i.e., profit oriented as much as possible), and that it remains at a level that provides an appropriate rate of return to the upstream developer and ensures sufficient cash flow to fund current capital expenditures. This includes the following general recommendations:

  — Establish a simple and clear procedure for applying for and determining MRET reductions for low-margin deposits. This is a common international practice for hard-to-recover and high-cost marginal deposits. The existing procedure is relatively arcane and nontransparent.

  — Introduce accelerated depreciation for upstream developers; in recent years, many governments around the world have come to realize that that accelerated

[122] See PwC, KazEnergy: A Comparative Study of Oil Tax Regimes, October 2014.

depreciation and amortization can serve as an important incentive to attract investments (e.g., Canada replaced the three-year tax exemption for 100% depreciation, and in Norway, capital expenditures are subject to proportional write-off over 6 years, and additional depreciation is even allowed).

— Establish special investment preferences or incentives for projects where appropriate, such as for established high-priority government goals.

— The government should consider reducing the top marginal tax rate for the excess profits tax; at the very least, it should returning to the previously applicable (until 2009) method for calculating the tax based on accumulated annual cash flows and the internal rate of return (IRR)

- Kazakhstan should consider establishing a stable long-term contractual framework (or even re-instating PSAs) for large, high-risk projects with long gestation periods for investment, such as for offshore blocks.

COAL SECTOR

8. Coal Sector

8.1. Key Points

- Kazakhstan is a significant producer and consumer of coal. It contains the world's eighth largest proven reserves of coal (34.2 billion tons), almost 4% of the world's total, which is sufficient to support current rates of production for at least 300 years. It annually ranks among the top 10 countries in the world in mine output (108.7 MMt in 2014). However, most coal deposits have high moisture content and relatively low heating values, as well as high ash and sulfur content. These characteristics, as well as high levels of methane in some deposits, mean that the production and consumption of coal in Kazakhstan is "dirtier" than in many other parts of the world, despite the fact that most volumes of coal are based on open-pit mining methods (e.g., Ekibastuz) that are highly competitive due to their very low extraction costs.

- Coal is the fuel that drives Kazakhstan's economy, currently accounting for over 60% of the country's primary energy consumption. Although coal's relative share is expected to decline over the longer term, coal's dominance in the country's energy mix longer term will remain. Typically, some 25–30% of total output is exported (mainly to Russia), although the country faces a difficult environment for boosting exports. Challenges include lower purchasing volumes from Russia (due in part to its recent economic slowdown), the limited competitiveness of Kazakhstan's coal in international markets (vis-à-vis not only domestic coal but gas and hydro), and policies of neighboring countries (e.g., Russia, China) either promoting energy independence or reduced dependence on imports.

- Coal production is expected to expand at an annual average rate of 3.0% between 2000 and 2020; however, production declines slowly at just under 1% annually, between 2015 and 2040 (from 108.7 MMt in 2014 to about 86.9 MMt in 2040). Apparent consumption follows a similar trajectory, increasing at a 3.1% annual rate during 2000–2020, before slowly declining from 82.7 MMt in 2014 to roughly 70 MMt in 2040. Analysis of consumption by economic sector reveals that coal's future in Kazakhstan continues to be closely linked to electric power generation. The electric power sector's share in overall coal consumption in the economy remains remarkably steady over time, maintaining its current three-fifths share throughout the remainder of the forecast period.

8.2. Coal Reserves

With proven reserves at 33.6 billion tons (recoverable ["balance sheet"] reserves are 34.2 billion tons)[1] and amounting to almost 4% of the world's total, Kazakhstan is a major world producer and consumer of coal. The country possesses the eighth largest reserves of coal globally, sufficient to last at least 300 years at current rates of production. Bituminous and sub-bituminous coal (the two types categorized as "hard coal" in Kazakh nomenclature) account for 64% of Kazakhstan's reserves (21.5 billion tons),[2] and the remainder of reserves consists of lignite (or "brown coal" at 12.1 billion tons). Over nine-tenths of total coal reserves are located in the central and northern parts of the country. The largest basins are Ekibastuz (12.5 billion tons), Karaganda (9.3 billion tons), and Turgay (5.8 billion tons) (Figure 8.1). Deposits in the Ekibastuz basin in particular stand out in terms of the low cost at which they can be produced; the seams are thick and located near the surface, making them easy to mine using open-pit methods (Table 8.1).

[1] The first figure is reported in the BP Statistical Review, whereas the second figure is reported by Kazakhstan's Geological Committee.

[2] Slightly over 5 billion tons of this figure is higher grade coking coal, used in ferrous metallurgy.

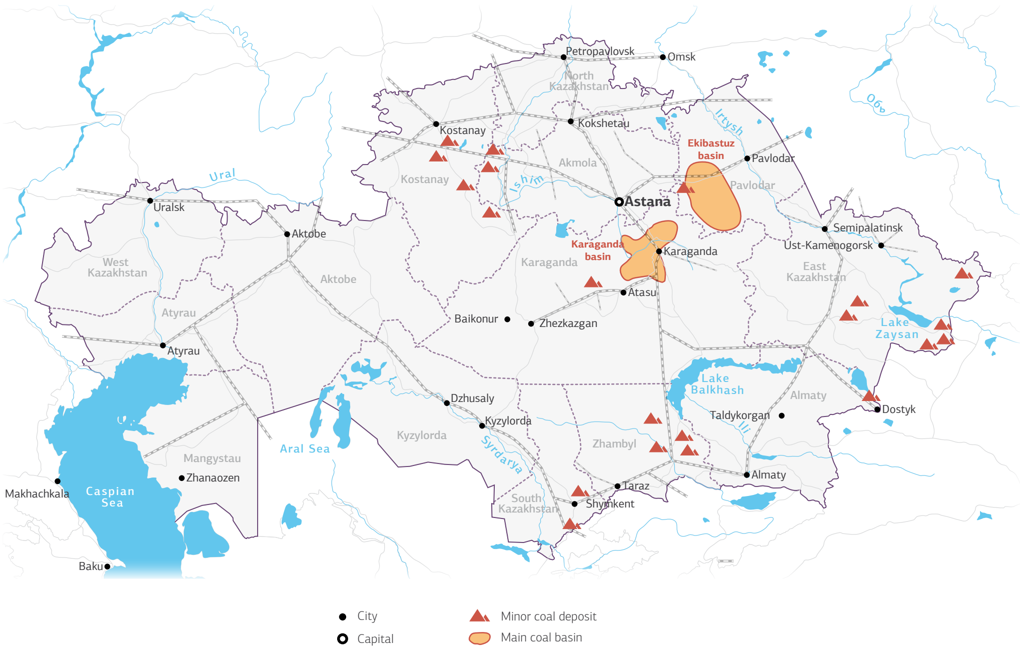


Figure 8.1 Kazakhstan's major coal basins

	Lower cost range	Higher cost range
Australia	28.91	56.33
South Africa	25.82	39.56
Colombia	35.25	41.44
Russia	23.39	27.26
China	42.56	49.88
Indonesia	21.89	47.95
Canada	26.29	34.96
USA - CAPP (EC/GC)	30.32	90.94
USA - NAPP (EC)	41.89	58.97
USA - PRB (Vancouver)	24.25	43.54
Kazakhstan	10.5	20.11

Source: IHS Energy.
Notes:
Costs are based on qualities of coals at individual mines/regions within each country, except for the USA (see below).
Costs presented are on a saleable basis.
CAPP = Central Appalachia.
NAPP = Northern Appalachia.
PRB = Powder River Basin.
EC = East Coast.
GC = Gulf Coast.
CAPP costs are based approximately on 6,400 kilocalories per kilogram NAR.
NAPP costs are based approximately on 6,960 kilocalories per kilogram NAR.
Illinois Basin costs are based approximately on 6,960 kilocalories per kilogram NAR.
PRB costs are based approximately on 4,720 kilocalories per kilogram NAR.

Table 8.1 Coal mining cost range in select countries, 2014

Although Kazakhstan's coal reserves are large, most deposits have high moisture content and relatively low heating values, as well as high ash and sulfur content. The latter means that their combustion (if untreated) is associated with substantial emissions of particulate matter and sulfur dioxide. The average ash and sulfur content of Kazakhstan's deposits exceeds that of coals in several other major producing countries (Table 8.2). At Ekibastuz, the leading basin in terms of production, the ash content is particularly high (42–44%), and the specific structural properties of the coal make it difficult to enrich. This limits its ability to penetrate many export markets (e.g., the European Union) in which stringent emissions controls are enforced. An exception to this general situation is the Shubarkol basin, where coals have much lower ash and sulfur levels (5–15% and 0.5%, respectively) and a higher heat value (5,600 kcal/kg). However, Shubarkol coal contains a high level of volatile components, presenting challenges to its transportation and storage.

In addition to these issues, part of Kazakhstan's coal is found in deposits that contain large volumes of methane gas, which serves both as a potential resource (coal-bed methane and coal mine methane, described below) and an environmental and mine safety issue (the need for methane drainage) under certain conditions. Consequently, if for no other reason than the chemical composition of the coal itself, the production and consumption of coal in Kazakhstan is "dirtier" than in many other parts of the world, despite the competitive conditions afforded by its low cost of extraction.

Country	Average ash content, %	Sulfur content, %
Australia	6	0.6
Colombia	8	0.6
United States	10	0.6
Poland	14	0.6
Russia	15	0.5
South Africa	17	0.9
Kazakhstan	29	1.7

Source: National Energy Report 2013. Astana: KazEnergy, p. 75.

Table 8.2 Average ash and sulfur content of coal deposits in several major coal-producing countries

8.3. Coal Production and Supply Structure

Kazakhstan ranks tenth among the leading coal-producing countries in the world. In 2014 aggregate coal production was 108.7 MMt (Table 8.3), a slight decrease from 2013 and 2012 (which was the highest level recorded since 1993).[3] As in previous years, the majority of output (94%) was considered hard coal; included in the hard coal total is 11.7 MMt of coking coal, used in metallurgy. Of total coal output, 82.5 MMt was consumed domestically and net exports amounted to 26.0 MMt. Kazakhstan imports an insignificant quantity of coal, mainly used as an energy fuel in border areas.[4]

Kazakhstan's maximum production level was achieved in 1988 at 143 MMt, and declined during the 1990s, with coal production plummeting in the initial years after independence due to the broad economic decline in the post-Soviet economies and the breakdown in inter-republic trade relations. Since 1999 production began to recover; the average annual rate of production growth for the period 1999–2012 was over 5%. Most (over 70%) of Kazakhstan's coal is produced at three giant open-pit mines (Bogatyr[5], Severnyy, and Vostochnyy) in the Ekibastuz basin in Pavlodar Oblast and in four open-pit mines (Borly, Shubarkol, Kushoky, and Saryadyr) in Karaganda Oblast. Most of the remaining output is from underground mines in the Karaganda basin (supporting local metallurgy) and lignite production in the Maykuben basin. Like Ekibastuz, the Turgay basin has enormous potential (60 billion tons of resources according to Energy Minister Vladimir Shkolnik) that lie near the surface. However, coal production at the Turgay basin is not expected to begin until 2020.

[3] The reported total is for run-of-the mine output. The total does not include coal concentrate, as is the Kazakh statistical practice. Coal concentrate is a product of processing (in washeries) that removes impurities such as stone and dirt. Coal concentrate production in Kazakhstan was 5.2 MMt in 2014.

[4] In Table 8.4, the category of net imports reports the balance between imports and exports. For example, the figure for 2010 reported in the table (–32.4), reflects exports of 32.7 MMt and imports of 0.3 MMt.

[5] In 1985, the Bogatyr mine was listed in the Guinness Book of Records as the largest coal mine in the world.

	1999	2000	2002	2004	2006	2008	2009	2010	2011	2012	2013	2014
Kazakhstan (total)	58.4	74.9	73.7	86.9	96.2	106.0	96.1	106.6	111.4	115.7	114.6	108.7
Hard coal	56.6	72.4	70.7	82.9	91.6	101.2	91.0	99.3	103.0	107.9	107.7	102.5
Coking coal	n.a.	n.a.	n.a.	n.a.	n.a.	n.a.	n.a.	11.7	11.5	11.3	11.7	11.7
Lignite	1.8	2.4	3.0	3.9	4.7	4.8	5.1	7.3	8.4	7.7	6.9	6.2
DISTRIBUTION BY BASIN:												
Kazakhstan (total)	58.4	74.9	73.7	86.9	96.2	106.0	96.1	106.6	111.4	115.7	114.6	108.7
Karaganda	15.1	17.9	23.1	25.5	26.8	27.3	26.0	28.2	30.2	30.5	32.0	33.0
Ekibastuz (hard coal)	38.9	51.8	46.8	52.9	60.3	68.8	60.2	66.6	68.7	71.3	69.3	63.1
Other	4.4	5.2	3.8	8.5	9.2	9.9	9.9	11.8	12.5	13.9	13.3	12.6
DISTRIBUTION BY OBLAST:												
Kazakhstan (total)	58.4	74.9	73.7	86.9	96.2	106.0	96.1	106.6	111.4	115.7	114.6	108.7
Akmola	0.1	0.1	0.4	0.2	0.0	0.0	0.2	1.5	2.0	3.5	3.2	2.0
Aktobe	0.0	0.1	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	—	—
Almaty	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
East Kazakhstan (Semipal-antinsk)	2.5	2.6	3.4	4.3	4.5	5.4	5.4	5.8	6.2	6.2	6.0	6.4
Zhambyl Oblast	0.0	0.0	—	0.1	0.0	0.3	0.4	0.3	0.3	0.1	0.1	0.1
Karaganda	15.1	17.9	23.1	25.5	26.8	27.3	26.0	28.2	30.2	30.5	32.0	33.0
Kostanay	—	—	0.1	0.1	0.1	0.1	0.0	0.0	0.0	0.0	0.0	—
Pavlodar	40.6	54.1	46.8	56.6	64.8	72.8	64.2	70.6	72.7	75.3	73.3	67.1
South Kazakhstan	0.0	0.0	0.0	0.0	—	—	—	—	—	—	—	—

Note: Output is reported as run-the-mine before processing.
Source: Kazakhstan Committee for Statistics.

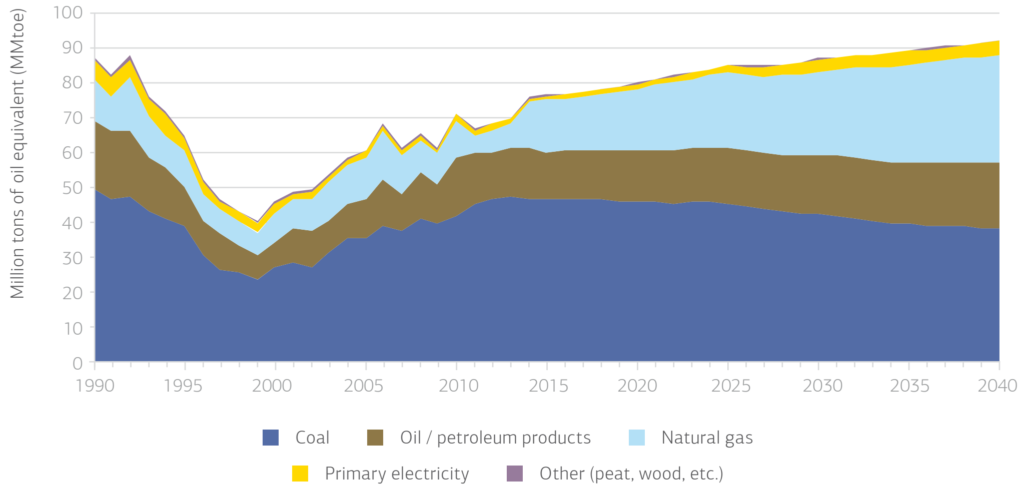
Table 8.3 Kazakhstan's coal production (million metric tons), 1999–2014

Coal production has been administered via a decentralized management framework since a restructuring and privatization of the industry occurred during the mid-1990s. Currently, a total of 26 companies are involved in the mining of coal; most of these are domestically owned but some are foreign-owned or are joint ventures. The regulatory body is the Department of Electric Power and Coal Industry Development. Formerly under the Ministry of Industry and New Technologies (liquidated during the ministerial reorganization in August 2014), it is now part of the enlarged Ministry of Energy. Kazakhstan's largest producer is the Bogatyr Komir LLP, which mines the gigantic Bogatyr pit in the Ekibastuz basin. It accounts for approximately two-fifths of national output, followed by Eurasian Energy Corporation JSC (one-fifth). Three additional producers account for about 7% each—the ArcelorMittal Temirtau Coal Company (underground mine production in the Karaganda basin), the Borly Coal Company, and the Shubarkol Komir JSC. ArcelorMittal Temirtau is the only company that produces coking coal.

8.4. Coal Consumption Patterns

Quite literally, coal fuels Kazakhstan's economy, as the country has the highest dependence on coal in its energy mix of any of the former Soviet republics. Since 1990 the share of coal in the total primary energy consumption balance generally has fluctuated at between 50% and 60%, rising above 66% in some years (Figure 8.2). This share is expected to gradually decline, falling below 50% in 2030 and to almost 40% in 2040. This expectation is derived from the IHS integrated energy balance model, employed in this report, accounting for development of other energy sectors (gas, nuclear) in the economy. Notwithstanding its declining share, coal will remain an important fuel in the energy mix for the foreseeable future.

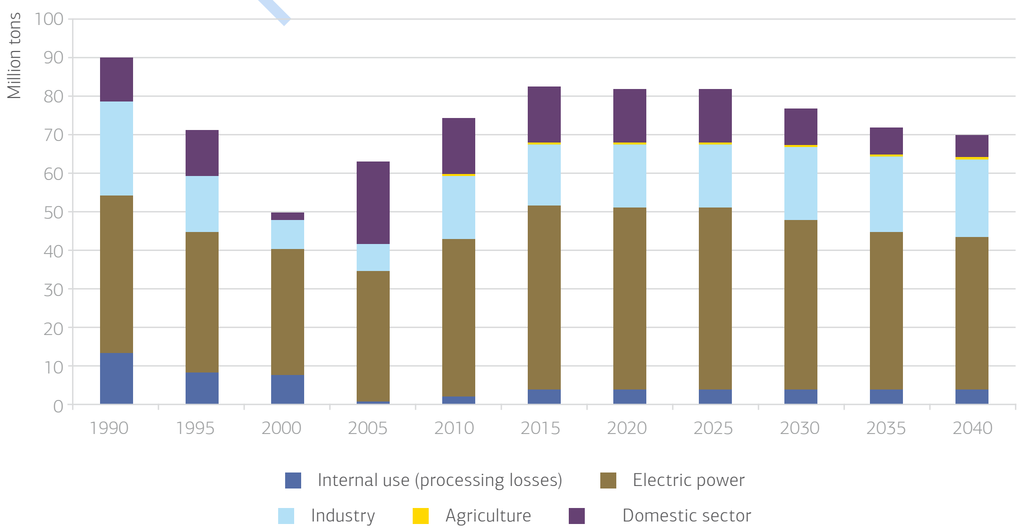
The use of coal is ubiquitous in Kazakhstan's economy, especially in power generation, heavy industry, mining and other resource extractive activities, and even in the residential-commercial-municipal sector. Apparent consumption (production minus exports plus imports) in the late Soviet period was 90 MMt (1990), but declined steadily during the upheavals of economic transition, reaching a nadir in 1999 (at 43 MMt). Since that time, consumption has recovered steadily, reaching 83 MMt in 2014.



Source: IHS Energy

Figure 8.2 Kazakhstan's primary energy consumption

Electric power stations are the largest consumers of coal, responsible for over half of total consumption (Figure 8.3); more specifically, in 2014 the electric power sector accounted for roughly 61%. The share of metallurgy and other industry in total consumption is comparable to that of the domestic (residential-commercial) sector's consumption, each representing nearly one-fifth of total consumption. As discussed in greater detail in Chapter 10, the power sector's coal demand will continue to be significant. However, power-sector coal consumption is expected to peak in about 2020, after which other energy sources (natural gas and particularly nuclear) are expected to displace some coal. IHS projects modest growth (0.9% annually) in the consumption of coal by industry through the end of the forecast period (2040), although this could be accompanied by the growing use of other fuels (e.g., natural gas) in industry as well. Consumption in the residential-commercial sector will almost certainly decrease, with consumers switching to natural gas (or liquefied petroleum gases [LPGs]) when possible for reliability and convenience, as has been the case in other industrialized countries. Indeed, the share of residential-commercial sector consumption at the end of the forecast period (2040) is projected to be less than half the 2010 level (Table 8.4). Thus, while apparent levels of coal consumption are expected to decline slowly from current levels, and eventually to reach 70 MMt by 2040, the share of power sector coal demand remains steady at more or less the current 61%.



Source: IHS Energy

Figure 8.3 Coal consumption in Kazakhstan by sector

												Average annual growth	
	1990	1995	2000	2005	2010	2015	2020	2025	2030	2035	2040	2000-2020	2015-2040
Production	131.6	83.2	74.8	86.6	106.6	108.2	107.8	106.7	99.6	91.4	86.9	3.0	–0.9
Net imports	–41.5	–11.8	–25.0	–23.7	–32.4	–25.7	–26.2	–25.0	–22.9	–19.8	–17.0	2.7	–1.6
Apparent consumption	90.1	71.4	49.8	63.0	74.2	82.5	81.6	81.7	76.8	71.6	69.9	3.1	–0.6
Internal use (processing losses)	13.2	8.4	7.5	0.8	2.0	3.6	3.7	3.9	3.8	3.7	3.7	–2.1	0.1
CONSUMPTION	76.9	63.1	42.3	62.1	72.2	79.0	77.9	77.8	73.0	67.9	66.3	3.6	–0.7
Electric power	40.8	36.3	33.0	33.5	41.0	48.0	47.2	47.0	44.0	40.9	39.8	2.4	–0.7
Pct. of total	53.0	57.6	78.0	53.9	56.8	60.7	60.6	60.4	60.3	60.2	60.0		
Industry	24.4	14.1	7.2	7.0	16.2	15.9	16.4	16.5	18.6	19.7	19.8	3.6	0.9
Pct. of total	31.7	22.3	17.0	11.3	22.4	20.1	21.0	21.2	25.4	29.0	29.8		
Coking	8.2	4.0	3.1	7.5	9.9	10.4	11.3	12.0	12.8	13.5	14.2	4.5	1.2
Pct. of total	10.7	6.4	7.3	12.1	13.7	13.1	14.5	15.4	17.5	19.9	21.4		
Agriculture	0.5	0.3	0.3	0.3	0.4	0.6	0.6	0.6	0.6	0.6	0.6	3.1	0.1
Pct. of total	0.9	0.6	0.4	0.6	0.7	0.9	0.9	1.0	1.0	1.0	1.0		
Domestic sector	11.0	12.1	1.6	21.2	14.5	14.5	13.7	13.6	9.7	6.6	6.0	16.2	–3.4
Pct. of total	14.3	19.2	3.9	34.1	20.1	18.3	17.5	17.5	13.2	9.8	9.0		

Source: IHS, Kazakhstan Committee for Statistics.

Table. 8.4 Coal balance for Kazakhstan, 1990–2040 (million metric tons)

8.5. Coal Exports

Over 25% of Kazakhstan's total coal production typically is exported (26.2 MMt net exports in 2014). Considerably more coal likely could be sold abroad if not for the remoteness from large export markets (see below). Russia has been the primary destination, receiving nearly 30 MMt of coal from Kazakhstan in each of 2012 and 2013 (largely lower quality sub-bituminous grades). Ekibastuz coal accounts for over 90% of these exports (primarily to power stations in the Urals). To some extent, this represents a legacy arrangement, in that some power plants were expressly designed to burn Ekibastuz coal. In addition, 0.9 MMt of coking coal from the Karaganda basin were exported to iron and steel plants and other industrial plants in Russia in 2013. A coal balance agreement between Russia and Kazakhstan envisions that Kazakh coal exports to Russia will total roughly 29 MMt per year, even though Kazakh coal is struggling to compete with local Russian coal due to high transportation costs (see text box below for more). Kazakhstan also exports some coal to Ukraine and Kyrgyzstan, and small amounts are delivered to Belarus, Georgia, Uzbekistan, Turkmenistan, and even some EU countries on occasion (e.g., Latvia, Lithuania, Romania) (see Table 8.5). The EU exports tend to be limited to Shubarkol coal, which meets the EU's specifications for ash content and heating value.

	2009	2010	2011	2012	2013
Total	26 261	32 629	27 781	30 005	30 821
CIS countries	25 912	32 120	26 204	28 320	27 012
Kyrgyzstan	1 087.6	1 003.3	969.1	1 277.8	1 081.8
Moldova	--	--	--	0.4	--
Russia	23 760.9	30 318.1	24 614.4	26 247.0	25 349.1
Tajikistan	--	0.5	0.1	5.1	0.4
Uzbekistan	3.7	2.8	2.5	22.9	5.7
Ukraine	1 059.4	795.3	617.9	766.4	574.9
Georgia	--	8.5	--	1.5	0.2
Non-CIS countries	350	509	1 577	1 686	3 809
Bulgaria	5.0	5.0	1.7	24.7	--
British territories of the Indian Ocean		--	--	--	41.2
Hungary	22.0	9.9	--	--	--
Greece	--	--	134.3	309.7	168.8
Spain	--	--	--	--	0.4
Italy	9.9	--	--	--	73.9
Cyprus	--	--	--	--	72.5
China	--	0.0		0.0	219.3
Latvia	--	6.3	--	--	0.3
Lithuania	--	--	--	--	3.0
Poland	296.5	295.3	238.8	285.8	62.9
Romania	--	--	5.9	37.7	47.6
Syria	--	--	--	26.1	--
UK	--	--	69.0	489.9	176.4
Turkey	0.1	45.8	--	--	6.7
Finland	15.9	137.8	754.3	299.8	2 765.5
Croatia	--	--	--	--	10.2
Japan	--	--	--	--	162.3
European countries	349.3	454.3	1 204.0	1 447.6	3 381.5

Source: Kazakhstan foreign trade statistics

Table 8.5 Exports of coal from Kazakhstan by country, (thousand metric tons)

The overall price environment for thermal coal exports globally is expected to exhibit continued weakness in 2015. Soft demand in China (see Chapter 6) and strong mine ramp-ups around the world are exerting downward pressure on prices. According to forecasts issued in 2014 by the Bank of America Merrill Lynch (BAML) and the Economist Intelligence Unit (EIU), an Asian benchmark price (Newcastle, Australia) is expected to fall to $65–$67 per ton in 2015, down from $70 per ton in 2014. A new 6% import tax on Australian supplies to China could depress the price further[6], as could a potential negative demand shock from disappointing global economic growth or further protectionist measures by China. After 2015 the EIU forecast projects a more balanced market in which the downside risks to thermal coal prices begin to dissipate, with the price rising from $74.80 per ton (2016) to $75 per ton in 2017 and $80 by 2019. The BAML forecast projects a more rapid upward price trajectory, from $72 per ton in 2016 to $82 in 2017.[7]

[6] China and Australia signed a bilateral free trade agreement in June 2015 which immediately exempts Australian exporters of coking coal from the 3% import tax rate, while the 6% thermal coal tax will be initially reduced to 4% and subsequently canceled altogether by the end of 2017.

[7] See Jonathan Rowland, "Thermal Coal Prices to Stay Weak through 2016," World Coal, 11 March 2014. It should be noted that the Newcastle price historically has been volatile, as it has thus far in 2015. A tropical cyclone that hit Australia's east coast in February 2015, temporarily shutting in coal production at several mines and putting a near-term dent in supply, drove (perhaps together with some speculation in the markets) the Newcastle price to a high of $80.50 on 2 March 2015. However, by 17 March, the price had already settled back down to $67.55.

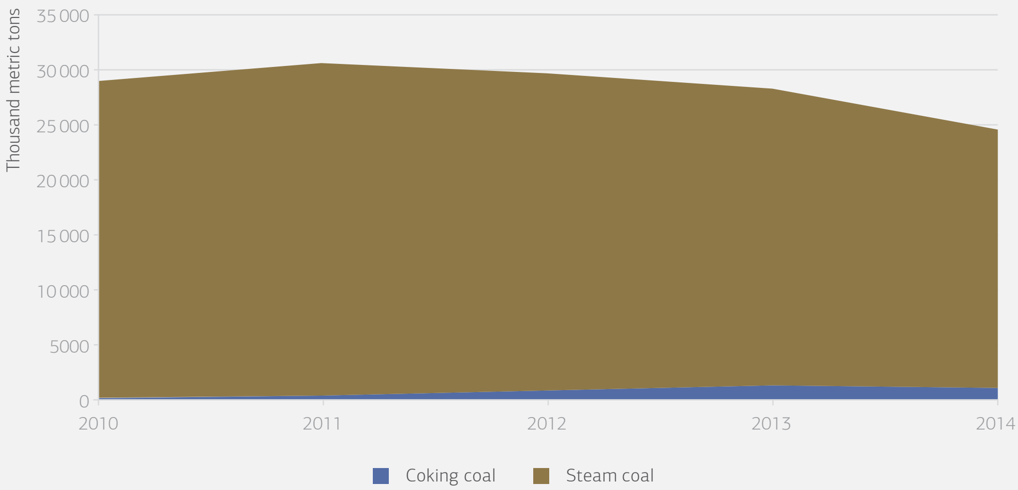
8.6. Competitiveness of Kazakhstan's Coal in International Markets

The competitiveness of Kazakhstan's coal exports is influenced by several important factors, including production costs, quality of coal, and transportation costs to international markets. In addition, coal faces competition from other fuels in the consuming markets, such as oil, gas, and even renewables. After considering the environmental impact of coal mining and use, coal's attractiveness as a fuel of choice is likely to suffer in the modern economy.

One of the main advantages of Kazakh coal is its abundance and low cost of production (lower than in the other CIS states). Production costs are especially low in the Ekibastuz basin, which serves as the main source of exports to Russia.[8] Although production costs in absolute terms have more than tripled since 1996, they remain comparatively low: in 2011, the average cost of producing coal in Kazakhstan was $10 per ton. Yet despite low production costs, by the time coal reaches foreign consumers its price increases substantially due to transportation costs (see below).

Kazakh Coal's Position in Russia's Power Sector Weakening

Owing to a general slowdown in Russia's economy, Kazakh coal exports to Russia dropped by 13.2% year on year in 2014, to 24.6 MMt; 23.6 MMt was comprised of steam coal and 1.0 MMt was coking coal (see Figure 8.4 Russia's coal imports from Kazakhstan). Most of the steam coal is from the Ekibastuz coal basin. As a result of central planning of the power system in the Soviet era, several power plants in Russia—in the southern Urals and West Siberia—were designed to burn Kazakh steam coal, and under most conditions Kazakh coal remains more economic than competing sources of fuel in Russia. Yet coal trade between the two countries is set to face further short- to medium-term economic volatility as well as medium- to long-term Russian policy headwinds.



Source: IHS Energy, TEK Rossii

Figure 8.4 Russia's coal imports from Kazakhstan

Russian coal consumption stumbles on Russia's recent economic woes

The recent slowdown in Russia's economy has brought about some volatility for short-term power demand, and consequently demand for fuel. However, electricity consumption in Russia has been slipping since 2012, but more recently the Russian ruble volatility also has damaged the Kazakh coal trade considerably.

Power plants in Russia's Sverdlovsk, Chelyabinsk, and Omsk oblasts consume the vast majority of exported Kazakh coal (see Table 8.6). Since 2012, power consumption in Sverdlovsk Oblast has declined by 4.4%, in Chelyabinsk by 1.4%, although in Omsk consumption has declined only very slightly. These overall declines in power consumption have naturally influenced electricity production levels, and consequently the need for fuel. In particular, Russian power plants burning Kazakh coal have registered declines in power production. For example, the Reftinsk regional power plant (GRES) in Sverdlovsk Oblast, with an installed capacity of 3,800

[8] In the mid-1990s, for example, strip mine production, using large rotating excavators, at Ekibastuz was only one-fifth the cost of an average ton from the Karaganda field (where mines are underground), and even 10 years later was one-fourth.

MW, consumes about 13 MMt of coal annually and is by far the largest single consumer of Kazakh coal in Russia. The plant registered a 12% decline in power production in 2013. Also, comparing 2013 with 2012, the Troitsk GRES (in Chelyabinsk Oblast), with an installed capacity of 2,500 MW, consumes about 3 MMt of coal, and experienced a decline of 14% in electricity production in 2013. Another Urals plant, the Serov GRES (in northern Sverdlovsk Oblast), which consumes about 1.5 MMt of Kazakh coal, registered a decline of 25% in electricity generation in 2013.

These general declines in demand have been further aggravated by the depreciation of the Russian ruble, which has made Kazakh coal relatively more expensive for buyers. For example, coal contracts between Russia and Kazakhstan are denominated in Russian rubles, and the severe currency fluctuations and overall devaluation of the ruble has dramatically stifled coal trade between the two countries (as is also the case in the electric power trade).

Essentially, declining power production from generators burning Kazakh coal resulted in a 6% decline in Kazakh steam coal exports to Russia in 2013. This trend continued in 2014, when it was compounded by ruble depreciation and volatility, leading to the 13% fall in Kazakh coal exports to Russia noted above.

Electric power plant	Volume of coal in 2012, million tons
Reftinsk GRES	13.2
Omsk TETS 4 and 5	4.6
Troitsk GRES	3.1
Yuzhnouralsk GRES	2.1
Verkhnetagilsk GRES	1.6
Serov GRES	1.5
Other	1.2

Source: The Ministry of Investment and Development of Republic of Kazakhstan

Table 8.6 Kazakh coal deliveries to Russian power plants

Russian policy set to alter appetite for Kazakh coal longer-term

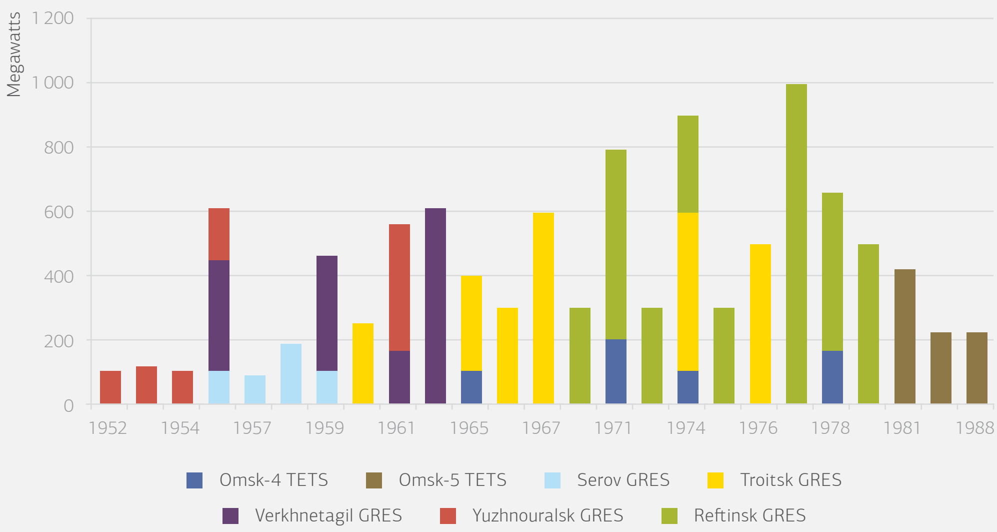
While Russian policymakers view coal-fired capacity in the country as likely to remain relatively stable longer term, the Russian state also hopes to reduce its dependence on inefficient capacity (reducing emissions by 50%), as well as decommissioning old inefficient generation. At the same time, the government has signaled its intention to favor domestic coal supplies. If these policy initiatives are played out, this will inevitably lead to a gradual decline in demand for Kazakh coal over the longer term.

Since 2000, the trend has been for internal coal consumption in Russia to slowly contract, by around 0.8% a year on average (with consumption in the metallurgical sector decreasing by 1.5%, in the power sector by 1.4%, and in the agricultural and communal sectors by 2%). In acknowledgement of this trend, official documents have been guiding the power and coal sectors' development policy since 2003.[9] Each successive document has envisioned a declining share of coal in the fuel balance of the power sector and changed the projections of coal-fired generation growth to "insignificant." The latest document on power sector development to 2035 (Draft Energy Strategy to 2035) continues the previous trajectory. Essentially, Russia's Draft Energy Strategy to 2035 targets innovation, increasing technological and economic efficiency, and substituting fuel imports as the key aspects of future of energy sector development. Overall, in the draft energy strategy, the government envisages Russia's fuel mix will continue relatively unchanged, with gas remaining core and in some cases displacing coal capacity, but for coal capacity, the emphasis will be placed on modernizing units or adapting boilers to burn domestically sourced coal.

Currently, it is not likely that the economic situation, or policy, will force a blanket replacement of reliable coal-only capacities (that burn Kazakh energy coal) with that of Russian indigenous gas. Despite a gas network competing in their areas, the Reftinsk GRES, Troitsk GRES, and Omsk heat and power station (TETs) are not

[9] These views are expressed in various government policy documents: Energy Strategy to 2020; General Scheme of Power Assets Location to 2020; Energy Strategy to 2030; General Scheme of Power Assets Location to 2020 with a View through 2030; and Long-Term Coal Industry Development Program to 2030.

yet considered too old by Russian standards (see Figure 8.5). It is unlikely that increasingly scarce investment capital will be allocated over the near term for the purpose of fuel conversion at these facilities until they must be replaced or refurbished. But some fuel displacement could occur at the Verkhnetagil GRES, Yuzhnouralsk GRES, and Serov GRES, as these plants have gas infrastructure in place and can already switch between natural gas and coal as a main fuel.



Source: IHS Energy

Figure 8.5 Age distribution of Russian power plants that burn Kazakh coal

Consequently, although plants burning Kazakh coal will likely remain competitive in Russia's power sector for some time to come, over the longer term the outlook is more challenging. Because some 45% of the units burning Kazakh steam coal entered service prior to 1970, it is feasible that by 2025 these capacities will face replacement or refurbishment. At that time, per the Russian government's energy strategy, asset owners may use this opportunity to shift from Kazakh-sourced coal to burning domestic coal or gas.[10] Among the sites where this might occur, the aforementioned Verkhnetagil, Yuzhnouralsk, and Serov plants not only have gas infrastructure in place, but operate some of the oldest capacities. A fuel switch at these three plants would mean Kazakhstan could feasibly lose at least 5 MMt of steam coal from its export portfolio.

At the same time, Kazakh coal has several disadvantages. First, as noted above, on average its quality is not very high, and even the best quality coal has a relatively high ash content (at least 20% compared to an average in world markets of no more than 10%), making Kazakh coal less attractive. Coal which has a low calorific value is always sold at a substantial discount to standard 6,000 kilocalorie-per-kilogram coals. Ekibastuz coal, Kazakhstan's main export coal, is high in ash content (~40%) and relatively low in calorific value (3,800–4,000 kilocalories per kilogram), although it is officially considered a hard coal (internationally, it would be considered sub-bituminous) (Table 8.7). Consequently, although it is an important source of steam coal for thermal power generation, it is less useful in industrial applications. Karaganda coal is of higher quality and can be used in industry. Karaganda's bituminous coal can be used for coking and is mostly consumed domestically.

[10] See the Long-Term Program of Coal Industry Development to 2030, Government provision No.14-p of 24.01.2012. One of the goals is development of the domestic market for coal consumption.

Deposits and basins	Average ash content by deposit, %	Heating value, kcal/kg
Karaganda basin	29.5	5200
including coking coals	24.0	5700
Shubarkol deposit	8.0	5593
Kuu-Chek deposit	41.0	4260
Borlo deposit	46.0	3472
Ekibastuz basin	42-44	3830-4060
Maykuben basin	22.4	4057
Yubileynoye ("Karazhyra") deposit	20.4	4438

Source: Geology and Mineral Development Committee of the Ministry of Industry and New Technologies of Kazakhstan

Table 8.7 Quality of Kazakhstan's coal resources by deposit

Second, high transportation costs, reflecting the long distances between sites of production and potential markets, render Kazakhstan's coal relatively expensive to consumers and reduce its competitiveness even in the Russian market, the closest export market. Transportation accounts for over 40% of the total delivered costs to the Russian coal buyers. Such costs were a major factor underlying the decision to construct large mine-head power stations in north-central Kazakhstan based on Ekibastuz coal during the Soviet period (e.g., Yermak GRES, Ekibastuz GRES-1, Ekibastuz GRES-2); planners calculated that it was cheaper to transmit energy in the form of electricity to consumers in the Urals and West Siberia than it was to transport the coal (with high ash content) used to generate the electricity there.

Coal is subject to relatively high rail transportation costs within Kazakhstan, and in the immediate post-Soviet period also suffered from higher rail tariffs (higher than on domestic Russian coal) on Russian territory. With the recent introduction of the Eurasian Economic Union (EEU), these tariffs are being harmonized, although harmonization alone may not do much to ease the high transportation component in overall costs. From January 2013 export and domestic tariffs were harmonized within each country of the union (Kazakhstan, Belarus, and Russian Federation), with tariff harmonization among the countries and harmonization of tariffs for export outside the union to be determined at a later date. Kazakhstan's Temir Zholy, the national railway company, is in a difficult financial position and is looking for ways to increase tariffs, not reduce them (see text box: Rail Transportation and the Energy Sector in Kazakhstan).[11] Higher transportation tariffs effectively reduce the radius available for coal to be railed and to remain profitable.

Rail Transportation and the Energy Sector in Kazakhstan

Rail transport figures prominently in the movement of key energy commodities in Kazakhstan, including coal, refined products, and uranium. Its importance for crude oil transportation is becoming less significant with the availability of more pipeline capacity. In 2013, the Kazakh rail system carried 293.7 MMt of freight (see Table 8.8). Of this, 105.1 MMt was coal (35.8%), 0.4 MMt was coke (0.1%), and 26.8 MMt was oil (crude oil and refined products [9.1%]). So all together, these major energy commodities accounted for 45% of all railroad freight.

[11] Kazakhstan's railroad network experiences significant bottlenecks in high-traffic areas. A major program is under way to upgrade the rail network, although it also requires significant investment. Some of this may be forthcoming from the new Nurly Zhol economic development plan, but a considerable part can only be financed through higher transportation tariffs.

	2000	2001	2002	2003	2004	2005	2006	2007	2008	2009	2010	2011	2012	2013	2014
Total (all railroads)	**156.4**	**183.8**	**178.7**	**202.7**	**215.6**	**222.7**	**246.9**	**260.6**	**269.0**	**248.4**	**267.9**	**279.7**	**294.8**	**293.7**	**273.4**
Total (common carrier)	**156.4**	**183.8**	**163.3**	**185.3**	**193.6**	**198.4**	**217.8**	**226.6**	**234.9**	**219.6**	**237.9**	**247.3**	**256.2**	**253.1**	
Hard coal	74.2	77.9	72.2	82.1	82.7	84.1	90.4	90.4	101.7	91.6	98.4	104.2	107.5	105.1	
Coke	0.2	0.3	0.2	0.4	0.5	0.5	0.4	0.5	0.7	0.3	0.6	0.6	0.4	0.4	
Oil/refined products	17.7	19.8	18.7	19.2	20.2	22.2	23.7	23.6	25.1	27.9	26.4	26.6	25.3	26.8	
Metal ores (all types)	n.a.	n.a.	31.5	34.9	37.7	37.6	45.2	45.0	42.9	41.5	44.3	44.0	46.4	45.9	
Ferrous ores (iron and manganese)	19.2	18.5	18.7	22.7	24.9	23.0	27.9	28.8	25.8	27.1	29.2	28.9	30.6	30.1	
Ferrous metals	4.7	4.7	5.1	5.4	5.8	5.4	5.5	6.5	6.4	6.0	6.1	6.4	5.8	5.3	
Scrap metal	n.a.		2.0	2.2	3.1	3.2		2.9	2.9	2.1	2.4	2.5	2.0	1.5	
Chemicals and mineral fertilizers	0.8	1.4	1.8	2.0	2.6	2.1	1.4	1.5	2.2	1.2	1.6	2.5	2.7	2.6	
Construction materials	n.a.	n.a.	n.a.	15.9	18.2	18.0	20.4	23.5	18.9	13.7	16.8	28.1	28.7	30.9	
Cement	1.0	1.4	1.7	2.1	2.4	2.8	3.0	3.8	3.2	n.a.	n.a.	n.a.	n.a.	n.a.	
Forestry products and wood	0.7	0.6	0.7	0.6	0.7	0.7	0.7	1.0	0.9	1.4	0.6	0.8	0.8	0.7	
Grain and milled products	6.4	4.4	5.2	7.1	4.5	4.0	6.3	11.0	10.8	9.6	8.6	7.1	11.4	8.2	
Other	51.7	74.7	41.3	32.9	39.6	44.9	52.9	54.7	56.5	53.1	62.1	56.9	63.8	66.3	

Note: Shipment data for freight categories are for common carriers only

IN PERCENT:

Total	**100.0**	**100.0**	**100.0**	**100.0**	**100.0**	**100.0**	**100.0**	**100.0**	**100.0**	**100.0**	**100.0**	**100.0**	**100.0**	**100.0**	
Hard coal	47.4	42.4	40.4	40.5	38.4	37.8	36.6	34.7	37.8	36.9	36.7	37.3	36.5	35.8	
Coke	0.1	0.2	0.1	0.2	0.2	0.2	0.2	0.2	0.3	0.1	0.2	0.2	0.1	0.1	
Oil/refined products	11.3	10.8	10.5	9.5	9.4	10.0	9.6	9.1	9.3	11.2	9.9	9.5	8.6	9.1	
Metal ores (all types)	0.0	0.0	17.6	17.2	17.5	16.9	18.3	17.3	15.9	16.7	16.5	15.7	15.7	15.6	
Ferrous ores (iron and manganese)	12.3	10.1	10.5	11.2	11.5	10.3	11.3	11.1	9.6	10.9	10.9	10.3	10.4	10.2	
Ferrous metals	3.0	2.6	2.9	2.7	2.7	2.4	2.2	2.5	2.4	2.4	2.3	2.3	2.0	1.8	
Scrap metal	0.0	0.0	1.1	1.1	1.4	1.4	0.0	1.1	1.1	0.8	0.9	0.9	0.7	0.5	
Chemicals and mineral fertilizers	0.5	0.8	1.0	1.0	1.2	0.9	0.6	0.6	0.8	0.5	0.6	0.9	0.9	0.9	
Construction materials	0.0	0.0	0.0	7.8	8.4	8.1	8.3	9.0	7.0	5.5	6.3	10.0	9.7	10.5	
Cement	0.6	0.8	1.0	1.0	1.1	1.3	1.2	1.5	1.2	n.a.	n.a.	n.a.	n.a.	n.a.	
Forestry products and wood	0.4	0.3	0.4	0.3	0.3	0.3	0.3	0.4	0.3	0.6	0.2	0.3	0.3	0.2	
Grain and milled products	4.1	2.4	2.9	3.5	2.1	1.8	2.6	4.2	4.0	3.9	3.2	2.5	3.9	2.8	
Other	33.1	40.6	23.1	16.2	18.4	20.2	21.4	21.0	21.0	21.4	23.2	20.3	21.6	22.6	

FREIGHT TURNOVER ON KAZAKHSTAN'S RAILROADS (billion ton-kilometers)

	2000	2001	2002	2003	2004	2005	2006	2007	2008	2009	2010	2011	2012	2013	2014
Total	**125.0**	**135.7**	**133.1**	**147.7**	**163.5**	**171.9**	**191.2**	**200.8**	**214.9**	**197.5**	**213.2**	**223.6**	**235.9**	**231.3**	**214.1**

AVERAGE LENGTH OF HAUL (kilometers)

	2000	2001	2002	2003	2004	2005	2006	2007	2008	2009	2010	2011	2012	2013	2014
Total	**799.2**	**738.3**	**744.8**	**728.7**	**758.3**	**771.9**	**774.4**	**770.5**	**798.9**	**795.1**	**795.8**	**799.4**	**800.2**	**787.5**	**783.1**

Source: Kazakhstan Committee for Statistics

Table 8.8 Freight shipped on Kazakh railroads (million metric tons)

Kazakhstan has a sizable and effective rail system, operated by state-owned national railroad company Temir Zholy. The system included 15,341 km of trunk line in 2013, 1,896 locomotives (of which 563 were electric), and 129,280 freight cars. Of the rail car fleet (rolling stock) for carrying freight, 65,803 cars (51%) were common-carrier, owned by Temir Zholy, while 63,477 were owned by private operators. Most of Kazakhstan's tank cars, for carrying liquids like crude oil, refined products, sulfur, and LPGs, are held by the private operators. The common-carrier fleet includes only 6,492 tank cars (10% of the total). The major private owners specializing in liquid shipments include Kaztemirtrans (with about 7,200 tank cars), Eastcomtrans (about 4,600 tank cars), Tengiz Trans Group (about 2,000 tank cars), Golden Eagle, Petrokazkahstan Kumkol Resources, and Plzha (with about 800 tank cars each), and Turgay Petroleum (with about 600 tank cars). Because of the volume of liquid shipments in Kazakhstan, the country also relies heavily on Russian and Ukrainian rolling stock, with Russia's largest rail car fleet operator, PGK, also being a major player.

The focus on liquids transport is because oil and oil products are the most profitable large-volume freight segment for the railroad system. Effectively, these shipments "subsidize" the transport of coal and other bulk commodities on the Kazakh system. Today, coal is shipped for roughly 30–50% less than oil and oil products for similar distances (on a ton-km basis). This is largely a result of the oil industry's ability to pay a premium for moving products that can be sold at relatively high prices, primarily on the global market. Although coal is essentially a low-margin line of business for the rail industry, it is crucial because it contributes the greatest turnover (in tons shipped and in ton-km) of any single product for the railroad system.

As a result, the setting of rail tariffs for coal, which ends up being critical in terms of determining its overall competitiveness in the end-user markets (transport cost is a large component of total delivered costs for coal), is closely tied to that of oil and oil products. But three factors are expected to change rail tariffs in the future. First, the construction of additional pipeline capacity has shifted much of the lucrative transport of crude oil (and perhaps later, oil products) from the rail system. Total shipments of oil and oil products by rail had been fairly stable, at around 26–27 MMt per year through 2013, but oil shipments already began to decline in 2014, notably with the expansion of the CPC and the decline of rail exports of crude to the Black Sea. Rail shipments of crude for export dropped sharply in 2014, from 8.7 MMt in 2013 to only 1.8 MMt. Second, Kazakh refineries are expected to produce less mazut and shift from exports of excess mazut (mainly to the EU) to delivery of more light products to the domestic market. Overall shipments of refined products may not increase substantially, but because of the shorter distances the products are moved, this means less high-value shipments and less total revenue for the rail system. Finally, government proposals to harmonize transportation tariffs for exports and domestic shipments across the Eurasian common economic space will push down real effective tariffs for oil and oil products because of similar trends within the Russian rail system. Ultimately, these three factors will place upward pressure on rail tariffs for coal, which are currently just slightly above break-even levels for the rail industry.

What is clear is that the rail industry operates in a tight pricing window. On one hand, the rail operator must have positive margins on freight hauls to offset losses in passenger transport and to finance significant investments in construction of new rail infrastructure, including construction of a new rail terminal in Astana for EXPO 2017. On the other, major tariff increases would easily price coal out of the market. Our current forecast does not envision this outcome (see below) but the situation warrants close attention.

There is some concern about a possible weakening in Russian demand after 2025 (see text box: Kazakh Coal's Position in Russia's Power Sector Weakening), as some of the Russian generating capacity currently designed to be fueled by Ekibastuz coal becomes outmoded and will need to be replaced. At that point, Kazakh coal might face much greater competition with Russian coal or natural gas for this capacity. However, the timetable for power sector modernization could be pushed back if investment capital is not readily available, and the EEU framework is expected to make it increasingly difficult for Russia to unilaterally force a switch to Russian fuels. Thus Kazakhstan's coal exports to Russia are projected to continue for the foreseeable future. Because of their low production costs and proximity to Urals power plants, they should remain economically competitive with both Russian coal (from the Kuzbas or local mines) and Russian gas.

Plans to launch Kazakh coal exports to China are less likely to prove economically viable, given the relatively low quality of the coal and the very high transportation costs that would be involved over such long distances (China's main coal consumption centers are in the east). Furthermore, coal demand growth in China is expected to decelerate over the next decade as a result of a variety of factors, including moderating economic growth, fuel diversification, and public pressure to reduce air pollution levels in some areas—now manifest in a specific commitment by China's State Council to cap coal consumption growth by 2020 (see Chapter 13). In fact, coal demand already is showing signs of weakening. Coal consumption in China's electric power sector fell by 3% in 2014, in response to weak national electric power demand growth as well as competition from a surge in new hydroelectric generating capacity; total coal consumption in the country declined by 2.2% in 2014.[12]

As part of the effort to reduce air pollution in its eastern provinces, China also intends to shift local coal-fired generation capacity to interior locations and especially to its energy-rich Xinjiang Province and Inner Mongolian Autonomous Region in the northwest and north, respectively. This has become possible as a result of advances in long-distance electricity transmission via extrahigh-voltage and ultrahigh-voltage lines, as outlined in Chapter 6. Although Kazakh coal would certainly be geographically nearer to power plants in Xinjiang than in Beijing or Shanghai, China plans to fuel such plants with locally plentiful coal, natural gas, and wind energy, not imported coal (see the discussion of prospects for coal and electricity exports in Chapter 6).

In short, China has abundant undeveloped energy reserves of its own, and is taking steps to first stabilize and then reduce its consumption of coal. This is already driving domestic Chinese coal prices downward in the main consuming areas in eastern China. With Chinese domestic coal prices essentially setting the ceiling for what Kazakh coal can fetch in Chinese markets, it thus appears that delivered costs of Kazakh coal would be much higher than prevailing domestic prices in China. Moreover, although China's total coal consumption is expected to return to growth in 2015, the long-distance transmission of electricity from the interior to the eastern

[12] IHS Energy, Life after the Super Cycle: China's Energy Oversupply Casts a Global Shadow. China Energy Watch, December 2014. Xiaomin Liu, China Coal Market Briefing: Annual 2014. IHS Energy Market Briefing, March 2015.

provinces, which has ramped-up very rapidly since 2012, is already displacing imports of coal used to fire local thermal generation there. It is estimated that in 2014 coastal China met as much as one-fifth of its total power demand through long-distance transmission from the interior. This coastal region is the market for China's coal imports, and as a result the country's thermal coal imports already were falling in 2014 (to 198.8 MMt) and are expected to continue to decline going forward. China's coal imports may well have peaked.

Thus, prospects for a major near-term expansion of energy coal exports in the Chinese market appears to be limited at best. Exports in the immediate Central Asian region might be increased, especially after Kyrgyzstan (which currently accounts for about 7% of Kazakhstan's coal exports) accedes to the Eurasian Economic Union. Another existing customer, Ukraine (~5% of Kazakhstan's coal exports) may seek to import more coal as a result of the loss of mining capacity due to the ongoing unrest in its eastern regions. Whether the regional geopolitical situation, or Ukraine's dire financial situation, makes such imports feasible is an open question.[13] Limited exports to Europe might also continue, if economic growth accelerates and there is a need for greater base generating capacity to accommodate renewable capacity additions. However, this may be challenging considering the EU focus on meeting carbon emission targets, with Germany for example moving to constrain its lignite use. Still, the higher quality Shubarkol coal, which already is exported in small amounts to the Baltic States, appears best positioned to withstand the transport costs of reaching these markets. The new Shubarkol-Arkalyk rail line, commissioned in 2014 (currently related infrastructure construction is continuing), significantly improves the infrastructure supporting the export of Shubarkol coal.

The situation with respect to coking coal, for which there is a more specialized market, could prove more favorable (e.g., if there is a recovery in demand for coking coal in metallurgical plants in Russia). Coking coal exports appear to have increased from 0.9 MMt in 2013 to 3.4 MMt in 2014. However, the quantities involved are considerably less than for energy coals.

Given the limited prospects for a rapid expansion in coal export volumes, industry officials are exploring options for the further utilization of coal in Kazakhstan's domestic economy. The potential benefits are not restricted to retaining jobs and economic vitality in the coal-producing regions. Synthetic liquids production may make it possible for Kazakhstan to utilize its abundant coal deposits to produce more of the refined oil products (e.g., gasoline, diesel) it currently imports from Russia. The concluding section of this chapter, which explores the outlook for coal longer term, examines some of these options.

8.7. Coal Mine Methane

Partly because of the negative environmental externalities associated with coal production and use, as well as the difficulties of transporting coal to Russia and other markets, research on the potential for utilizing coal mine methane (CMM) and coal-bed methane (CBM) as an energy source is underway.[14] Kazakhstan's coal mines are particularly gassy, and CMM accumulates to potentially dangerous levels (18–24 m^3 per ton on average, with concentrations up to 33 m^3 per ton) in deep coal mines such as those in the Karaganda basin, making its removal ("drainage") an important safety imperative. The ability to utilize the gas in some way, rather than simply releasing it into the atmosphere, would thus contribute to a reduction of some of the GHG emissions associated with coal mining.

A pre-feasibility study of coal mine methane drainage and utilization was recently completed in the Karaganda basin. The study was sponsored by the U.S. Environmental Protection Agency[15] and targeted six of the eight underground coal mines in the basin owned and operated by ArcelorMittal, also the owner of the large Karaganda steel mill. The assessment concluded that CMM quality in the mines is not sufficient at current gas market prices to support projects for CMM enrichment for pipeline, compressed natural gas (CNG), or LNG applications.[16] Nor was the necessary infrastructure in place to make CMM projects based on district heating, industrial raw CMM use, or slurry drying practical. However, the study did conclude that small-scale electrical generation at the sites of production (mines) could be feasible. More specifically, it recommended implementation of a three-stage power generation project that would involve the construction of several small (2–12 MW) power plants, each at a single mine, using fuel collected from multiple gas extraction facilities at each mine.[17] A standard discounted cash flow model estimated that cash flow would become positive in the fifth year of the (10-year) project, with a 10-year return on investment (IRR) over 13%. As the next step, it recommended that the company undertake a full economic feasibility analysis of

[13] A joint statement by Ukrainian President Petro Poroshenko and Kazakhstan's President Nursultan Nazarbayev in December 2014 announced an agreement in principle to begin exports of an unspecified quantity of Ekibastuz coal to Ukraine.

[14] Although the distinction is at times somewhat vague, CMM refers to methane in operating and abandoned mines, whereas CBM is methane residing in undeveloped coal deposits, which is accessed via wells like conventional gas production. This section follows this convention, except when the discussion is about the total methane resource (both in mines and undeveloped deposits); in the latter case the term CBM is used.

[15] Arcelor Mittal Coal Mines Karaganda Coal Basin, Kazakhstan: Pre-feasibility Study for Coal Mine Methane Drainage and Utilization. Washington, DC: U.S. Environmental Protection Agency, April 2013.

[16] The methane concentration in most CMM deposits at Karaganda ranges from 15% to 40%, whereas gas processing to pipeline quality is not commercially practical below 50% methane, and the typical threshold for gas cleaning in the US is 70% methane (ibid., p. 7).

[17] At the time of the study, CMM already apparently was being extracted from one mine (Kazakhstanskaya) and used as a boiler fuel for operations in neighboring mines.

electric power generation at the six mines, and to ascertain whether the project could be assisted by any national incentives toward carbon emissions reduction.

Switching the focus now to the total methane resource in mined and unmined coal deposits (referred to here as CBM), preliminary estimates indicate that the inferred resource (gas initially in place) could be as large as 3 trillion cubic meters (Tcm). Not all of this is recoverable at current levels of technology, but to place this in some context, Kazakhstan's conventional proven natural gas reserves are estimated at 1.3 Tcm and proven+probable natural gas reserves at 3.9 Tcm. Some 490 billion cubic meters (Bcm) of CBM is believed to exist above a depth of 1500 m at Karaganda alone. The CBM resource at Ekibastuz is less well studied. Concentrations averaging 21.4 m^3 per ton of coal are believed to lie at depths of 70–340 m.

CBM in some regions of Kazakhstan has sufficiently high methane content to allow its use as a close alternative to natural gas. Its potential appears to be greatest in areas near sites of coal production that are not yet served by the national gas pipeline network—i.e., in much of northern, central, and eastern Kazakhstan. If production and consumption of CBM is monitored so as to keep leakage into the environment to an acceptable level (Chapter 13 points out that methane is a much more potent heat-trapping gas than is carbon dioxide), this should support Kazakhstan's efforts to diversify the fuel mix in this region. At the very least, continuing progress toward the capture of escaping CMM at existing mines represents a major opportunity for Kazakhstan to reduce its greenhouse gas emissions.

Whether CBM might ultimately provide the solution to higher-order energy challenges, such as the gasification of the Karaganda region or even Astana, remains an open question. As noted above, the resource base is still being studied, and it is not clear yet whether CBM resources in suitable proximity to potential consumers have sufficiently high methane content for pipeline transmission, CNG, or LNG applications. Nor is it clear whether existing commercial-scale extraction technologies utilized elsewhere in the world will prove viable in Kazakhstan.[18] A preliminary methane extraction well drilled 800 m into the Taldykuduk coal deposit in central Kazakhstan was unsuccessful, and further tests are being conducted.

Coalbed Methane Production in Global Context

The production of coalbed methane (CBM) began as a safety measure to extract methane—an explosion hazard—from coal prior to mining. And once deep-shaft coal mines become operational, methane recovery—often referred to as coalmine methane (CMM)—remains an integral part of the standard mining technique of degassing. The volumes of methane recovered from mines are generally relatively small and can be used to support the coal mining operations (e.g., in mine power generation).

Unlike dry or associated natural gas, methane in coal is not trapped under pressure in the coal-bearing strata. Moreover, less than 10% typically exists as "free" gas within fractures and joints. Rather most CBM is adsorbed within the micro-porous matrix of the coal itself.

These properties mean that when the methane itself is viewed as the resource to be developed (and not the coal), it is commonly extracted using a enhanced recovery techniques similar to the hydraulic fracturing now responsible for the rapid rise in unconventional oil and gas production, although the mechanics and rates of flow of the gas to the production wells are different. A fracturing fluid (typically water but sometimes also acids and other additives) and a "proppant" (an agent that props open the fractures, typically sand, after the injection fluid is removed) are injected into the targeted coal zones at high pressure. The technology generally enlarges already existing fractures (or "cleats") present in the coal, and increases the connections between natural fracture networks and between these networks and the production wellbores. Because CBM itself is not trapped under high pressure, the mechanism for inducing methane flow from the fractured horizons is the removal of significant amounts of formation water to the surface, in order to sufficiently reduce the subsurface hydrostatic pressure to a point (close to normal atmospheric pressure) where the methane can desorb from the coal. Methane then flows via the fractures to the network of production wells. Unlike the production of conventional natural gas, in which the output of gas is initially high before becoming progressively depleted as the water cut increases, the proportion of water to CBM is initially high but declines over time as CBM production increases (most of the gas is recovered during the last 50% of the pressure drawdown).

The economic feasibility of CBM production depends on a number of factors. Some of these are directly related

[18] An international forum was held in July 2014 to explore options for the development of a coal-based gas industry in Kazakhstan (and in particular for the gasification of Astana and Karaganda), with the primary objective of investigating how best world practice could reduce costs (see "Coal Bed Methane in Kazakhstan," World Coal, 23 July 2014).

to the specific character of the coal deposit, including gas content, seam thickness and depth, permeability (ease of flow of gas through the coal matrix), and water chemistry and disposal volumes. Other factors include access to potential markets via pipeline (CBM is over 90% methane, and is generally suitable for introduction into a commercial pipeline with little or no treatment) or as CNG or LNG, as well as the availability and price of competing fuels, such as natural gas. In what follows, we discuss several of these interrelated factors in greater detail, before investigating how they have influenced production decisions in major countries already producing CBM on a commercial basis or poised to do so in the near future.

Gas content is in general positively associated with the rank or grade of coal, being relatively low for lignite, but rising through the sub-bituminous and bituminous grades, and reaching its highest levels for anthracite. Reflecting this gradient (degree of compression), the average CBM content of US coals, for example, ranges from roughly 2.8 to 22.6 cubic meters/ton. Depending on other conditions, the lower bound for net positive return (NPV) in the US ranges from 3.5 to 11.3 m^3/t), with 7.0 m^3/t sometimes being used as a crude benchmark for profitability. However anthracite, at the upper bound of the compression gradient, is very dense and consequently has very low permeability, making it difficult to fracture. Thus, the most favorable coal grades for CBM development tend to lie in the middle of the coal spectrum (sub-bituminous and bituminous).

All things being equal, thicker coal seams are more economic than thinner ones; although individual coal beds should ideally have a minimum thickness of 1 m, a sequence of coal beds measuring at least 10 m in cumulative thickness is often considered a minimum commercial requirement, and the optimal thickness is more than 25 m. Similarly, deposits at shallower depths from the surface are more economic than those at greater depths. Near-surface deposits can be exploited using simpler technologies at lower drilling cost, and at higher well densities. Depth is also related to permeability; higher pressures at greater depths tend to reduce open space within the coal matrix (closing fractures), thus making it less permeable and reducing flow rates during gas recovery. This reduced permeability typically means that optimum CBM production comes from coal seams at depths above 1500 m.

Unlike conventional oil and gas, CBM cannot be extracted without producing a large amount of water (the formation water already present in the coal in large quantities as well as the fraccing fluid when the hydraulic fracturing method is employed). In some formations, such as the Powder River basin in the US, the production water is potable and can be used in agriculture (e.g., for livestock) or can be discharged directly into watercourses. However, more commonly production water contains a variety of mineral salts, chemicals, and sometimes also heavy metals and radionuclides. In such cases, a disposal strategy is necessary (e.g., reinjection or storage in collection ponds) to mitigate adverse environmental impacts. Thus a high water content in coal formations affects production economics both by increasing costs (of pumping, environmental remediation, and storage/reinjection) and by lowering gas content (by reducing gas storage capacity).

Approximately 70 countries worldwide have coal-bearing regions, and roughly 20 have undertaken active CBM drilling programs at one time or another. The bulk of commercial production is currently from four countries (US, Australia, Canada, and China). The United States pioneered commercial CBM production during the 1980s, when energy security concerns and high oil and gas prices spurred the US Government to promote the development of unconventional energy sources through a system of tax credits and incentives. In recent years, total US production has fluctuated between 45 and 55 billion cubic meters (Bcm), and accounts for roughly 7% of total US dry gas production.[19]

Australia initiated commercial CBM production much later (1996), but had been increasing output rapidly until 2011. Deposits in the Bowen and Surat basins of Queensland and New South Wales (NSW) accounted for a national output of 4 Bcm in 2008 and 6 Bcm in 2011, by which time CBM accounted for roughly 10% of the country's total dry gas production. Recently, the constraints to continued production growth have been regulatory rather than geological in nature. In 2011, a new state government in NSW, concerned about the environmental risks posed by CBM production to surface and ground water, placed a 17-month moratorium on all CBM hydraulic fracturing activities. This moratorium ended when the government introduced a new suite of CBM regulations that significantly increased the regulatory burden and costs associated with CBM development in NSW. Then in March 2014, after leaks from a fraccing fluid evaporation pool at the Santos Pilliga site, the NSW government imposed a six-month moratorium on the issuance of new exploration licenses and an audit of all existing licenses. These measures are expected to slow the rate of Australia's production growth until a more stable and predictable regulatory environment can be put in place in NSW. Nonetheless, because most current production is in Queensland and not NSW, national output in 2014 had increased to 8.9 Bcm.

[19] The San Juan basin (Colorado, New Mexico), which has the largest reserves and accounts for the most production (53% of total output), has a favorable combination of high gas content, permeability, and relatively thick (15 m average) seams. In the Powder River basin (Wyoming, Montana), lower gas concentrations of sub-bituminous coals are offset by thicker seams (30 m) located closer to the surface (125–300 m). In the Black Warrior basin (Alabama) seams are thinner (typically 1 m or less), but coal grade, depth, permeability, and gas content are favorable; production here has also benefitted from market access and extensive use of enhanced recovery methods (e.g., fracturing, multizone completion, computer simulations) and water management techniques.

Canada is another country that has ramped up CBM production rapidly—from only about 1 million cubic meters (MMcm) in 2003 to 5 Bcm a decade later. Commercial production is currently limited to the province of Alberta, where there are currently over 6000 CBM production wells operating in two production basins. Roughly 85% of current production occurs at favorable depths of between 200 and 1000 m in coals of the Horseshoe Canyon and Belly River formations. These formations have up to 10 major sub-bituminous coal zones of moderate gas content and permeability (well output averages about 3.4 thousand cubic meters [Mcm] per day), with cumulative seam thicknesses of 15–20 m, and are dry and hence require no dewatering (recovery is stimulated using nitrogen). Production also has extended to portions of the Mannville formation, where sub-bituminous to bituminous coals lie at greater depths, at 500–2000 m. Due to the greater depths and a saline water removal requirement at some sites, development costs are higher, but are compensated by a higher gas content and permeability (and hence higher well production rates of 14 Mcm per day), and seams that are up to 15 m thick.

China, another major producer, appears to have averaged between 1.5 and 2 Bcm of CBM in recent years, less than 2% of the country's total dry gas supply (CMM production, at ~6 Bcm, is considerably greater). However, CBM volumes could increase to 10–20 Bcm by 2020. Almost one-third of China's economically recoverable resource is located in the Ordos basin, in the north-central part of the country. Coal seams here typically lie at considerable depth (1000 m), so relatively low permeability is an issue. Most of China's current production, however, is from the Qinshui basin in Shanxi province, where proximity to the West-East gas pipeline (affording access beyond local markets) is a major driver. Pipeline access is an important issue that will affect the scale of CBM development. China's national oil companies own and operate the country's major trunk pipelines, whereas production and exploration rights for CBM are held by PetroChina, China United Coal Bed Methane, and smaller players. Operations not of sufficient size to negotiate access (and build feeder lines) to these trunk pipelines will likely be "stranded," perhaps in local CNG and LNG markets. Thus government and industry coordination will be necessary to accommodate a large-scale build-out.

In Russia, no commercial CBM output is yet forthcoming, but an ongoing geological exploration program has revealed that the country possesses the world's largest CBM resource (84 trillion cubic meters [Tcm] down to a depth of 2000 m), and the world's largest explored CBM basin, Kuznetsk (>13 Tcm), which is the main focus of attention. Russia's Gazprom is charged with exploring and producing the resource, and the goal, as in north-central Kazakhstan, is to supply a gas-starved, industrialized, coal-producing region (Kuznetsk) with an alternative, cleaner fuel. In 2003, Gazprom Dobycha Kuznetsk was granted a license to prospect, explore, and produce CBM within a group of coal fields in the southern Kuznetsk basin. In 2008–2009, eight wells were drilled in the basin's Taldinskoye field at depths of 600–1000 m, and in 2010 a pilot project was launched to produce CBM for use in local vehicle fueling stations (CNG) and to power two small electrical generating plants. In 2012 a plan for the commercial development of the southeastern part of the Taldinskoye field was approved, and field development work is now under way, including drilling 14 production wells. According to Gazprom, the plan is to slowly ramp up production from Taldinskoye (and perhaps other sites), so that total Kuzbas output rises from the 20 mcm characterizing Taldynskoye's pilot phase to 2.1 Bcm in 2016, 3.1 Bcm in 2017, and roughly 4 Bcm once first-phase development in the southern Kuzbas is completed in 2021. CBM output ultimately could grow to as much as 18–21 Bcm over the longer term.

Kazakhstan, like Russia, is in the process of both identifying prospective sites for commercial CBM production and applying the appropriate technologies for methane extraction at these sites. According to preliminary assessments, the country has about 3 Tcm of inferred CBM resources. As discussed elsewhere in the report, CBM is being considered as one possible solution for the gasification of the Karaganda region as well as of the capital, Astana, and most plans for its commercial development have this goal in mind. The methane resource base of the surrounding region is still being studied, and it is not clear yet whether CBM resources in suitable proximity can be developed on a commercial basis for pipeline transmission or for CNG or LNG applications. An international forum was held in July 2014 to explore options for the development of a coal-based gas industry in Kazakhstan (and in particular for the gasification of Astana and Karaganda), with the primary objective of investigating how best world practice could reduce costs.[20]

Two fields have recently been the focus of attention. The Taldykuduk field in central Kazakhstan is located on a southern extension of the Karaganda syncline in an area with rather complex geology that initially was thought to provide high gas content and permeability.[21] The field overall has 20 coal seams, 17 of which are of working thickness (ranging from 1 to 6.3 m), with a cumulative thickness of 47 m. Depths also fall within the potentially commercial category, ranging from 200 to 700 m. Methane content increases from 10 m^3/ton at 200 m to 23 m^3/ton at 700 m. However, the drilling of a single extraction well in 2013–2014 was unsuccessful (in the absence of enhanced recovery techniques), and further tests are now being conducted.

The potential of the Sherubay-Nurinsky area on a northeastern extension of the same Karaganda syncline also is being actively explored. The coal seams here lie at greater depth (700–1500 m), and 15 of the 20 seams

[20] See "Coal Bed Methane in Kazakhstan," World Coal, 23 July 2014.

[21] N.S. Umarhajieva, R. K. Mustafin, and E.G. Alexeev, "Central Kazakhstan Coal-Fields Potential for Development of Coalbed Methane Production Projects," n.d. http://www.coalinfo.net.cn/coalbed/meeting/2203/papers/coal-mining/CM025.pdf.

are of workable thickness (cumulative thickness is 37.6 m). The gas content of the seams is rather stable and increases gradually with depth (from 24 m^3/ton at 700 m to 27 m^3/ton at 1500 m). In April 2015, KazTransGaz and the Saryarka Social-Entrepreneurial Corporation launched a pilot project to explore and subsequently develop the methane resource at Sherubay-Nurinsky. Preliminary data indicate the area may contain a potential resource of 50 Bcm. Exploration will take place in 2015–2017; this will be followed by a production phase if the results prove favorable.

In terms of some of the basic parameters used to assess potential commerciality, the areas being considered for CBM development in Kazakhstan do not appear to differ substantially from deposits already being exploited commercially elsewhere in the world. The challenge, as noted above, will be finding suitable matches between extraction technologies and the geological characteristics of particular deposits. A further challenge, as with natural gas, is the build-out of transmission and distribution infrastructure to deliver the gas to potential demand centers.

Despite the limited commercial experience to date, CBM does have potential advantages vis-à-vis long-distance pipeline gas as a supply source for Astana or other urban centers in north-central Kazakhstan. Distances between sites of production and markets are less (on the order of 100–200 km) as opposed to the now-suspended Kartaly-Astana natural gas pipeline project (830 km), thus making liquefaction and LNG delivery by rail or truck a possible option (see Chapter 7.3.7).

8.8. Coal Balance Outlook to 2040

Examination of Kazakhstan's coal balance between 1990 and the present, and estimates out to the end of our forecast period in 2040 (Table 8.4), reveal a number of important trends. Coal production slowly declines from the current levels of 108.7 MMt to 86.9 MMt in 2040. Apparent consumption follows a similar trajectory, slowly declining from 82.7 MMt in 2014 to roughly 70 MMt in 2040. These trends are consistent with an outlook for the economy of gradually utilizing energy more efficiently (Chapter 11), that gas use will slowly increase, and that some nuclear generation capacity will eventually come on line after 2025 (see Chapter 10). All of these developments will exert downward pressure on coal consumption. Despite the challenging environment, exports ("net imports" in the table 8.3; see note 4 in this chapter) remain relatively stable until almost 2030, building upon the current coal trade between Russia and Kazakhstan and its possible continuation within the Eurasian Union. The intrinsic economic competitiveness of Ekibastuz coal in the southern Urals (vis-à-vis Kuzbas coal and other fuels) should allow it to maintain a niche in this market at least over the medium term.

The breakdown of coal consumption by economic sector in Table 8.4 highlights several trends discussed earlier in the chapter. Consumption should hold steady near present levels in the electric power sector in the period out to 2025, before tapering off subsequently (average annual growth for the entire period of 2015–2040 is -0.7%) (see Chapter 10 for more detail). Consumption in industry and agriculture exhibits a somewhat similar trend, with moderate average annual rates of growth over the period 2000–2020 (~3%) tapering down to much smaller rates (below 1%) during 2015–2040. Domestic (residential) sector consumption displays a somewhat different trend, transitioning from very high rates of growth during the 2000s (off of a low base) to a long-term secular decline as households switch to more convenient fuels, such as piped gas or LPGs. As a result of these countervailing trends in the individual sectors of the economy, the electric power sector's share in overall coal consumption in the economy remains remarkably steady going forward, at about 60% through the remainder of the projection period.

Alternative Uses of Coal as a Fuel

Coal Gasification

- **Process.** Oxidation of coal through combustion in the presence of steam.
- **Product.** So-called "syngas"—a combination of CO and H_2.
- **Applications.** Gaseous fuel that can be (a) burned to generate heat or power either in a gas or a steam turbine or (b) used as a feedstock in liquid fuels production via the Fischer-Tropsch process.
- **Limitations.** Difficulty in competing with natural gas on a price basis (its energy density is only about half that of natural gas); has an efficiency rate of 40% versus 57% for natural gas in a combined-cycle gas turbine, and also requires additional infrastructure (coal treatment facilities, gasification units), significantly adding to costs. Moreover, for transmission via the existing natural gas pipeline network, certain processes must be incorporated into the syngas production train so that the methane content can be elevated to the

point where syngas can be fed into the network.

Synthetic liquid fuels

- **Processes.** Indirect liquefaction, coal pyrolysis, or coal hydrogenation; indirect liquefaction via Fischer-Tropsch synthesis, pioneered on a large scale in the 20th century by Germany and South Africa, most widely used; involves conversion of syngas produced by coal gasification into liquid hydrocarbons.
- **Products.** Synthetic oil and oil products, including gasoline and diesel.
- **Applications.** Similar to those of natural oil and oil products (vehicle fuels, lubricants, chemical feedstocks).
- **Limitations.** Unlike conventional technologies used for liquid petroleum products, synthetic products require substantial amounts of hydrogen which is typically derived from water. Taking into account the problems with water supply in the Republic of Kazakhstan, this factor is critical for production planning, since all the water used in production is non-recoverable.

Coal-water slurry

- **Process.** Fine coal fractions (including from lignite) are milled and blended with water and a stabilizing agent.
- **Product.** A slurry of coal (60–70%) and water (30–40%) delivered to end-users by pipeline or tanker truck.
- **Application.** Replaces heavy oil (mazut) as a boiler fuel for low-capacity consumers.
- **Limitations.** Currently not competitive with natural gas on a price basis (due to additional post-extraction costs of coal milling and slurry preparation); high water consumption.

The projected volumes of coal production and consumption in our coal balance outlook to 2040 are constrained by: the challenging environment for exports described above; Kazakhstan's official commitment to reducing greenhouse gas emissions (described in Chapter 13); and the experimental nature of alternative uses for coal, such as coal gasification, synthetic liquid fuels production, and coal-water slurry (see text box: "Alternative Uses of Coal as a Fuel"). Any technological breakthrough in the latter (alternative uses) could potentially raise projected volumes of demand, providing the environmental costs are acceptable. This is especially the case with synthetic liquids production, which has the potential to reduce Kazakhstan's imports of refined products such as gasoline and diesel from Russia (see Chapter 7.4) through their replacement by domestically produced coal-based synthetic equivalents.[22]

Progress in alternative uses notwithstanding, the balance of coal production and consumption in Kazakhstan appears to be closely linked to electric power generation for the foreseeable future. This reflects the inertia built into the structure of the electric power sector (where 64% of capacity is coal-fired; see Chapter 10). Even with the continued gradual growth in gas-fired power generation and the phasing in of some renewable and nuclear capacity, coal will remain the dominant fuel in the power sector through the end of the outlook period.

[22] A more prosaic use of brown coal (and indeed potentially of hard coal fines recovered from waste dumps and tailings ponds [see Chapter 13.2.4.3]) is crushing and compression into blocks (briquettes) of varying size and shape that are still widely used in some countries (i.e., China, Korea, Vietnam) for residential cooking and heating. Due to the already low costs of briquettes in these markets (and the fact that they can be fabricated from a variety of locally ubiquitous materials such as recycled paper, wood charcoal, sawdust, and rice and peanut chaff), it is difficult to envisage how coal briquettes exported from Kazakhstan would be competitive.

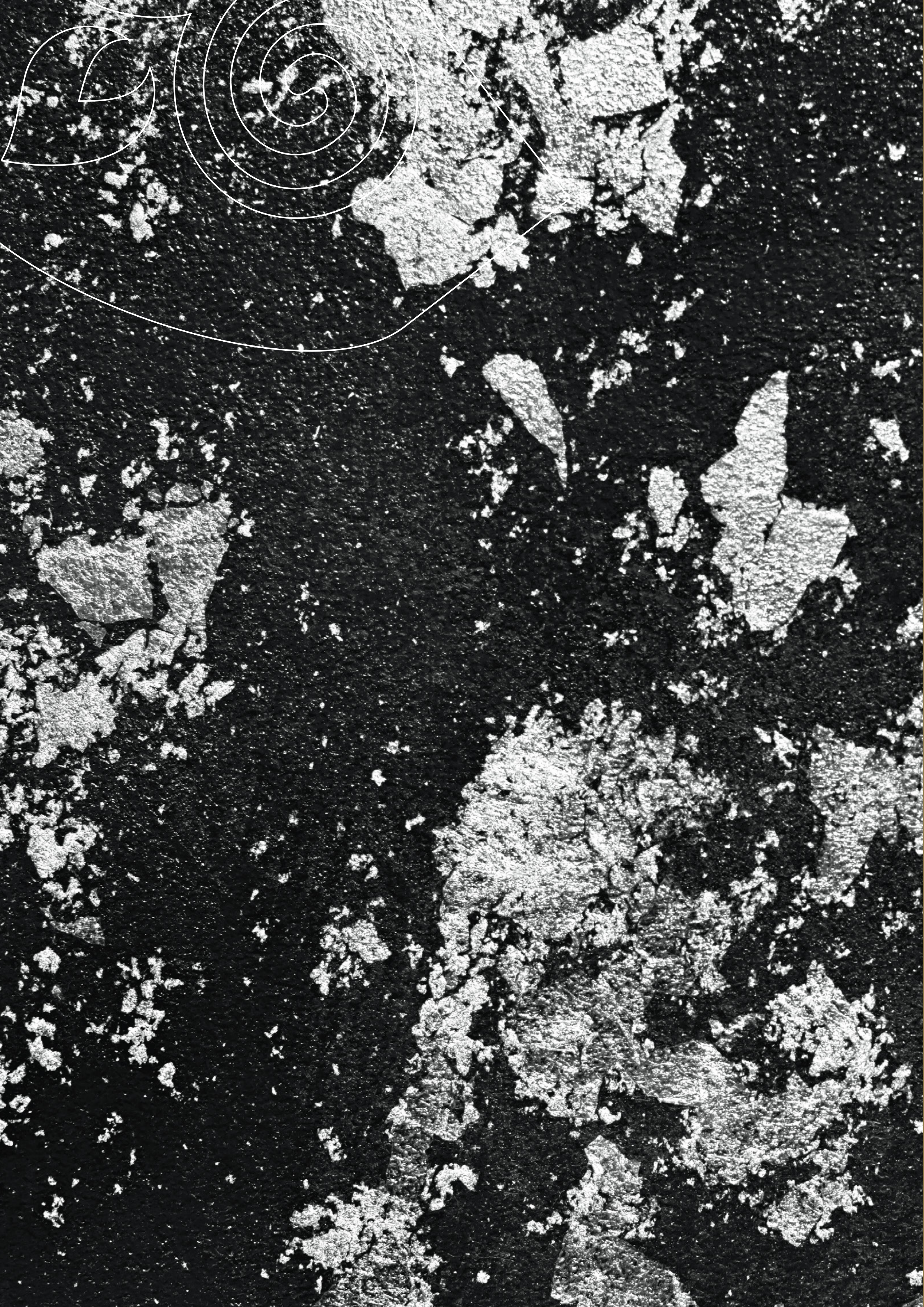
Key Recommendations

- Continue to explore the potential for utilizing Kazakhstan's coal unconventionally, including coal mine methane (CMM), coal-bed methane (CBM), and other coal utilization options, such as synthetic liquid fuels production, coal slurry, briquettes, etc. as a promising way of using more of Kazakhstan's low-cost coal in the economy.

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

- Continue research on ways to use coal more cleanly and efficiently, especially in power generation by incremental improvements, such as reducing emissions through improving efficiency of fuel utilization. If at least marginal progress can be demonstrated on the carbon footprint, perhaps the timetable for coal's replacement by other fuels can be stretched out.

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



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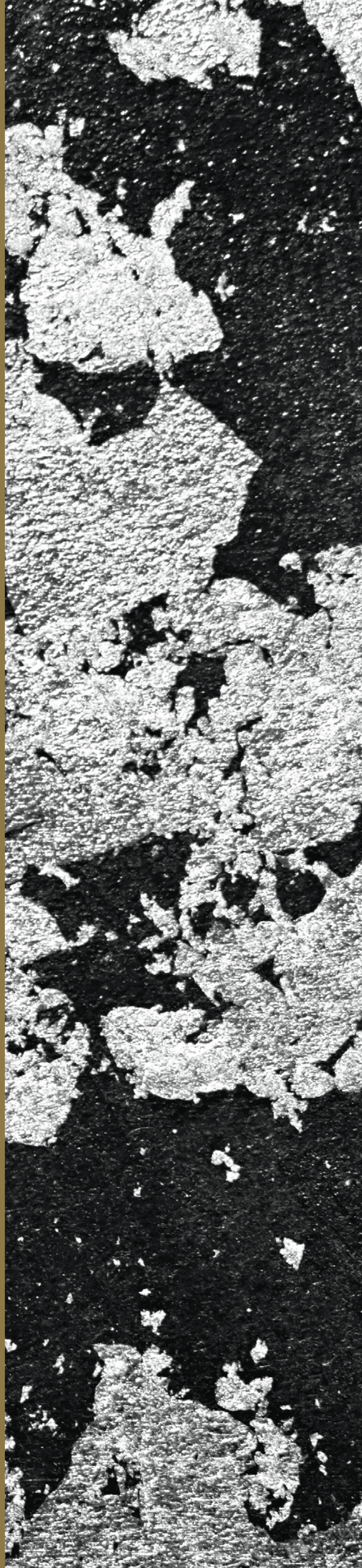


9. Uranium

9.1. Key Points

- While it has not yet re-established its domestic nuclear generation capacity (a nuclear plant was in operation in the country 1973–1999), Kazakhstan is a leading resource holder and the world's largest producer of natural uranium, accounting for more than one-third of global production. All of this output ultimately is exported, primarily to China, but also to the EU, South Korea, and United States.

- Kazakhstan's competitive advantage is that most of its reasonably assured and inferred resources of uranium are held in sandstone deposits that are developed through the in-situ leaching production method, which is more cost-effective and less environmentally harmful than traditional (hard-rock) production methods.

- Unlike the situation with certain other energy commodities that Kazakhstan exports, Kazakhstan to date has found ready markets for its uranium, expanding exports as rapidly as it can grow production. Global demand for uranium is expected to increase to 2035 under virtually any economic scenario, reflecting increased nuclear generation of electricity. However, Kazakhstan's recent export growth has coincided with a rapid demand surge in China, which may not be sustainable after the latter country's inventory build-up is completed.

- Kazakhstan is not presently represented in all stages of the nuclear fuel cycle. It currently undertakes mining and primary processing of uranium after which uranium concentrate is then sent to Russia for conversion and enrichment, before being returned for production of fuel pellets, while production of the following fuel components (fuel elements [rods] and fuel assemblies) in Kazakhstan is unavailable. Current fuel pellet production capacity utilization is no more than 1-2% of the design capacity, since in 2008 Russia stopped buying pellets in favor of its domestic producers. Fuel pellet production capacity underutilization (Ulba Metallurgic Plant - UMP) constitutes the basic problem of the uranium industry in Kazakhstan.

- Several joint initiatives have been undertaken over the past years in order to develop facilities in Kazakhstan for conversion and reactor fuel assembly production, in order to increase the value-added component in uranium products and to utilize fuel pellet production capacities. In 2014, an agreement was reached between JSC NAC Kazatomprom and China General Nuclear Power Corporation (GGNPC) stipulating construction of a UMP-based plant to produce fuel assemblies. The plant's production capacity will be 200 tons per year with possible further expansion.

- Kazakhstan proposed an initiative to host an IAEA Nuclear Fuel Bank[1] on its territory to provide open access to low-enriched uranium for the countries developing a nuclear power industry, to build a fuel inventory, and to strengthen the nuclear nonproliferation regime. In 2015, Kazakhstan and the IAEA reached the final agreement on locating the Nuclear Fuel Bank in Kazakhstan (at UMP). Since an agreement on the Iranian nuclear issue has been reached, it has become possible to source low-enriched uranium from Iran to build up the Nuclear Fuel Bank inventory.

- The country is also actively planning for the development of the nuclear power industry with construction of one or more new nuclear power plants (NPPs) to support, among other things, domestic consumption of nuclear fuel. Taking into account that the town of Kurchatov holds a unique nuclear research and nuclear power base, Kazakhstan may consider the initiative to establish an international platform for development and construction of pilot "fourth generation" reactors. This initiative will allow Kazakhstan to become a significant player in the knowledge-intensive and high-tech nuclear industry.

9.2. Uranium Reserves

In terms of reasonably assured resources (RARs)—the category used by the International Atomic Energy Agency and the OECD's Nuclear Energy Agency, and approximately corresponding to the A+B+C1[2] reserves category used in the CIS states—Kazakhstan is the world's fourth largest reserves holder with 0.4 million metric tons (MMt) of uranium (8% of the world's total), trailing only Australia, the USA, and Canada (which hold 1.2, 0.5, and 0.4 MMt respectively; see Table 9.1). However, considering only resources that cost less than \$80 per kilogram (kg) of uranium to produce (which is an equivalent of \$31 per pound of U_3O_8),[3] Kazakhstan has the world's second largest reserves, at 0.2 MMt (16.5% of the world's total), lagging behind only Canada, with 0.3 MMt. In terms of inferred resources (IRs)—the category corresponding to the C2 reserves category used in Kazakhstan—the country holds a total of 0.5 MMt (17% of the world's total), which is second to Australia's 0.6 MMt. Taking into consideration only those resources that cost less than \$80 per kg to produce, Kazakhstan has the world's largest resource position, at 0.3 MMt (42% of the world's total; Table 9.2).

[1] With a storage capacity up to 90 tons of low-enriched uranium hexafluoride.

[2] According to Geology Committee data from 1 January 2015, A+B+C1 uranium reserves amount to 344.4 thousand tons (balance sheet reserves [recoverable reserves] amount to 928.5 thousand tons).

[3] In early February 2015, the world spot market price for uranium was ~\$37.50 per pound (or \$82.50 per kg). Although over 80% of uranium sales occur under long-term (3 to 15 year) contracts with a more stable price than that of the spot price, contract prices are nonetheless linked to the spot price at the time of shipment. Therefore the \$80 per kg price can be viewed as a rough approximation of a "break-even" price for mine production at current levels of demand.

Country	Cost ranges			
	<USD 40/ kgU	<USD 80/ kgU	<USD 130/ kgU	<USD 260/ kgU
Kazakhstan	20,400	199,700	285,600	373,000
Canada	256,200	318,900	357,500	454,500
Brazil	137,300	155,100	155,100	155,100
South Africa	0	113,000	175,300	233,700
China[e]	51,800	93,800	120,000	120,000
Mongolia	0	108,100	108,100	108,100
Russian Federation[c]	0	11,800	216,500	261,900
Uzbekistan[*]	41,700	41,700	59,400	59,400
Ukraine	0	42,700	84,800	141,400
Tanzania[*e]	0	38,300	40,400	40,400
Argentina	0	5,100	8,600	8,600
Slovak Republic[c,e]	0	8,800	8,800	8,800
Slovenia[d,e]	0	1,700	1,700	1,700
Turkey[c,e]	0	6,800	6,800	6,800
Peru[d,e]	0	1,400	1,400	1,400
Italy[d]	0	4,800	4,800	4,800
Portugal[d]	0	4,500	6,000	6,000
Niger[*]	**0**	**14,800**	**325,000**	**325,000**
Namibia[*]	**0**	**0**	**248,200**	**296,500**
Australia			1,174,000	1,208,000
United States	0	39,100	207,400	472,100
Central African Republic[*]	**0**	**0**	**32,000**	**32,000**
Japan[d]	**0**	**0**	**6,600**	**6,600**
Mexico[b,e]	**0**	**0**	**2,900**	**2,900**
Finland[d,e]	**0**	**0**	**1,200**	**1,200**
World total[f]	**507,400**	**1,211,600**	**3,698,900**	**4,587,200**
Cumulative reserves	11.1	26.4	80.6	100
Reserves life, years	8.5	20.3	62	76.9
Kazakhstan, % of total	4	16.5	7.7	8.1

[a] *Recoverable resources as of 1 January 2013, rounded to nearest 100 tons.*
[b] *Not reported in 2013 responses, data from previous Red Book.*
[c] *Assessment within the last five years.*
[d] *Assessment not made within last five years.*
[e] *In situ resources were adjusted by Secretariat to estimate <USD 260/kgU category.*
[f] *Totals related to cost ranges <USD 40/KgU and <USD 80/kgU are higher than tables because certain countries do not report low-cost resource estimates, mainly for reasons of confidentiality.*
[*] *Secretariat estimate.*

Source: International Atomic Energy Agency (IAEA) and OECD Nuclear Energy Agency, Uranium 2014: Resources, Production, and Demand ("Red Book"), 2014.

Table 9.1 Reasonably assured resources (RAR), tons U[a], for selected countries

Country	Cost ranges			
	<USD 40/ kgU	<USD 80/ kgU	<USD 130/ kgU	<USD 260/ kgU
Kazakhstan	68,900	316,000	393,700	502,500
Canada	65,600	99,400	136,400	196,000
Brazil	0	73,600	121,000	121,000
South Africa	0	69,300	162,800	217,100
China[e]	13,900	54,800	79,100	79,100
Mongolia	0	33,400	33,400	33,400
Russian Federation[c]	0	30,500	289,400	427,300
Uzbekistan[*]	24,700	24,700	31,900	31,900
Ukraine	0	16,900	32,900	81,300
Tanzania[*e]	0	8,500	17,700	17,700
Argentina	2,400	4,000	9,900	11,000
Slovak Republic[c,e]	0	3,900	6,700	6,700
Slovenia[d,e]	0	3,800	7,500	7,500
Turkey[c,e]	0	1,900	1,900	1,900
Peru[d,e]	0	1,500	1,500	1,500
Italy[d]	0	1,300	1,300	1,300
Portugal[d]	0	1,000	1,000	1,000
Niger[*]	0	600	79,900	79,900
Greenland	0	0	0	221,200
Namibia[*]	0	0	134,600	159,100
Czech Republic	0	0	100	68,300
Botswana[*]	0	0	56,000	56,000
Jordan[c,e]	0	0	40,000	40,000
Zambia[*e]	0	0	14,700	14,700
Hungary	0	0	0	13,500
Sweden[*d,e]	0	0	4,700	4,700
Malawi[*]	0	0	2,300	4,600
Mali[*e]	0	0	4,500	4,500
Germany[d]	0	0	0	4,000
Romania[*b,d]	0	0	3,600	3,600
Iran	0	0	3,400	3,400

Australia			532,100	590,300
World total[f]	175,500	745,100	2,204,000	3,048,000
Cumulative reserves	5.8	24.4	72.3	100
Reserves life, years	2.9	12.5	36.9	51.1
Kazakhstan, % of total	39.3	42.4	17.9	16.5

[a] *Recoverable resources as of 1 January 2013, rounded to nearest 100 tons.*
[b] *Not reported in 2013 responses, data from previous Red Book.*
[c] *Assessment within the last five years.*
[d] *Assessment not made within last five years.*
[e] *In situ resources were adjusted by Secretariat to estimate <USD 260/kgU category.*
[f] *Totals related to cost ranges <USD 40/KgU and <USD 80/kgU are higher than tables because certain countries do not report low-cost resource estimates, mainly for reasons of confidentiality.*
[*] *Secretariat estimate.*

Source: International Atomic Energy Agency (IAEA) and OECD Nuclear Energy Agency, Uranium 2014: Resources, Production, and Demand ("Red Book"), 2014.

Table 9.2 Inferred resources, tons U[a], selected countries

9.3. Uranium Production

Mine production of uranium (U) in Kazakhstan has risen rapidly in the twenty-first century, increasing from 3.3 thousand metric tons (Mt) in 2003 to 23.1 Mt in 2014, or by 19.4% on average annually! Over the same period, global production of uranium rose from 35.6 Mt to 56.3 Mt, or by 4.3% annually (Table 9.3). As a result, since 2009 Kazakhstan has been the leading world producer, and has been increasing its share of total world production from 28% (2009) to 41% (2014). Kazakhstan's largest entitlement uranium producer is state-owned KazAtomProm: in 2014 it produced 13.1 Mt, which constitutes 57% of the country's total uranium output. The remaining production is largely from mines worked by international joint ventures between Kazakh firms and companies from other countries (e.g., Canada, France, Japan, and Russia).

	Production (tons U), % change									% change
Country or area	**2003**	**2005**	**2007**	**2009**	**2010**	**2011**	**2012**	**2013**	**2014**	**2013–14**
Kazakhstan	3,300	4,357	6,637	14,020	17,803	19,451	21,317	22,567	23,127	2
Canada	10,457	11,628	9,476	10,173	9,873	9,145	8,999	9,332	9,134	-2
Australia	7,572	9,516	8,611	7,982	5,900	5,983	6,991	6,350	5,001	-21
Niger	3,143	3,093	3,135	3,243	4,198	4,351	4,667	4,528	4,057	-10
Namibia	2,036	3,147	2,879	4,626	4,496	3,258	4,495	4,315	3,255	-25
Russia	3,150	3,431	3,413	3,564	3,562	2,993	2,872	3,135	2,990	-5
Uzbekistan	1,589	2,300	2,320	2,429	2,400	3,000	3,000	2,400	2,400	0
USA	779	1,039	1,654	1,453	1,660	1,537	1,596	1,835	1,919	5
China	750	750	712	750	827	1,500	1,500	1,450	1,500	3
Ukraine	800	800	846	840	850	890	960	1075	962	-11
South Africa	758	674	539	563	583	582	465	540	573	6
India	230	230	270	290	400	400	385	385	385	0
Malawi	0	0	0	104	670	846	1101	1132	369	-67
Brazil	310	110	299	345	148	265	231	198	231	17
Czech Republic	452	408	306	258	254	229	228	225	193	-14
Romania	90	90	77	75	77	77	90	80	77	-4
Pakistan	45	45	45	50	45	45	45	41	45	10
Germany	104	94	41	0	0	52	50	27	33	22

France	9	7	4	8	7	6	3	5	3	-40
Total world	35,576	41,179	41,282	50,772	53,663	54,610	58,394	59,673	56,252	-6
Kazakhstan, percent of total	9.3	10.6	16.1	27.6	33.2	35.6	36.5	37.8	41.1	

Source: International Atomic Energy Agency (IAEA) and OECD Nuclear Energy Agency, Uranium 2014: Resources, Production, and Demand ("Red Book"), 2014.

Table 9.3 Uranium production by country, 2003–2014

Of the 74 identified uranium deposits in Kazakhstan, 19 are currently either producing or under development. On a production capacity basis, the largest are North Kharasan (Kyzylorda Oblast) and Moinkum (South Kazakhstan Oblast), which are capable of producing 5 Mt of uranium annually each. This is followed by three deposits in southern Kazakhstan—Budenovskoye, Inkay, and Mynkuduk—each with a production capacity of 4 Mt. The Zarechnoye desposit (South Kazakhstan Oblast), with a production capacity of 2 Mt, and the Karamurun (Kyzylorda Oblast) and Akdala deposits (southern Karaganda Oblast; 1 Mt each) also are large producers. In terms of actual mine output, as opposed to capacity, the largest producers are shown in Table 9.4.

Producer	JV	Deposit	2014
JV Inkai LLP	Kazatomprom-Cameco	Inkai 1+2+3	1 930.3
KATCO LLP	Kazatomprom-Areva	Southern Moiynkum	2 089.5
		Tortkuduk	2 019.9
JV Betpak-Dala LLP	Kazatomprom-Uranium One	Inkai 4	2 001.5
Karatau LLP		Budenovskoye 2	2 083.6
PE Ortalyk LLP	Kazatomprom	Central Mynkuduk	1 805.8

Source: JSC "Kazakh Institute of Oil and Gas"

Table 9.4 Uranium production in 2014 for the largest deposits (tons U)

Nearly 99% of all current uranium mine production in Kazakhstan is from sedimentary (sandstone) deposits utilizing the in-situ leaching (ISL) method, a technology developed independently in the USSR and US in the mid-1970s. This method typically entails pumping a leaching agent (e.g., 1–2% sulfuric acid [H_2SO_4] solution)[4] into a water-saturated permeable ore body via a system of injection wells. At present drilling is at depths no greater than 750 meters, although deeper horizons may be developed in the future. The leaching agent dissolves uranium and the "productive solution" (usually containing less than 0.1% uranium) is then recovered by a network of extraction (or production) wells and undergoes primary processing (where the uranium is removed using an ion exchange resin) before being ready for conversion and enrichment (see section on nuclear fuel cycle below).[5]

The ISL production method has distinct cost and environmental advantages vis-à-vis traditional hard-rock (underground mine and open pit mine) extraction methods. Because the resource is recovered without moving the surrounding rock (overburden), capital costs for extraction (earth-moving) and mine structural costs are greatly reduced if not eliminated, and operating costs are much less as well. For the same reason, impacts on the environment are mitigated. Unlike in open pit and underground mines, the soil surface is barely disturbed, no tailings or waste rock are formed, radon emissions are minimized, and no toxic dust is created. There is the need to dispose of the productive solution (which contains the leaching agent and mine wastewater) after primary processing, however. In Kazakhstan the solution (after being refortified with an oxidant and complexing agent) is returned to the injection wells for reuse (i.e., reinjection into the orebody) and this recycling greatly reduces overall water and sulfuric acid consumption in the process. Any solution not reinjected into the orebody (e.g., a small flow is must be bled off to maintain a pressure gradient in the wellhead) must be treated as waste, as it contains various dissolved elements such as chlorides, sulfates, radium, arsenic, and iron that must be stored at approved disposal sites (e.g., disposal wells in a depleted portion of the orebody).

One of the environmental challenges involving ISL is the need to avoid contamination of groundwater away from the orebody. The pressure gradient maintained at the wellhead helps accomplish this; it ensures a steady flow into the field or orebody from the surrounding aquifer, and restricts the

[4] In the US, the leaching system is not acidic (as in Kazakhstan and Australia), but a less efficient alkaline, primarily carbonate based one (due to the significant quantities of acid-consuming minerals such as gypsum and limestone in the host aquifers).

[5] Discussion of the ISL technology and its environmental and cost benefits can be found in KazEnergy, The National Energy Report 2013. Astana: KazEnergy, 2013, pp. 95–96, 99, 103.

flow of mining solutions away from the mining area.[6] This limits groundwater contamination to the field itself. After ISL mining is completed, wells are sealed or capped, and the quality of the remaining groundwater in the field must be restored to a baseline standard determined before the start of the operation. Upon decommissioning, the usual radiation safeguards should follow, even though most of the orebody's radioactivity remains rather deep underground. Routine monitoring of air, dust, and soil is required.

The favorable prospects for the ISL method as a basis for Kazakhstan's future uranium production are underscored by the fact that 80% of the country's uranium resources are concentrated in sandstone-hosted deposits that can be exploited using this method. One of the economic challenges to expansion of ISL-based uranium production volumes is the need to access large quantities of sulfuric acid: to produce one ton of uranium in Kazakhstan, between 70 and 80 kg of acid is needed, compared to 3 kg in Australia; as a result, the costs of acid constitute somewhere between 15% and 20% of the operating costs for a Kazakhstan uranium producer. Periodic shortages of sulfuric acid have constrained production in the past. For instance, a fire in a sulfuric acid plant in 2007 created shortages that depressed output well into 2009. However, with the construction of a new sulfuric acid plant (SKZ-U), Kazakhstan has now fully met its own demand for sulfuric acid.

Fortunately, Kazakhstan's hydrocarbon extraction and metallurgical industries generate large quantities of byproduct sulfur that can be used as a feedstock for sulfuric acid production. In the oil and gas industry, a rich supply of sulfur is a reflection of the high sulfur content of production at major fields such as Tengiz and Kashagan. TCO, the operator of the Tengiz field, now produces on the order of 2.3 MMt of byproduct sulfur annually, and Kashagan's pilot development program is expected to produce 1.2 MMt annually (see Chapter 7.3.15).[7]

9.4. Uranium Exports

Because Kazakhstan does not presently possess nuclear power generation capacity (only research reactors), all of the produced uranium is exported, primarily under long-term contracts. Unlike the situation with certain other energy commodities that it exports, Kazakhstan to date has found ready markets for its uranium, expanding exports as rapidly as it can grow production. China is the largest importer of Kazakhstan's uranium and accounts for over half (56%) of Kazakhstan's total exports; major importers are China General Nuclear Power Corporation and China Nuclear Energy Industry Corporation. In Europe, which is the second largest buyer, accounting for 18% of Kazakhstan's exports, uranium is supplied to Electricite de France among others. The share of South Korea's KEPCO in Kazakhstan's total uranium exports is 11%, and roughly 4% of exports are destined for the United States (see Figure 9.1). However, in the future, the export situation is somewhat more complicated for Kazakhstan than indicated by the recent picture of steady production and export growth. Kazakhstan's rising exports have coincided with a demand surge in China, which may not be sustainable over the longer term. Reflecting a rapid ramp-up in reactor commissioning, China's uranium consumption increased from only 2 Mt in 2010 to about 7 Mt in 2015; it is expected to be as high as 13 Mt in 2020.[8] Yet China's uranium imports have increased much more rapidly than what is needed to meet this domestic demand growth. The surplus has gone into inventory, and since 2010 the Chinese have undertaken the single biggest uranium inventory build in the world.[9] Between 2010 and 2014, trade statistics show that China imported over 80 Mt of uranium—or an average of 16 Mt annually, 70% of it from Kazakhstan. Additional supplies were sourced from China's domestic mine production—approximately 6 Mt in aggregate for this five-year period. When these increments to supply are compared to China's estimated reactor consumption, the inventory build between 2010 and 2014 appears to be on the order of 65 Mt;[10] depending on the quantity of uranium that may have been in the inventory prior to 2010, China's current inventory could exceed 70 Mt.

The rapid inventory growth can be interpreted as a prudent step to support the nuclear power goals of the State Council's Energy Development Strategy Action, which envisages nearly a tripling of installed capacity between 2014 and 2020 (from 19 GW to 58 GW). This would give China the world's third largest nuclear generation capacity, after the US and France. The large inventory would afford a robust buffer against potential future supply disruptions and, additionally, leverage in future negotiations on long-term delivery contract prices. However, inventory building cannot be expected to continue indefinitely. Thus the question arises as to when and at what level China's imports might be scaled back. In addition to assessments concerning the optimal size of its uranium inventory, China's future imports also will be shaped by other factors, which do not necessarily point to continued rapid Chinese import growth. These include whether China can develop a major fuel reprocessing capacity, thereby lowering import requirements, and how rapidly the Husab uranium mine in Namibia (largely owned by the China General Nuclear Power Corporation) can ramp up mine output, starting in 2016.[11] Estimated volumes that China is currently importing exceed those traded on the world spot market, and consequently have a major effect not just on Kazakhstan's exports, but

[6] Monitor wells are installed above, below, and around the target zones (i.e., portions of the ore body being exploited) to ensure that mining fluids are not migrating outside of the permitted mining area.

[7] Kazakhstan's total production of elemental sulfur was 2.455 MMt in 2014, up slightly from 2.443 MMt in 2013. Production of sulfuric acid was 2.277 MMt in 2014, up 9.4% from 2013.

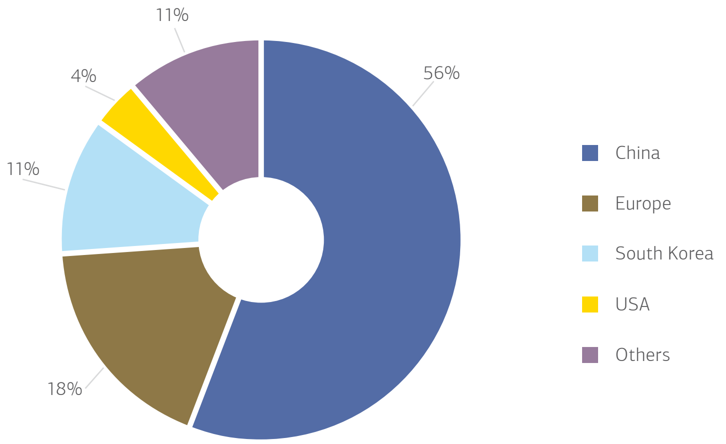
[8] See Steve Kidd, "China-Kazakh Relationship Shapes Uranium Market," Energy Intelligence World Energy Opinion, March 2015.

[9] Reference here is to the civilian inventory of uranium (for power generation, research, medical applications, etc.). As noted below, the size of military (and thus overall) inventories of uranium is not known precisely.

[10] Kidd, "China-Kazakh Relationship Shapes Uranium Market," 2015.

[11] The mine's peak capacity is estimated to be 6 Mt per year.

on the global uranium market. Thus it is not inconceivable that if China's inventory build suddenly slows, something resembling the buyers' market for uranium prevailing after the disintegration of the Soviet Union (when large supplies of weapons-grade uranium entered the civilian market after downblending; see below) could return.



Source: International Atomic Energy Agency (IAEA) and OECD Nuclear Energy Agency, Uranium 2014: Resources, Production, and Demand ("Red Book"), 2014.

Figure 9.1 Kazakhstan's uranium exports in 2013 by destination

9.5. Nuclear Fuel Cycle and Proposed Reactor Construction

The front end of the nuclear fuel cycle encompasses the steps necessary to produce nuclear fuel from raw uranium, and includes production (mining) of uranium oxide, conversion to uranium hexafluoride, enrichment of uranium hexafluoride to increase concentration of the U-235 isotope, reconversion and its transformation to uranium oxide with fuel pellet fabrication, and finally, fuel assembly. Of these stages, only uranium mining, reconversion, and fuel pellet fabrication are currently represented in Kazakhstan.

Kazakhstan is moving forward with plans to enter the conversion segment through joint work between KazAtomProm and Canada's Cameco Corporation, which completed a pre-feasibility study on a conversion facility (refinery) in 2013. The project would require an intergovernmental agreement with Canada that would allow the transfer of Cameco's proprietary uranium refining technology.

Entry into the enrichment segment is being implemented through a 2013 deal between KazAtomProm and Russia's TVEL, whereby a 50-50 joint venture between the two companies acquired 25% plus one share of the Ural Electrochemical Integrated Plant (in Sverdlovsk Oblast, Russia)—the world's largest uranium enrichment facility. Half of the facility's output will be dedicated to processing the joint venture's uranium hexafluoride. In addition to the Urals enrichment facility, some of Kazakhstan's uranium is enriched at the Angarsk International Uranium Enrichment Center (IUEC), in which KazAtomProm has 10% ownership. Thus, over the near term at least, Kazakhstan has pursued a course of securing enrichment capacity by obtaining ownership stakes in plants located on Russian territory that in aggregate account for 45% of global capacity.

Kazakhstan's Ulba Metallurgical Plant (UMP) near Ostkamen (Ust-Kamenogorsk) uses enriched uranium (supplied in the form of uranium hexafluoride) to produce fuel pellets, which until 2008 had been exported to Russia's Rosatom corporation for subsequent use in the production of fuel assemblies for that country's nuclear reactors. With the decline and now suspension of Russian pellet orders, Ulba has shifted toward the conversion of uranium hexafluoride to powder for use in fuel fabrication facilities in other countries.[12] Kazakhstan also intends to launch its own domestic production of fuel assemblies as a further step towards expanding its capabilities along the nuclear fuel cycle. In December 2014 KazAtomProm and China General Nuclear Power Corporation signed an agreement to establish a joint fuel assembly production facility (with a productive capacity of 200 tons per annum and a possibility for further expansion) at UMP.

Finally, initiatives continue to be explored to construct new nuclear power generation capacity on the territory of Kazakhstan. This topic is covered more fully in Chapter 10.7.4. The country's first reactor, the BN-350 at the Aktau Nuclear Power Plant, was the first industrial-scale fast neutron reactor in the world. Cooled by sodium, the BN-350 supplied power and heat to the city of Aktau, and was used to desalinate waters of the Caspian Sea to provide 120,000 m^3 of fresh water daily. The reactor, which began operation in 1973, successfully operated through 1993 (its project lifetime), and continued operations at reduced capacity until 1999.

The Aktau site is one of several locations that have been considered for the construction of a new nuclear power plant. Over the past decade, Kazakh officials have undertaken wide-ranging talks on cooperation in reactor construction with a number of potential partners, including those from Russia, China, Japan, India, and South Korea. Many of the discussions are ongoing, as the plan is not necessarily con-

[12] During Soviet times, the UMP supplied up to 80% of the fuel pellets' needs of nuclear power plants in the USSR.

fined to the construction of a single nuclear power plant. The talks reflect the Kazakhstan government's plans for nuclear power to reach a certain share in the total electric generating capacity by 2030.

Talks appeared to be quite advanced between KazAtomProm and Rosatom (Russia's nuclear energy company), based on the use of VBER-300 reactors and focused on the site at Aktau: KazAtomProm's proposal to the government for construction of a power plant at Aktau was accepted.[13] However, due to the ownership and copyright (VBER-300 reactor design) issues, the project was suspended.

Kurchatov (the administrative center of the closed Semipalatinsk nuclear test site in East Kazakhstan Oblast) has now become perhaps the leading candidate for the construction of NPPs with VBER-300 reactors.[14] It should be noted that the town of Kurchatov hosts a unique nuclear research base with high human resource potential. The research centers, including research reactors and test facilities, were built in Kurchatov within the framework of the Soviet program to create a high-temperature nuclear rocket engine. Kurchatov's unique research base and human resource potential as well as its location within the Semipalatinsk nuclear test site allow Kazakhstan to involve countries developing new "fourth generation" reactor technologies in joint construction of an experimental pilot nuclear power plant. Discussions also are continuing between Kazakhstan's National Nuclear Center and three Japanese entities (Japan Atomic Power Company, Toshiba, and Marubeni) for the construction of a 600 MW nuclear power reactor. A wide range of potential sites are under consideration, including Ulken on the western shore of Lake Balkhash (Almaty Oblast), Turgay (Kostanay Oblast), Kostanay (northern Kazakhstan), Kurchatov, and Taraz (Zhambyl Oblast).

9.6. Global Uranium Market Overview

The world's reasonably assured resources (RARs) of uranium that are recoverable at market prices of below $40 per kg amount to 507 Mt (Table 9.1). This constitutes 11% of the world's total uranium RARs recoverable at a price level below $260 per kg. At the current global annual production rate of ~56 Mt, these reserves will last for 9 years. Inferred resources (IRs) in the below $40 per kg category will add 176 Mt (Table 9.2), increasing the reserves-to-production ratio to 12 years assuming the current level of production. Considering reserves recoverable at a market price below $80 per kg, RARs and IRs amount to 1,212 and 745 Mt, respectively, representing 26% and 24% of the total reserves recoverable at prices below $260 per kg. Therefore, at the current annual production level, the total RARs in the price category of $80 per kg will last for 22 years, while the total RARs and IRs will last for 35 years.

Since the start of nuclear power generation in the 1950s, production of uranium has exceeded commercial demand, as large volumes were used for military purposes. With the collapse of the Soviet Union and the subsequent implementation of nuclear disarmament initiatives (such as a 20-year Intergovernmental Agreement between the United States and Russian Federation from February 1993, also referred to as the Megatons to Megawatts Agreement), primary and especially secondary supplies of uranium entered the market, drastically impacting global production, which decreased from about 60 Mt in 1989 to about 35 Mt in 1992, as demand grew from about 50 Mt to about 60 Mt. For example, the World Nuclear Association has estimated that highly enriched weapons grade uranium (with a U-235 content of 85%–90%) entering the market from weapons stockpiles was displacing some 8.8 Mt of uranium mine production annually toward the end of the program (2013)–on the order of 13–19% of world reactor demand.[15] This gap narrowed after the end of the Megatons to Megawatts Agreement, so that 90% of global demand is now met with primary production.[16]

Currently, demand for uranium is generated by 437 nuclear reactors in 30 countries, with a total net installed electricity capacity of 380 GW. In 2013, 71% of global demand—or 44 Mt—was from OECD countries. This was about 4 Mt lower than in 2012 as the result of shutdowns of capacity in Japan, following the Fukushima Daiichi accident in 2011, and in Germany as well.

In terms of primary production, three countries—Kazakhstan, Australia, and Canada—accounted for about two-thirds of total global output, while seven countries—also including Niger, Namibia, Russia, and Uzbekistan—produced almost 90% of the world's total output. At the company level, Kazakhstan's KazAtomProm is the world's leading producer of uranium with output of 13 Mt, followed by France's Areva and Canada's Cameco, which produced 9 Mt each. Of the total world's primary output, these volumes constituted 21%, 16%, and 15%, respectively.

There is no precise information about stocks of uranium (held in storage), as most of these volumes have been reserved for military applications. Considering the difference between the historical cumulative production and demand, the upper limit can be estimated at 550 Mt. Civilian stocks of natural and enriched uranium held both by governments and businesses were estimated by the OECD and other sources at about 80–100 Mt of natural uranium equivalent.

[13] World Nuclear Association, "Uranium and Nuclear Power in Kazakhstan" updated 15 January 2015 (http://www.world-nuclear.org/info/Country-Profilees/Countries-G-N/Kazakhstan/), accessed 5 February 2015).

[14] In May 2014 several agreements were signed between KazAtomProm and Rosatom, including a memorandum of understanding for construction of a nuclear power plant at an unspecified site using larger VVER reactors with a capacity of up to 1,200 MW each.

[15] World Nuclear Association, "Military Warheads as a Source of Nuclear Fuel," August 2014 (http://www.world-nuclear.org/info/Nuclear-Fuel-Cycle/Uranium-Resources/Military-Warheads-as-a-Source-of-Nuclear-Fuel), accessed 12 June 2015.

[16] World Nuclear Association, "Uranium Markets" February 2015 (http://www.world-nuclear.org/info/Nuclear-Fuel-Cycle/Uranium-Resources/Uranium-Markets/), accessed 12 June 2015. The remaining demand comes from secondary sources. These include uranium held in government and commercial inventories, reprocessed spent fuel, and re-enrichment of depleted uranium tailings.

Despite the end of the Megatons to Megawatts Agreement (MTMA), substantial volumes of weapons-grade uranium and plutonium remain in US and Russian military stockpiles. For example, Russia still possessed at least 27 tons of highly enriched uranium (HEU) in its military stockpile at the end of 2012, and world stockpiles of weapons-grade plutonium (PU-239 content of 93%) are reported to be some 260 tons. Some of these nuclear materials declared surplus to military requirements by the US and Russia will continue to be converted into fuel for commercial nuclear reactors. For example, the US and Russia agreed to dispose of 34 tons each of their remaining plutonium stockpiles by 2014 in the manufacture of 1500 tons of mixed-oxide fuel (see below). Regardless of the volumes in inventory, it is highly unlikely that the sustained high volumes of secondary supply entering the market that were characteristic of the two-decade-long MTMA program will be replicated in the future.

Plutonium and some uranium recovered through the reprocessing of spent reactor fuel—as well as weapons-grade plutonium—also can be used in reactors licensed to use mixed oxide fuel (MOX), a fuel consisting of more than one oxide of fissile material (usually plutonium blended with natural uranium, reprocessed uranium, or depleted uranium). If the world's existing weapons-grade plutonium stockpile were to be used to produce mixed oxide fuel for use in conventional reactors, the equivalent to a little over a year's world uranium mine production would be displaced. MOX production facilities exist in several countries, including Russia,[17] China, United States, United Kingdom, France, India, and Japan. However, the use of MOX fuel is limited, as only 35 reactors (or 8% of the total number of reactors operating globally) are licensed to use MOX, of which 22 are located in France. In addition, the number of times spent fuel can be recycled under existing technologies is limited. This means that the potential of plutonium produced from recycled fuel to displace uranium is limited. Recovery of uranium (known as RepU) through spent fuel reprocessing is a costly process; as a result, its production also is limited—it is currently carried out only in Russia and France—and constitutes no more than 1% of the total global demand. However, if countries developing commercial methods of reprocessing spent nuclear are successful, they may create a more significant secondary source of supply.

Finally, depleted uranium hexafluoride (DUHF)—a byproduct of uranium enrichment—represents another source of secondary supply. DUHF is the uranium waste (or "tails assay") remaining after the removal of the enriched fraction and has a much lower concentration of the fissile isotope U-235 (0.3%) than natural uranium (0.72%). However, when uranium prices and enrichment costs are favorable, it can be economically feasible to reprocess the DUHF at an enrichment plant (a process referred to as "re-enrichment"). In the United States, 9 Mt of DUHF held by Department of Energy was re-enriched during 2005 and 2006 to produce about 2 Mt of uranium to be used within eight years at Energy Northwest's Columbia Generation Station. The latest estimations by the OECD's Nuclear Energy Agency, made in 2007, concluded that re-enrichment of the global DUHF stock of 1.6 MMt (as of year-end 2006) would be sufficient to meet global demand for uranium at 2006 levels for about seven years. However, re-enrichment has its limitations, as it is economically viable only in low-cost centrifuge enrichment plants with spare capacity. Rather than re-enrichment, at current uranium prices more specialized uses of DUHF make greater economic sense (e.g., in downblending/diluting weapons-grade HEU and in mixing with plutonium in MOX production).

In the global market, uranium can be sold at spot prices for immediate or short-term delivery, but such transactions typically apply to no more than 15% of uranium sales. Most transactions are on the basis of long-term contracts, which typically reflect a premium of at least \$25.80/kg (\$10/lb) above the spot market. Reflecting developments in market fundamentals—i.e., the market oversupply that existed through the 1990s—prices headed downward; spot prices fell to about \$18/kg of uranium (\$7/lb of U_3O_8) in 2001. However, beginning in 2002, uranium prices began to rise as a result of several factors, including expectations of further penetration of nuclear power in electricity generation, declining inventories (including the drawdown of supplies of HEU from military stockpiles), and US dollar appreciation (Figure 9.2). By June 2007, spot prices reached as high as \$350/kg of uranium (\$136/lb of U_3O_8). However, as the 2007–2008 financial crisis unfolded, prices resumed their downward trend, falling to \$106/kg of uranium (\$41/lb of U_3O_8) in 2010. The 2011 incident at Japan's Fukushima Daiichi nuclear plant pushed prices further downward, to \$88/kg of uranium (\$34/lb of U_3O_8) by the end of 2013. By early 2015 the price was roughly \$82.50/kg (\$37.50/lb).

[17] Russia uses plutonium to produce MOX fuel to power not conventional reactors but fast neutron (breeder) reactors, such as the BN-800 at Beloyarsk (Sverdlovsk Oblast), which has a 100% MOX fuel core. The BN-800, which is scheduled to enter commercial production in 2015, is the world's first commercial plutonium-cycle breeder. A high-density nitride MOX fuel (which will make the subsequent stage of recycling easier) was developed within the framework of BN-800 project.

Source: Uranium Miner, 15 June 2015

Figure 9.2 Uranium spot prices since 2002

Although the present spot price is well above the ~$25.80/kg ($10/lb) level that prevailed from the late 1980s until 2002, it is widely believed that very few new mines will be developed at today's price level. The common assumption, therefore, is that rising future global demand (see following section) will be accompanied by shortages of supply, leading to higher prices. However, this assumption fails to anticipate recent trends toward a segmentation of the global uranium market into three (or more) markets, two of which will experience moderate growth and the third much slower growth or stagnation.[18]

In the first market, China, the focus will be on investing directly in mines (e.g., Husab in Namibia) to satisfy domestic requirements (not always necessarily the lowest-cost producers), and secondarily to maintain long-term supply contracts with a select few trading partners, such as Kazakhstan. Due to geopolitical considerations and having learned a painful lesson in other global commodity markets (e.g., for iron ore), China does not wish to be overly exposed to supply vulnerabilities in the uranium spot market. Although China will maintain a presence in this market, the volumes of its long-term supply contracts with favored producers such as Kazakhstan already exceed total volumes traded on the spot market, as noted above. Consequently, through dedicated mine output and bilateral negotiations with select suppliers, China should be able to exercise leverage over the prices it pays, independent of spot market price trends.

In Russia, the second market, producers will continue to export nuclear fuel, but the domestic market will remain essentially closed to outsiders. Russia also still has secondary supplies, such as surplus HEU available for downblending as well as substantial volumes of DUHF that are processed at enrichment plants operated by Rosatom's Tenex enrichment company. Thus Russia can invest directly in domestic uranium assets as needed to support its own generation needs rather than resorting to the spot market.

Kazakhstan is closely involved in both of these first two markets, having forged a long-term supply relationship with China for its upstream production and participating in several downstream ventures with Russian partners for uranium conversion and enrichment. But it, along with other established uranium producers, will also be involved in the remaining, third ("rest of the world") market. Although this third market includes some "bright spots" in countries such as South Korea and regions such as the Middle East, where uranium demand will grow as new nuclear generating capacity is added, it is dominated by regions (Europe, North America) where demand is expected to decline as old reactors are decommissioned and replaced by gas-fired generation or renewable energy. In this market, demand growth may not be sufficiently robust to exert any substantial upward pressure on prices.

This trend toward market segmentation and the way in which the first two markets operate (major actors with increasing demand choosing to acquire supplies outside of a globalized world fuel market) may begin to limit the utility of world supply-demand balances and uranium supply curves (based on mine cost data) as price predictors. These tools best explain price trends in an open market. We include such analyses in this chapter with the understanding that they remain valid in terms of presenting a broad picture of how much new supply will be needed to accommodate projected future demand globally, but the signals they transmit about prices are not entirely transparent. Although prices are unlikely to return to the low levels of the late 1980s and 1990s, due to the escalation of the costs of mine production, it is likely that producers who can remain competitive in a low price environment through their own low costs of production—including Kazakhstan—will have the best prospects for maintaining or increasing production.

[18] The arguments that follow in this section are based on Steve Kidd, "The Future of Uranium—Higher Prices to Come?" Nuclear Engineering International, 6 May 2014 (http://www.neimagazine.com/opinion/opinionthe-future-ofuranium-thigher-prices-to-come/).

9.7. Uranium Balance Outlook

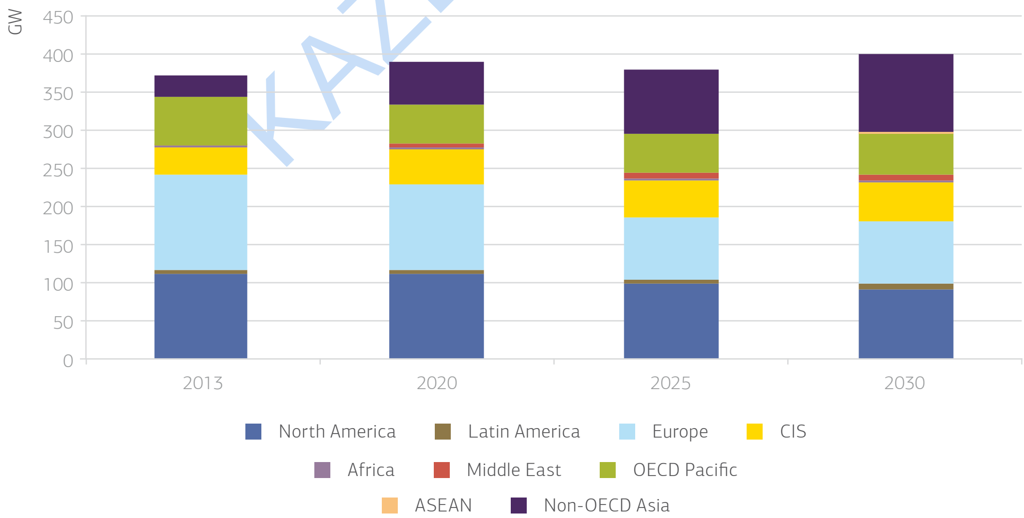
On the demand side, while the world's overall nuclear generation capacity is projected to increase, the pace of this growth is expected to diverge widely, according to whether low or high demand scenarios are employed. More specifically, demand is difficult to project over the medium to long term due to a number of uncertainties: (a) the rate of decommissioning of 1960s- and 1970s-era reactors in the United States, which are nearing the end of their project lifetimes; (b) the extent to which uranium enrichment capacity is adequate to compensate for the winding down of a large-scale infusion of secondary supply (weapons-grade uranium) into the market; (c) how much generation capacity ultimately will be recertified to come back on line in Japan, and the pace of Germany's and France's capacity decommissioning; (d) the build-out rates of new capacity in China and other developing countries; (e) the economic competitiveness in electric power generation of nuclear versus renewable energy or gas-fired generation if gas prices remain low or fall further; and (f) whether new uses of nuclear energy (e.g., in large-scale desalination) will substantially increase demand for nuclear generation.

Over the longer term, a much greater—perhaps even "game-changing"—effect on demand could be exerted by technological advances (e.g., in fast neutron reactors with processing facilities and spent fuel recycling) that could increase the efficiency of natural uranium in the fuel cycle tenfold or more. If the fuel cycle were to reach a tipping point between what is characterized as an "open" cycle (spent fuel is not recycled) to something approaching one that is "closed" (so that nuclear power practically becomes a "renewable" resource through fissile element breeding in fast reactors), then demand for new supply could wither rapidly.[19] The transition to such a closed cycle would require a massive global research program, investment and a long time for implementation of the main fuel cycle components, and thus this reason for declining demand does not figure into the medium-term demand scenarios described below.

As illustration of the divergence of projected demand, the OECD projects a net increase in global capacity (accounting for both new capacity buildup and closures) from the current capacity level of 372 GW to 400 GW by 2035 in a low demand scenario, and up to 680 GW in the high demand scenario. The resulting increase in reactors' demand for uranium (from the current level of 62 Mt) rises to 72 Mt and 122 Mt under the respective scenarios.

The OECD projections are lower than those offered by the International Atomic Energy Agency (IAEA), which uses similar low and high demand scenarios to forecast capacity out to 2030.[20] In the IAEA low-demand projection, global capacity reaches 400 GW by 2030, five years earlier than the OECD forecast (and 145 GW less than the IAEA's projection for 2030 capacity made shortly before the Fukushima Daiichi accident). Similarly, the IAEA's high demand projection for 2030 is 699 GW.

The largest increase in regional generation capacity projected by the OECD is for East Asia, where new capacities of between 57 GW and 125 GW are projected to be installed. The second largest increase—ranging from 20 GW to 45 GW—is expected in non-EU countries in Europe. Increases also are projected for the Middle East, as well as in South and Southeast Asia. In contrast, in North America and the EU, nuclear generation capacity is expected to decrease or increase only slightly, depending on the scenario. Figure 9.3 provides a graphic illustration of these regional differences in capacity growth over the period 2013–2030, based the IAEA's low demand projection. Although the regional categories employed are slightly different from the OECD's, the overall picture is the same: most of the growth is registered in Asia (non-OECD Asia), non-EU Europe (CIS), and the Middle East, with declines in North America and Europe.



Source: IAEA, Board of Governors General Conference, International Status and Prospects for Nuclear Power 2014, 4 August 2014.

Figure 9.3 Projected nuclear power capacity by region, low scenario, 2013–2030

[19] See the discussion in KazEnergy, The National Energy Report 2013, pp. 91, 96–97.

[20] The low demand scenario assumes current trends continue with few changes in policies affecting nuclear power; it is a conservative but plausible projection. The high demand scenario assumes that current financial and economic crises will be overcome relatively soon and past rates of economic growth and electricity demand will re-emerge, particularly in East Asia, and that stringent global policies to address climate change will be adopted. In both scenarios experts around the world consider all operating reactors, possible license renewals, planned shutdowns, and plausible construction projects foreseen for the next several decades.

On the supply side, primary production capacities, including existing, committed, planned, and prospective projects, will meet OECD-projected high case demand by 2032, and low case demand by 2035, provided the projects are implemented as planned and producing at about full capacity. Specifically, the world's total production capacity from existing and committed projects in terms of RARs and IRs recoverable at prices below \$130/kg of uranium (\$50/lb of U_3O_8), is expected to increase from 74 Mt in 2013 to 105 Mt in 2020, declining afterwards to 86 Mt in 2030 and 74 Mt in 2035. Capacity from production projects that are in the planned, non-committed stage (prior to a final investment decision [FID]) amounts to an additional 24 Mt in 2020 and 40 Mt in 2035.

In terms of secondary supply, there is a potential for the stockpiles of previously mined uranium, which were reserved primarily for military applications, to enter the market (noted above). Technology advancements—for example, an ongoing transition from gaseous diffusion to centrifuge and laser enrichment in the USA, or developing commercially feasible ways to enrich DUHF—also have the potential to create additional uranium supply.

Further, it appears that sufficient enrichment capacity exists to meet demand for low enriched uranium (LEU) for reactor fuel assemblies for the foreseeable future. At present 13 countries in the world have enrichment capability or near capability, with the five "nuclear weapons states" (Russia, US, China, UK, and France) accounting for 90% of current capacity. These states, plus Germany, Netherlands, and Japan, provide toll enrichment services to the commercial market. According to the World Nuclear Association, "there is a significant surplus of world enrichment capacity," which is set to widen over the near term as new centrifuge (and perhaps laser) capacity is added over the period from 2015 to 2020 (Table 9.5).

In short, it is difficult to envision a catalyst (supply, demand, processing capacity) under a conservative, low demand scenario that would exert substantial upward pressure on world uranium prices over the near term. This is not a uniformly negative outcome for Kazakhstan, which is one of the world's low cost producers and is active in all three uranium "markets" described above. Furthermore, its participation in important international nuclear initiatives, such as the uranium fuel bank (discussed below), could open new markets for some of its production.

Country	Company and plant	Technology	2013	2015	2020
France	Areva: George Besse I[3] and II[4]	Gaseous diffusion/centrifuge	5 500	7 000	8 200
Germany-Netherlands-UK	Urenco: Gronau, Almelo, Capenhurst	Centrifuge	14 200	14 200	15 700
Japan	JNFL: Rokkaasho	Centrifuge	75	1 050	1 500
US	USEC: Paducah[5], Piketon[6]	Gaseous diffusion/centrifuge	0	0	3 800
US	Urenco: New Mexico	Centrifuge	3500	5 700	5 700
US	Areva: Idaho Falls	Centrifuge	0	0	3 300
US	Global Laser Enrichment	Laser	0	0	3 000
Russia	Tenex: Angarsk, Novouralsk, Zelenogorsk, Seversk	Centrifuge	26 000	30 000	37 000
China	CNNC: Hanzhun, Lanzhou	Centrifuge	2 200	3 000	8 000
Other	Other (Brazil, India, Iran)	Centrifuge	75	500	1 000
	World (approx.)		**51 550**	**61 450**	**87 200**
	World requirement[2]		**49 154**	**51 425**	**59 939**

[1] *SWU = separative work units.*
[2] *According to World Nuclear Association reference scenario.*
[3] *Gaseous diffusion; closed in mid-2012.*
[4] *Centrifuge.*
[5] *Gaseous diffusion; still operating.*
[6] *Centrifuge; under development.*

Source: World Nuclear Association, "Uranium Enrichment," April 2015 (http://www.world-nuclear.org/info/; accessed 12 June 2015.

Table 9.5 Operational and planned uranium enrichment capacity (thous. SWU/yr)[1]

9.8. Kazakhstan to Host IAEA Nuclear Fuel Bank

Since as early as the late 1950s, the idea of providing an assured international supply of reactor fuel (i.e., low-enriched uranium) to countries embarking upon the development of their nuclear power industries has been proposed as a way of curbing the proliferation of nuclear weapons. More specifically, countries already possessing the technology to enrich uranium could sell a portion of their low-enriched uranium (LEU) to a "fuel bank," from which countries lacking such technology could obtain fuel for their power reactors during periods when it was not readily available from other sources. Because uranium enrichment capacity can be used to create both reactor fuel and weapons-grade nuclear material, convincing new entrants that there is no need to develop a domestic capacity to enrich uranium for reactor fuel is thus a significant tool in the fight against the proliferation of nuclear weapons.[21] In principle, the bank would not function as any country's primary source of supply, but rather would serve as a last-resort source of supply should a country not be able to procure adequate supplies on the international market.

The vanguard in the effort to establish such fuel banks has been the IAEA, a UN organization of 164 member states that seeks to promote the peaceful use of nuclear energy. In March 2010, the IAEA and the government of the Russian Federation agreed to establish the first such fuel bank in Angarsk, which became operational on 1 December of that year. The fuel bank, which is located on the grounds of Russia's International Uranium Enrichment Center (IUEC),[22] will eventually hold a stockpile of 120 tons of LEU. Under the agreement, countries can formally file a request, in cases of urgent need and to avoid interruptions in supply, with the IAEA for nuclear fuel, which would then transfer the request to the fuel bank. Russia has borne the costs involved in setting up the bank (somewhat reduced because it is part of an already existing facility), and the IAEA bears the costs of the purchase and delivery (import-export) of LEU (backed in part by $150 million in funding from the international community).

In December 2010, the IAEA announced its intention to establish a second fuel bank, at Kazakhstan's Ulba Metallurgical Plant (UMP), which could store up to 90 tons of LEU. Finalization of the plan was delayed by, among other things, the need for technical studies to determine the seismic stability of the site. However, by mid-2014 the ongoing international negotiations on the lifting of sanctions on Iran's nuclear program increased the urgency of demonstrating the existence of additional LEU reserves accessible to Iran (and other countries) on a non-political basis. The proximity of the Kazakh site to Iran and maritime routes of supply via the Caspian Sea were viewed as advantageous, as was Kazakhstan's lengthy experience in the handling and storage of nuclear materials as part of international nonproliferation initiatives.[23] A draft agreement between the government of Kazakhstan and the IAEA formally establishing the fuel bank at Ulba was signed by Kazakhstan's Energy Minister Vladimir Shkolnik in May 2015; the final agreement was concluded on 27 August 2015. At least initially some of the LEU stored at Ulba will be enriched in Russia, albeit at joint-venture facilities half- or partly owned by Kazakhstan (see above). Iranian LEU stockpiles could also be placed in the Nuclear Fuel Bank.

Key Recommendations

- Kazakhstan is a highly competitive mine producer of uranium because of its low costs of production. Even if prices remain relatively low compared to levels of the recent past, Kazakhstan should continue to have a strong competitive position in a part of the world where nuclear fuel demand is expected to grow (e.g., Eastern Europe, Middle East, Asia). This notwithstanding, Kazakhstan should continue its efforts to increase the value-added of (and diversity of sales options for) its uranium production by extending its participation to parts of the nuclear fuel cycle where it presently lacks domestic capacity.

- The world uranium market is starting to become segmented. Two major players, Russia and China, are increasingly inclined to take actions outside of the world spot market by investing in dedicated mines in other countries or by insulating their domestic markets from market price and supply fluctuations. Kazakhstan, unlike any other country, has strong uranium trade relations with both of these players, as well as the rest of the world. Kazakhstan should seek to maintain these close Russia/China trade connections, as they may prove advantageous in an environment in which reactor fuel demand in other major markets such as the US and EU stagnates or possibly declines, putting pressure on spot market prices. Strengthening relations with other potential trading partners (especially new entrants) is also important, and Kazakhstan's willingness to host an IAEA-sponsored nuclear fuel bank is a significant indication of its commitment to be a responsible actor on the international stage.

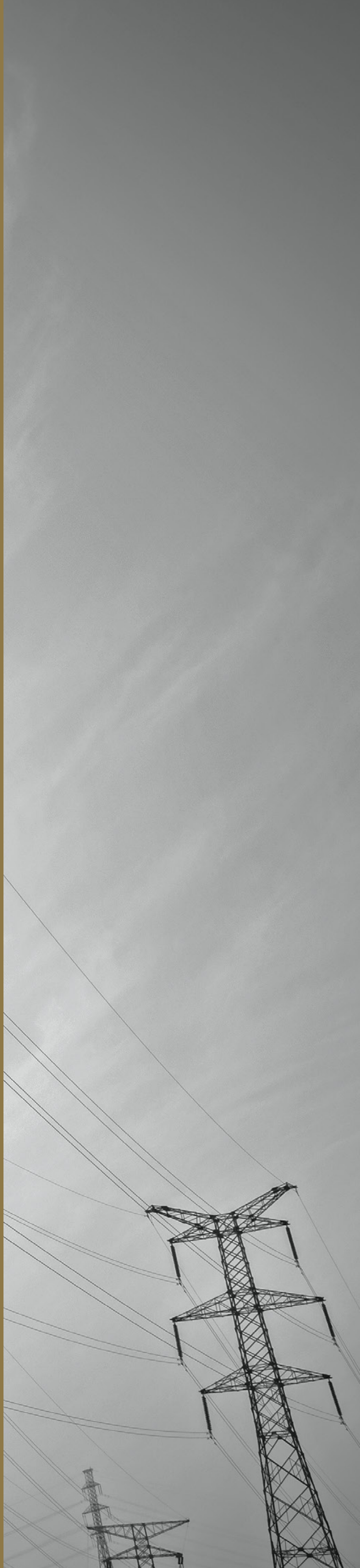
- One of the ways that Kazakhstan can boost demand for its uranium mine production is for end consumption of that commodity to occur domestically. This becomes possible through the construction of one or more nuclear reactors in Kazakhstan after careful studies designed to identify appropriate technologies and sites within the national electrical grid. Such construction should fit within the framework of a comprehensive strategy for supply diversification and reduction of the country's greenhouse gas emissions. We build in this eventuality in our electric power projections after 2025 (see Chapter 10.7.4).

[21] An additional argument in favor of new entrants foregoing enrichment capacity is the current surplus of world enrichment capacity noted above.

[22] It should be noted that the IUEC, unlike the fuel bank, is a for-profit entity owned by state-backed companies (i.e., is a joint-stock company 80% owned by Rosatom, with minority shares held by KazAtomProm and other investors), and gives preferential treatment to its shareholders when selling enrichment services.

[23] In a multi-year joint operation involving KazAtomProm and the Nuclear Threat Initiative that began in 2001, 2900 kg of 25% enriched nuclear fuel was transferred from the decommissioned Aktau nuclear plant to Ulba to be blended down to non-weapons grade uranium for use in scientific and commercial activities.

KAZAKHSTAN'S ELECTRIC POWER SECTOR



10. Kazakhstan's Electric Power Sector

10.1. Key Points

Kazakhstan's "national" power sector comprises three power zones, two of which are interconnected (North and South) and a separate power system in the west, all covering an area of 2,717,300 square kilometers (larger than Western Europe).[1] A vast amount of Kazakhstan's predominantly coal-fired power production remains closely tied to large industrial consuming centers in the northern part of the country, but rapid growth in power demand in the southern and western parts of the country means power infrastructure needs to adapt relatively quickly (see Figure 10.1). And as Kazakhstan's economy continues to grow, maintaining robust power consumption growth (despite recent economic headwinds from falling oil prices and general slowing of the global economy), policymakers target better energy security and energy independence as important short- to medium-term goals. For these reasons, improving the grid network as well as revitalizing the country's power capacity is crucial to unlocking more value from existing assets, enhancing energy security, improving Kazakhstan's green credentials, and raising overall sector efficiency. With this mission in mind, consider the following key findings:

- **Kazakhstan is in the midst of a sustained effort to revamp its aging power system.** Since almost 20% of the country's power capacity was launched prior to the 1970s, Kazakhstan also has the opportunity, where practical and economically expedient, to shift from its dominant coal-fueled generation (coal-fired generation currently represents around 69% of Kazakhstan's total power production) to a more diversified mix with more gas (currently around 20% of total power production), renewables, and nuclear. Although gas will provide much of incremental generation going forward in the west and south, the share of generation will be limited mainly by gas pipeline availability and the price of gas relative to coal. Naturally, the cost of investing in new gas-fired generation is also a limiting factor. And while policymakers aim to realize Kazakhstan's renewables potential (by creating favorable conditions for investment and an unlimited quota of renewable generation), its combined impact should remain relatively small. Therefore, with Kazakhstan's abundance of low-cost coal, its established fleet of large coal-fired power plants will continue to dominate for the next two decades, although coal's share of total fuel balance will contract in the long term.

- **While many Kazakh power-producing provinces will remain predominantly fueled by coal, gas-fired generation will continue to grow as Kazakhstan's gas network expands and partial gasification of the economy proceeds.** Several new pipeline projects are expected to expand internal gas availability and aid in developing gas-powered generation (utility and, particularly, autoproduction) in selected areas. Moreover, in western and southern Kazakhstan where power demand looks set to expand significantly, incentivizing gas production (through pricing) for domestic use and planned power transmission projects hold the key to unlocking latent value through gas generation. At that, the higher cost of gas versus coal will remain one of the key factors limiting any aggressive lurch from coal to gas even if access to the gas network is improved. Growth of gas generation in western Kazakhstan will be driven by a further increase in oil production and utilization of associated gas.

- **Kazakh policymakers plan for nuclear power, hydropower, and renewables to play a role in diversifying Kazakhstan's capacity mix.** Kazakh policymakers are still evaluating several potential sites for a nuclear power station, while renewable energy sources (particularly solar and wind) will grow, albeit modestly. Even though nuclear power will boost Kazakhstan's green credentials, it still requires delicate political negotiation to find the best terms with technical and financial partners. For renewables the cost of solar and wind technologies and issues relating to their integration with power systems mean that this option is still untested for Kazakhstan, and thus requires continuous market and technical integration support, or risks losing traction. However, staged advances in energy-related technologies, for example in large-scale energy storage capacity, could have a profound impact on their overall viability in the future, however, still leaving the issue of low power output a challenge for renewables.

- **Kazakh policymakers strive to find the best market arrangement for supporting existing power and heat infrastructure that also stimulates efficiency and diversification in Kazakhstan's power sector.** Encouraging a greater take-up of gas-fired capacity and renewables in power generation or building new coal capacity or refitting older coal-fired plants with more efficient and cleaner technologies will require a delicate balancing of market incentives with state steering. However, several issues complicate finding a satisfactory market balance; in particular, Kazakhstan's heat provision is inextricably linked to the power sector due to a significant share of combined heat and power plants in power generation; domestic gas pricing also needs addressing, but most concerning is the potential impact of any market changes on end-user pricing.

[1] Kazakhstan's North and West power systems share several connections with Russia, while the South power system is connected with Uzbekistan and Kyrgyzstan.

* CHP = combined heat and power plant; TPP = thermal power plant
Source: SEEPX Energy and IHS Energy

Figure 10.1 Map of Kazakh power sector

10.2. Rules and Regulatory Background of Kazakhstan's Power Market

10.2.1. Background to Kazakhstan's power sector reformation

Similar to other countries of the CIS region, in the years immediately following the break-up of the USSR, Kazakhstan's power system remained organized administratively on two levels: a national system and multiple regional systems. Until 1996, the key national institution in the Kazakh electric power sector was Kazakhenergo, the republic's successor to the former KazSSR Ministry of Energy and Electric Power. The Kazakh state-owned entity included within its structure the integrated regional electric utilities (known as energos), the high-voltage transmission network, the national dispatch center, and miscellaneous design and construction enterprises.

The energos functioned as integrated regional utilities, operating the power stations, district heat networks, and most of the transmission and distribution power infrastructure within their areas (except for the portion of the high-voltage network used primarily for interconnecting the regional systems). Thus, the energos themselves comprised several subsidiary enterprises, such as individual power stations or local distribution grids. Operations and dispatch management were carried out at the national level as well as at the regional level by individual dispatch offices. Because many of the smaller thermal plants in Kazakhstan are combined heat-and-power generation units (in Russian the term is teploelektrotsentral, abbreviated as TETs), often there was little ability locally to respond to changes in electrical load, so the national system was tasked with responding to changes in load and maintaining system stability.

Power sector restructuring, including the separation of assets and corporatization of the operating entities, began in early 1996 with the adoption of a series of government resolutions. The first, Government Resolution No. 1033, created the National Energy System (NES) Kazakhstanenergo—principally a high-voltage network company with a few major generating stations attached (pulled out of the energos where they had previously been administered). These major stations were formed as independent companies.

Resolution No. 663 (adopted 30 May 1996) provided for full separation of all generation assets from NES Kazakhstanenergo. This resolution further stripped all the TETs and larger boiler facilities from the regional energos and transferred them to "communal ownership" (e.g., city and local governments) for subsequent privatization.

Resolution No. 499 (adopted on 16 July 1996) provided for the corporatization of the state-owned entities prior to their privatization. It ordered the power stations, regional energos, and other facilities (such as heating networks) into independent joint stock companies.

This was followed by the actual privatizations, most of which were completed by 2000. The State Property Committee (under the Ministry of Finance) transferred the ownership and hence signed the asset sales agreements. NES Kazakhstanenergo signed appropriate power purchase agreements with large generators, and the regional energos signed similar agreements for the smaller plants. The Ministry of Finance usually ended up taking on most of the past liabilities of the companies being privatized (e.g., debts, back wages, and unpaid pension liabilities), but the actual outcome was negotiated individually with the new buyers. Most of these privatized assets have since changed hands, with many of the initial owners (some of which were foreign) selling out to various Kazakh owners or the national welfare fund, Samruk-Kazyna.[2]

In September 1996, the government spun off all the high-voltage network assets into a new state-owned corporation, Kazakhstan Electricity Grid Operating Company (KEGOC). KEGOC also was designated to sign contracts with the generators previously signed by NES Kazakhstanenergo.[3]

10.2.2. Regional power pools and zones

The electric power system of the USSR centered on the Unified Power System, which consisted of 11 large interconnected regional electric grids or power pools. Kazakhstan's power plants operated as part of two of those. The North Kazakhstan grid serviced the more heavily industrialized northern and eastern portions of Kazakhstan, while the southern part of Kazakhstan was tied into the Central Asia grid together with Turkmenistan, Uzbekistan, Tajikistan, and Kyrgyzstan. These two power systems still operate within Kazakhstan (now known as the North Zone and South Zone (see Figure 10.2), as the North Kazakhstan grid was partly decoupled from a part of the larger Russian system in 1999.[4] So even though a substantial amount of power is transferred south as the two zones began operating in tandem, the southern part of Kazakhstan still engages in sizable exchanges of power with Kyrgyzstan and Uzbekistan. The North Zone accounts for nearly 66% of total national electricity consumption, and the South Zone about 22% (see Table 10.1).

The West Zone, comprising the western portions of the country (Atyrau, Mangistau, and West Kazakhstan oblasts) still operates separately from the rest of the Kazakh national grid. This was also true of the Aktobe area until 2009, when it was connected with the North Zone by a 500 kilovolt (kV) line. At one time, the westernmost areas (Atyrau, Mangistau, and West Kazakhstan oblasts) were isolated from the Soviet Unified Power System altogether, but they were finally connected with Russia's Middle Volga regional power pool via two 220 kV lines and a 500 kV line extending from Samara and Saratov to Uralsk during the 1980s. By the late 1980s, this area was operating in parallel with the Middle Volga power system.

[2] Ownership of generating assets has become highly concentrated, with Samruk alone holding about 39% of generating capacity, and other large vertically integrated industrial and mining groups, such as Kazakhmys, KazZinc, Kazatomprom, and ENRC Kazakhstan, holding much of the remainder.

[3] JSC "KEGOC" was established according to the Government Provision No.1188 of 28.06.1996 «On Some Structural Changes to the Management of Kazakhstan Power System". JSC "KEGOC" was registered on 11 July 1997.

Source: SEEPX Energy

Figure 10.2 Map of Kazakh power zones

	2009	2010	2011	2012	2013	2014	Pct. change 2009-12	Pct. change 2012-14
Kazakhstan total	77 959.6	83 767.1	88 136.0	91 444.2	89 640.8	91 661.0	17.3	0.2
North Zone	53 916.5	58 327.2	60 588.7	62 554.1	60 785.9	60 865.0	16.0	–2.7
West Zone	9 026.8	9 263.5	9 581.6	9 885.1	10 232.3	10 940.0	9.5	10.7
South Zone	15 016.3	16 176.4	17 965.7	19 005.0	18 622.6	19 856.0	26.6	4.5

Note: In 2009, the Aktobe area was connected with the North Zone, and its consumption is included in that category.
Source: KEGOC.

Table 10.1 Electricity consumption in Kazakhstan by regional power pools (million kilowatt-hours)

10.3. Regulation and Tariff Policy

Responsibility for overall power sector policy and regulatory oversight (e.g., approval of investment plans) was initially vested with the Ministry of Energy. Its successor ministries, currently again the Ministry of Energy following a reorganization in August 2014 that eliminated the Ministry of Industry and New Technologies that had been responsible for the sector, continues to supervise and control the activity of power sector participants, and also exercises a major role in sector strategy, technical policy, and licensing (see Figure 10.3).

The main price-setting body and de facto regulatory agency for the electricity sector in Kazakhstan is the State Agency on Natural Monopolies Regulation (now The Committee on Natural Monopolies Regulation and Competition Protection of the Ministry of National Economy, abbreviated as KREMiZK in Russian).[5] It sets maximum tariffs (price caps) for the services of natural monopolies. According to the law on Natural Monopolies of July 1998, the natural monopolies in Kazakhstan are services related to:

- Oil/products transportation through trunk pipelines;
- Marketable gas storage and transportation through connector pipelines, trunk pipelines and (or) gas distribution systems, storage tank system operation, as well as raw gas transportation through connector pipelines;
- Transmission and distribution of electric power;
- Production, transmission, distribution, and supply of heat energy;
- Technical dispatch of electric power into grid and consumption of electric power;
- Balancing of production and consumption of electric power.

Both tariffs and price caps for regulated services provided

[4] UES North Kazakhstan with dispatch at Alma-Aty (Almaty).

[5] Organized in 1991.

by natural monopolies shall not be lower than the cost of regulated services, which are set so to generate profit for a natural monopoly. In effect, the agency sets maximum prices for power sold in the wholesale market by generators. In 2009 the government approved price caps for power plants until 2016. But actual prices are determined by negotiated contracts in the wholesale power market. KREMiZK is a regulatory body for Kazakhstan's national grid company (operated by KEGOC) and sets a wholesale transmission tariff cap for national power plants. It also regulates activity of regional generating and distribution companies. Transmission and distribution tariffs set by KREMiZK, according to legislation should compensate expenditure and include investment costs.[6] KEGOC's transmission tariff comprises three parts: power transmission fee, technical dispatch of output, and power production and power consumption balancing. Since 1 August 2010 KEGOC has been using a new methodology to calculate transmission tariffs, where the tariff is calculated based on the volume transmitted and ignores travelling distances for power. By applying this methodology KEGOC has granted end-consumers non-discriminative access to the national power grid.[7]

Consumers with a minimum demand of 1 megawatt (MW), by law, can choose a supplier and negotiate the price after connecting to the regional electricity grid (REC), which entails payment of both KEGOC transmission and REC distribution fees.[8] A consumer must buy power from a local power supply company (abbreviated in Russian as ESOs) if its consumption is less than 1 MW. The end-user prices cover the cost of power that an ESO buys from a wholesale market (a power plant tariff), power transmission and distribution fees (KEGOC tariff and REC distribution company tariff), and a regulated ESO mark-up. The ESO calculates end-consumer tariffs differentiated by volume and time of the day.

KREMiZK sets tariffs for the ESOs, which are curbed by the pace of end-user tariff growth and are set last, after power generating companies' tariffs.[9] A later approval of ESOs' tariffs relative to the power plants makes tariff-setting for ESOs a longer process owing to ESOs' subsequent tariff re-application.

Once a year KREMiZK also set tariffs for heat energy generating and heat energy supply companies. Although the Ministry of Energy regulates the overall operation of large heat energy sources (above 100 gigcalories per hour [Gcal/h]), the responsibility for the regulation of small boiler houses lies with the Committee on Construction, Housing, and Utilities and Land Use of the Ministry of National Economy (the former Agency on Construction, Housing, and Utilities). **The absence of a single body regulating the activity of the heat energy market makes the development of a single heat energy market policy difficult, particularly in the absence of a separate single law on heat energy market operation.**

[6] The tariff methodology prevents tariff growth above regulator-set levels by restricting the amount of expenditure allocation and cost items.

[7] The tariff-setting for KEGOC and small distribution companies follows the methodology of standardized costs (norms) sufficient to cover operational and capital costs (costs+). The tariff review takes place every year, once a year. The tariffs of regional electricity grid companies are set following the benchmarking method for three years (with annual adjustments) to stimulate efficiency.

[8] Electric power consumers (inclusive of power supply companies) gain access to the national power grid subject to:
1) Signing an agreement with the System Operator:
- on power transmission services
- on technical dispatch of imported power (in case of power import)
- on power consumption/production balancing in UES Kazakhstan
- on purchase/sale of balancing power
2) Signing an agreement with a power distribution company on power distribution through the regional electric grid to which the power consumer is connected.

[9] Regional electricity grid company is a distribution company that operates regional electric grid; ESO is an energy supply company that sells purchased electric power and heat energy to the end consumers.

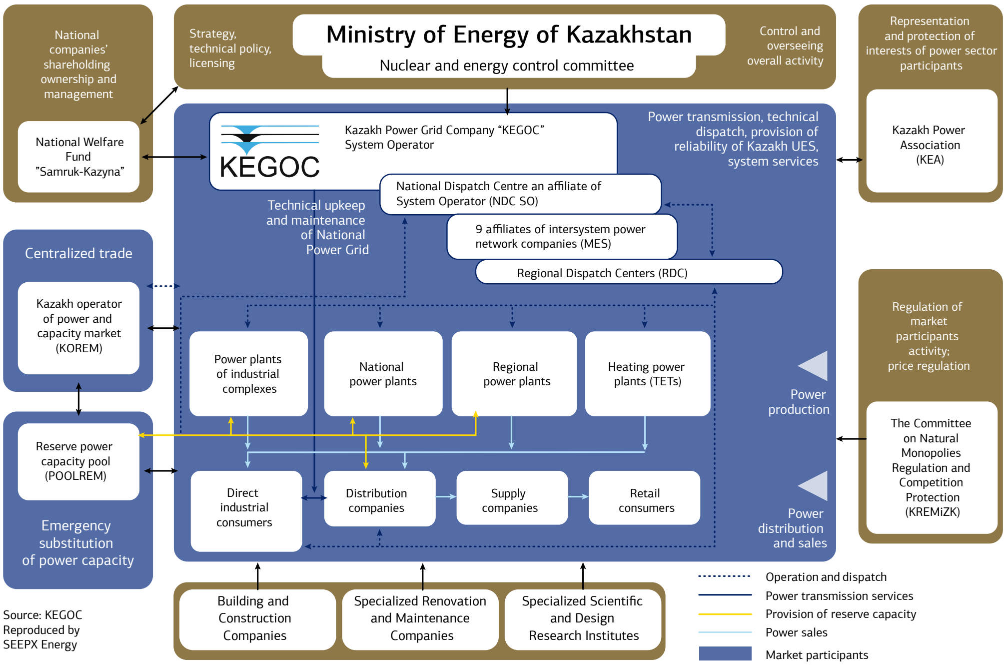


Figure 10.3 Organizational structure of Kazakhstan's power and heat sector

10.4. Kazakhstan's Power Infrastructure Adapts to Demand

Kazakh policymakers' recent planning considerations have been in response to relatively robust trends in power consumption growth (averaging 3.8% per year during 2000–2014 [based on data from KEGOC, the system operator]). In other words, because Kazakhstan's economy has been rapidly re-expanding, the government naturally reacts by looking for ways to improve overall reliability and security. But as a part of revamping the country's power sector, Kazakh policymakers also want to encourage a shift toward greater energy consumption efficiency and cleaner energy—which has a dampening effect on power demand.

Since 2010, Government Resolution No. 1129 has guided this effort (29 October 2010), which approved the "Program for Development of the Kazakhstan Electric Power Industry for 2010–2014." The program's objectives were to upgrade and rehabilitate existing as well as construct new generating capacities; to construct, upgrade, and rehabilitate transmission grid facilities; to develop the coal industry; to improve the market environment by creating a capacity market to support investment in new generating capacities; and to include renewable energy sources in the power infrastructure. The state has affirmed and reinforced the above goals in later documents that would cover Kazakhstan's short- to long-term economic development.[10] But at present Kazakhstan's legislation puts more emphasis on decreasing Kazakhstan's energy intensity throughout the overall economy (e.g., improving the energy efficiency of its industries; see Chapter 11) and lessening the sector's impact on the overall environment. Furthermore, Kazakhstan seeks to increase export of power not only to neighboring countries (mainly Russia), but also to other member countries of the Eurasian Economic Union (e.g., Belarus via Russia).

The overall goal of efficient, cleaner energy could be achieved by gradually switching from coal-fired capacity (currently accounting for about 63% of installed capacity and around 69% of total generation), to gas-fired, hydro, nuclear, and renewable generation. As gas is likely to play an important role in any potential fuel shift in the next two decades, the key and considerable hurdle preventing a swift transformation is the geographical separation between fuel resources, the need for additional gas pipeline infrastructure to make more gas available, and the economics for burning gas versus cheap and easily accessible coal.

Without such sizable infrastructural improvements, Kazakhstan's energy future will probably continue to be heavily shaped by the development path set in place before Kazakhstan's independence. During the Soviet period, Kazakhstan's power sector and the key consuming industries were planned around the country's vast and easily accessible coal reserves.

In contrast, in the western and southern parts of the country, gas-fired capacities were shaped in the 1960s and 1970s in line with the gradual maturing of the Central Asian gas-focused pipeline infrastructure. Therefore, Soviet-built gas-fired capacity remained predominantly in the south (with the exception of Almaty where coal-fired capacity is still dominant), where imported gas was available from Uzbekistan, and also in western Kazakhstan (based on indigenous associated gas). But gas remained essentially a "niche" generating fuel

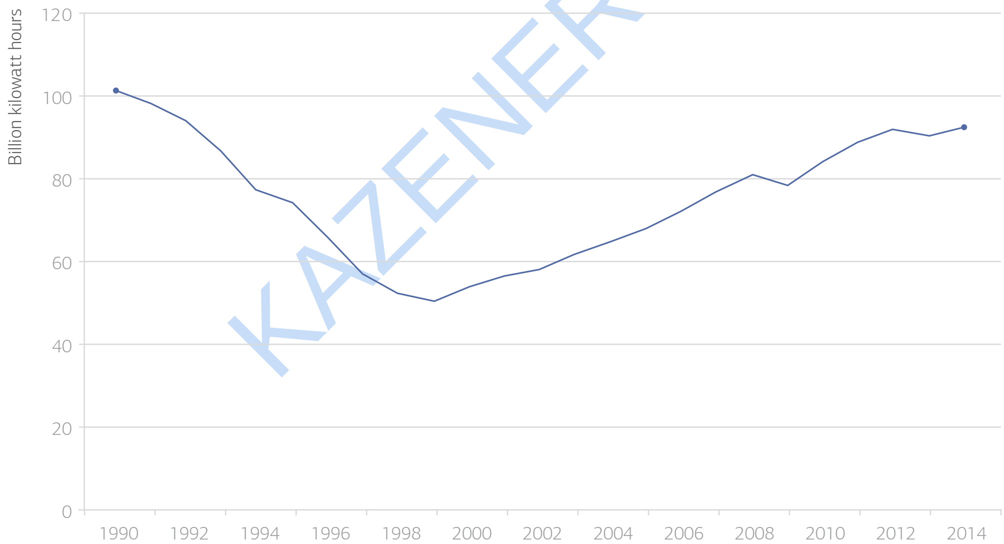
[10] This is laid out in the following official documents: Order of the President of the Republic of Kazakhstan No. 874 of 1 August 2014 on State Program of 2015–19 Industrial and Innovative Development of the Republic of Kazakhstan; The Strategic Plan of Kazakhstan Development by 2020; The Green Economy plan; Kazakhstan-2050 strategy; Government of Kazakhstan provision No. 724 of 28 June 2014 "Concept of Fuel and Energy Sector Development of the Republic of Kazakhstan to 2030."

in Kazakhstan. In 1990, gas accounted for only 10.5% of the fuel used in thermal generation while coal accounted for 77%. But since the early 1990s, in line with expanded oil production and some gas infrastructural development, a substantial number of gas-fired plants have been introduced within Kazakhstan. And as a result, the share of gas in total thermal generation (including gas turbine generation) in 2014 outstripped the Soviet period figure by twice, now standing at about 22% (coal 76% and oil 2%).

Therefore, notwithstanding a recent expansion of gas in Kazakhstan's generation mix (typically associated with the installation of gas-turbine plants to serve the needs of individual oil production projects [referred to as autoproducers]), the country's appetite for coal (driven by production costs) will continue to steer its capacity choices in favor of coal-fired generation for some time to come. At that, the planned transmission connection of the West Zone to Kazakhstan's North and South Zone (unified energy system [UES]) by 2030 will inevitably increase the share of gas in the fuel balance because gas-fired generation will discover new consumers, but in this case consideration should be given to the relatively low cost of producing power with coal. Understandably, policymakers expect an increased use of gas-fired generation in the West Zone in part owing to rising peak demand. And despite Kazakhstan's market architects' plan to connect the West Zone to the North and South zones, most of the power generated by autoproducers is likely to be reserved for the companies' own needs. Moreover, eventually we expect forced retirements of coal-fired capacity and launches of new gas-fired and renewable plants would bring down the overall share of coal-fired production in the thermal fuel mix to around 61% by 2040.[11]

10.5. Consumption Trends: Significant Differences between North and South

Kazakhstan is the third-largest electricity consumer within the CIS. Based on data from Kazakhstan's Statistical Committee, apparent (gross) electricity consumption reached a peak of 104.7 billion kilowatt-hours (kWh) in 1990, which has still not been exceeded.[12] During the 1990s, apparent consumption fell sharply, shrinking by more than half (down 52%), to only 50.3 billion kWh by 1999 (see Figure 10.4). Kazakhstan was one of the few countries in the former Soviet Union where the decline in electricity consumption was greater than the (percentage) decline in gross domestic product (GDP) during the initial transition period (see Figure 10.5).

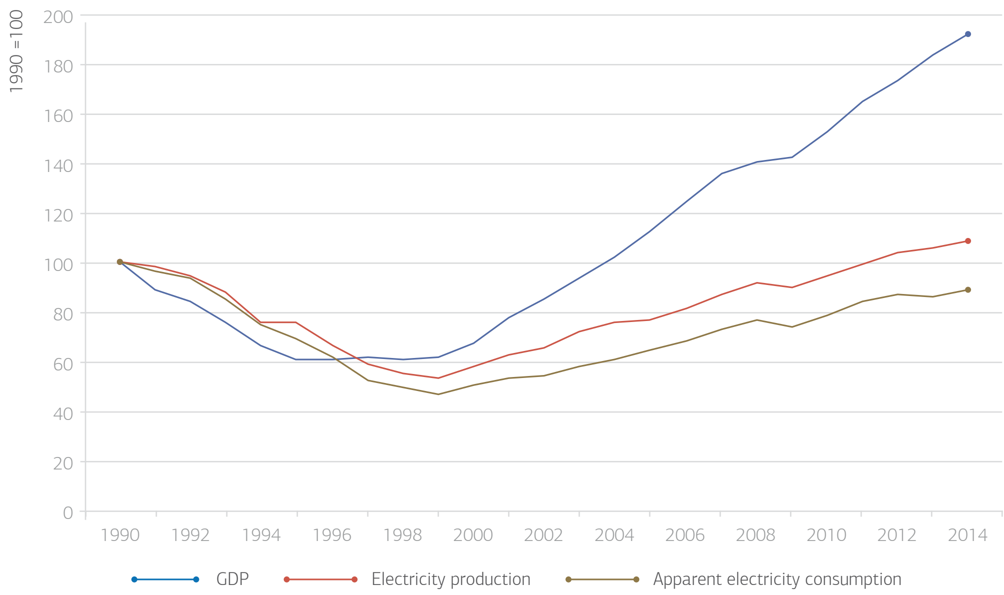


Source: IHS Energy, Statistical Committee of Republic of Kazakhstan

Figure 10.4 Kazakhstan's apparent power consumption

[11] According to Kazenergy's National Energy Report 2013, between 2013 and 2030 the government planned to retire 4.3 GW of coal-fired capacity and 478 MW of gas-fired capacity; at the same time it planned to launch 4.8 GW of new coal-fired capacity, 1.8 GW of new gas-fired capacity, and 5.3 GW of renewable capacity (inclusive of small hydro plants).

[12] There are small variations in consumption and production data between Kazakhstan's statistical agency and KEGOC.



Source: IHS Energy, KEGOC

Figure 10.5 Indexes of GDP, electricity production, and electricity consumption for Kazakhstan

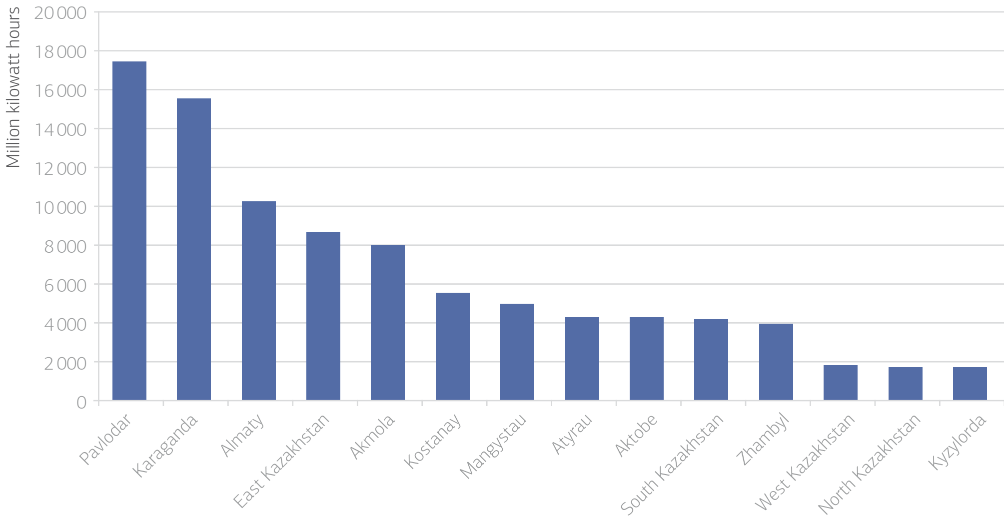
Under the impetus of very strong economic growth in the 2000s, Kazakhstan's electricity consumption rebounded; according to KEGOC, electricity consumption in the republic had increased by more than 69% by 2014, to 91.7 billion kWh. This represents an average annual growth rate of 3.8% between 2000 and 2014. During this period, GDP growth averaged 7.5% per year, so the average elasticity between GDP growth and electricity consumption at about 0.51 meant that power consumption grew 0.5% for every 1% of GDP growth.[13]

Emphasis on growth shifting to western and southern Kazakhstan

The locus of Kazakhstan's power consumption is in the northern and eastern regions (North Zone), which also happen to be well endowed with coal reserves and generating capacity. The largest power consuming provinces—Pavlodar (by far the most dominant consumer in Kazakhstan), Karaganda, and East Kazakhstan—together account for 45% of total power consumption (see Figure 10.6 and Figure 10.7). These regions represent the industrial heartland of Kazakhstan, positioned strategically during the Soviet period to take advantage of Kazakhstan's immense and easily recoverable coal reserves. The combined share of industrial power consumption in these regions is some 55% of Kazakh's total industrial power demand, while the same provinces only account for 27% of the country's residential consumption. But over the last decade the North Zone has demonstrated an average power consumption growth of about 3% per year, the rate of growth since 2010 has decreased to 1.1% per year, and since 2012 power consumption has plunged into negative territory, registering -2.7% annually.[14] This trend in power consumption is common for almost all of the largest power consumption areas in the North Zone. For instance, power consumption in Pavlodar Oblast over the last decade showed an average growth of 4.1% per year; however, since 2010 the rate of growth dropped to 0.1% per year, and since 2012 declined by 2.9% per year. Power consumption in Karaganda in 2010 dropped from a 10-year average growth of 1.2% per year to 0.2% per year, but since 2012 declined on average 2.3% per year. Similarly, East Kazakhstan Oblast grew by an average 1.4% per year since 2004, but had slipped to an average 1% per year since 2010, and since 2012 registered negative growth of 2.1% per year (see Figure 10.8, Figure 10.9, and Figure 10.10). These changes in power consumption growth are attributed to the overall global economic slowdown (in particular, the drop in global prices for non-ferrous metals from reduced demand). In contrast, the western and southern parts of Kazakhstan have enjoyed growth, owing in part to rapid population growth.

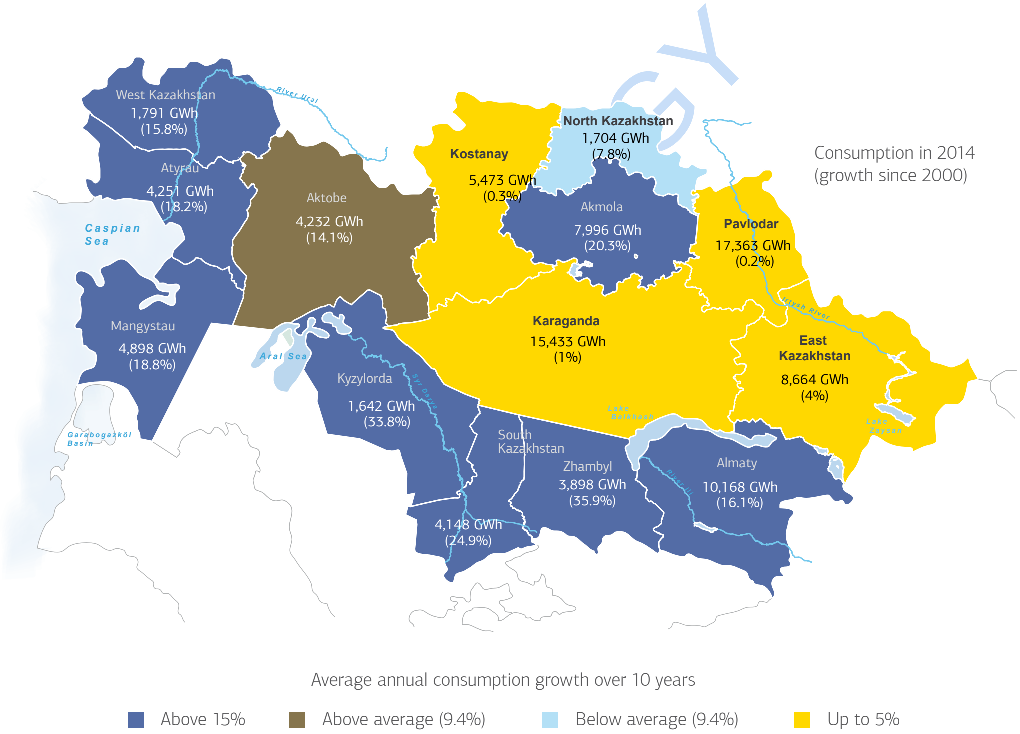
[13] Consumption and production data differ between Kazakhstan's National Statistical Agency and KEGOC (system operator). In this report, we predominately refer to system operator's figures.

[14] For the purpose of consistency in comparison, power consumption data for Aktobe Oblast have been included in the North Zone since 2004 (for the last decade of analysis), even though this oblast only became part of the North Zone in 2009. In any event, Aktobe Oblast data have had a positive impact on the overall statistics of the North Zone's power consumption. When Aktobe is excluded fully, the drop in the North Zone power consumption since 2012 reached -3.4% a year.



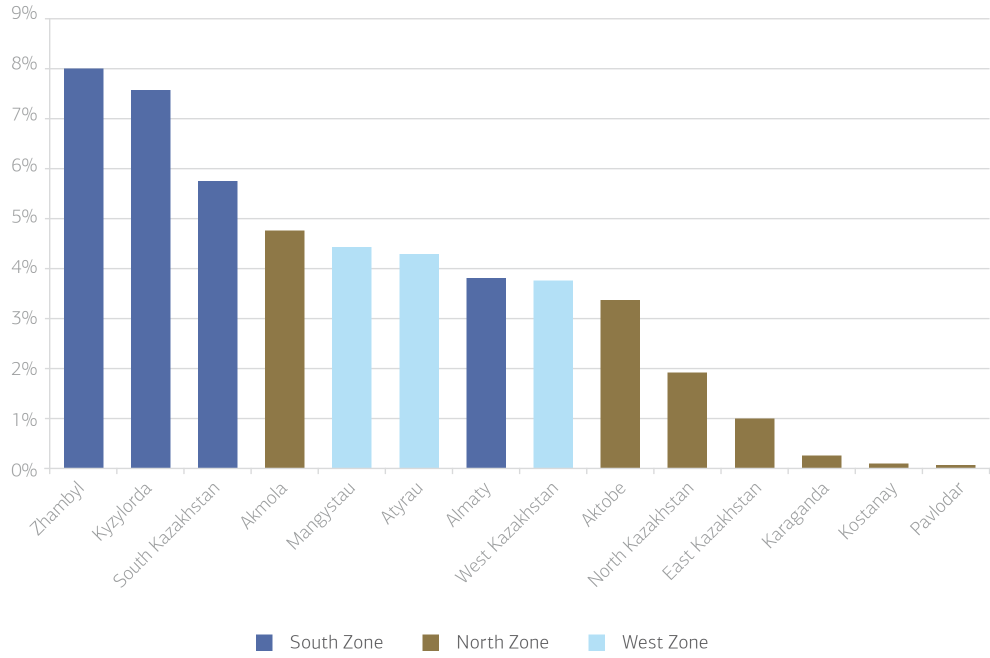
Source: IHS Energy

Figure 10.6 Kazakh regional power consumption in 2014



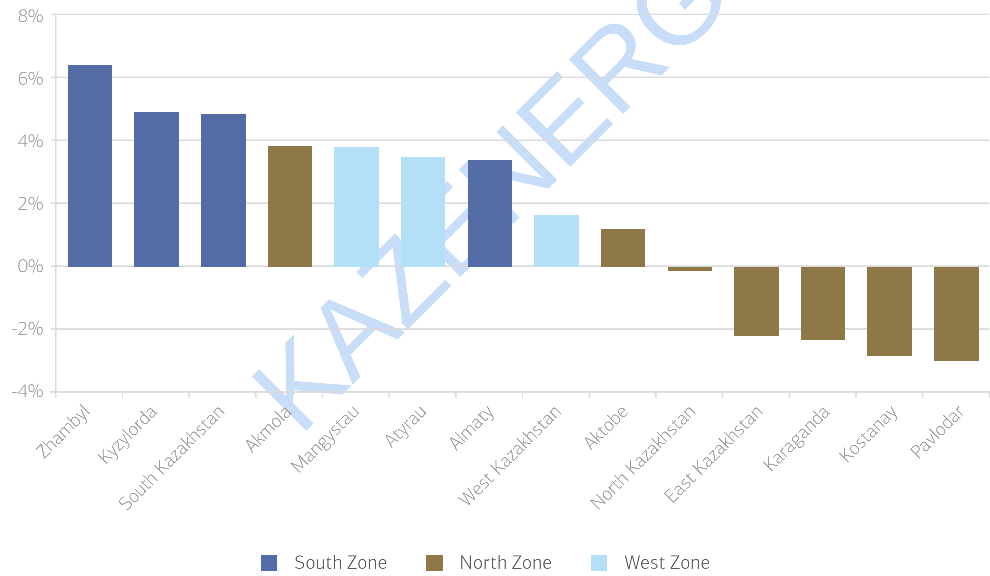
Source: SEEPX Energy

Figure 10.7 Map of Kazakh power sector



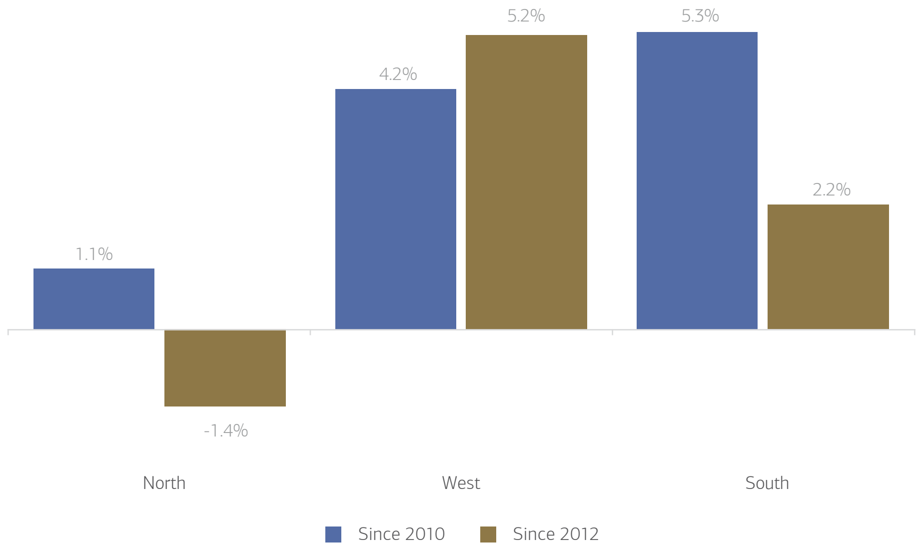
Source: IHS Energy, KEGOC

Figure 10.8 Regional power consumption: average annual growth since 2010



Source: IHS Energy, KEGOC

Figure 10.9 Regional power consumption: average annual growth since 2012



Source: IHS Energy, KEGOC

Figure 10.10 Average annual power consumption growth by Kazakh power zone

Power consumption patterns in Akmola Oblast stand out among its neighbors in the North Zone of Kazakhstan. This oblast, like its northern neighbors in the last decade, had been registering robust annual growth, averaging around 6.5%. However, growth in Akmola Oblast has been mainly attributed to residential growth due to the rapid expansion of Astana after it was designated the national capital; consequently, Astana has experienced the effect of shifting commercial activities and rampant construction. In addition, relatively buoyant oil prices influenced the speed of growth, which in turn expanded commercial activities, and helped swell the city's population. More evidence of this phenomenon can be found when examining Akmola's peak demand—that has grown more rapidly than any region of the country over the last 10 years. The upward trend in power consumption will continue due to the city's status. Since 2012, power consumption in Astana registered an average annual growth of 6.7% (the only other oblast in the North Zone to record consumption growth in this period is Aktobe Oblast).

Since 2010, in percentage terms, southern Kazakhstan has led power consumption growth in the country. For example, four of the top five growth provinces in Kazakhstan were in the south: Kyzylorda Oblast grew on average by 7.5% annually; Zhambyl Oblast—8%; Almaty Oblast—3.8%, and South Kazakhstan Oblast—5.7%. It appears that industry and commercial activities have been an important driver in the south. Over the last decade, industry-related power consumption growth in Zhambyl Oblast has been averaging around 4.8% per annum; Kyzylorda Oblast—19.2%, and South Kazakhstan Oblast—8.2% (see Figure 10.11 and Figure 10.12). Industrial growth in Almaty Oblast has been growing a modest 3.1% annually—emphasizing the former capital's more mature residential and commercial position in power demand, but also the impact from a general migration of activity and work force to Astana. Despite that, Almaty Oblast holds the third largest regional share in power consumption in Kazakhstan and still exhibits solid growth, but this is mainly owing to strong growth trends in consumption from Almaty's population, which more than negates mild declines in industrial consumption.[15] As a result, Almaty Oblast's commercial sector will continue to expand and peak demand will become more pronounced over the medium term.

Similarly to southern Kazakhstan, most provinces in western Kazakhstan are registering robust growth in power consumption. But in this case, western Kazakhstan's growth is attributed to population growth, most probably sustained by oil and gas developments.

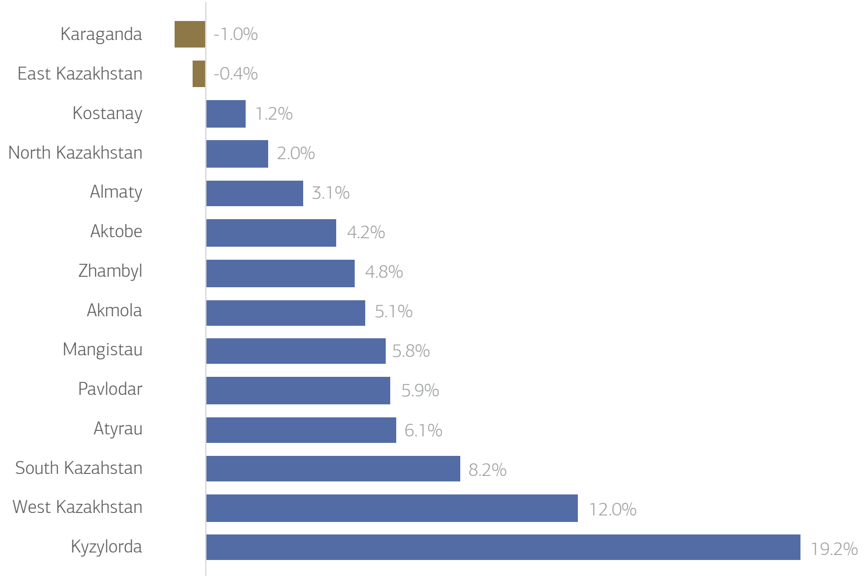
In summary, in southern and western Kazakhstan, consumption is clearly on the rise. Basically, in lockstep in consumption, these regions are also experiencing a sharp rise in population growth, which far outstrips that of northern Kazakhstan (outside of Astana; see Figure 10.13). This is clearly an important factor in the overall calculus, and one to watch closely moving forward.

For power consumption and overall peak demand, we expect southern and western Kazakhstan to continue a growth trajectory. This presents a challenge for policymakers to ensure that there is sufficient power to meet domestic needs. Currently, KEGOC typically moves power from the capacity-rich north to meet demand in the power-deficient south. In addition, Kazakhstan historically imported power from Kyrgyzstan's hydropower plants, mostly during the country's power-rich spring. But as Kazakhstan improves gas supplies, particularly in the south, the opportunity will arise for greater gasification of the power sector. For example, Almaty is likely to shift from coal to gas, but also, in time, new gas power projects are likely to emerge to satisfy a large share of demand.[16] The growth trend of industry in southern Kazakhstan is also likely to mean more private and autogeneration, as industrials try to counter evitable rises in power costs, along with improving the quality of overall power supply. As with Russia, with better availability of gas, and market incentives,

[15] Growth of power consumption by population is attributed to population increase and /or growth of domestic appliances use.

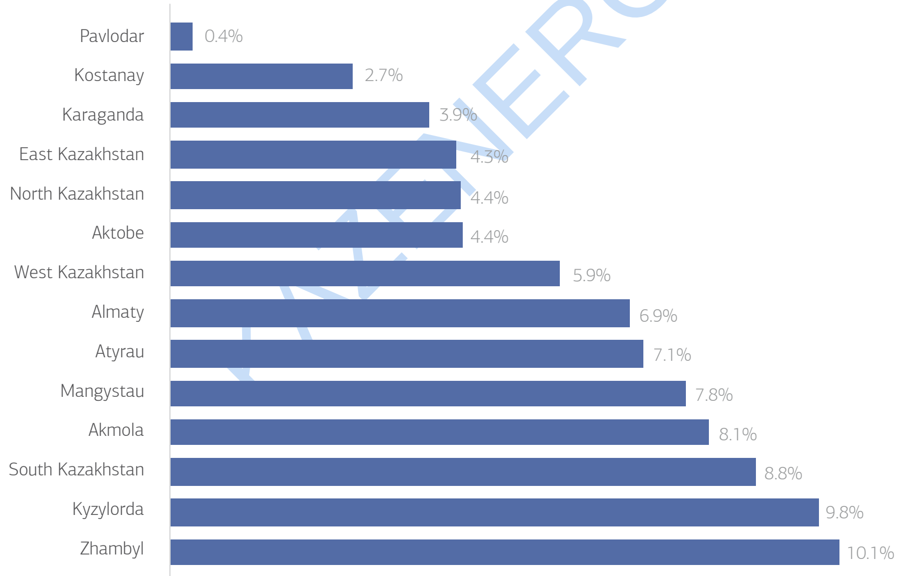
[16] A shift to combined cycle gas turbine (CCGT) units is being considered for the Almaty TETs-1 and Zhambyl GRES, as well as the gasification of Almaty City.

the rise in autoproduction in southern Kazakhstan could play a greater role in filling the gap between regional demand and electricity availability.



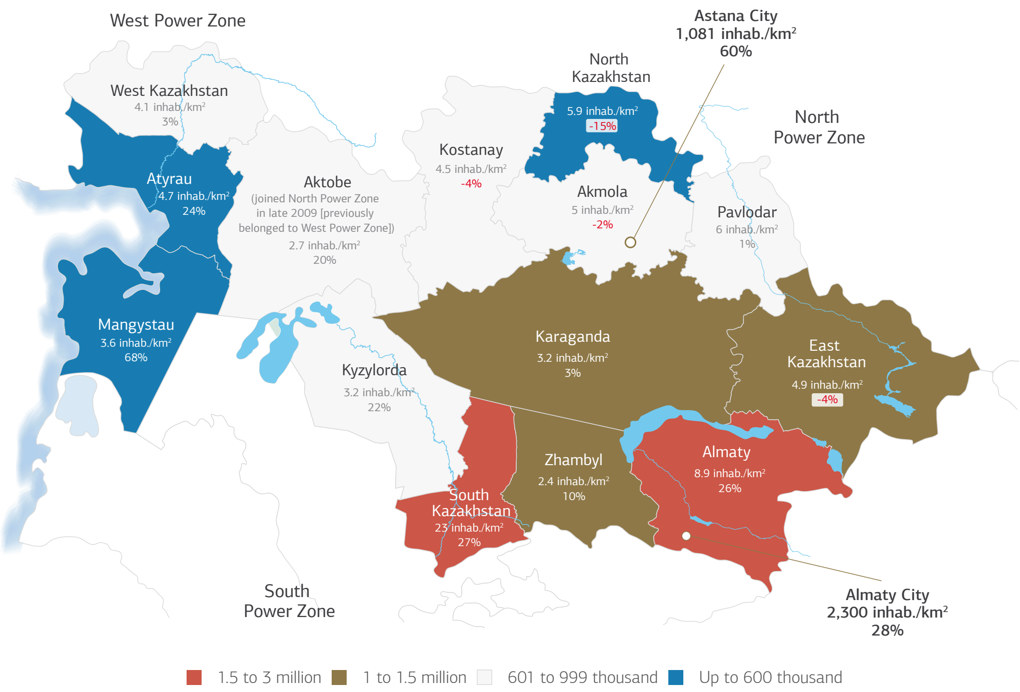
Source: IHS Energy, KEGOC

Figure 10.11 Industrial power consumption: average annual growth over 10 years



Source: IHS Energy, KEGOC

Figure 10.12 Residential power consumption: average annual growth over 10 years



Source: SEEPX Energy

Figure 10.13 Map of Kazakhstan's population; percentage figures indicate population change since 2004

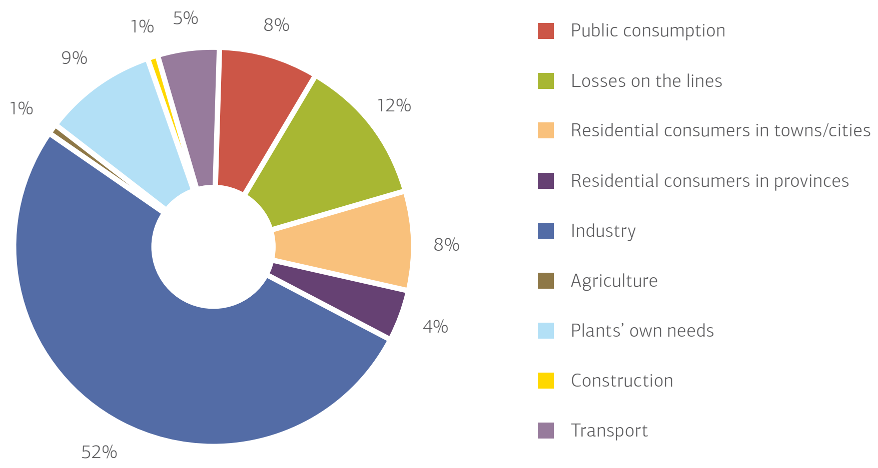
10.5.1. Industry: the key driver of electricity consumption

Industry has been the largest electricity-consuming sector in the Kazakh economy by far, accounting for just over 65% of final electricity consumption in the late 1980s and sliding to 64% in 1990 (when removing losses and power plant's own-power use in the calculation). However, industry's share contracted significantly to 52% by 2013 (see Figure 10.14), but in part this is because residential consumption has changed significantly in recent years.[17]

Kazakhstan's heavy industrial base, especially its large production of metals, makes it a very electricity-intensive economy. Per capita electricity consumption (6,389 kWh per capita in 1990, 3,663 kWh in 2000, and 5,357 kWh in 2014) is high compared to most countries. Similarly, in terms of electricity use per unit of GDP (energy intensity), Kazakhstan's power consumption remains among the highest in the world, as well as within the CIS. This is comparable only to Kyrgyzstan and Tajikistan, where electricity is a large share of primary energy consumption because of their sizable hydropower generation. Within industry, major consumers include metallurgy, the chemical industry, mining, oil and gas, and construction materials. Kazakhstan is a large producer of all of these products, with a number of large enterprises. Mining (extractive industries) accounts for about 20% of industrial consumption, and manufacturing about 60%. The largest consuming sector within industry is nonferrous metallurgy, which accounts for 24–25% of total industrial consumption. This is followed by ferrous metallurgy at about 20–21%, electric power generation and distribution at 15–16%, oil production about 10%, metal ore mining 9%, and chemicals 5%. Thus, altogether metallurgy by itself (nonferrous, ferrous, and mining of metallic ores) accounts for about 55% of total industrial electricity consumption.

Through 1990, agriculture and the housing/municipal sector consumed almost equal amounts of electricity, at 14–15% of final consumption each. But the statistical reporting methodology changed in 1996 to remove rural household consumption from agriculture, and now the housing/municipal sector is the second largest consumer by a considerable margin, accounting for 25% by 2013 (when removing losses and power plant's own-use in the calculation). This jump also reflects the growth of consumerism (more electric appliances, larger apartments, etc.) and the relative growth in the service sector that is part of the broader post-Soviet economic transition.

[17] Available data and collection methodology for power consumption in Kazakhstan vary considerably according to the collecting organization. Moreover, there have been several changes in accounting methodology over time.



Source: IHS Energy, KEGOC

Figure 10.14 Power consumption by category in 2013

10.5.2. Electricity consumption growth to remain robust despite lower economic growth

Kazakhstan's relatively rapid growth in electricity demand during the past decade, essentially a rebound, is unlikely to maintain the same momentum: electricity demand growth, like overall economic growth, is likely to be much slower going forward. Whereas annual average GDP growth during the 2000s was nearly 8%, IHS projects average annual growth in 2015–2040 at less than half of this rate, 3.3% per year, which is still fairly robust by international standards, though less than the official government forecast.[18] However, economic growth in 2015 is expected to be around the officially projected rate (1.6%). Longer term, the economy will remain relatively industrial given the country's resource base and its comparative advantage internationally.[19] Nonetheless, the average elasticity between power demand growth and GDP growth is expected to decline over time under a combination of improved efficiencies in use as well as structural changes in the broader economy that make it less energy intensive.[20] Thus, the IHS Energy outlook is for average annual growth of 1.2% in final electricity consumption during 2015–2040. This means average elasticity between GDP growth and electricity consumption over the entire period softens to about 0.32, from averaging 0.51 since 2000. Even though power-to-GDP elasticity has been significantly higher than what is expected moving forward, it is a common phenomenon for an industrial economy like Kazakhstan after experiencing a resurgence to then go through a sustained natural maturation period. Regardless of the precise rate of GDP growth, this maturation period will be mainly driven by:

- Rising power prices, forcing economizing and improved efficiency
- Saturation of home new appliances and slowdown of commercial sector development

National consumption in the outlook is aggregated upward from projections for each major sector. Final electricity consumption in 2035 is projected to be 103.8 billion kWh by 2035 (or 108.1 billion by 2040), and total apparent consumption (including self-use by power plants and line losses) is projected at 116.6 billion kWh in 2035, or 120.9 billion by 2040 (see Figure 10.15). Of final consumption, relatively little change is expected among the major sectors by 2040: industry still accounts for nearly 61% and the housing/municipal sector for 30%.[21]

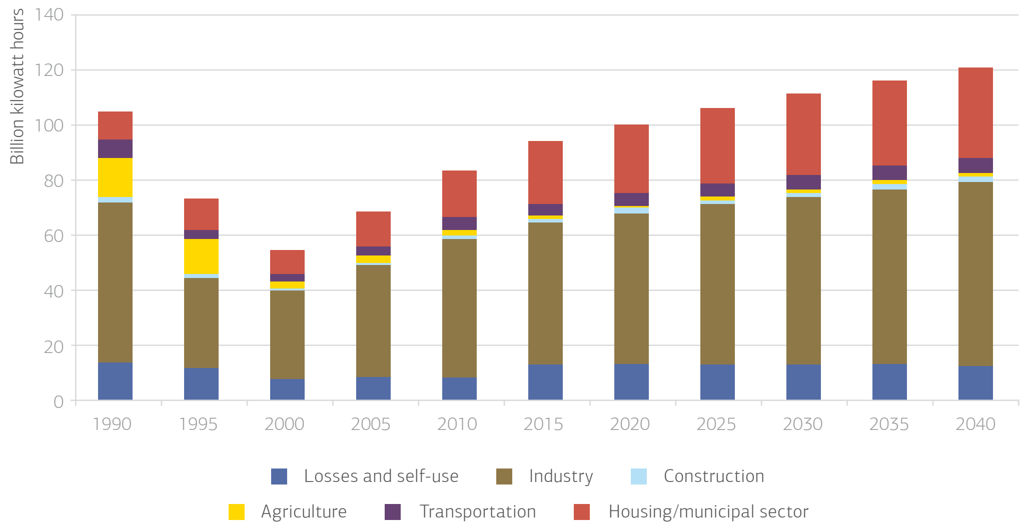
See section 10.12.3 for a more detailed breakdown on IHS Energy's methodology for the electric power outlook.

[18] The "Forecast of Socio-economic Development of Kazakhstan in 2015–2019" estimates economic growth at 5.0–6.8% annually, driven by an anticipated increase in investment activity and internal demand, as well as further industrialization of the economy and improved export conditions.

[19] See the text box below "IHS Energy Methodology for Electric Power Forecasts" and Appendix 10.12 for more detail on "Key Underlying Elements in Kazakhstan's Long-term Energy Outlook."

[20] The State Program of Industrial and Innovative Development of Kazakhstan for 2015-2019 targets decreasing energy intensity of processing industries by 15% by 2020; The Strategic Plan of Kazakhstan Development by 2020 targets a decrease of the country's GDP energy intensity by 25% by 2020; Kazakhstan "Energy Saving-2020" plan points to measures of increasing energy efficiency of large industrial companies through modernization of production.

[21] When removing losses and power plant's own-use in the calculation.



Source: IHS Energy

Figure 10.15 Outlook for electricity consumption in Kazakhstan

10.5.3. Key issues in the outlook

The official government forecast envisions a somewhat higher rate of growth in total electricity consumption, projecting total apparent consumption at between 136 billion and 175 billion kWh by 2030, subject to the scenario employed (growth at an average rate of 3–5% per year between 2012 and 2030). This is versus the IHS Energy outlook of 111.4 billion kWh in 2030 (1.1% annual growth).[22] Even though the government envisages a more rapid rate of expansion in residential-municipal electricity consumption, the anticipated growth appears aggressive.[23]

The annual average growth of power consumption is one of the fundamental criteria used in short- to mid-term planning for power sector development. Traditionally it is based on the forecast of a country's social and economic development. At present, Kazakhstan's forecast of its social and economic development in 2015–2019 is based on the assumption of a slow but gradual growth of the global economy, a price of oil of $90 per barrel, and an increase of export opportunities for Kazakhstan's industrial consumer base. While Kazakh policymakers plan for structural reforms and aim to diversify the country's economy long-term, in the short- to medium-term the reforms and the program of industrial and innovative development mainly anticipate the opening of further export potential for its processing and mineral resources companies. The continued dependence of Kazakhstan's economic growth on global trends means projected industrial growth will be lower, substantially affecting assumptions for future power consumption growth (given the impact of industry on power consumption in the country). In addition, the history of power market liberalization in other CIS countries has also revealed a tendency for overly ambitious planning on a regional level. In the absence of control mechanisms over accuracy and accountability for regional development forecasts, plans have tended to inflate the overall power consumption forecast figures. This in turn influences overall assumptions of sector investment needs, priority of investment, and launches of generating/grid assets, and has had a detrimental impact on end-user power costs.[24] Therefore power consumption projections should factor in all of the following variables:

- Historical elasticity of GDP to power consumption
- Elasticity of GDP to industrial production (adjusted for anticipated improvement in energy efficiency longer term)
- Elasticity of GDP to industrial production and power consumption
- Elasticity of GDP to power consumption by the population (considering both the impact of population growth and higher standards of living in the future).

[22] Government of Kazakhstan provision No. 724 of 28 June 2014 "Concept of Fuel and Energy Sector Development of the Republic of Kazakhstan until 2030."

[23] Per capita electricity consumption in Kazakhstan for just the housing/municipal sector is already quite high by international standards at over 1,100 kWh in 2012 (higher than in Russia, for example, and in many other middle-income developing countries), and therefore is unlikely to increase at a substantially higher rate than the national average in the outlook period. This relatively high consumption figure indicates a relatively high saturation of household appliances and household usage already. Newer (but more efficient) appliances are likely to increase their penetration as household incomes rise over time, but without raising sectoral consumption disproportionately.

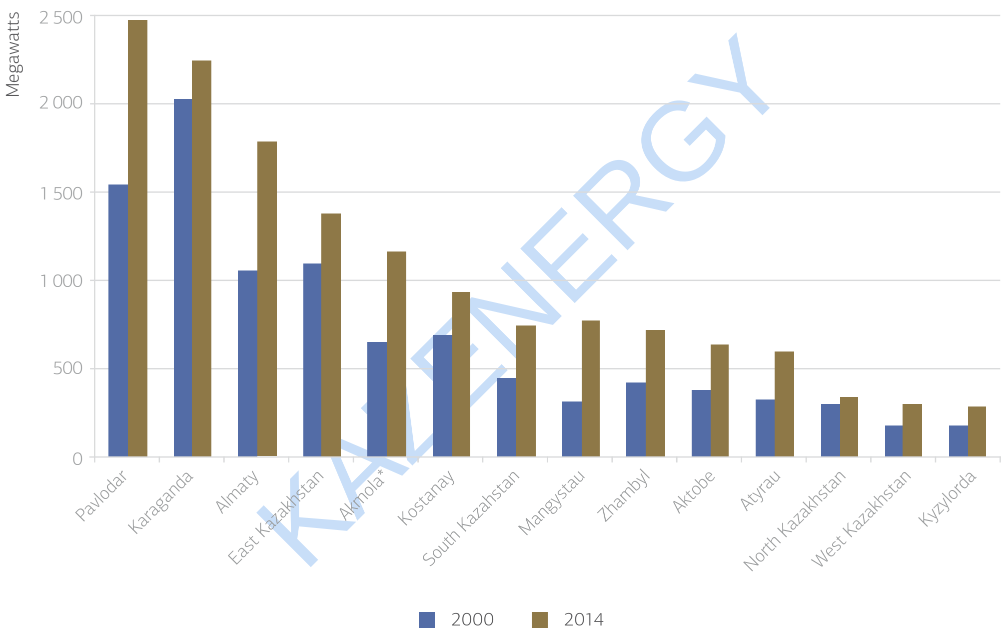
[24] According to neigboring Russia's Sovet Rynka (the regulator of Russia's wholesale power and capacity market), in 2015 Russia will have an estimated 20 GW of excess generating capacity. This excess capacity is a result of aggressive program implementation on new generating assets construction based on overinflated regional consumption projections as well as absence of market mechanism for decommissioning of aged capacity.

10.5.4. Peak load rising with total consumption

Peak load in the Kazakh grid has been steadily climbing, roughly matching growth in total electricity consumption. This is different from many other CIS countries, where the higher rate of growth of residential and service demand has boosted peak load at a faster pace than total consumption. However, a sharp growth in peak demand is characteristic in Kazakh regions where population has been growing fastest, typically in the western and southern parts of Kazakhstan. And Akmola Oblast in northern Kazakhstan stands out purely because of the rapid expansion of the capital city, Astana, where its population has grown by 60% over the past decade (see Figure 10.13, Figure 10.16, and Figure 10.17).

To date, peak demand estimates in Kazakhstan have been based on a scenario in which maximum consumption typically occurs once a year during December. However, after a sustained period of economic development the consumption patterns of certain demand centers are likely to exhibit a "peakier" profile (e.g., multiple peaks). Ultimately peak demand is central to Kazakhstan's short- to medium-term power sector development plans (KEGOC uses it as a basis for a seven-year forecast of the UES Capacity Balance). This is where policymakers would define power production needs, reserve capacity, investment requirements, direction of investment, and most importantly the financial burden on the end-user power costs.[25]

In the past 14 years, the peak load in Kazakhstan has grown by 5 GW (gigawatts), which is an average annual growth of 3.4% (from a low point in 2000 of 8.6 GW to 13.6 GW by the end of 2014).[26] Over the same period, power consumption has grown by 37 billion kWh, meaning that for every 1 GW of peak demand growth in the UES of Kazakhstan there has been a 7.3 billion kWh growth in power consumption. In line with our consumption forecast, IHS analysis indicates peak demand will reach only about 19.9 GW in 2040 (18.2 GW in 2030, and 19.1 GW in 2035); these figures are more commensurate with our lower projection of overall electricity consumption than in the government forecast.



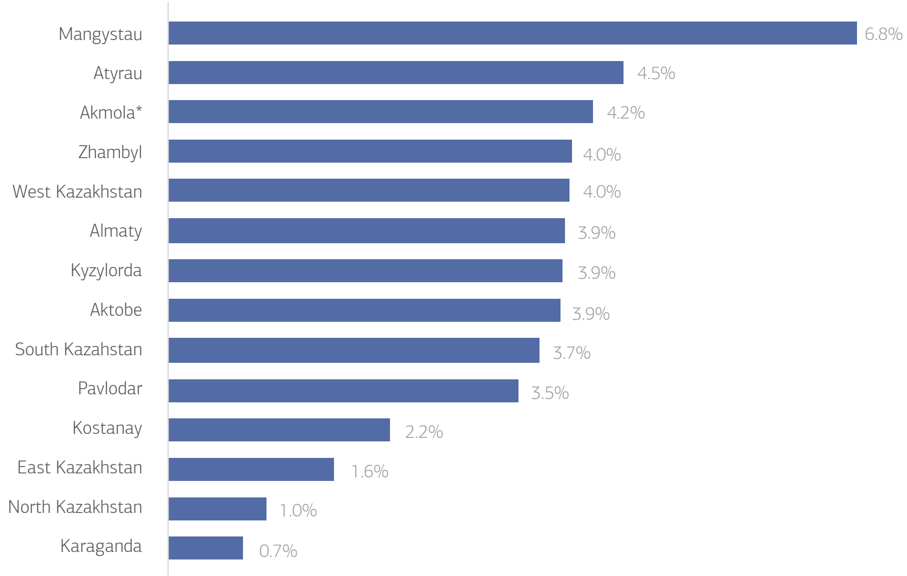
*Note: *Akmola combined peak*

Source: IHS Energy, KEGOC

Figure 10.16 Maximum peak power demand by oblast (2000 versus 2014)

[25] The Capacity Balance is made for a seven-year period and is reviewed annually.

[26] Peak demand in 2014 is estimated at 15 GW. For the first time it exceeds the Soviet-period high of 14.4 GW in 1990.



**Akmola combined peak*

Source: IHS Energy, KEGOC

Figure 10.17 Average annual peak power consumption growth since 2000

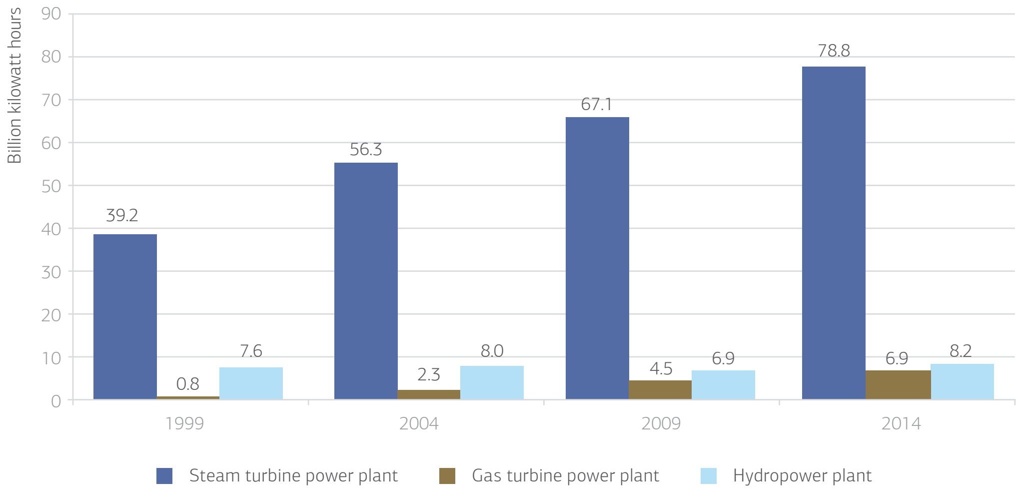
10.6. Electric Power and Heat Energy Production Trends

As noted above, Kazakhstan is the third-largest producer of electricity in the CIS, accounting for about 6% of the former Soviet total in recent years. Electricity production in Kazakhstan reached a Soviet-era maximum of 89.7 billion kWh in 1989 and output dropped by nearly half over the ensuing decade; by 1999, production was down to 47.5 billion kWh. However, electricity production rebounded in 2000, and by 2012, under the impetus of strong economic growth, actually surpassed the 1989 level; in 2014, according to KEGOC, output reached a new all-time high of 93.9 billion kWh, representing an average annual growth rate since 2000 of 4.4% (see Figure 10.18).

Given Kazakhstan's abundant fossil fuel resources, it is not surprising that almost all electricity production is from thermal stations (about 90%). Coal used to fuel power generation was about 69% of overall production, while gas was about 20% and oil just 2%. Hydropower produced about 9% and renewables (wind and solar) was less than 1% (see Figure 10.19). Coal-fired power plants, largely using cheap domestic coal (from the Ekibastuz and Karaganda basins as well as some local production in southern and eastern Kazakhstan), provide most of the power. In 2014, the share of fuel use for Kazakhstan's steam turbines (that is when excluding gas turbines), was 76% for coal, 22% was gas, and a small amount of oil (2%) comprises the residual.

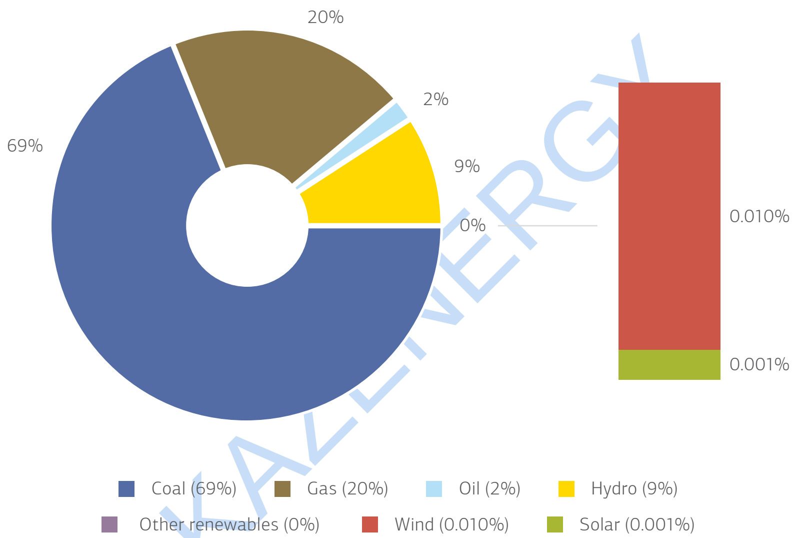
In 2014, installed capacity for gas-turbine power stations was 1.43 GW (available capacity was 1.39 GW), producing 8.2 billion kWh (see Figure 10.18), and accounting for about 7% of the national total. Production from gas-turbine power plants has grown on average 11% per year since 2000 versus almost 5% per year from other thermal power plant categories[27], and on average hydropower production has increased slightly by 0.7% per year—although it is likely to grow further with the Moinak hydropower plant in the Almaty Oblast (300 MW) coming online.

[27] The gas reciprocating plants characterized by high efficiency and ability to burn associated gas directly became popular with oil and gas companies. They are used for autonomous power supply so they are not really part of the overall power balance.



Source: IHS Energy, KEGOC

Figure 10.18 Electricity production in Kazakhstan by type



Source: IHS Energy, KEGOC

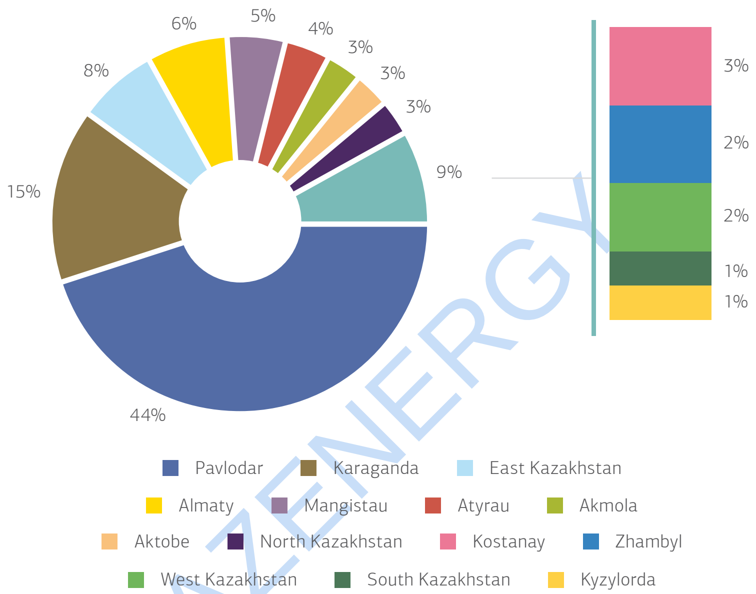
Figure 10.19 Share of electricity production in Kazakhstan by type in 2014

Power production is dominant in Kazakhstan's North Zone

Pavlodar Oblast accounts for almost half (40.8 billion kWh or 44% in 2014) of Kazakhstan's entire power production. Together with Karaganda, the two provinces make up 59% (54.6 billion kWh) of power production in the country (see Figure 10.20). These provinces house some of Kazakhstan's largest and most well-known generating assets: Ekibastuz GRES-1 (3500 MW [coal]) and Ekibastuz GRES-2 (1000 MW [coal]), Karaganda GRES-2 (715 MW [coal]), and Asku GRES (2100 MW [coal]). Since 2000, Pavlodar Oblast also stands out for significantly increasing annual production, by 22 billion kWh: this is slightly more than all of Kazakhstan's other provinces put together, which was 21 billion kWh.

In southern Kazakhstan, Almaty TETs-1 (145 MW [gas/coal]), TETs-2 (510 MW [coal]), and TETs-3 (173 MW [coal]) and Zhambyl GRES (1240 MW [gas/oil]) are the most prominent power producers in the region. However, southern Kazakhstan suffers from a capacity shortfall, mainly in the winter months. Over time, southern Kazakhstan is likely to add gas capacities (rather than coal), as more gas becomes available through higher production and expansion of Kazakhstan's gas pipeline network.

In western Kazakhstan, when adjusting for Aktobe Oblast, production since 2000 has accelerated when compared to the rest of the country, particularly since production has decelerated in recent years in the northern regions. Understandably, owing to the oil and gas industry activities, western Kazakhstan (mainly West Kazakhstan, Atyrau, and Mangystau oblasts, but also including Aktobe and Kyzylorda oblasts) has a high share of gas-turbine production versus other gas-fired technologies (about 35%).



Source: IHS Energy, KEGOC

Figure 10.20 Share of Kazakh electricity production by oblast in 2014

10.6.1. Cross-border electricity trade

As noted in the section on regional energy pools (above), Kazakhstan's power system operation still largely reflects its original [Soviet] design—to serve the needs of a single inter-state economy—and consequently, the country is still relatively involved in inter-republic electricity trade. Yet despite that, Kazakhstan has recently made considerable grid improvements that afford greater energy independence and, as a result, export and import volumes have plummeted since the breakup of the USSR. For instance, exports have contracted from 13.6% of total generation in 1990 to 1.4% in 2012, and imports make up 2.8% of its aggregate apparent consumption requirements, compared with 27.9% in 1990 (see Figure 10.21).

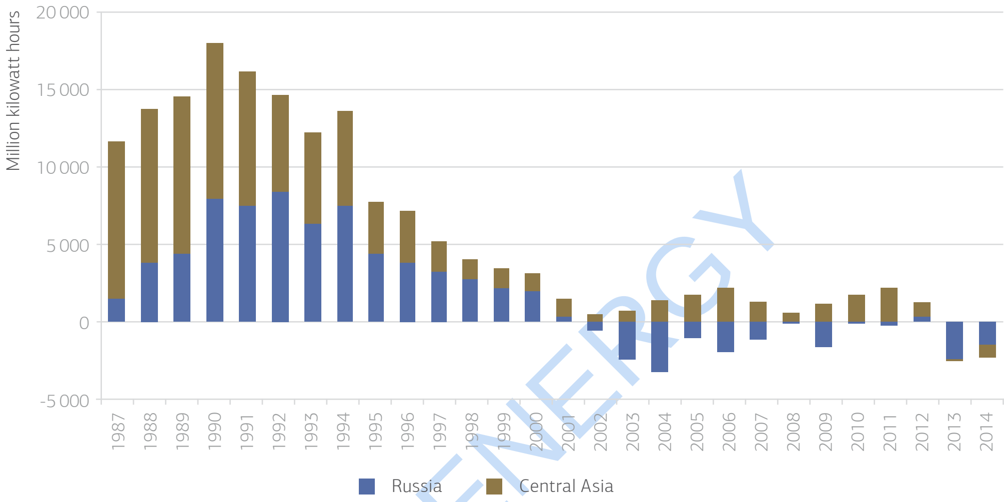
Notably, since 1999, which was the lowest point of power demand in Kazakhstan in the post-Soviet era, consumption and production have grown quickly, and have proven to be reasonably evenly matched (see Figure 10.22). This has meant that inter-republic power transfers have not returned to the 1990 highs. And as mentioned above, after grid strengthening and general improvements (since 2009 several new 500 kV links were established [connecting Aktobe with the North Zone and doubling transit capacity between the North and South zones]), Kazakhstan has found itself considerably better placed, relying less on imports by being able to shift more power internally. Despite this, power transfers with Russia and Central Asia are still important for balancing support with neighboring grids and overall stability. For instance, the western part of Kazakhstan (the main oil-producing area) gets support from power plants in neighboring Russia. And the grid system of southern Kazakhstan as a rule remains dependent on seasonal power exchanges with the Central Asian countries (especially Kyrgyzstan and Uzbekistan).[28]

[28] In 2014, with a fall in water levels at Kyrgyzstan's Toktogul Reservoir, and thus poor hydrological conditions for the country's cascade of hydropower plants, Kazakhstan has shifted from a historical net importer of power to exporting almost 35 million kWh to Kyrgyzstan.

The future for Kazakh power imports and exports will remain consistent with recent trends and developments irrespective of trade opportunities brought about by the single Eurasian power market.[29] The "Concept of a Single Eurasian Power Market" targets improved transparency, information disclosure, and accountability for parallel operation of the Armenian, Belarusian, Kazakh, Russian, and Kyrgyzstan power systems. Power trade will be subject to economic advantages and technical needs.[30]

Nevertheless, in a similar vein to Kazakhstan, Russia is working towards increasing its own energy independence. For instance, Russia is in the process of completing the 500 kV Voskhod-Vityaz-Kurgan transmission line, which will increase the capacity between Russia's Urals and Siberian power systems by some 400–600 MW. Naturally, this line will reduce Russia's dependence on Kazakhstan as a hub for power transfers and balances (between Russia's European and Siberian power systems) (see Figure 10.1). For Kazakhstan, Russia's Voskhod-Vityaz-Kurgan 500 kV line is likely to result in a decrease of power exports from Kazakhstan by around 20%. While power trade will continue somewhat, power market operations between Russia and Kazakhstan will be mainly technical balancing subject to power outages and emergency fluctuations.

Essentially, Kazakhstan will continue to transfer power as a system support measure, and naturally there will be also opportunistic trade with its neighbors when commercially viable. For example, there is potential for Kazakhstan's power exports to Central Asia as and when the CASA-1000 project (transmission link between Central Asia and Pakistan, via Afghanistan), and related projects, comes to full fruition.

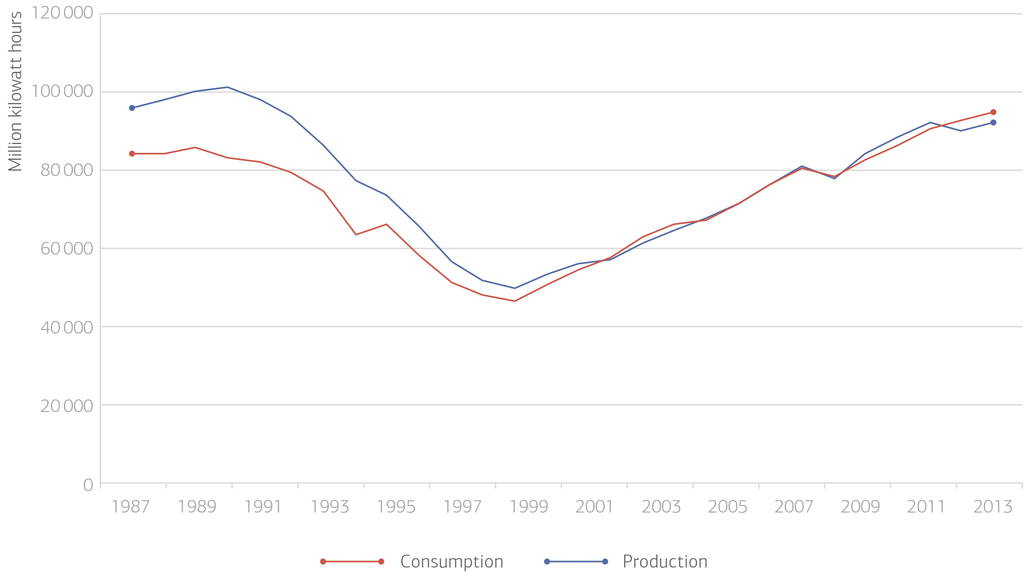


Source: IHS Energy, KEGOC

Figure 10.21 Kazakh power imports and exports

[29] "Concept of a Single Eurasian Power Market," resolution of the Supreme Eurasian Economic Council No.12 of 8 May 2015.

[30] According to current legislation in Russia, cross-border trade is limited to a single Russian entity, Inter RAO; Kazakhstan is likely to adopt similar legislation (Armenia and Belarus also have similar power trade companies holding a single mandate for international power trade).



Source: IHS Energy, KEGOC

Figure 10.22 Kazakhstan's electricity production and consumption

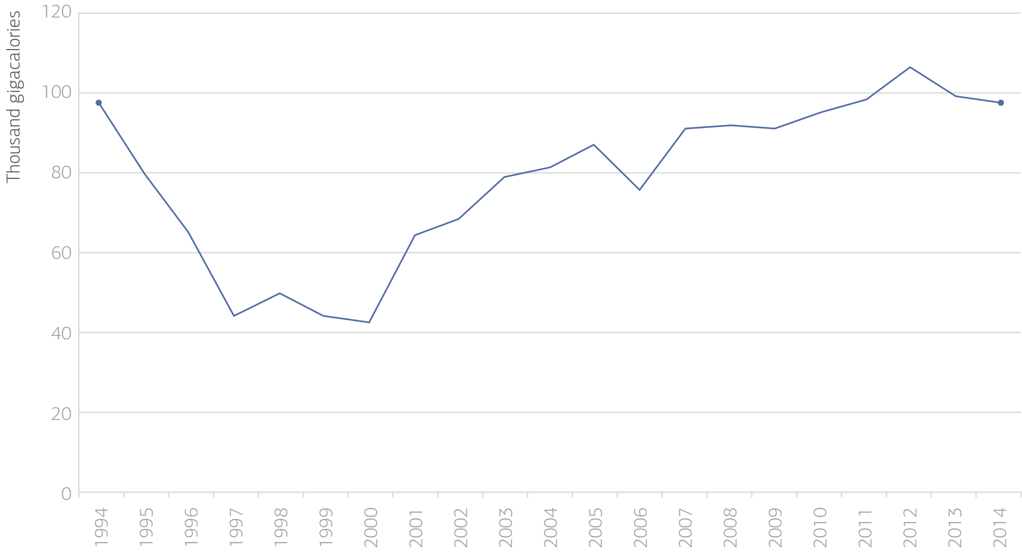
10.6.2. Kazakhstan's heat energy production and producer tariff formation

A common feature intrinsic to the energy balances of CIS states is the large share of centralized heat provision to meet final energy demand. Kazakhstan is no different, with centralized heat accounting for 15–17% of final energy demand in recent years.[31] For Kazakhstan's industrial sector, this figure was about 25% in 2013 and for the residential sector (households) the share of heat in overall energy consumed was about 22%. For households, the amount of energy consumed in the form of heat is exceeded only by electricity, including direct fuel consumption. District heating networks serve most major urban areas in Kazakhstan.

Production of heat energy in Kazakhstan was reported as 97.6 million gigacalories in 2014 (see Figure 10.23). Heat is produced by 40 heat-and-power plants (TETs), which account for 45% of the overall heat energy production in Kazakhstan, 28 large boiler houses, accounting for 35% of heat energy production, and 886 small boiler houses (less than 100Gcal.h), accounting for about 20% of heat energy production in the country. For the most part, these units are fairly dilapidated, with wear and tear of the heat energy generating equipment estimated at nearly 70%. About 24% of the 12,300 km network also requires urgent replacement (in some areas the wear and tear is as high as 50%). According to the 2014 Concept of Fuel and Energy Sector Development, only about 75% of the produced heat energy actually reaches the end-consumer.[32] This high degree of dilapidation is a result of decades of poor maintenance stemming from underfunding, violation of technical procedures (inclusive of insufficient coal and water quality control by boiler houses), and absence of effective regulation and planning.

[31] Final energy consumption is the energy delivered to end-users as opposed to intermediate use of primary fuels in transformation, such as petroleum refining, electricity generation, and heat production.

[32] Officially reported heat losses, according to Kazakhstan's statistical agency, have declined in recent years, from 11.9 million gigacalories in 2005 to 8.9 million in 2013, or from 13.0% of total production to only 9.3%.



Source: IHS Energy; Kazakhstan statistical committee

Figure 10.23 Production of heat energy in Kazakhstan

Kazakhstan's current heat tariff methodology

As discussed previously, the price of heat energy in Kazakhstan is regulated by the state. The TETs' tariff for the combined production of power and heat energy is set according to the cost allocation methodology. There are a number of approved methods of allocating variable costs between heat and power in Kazakhstan: physical, exergy, and proportional (used only at the MAEK plant in Mangistau Oblast).[33] The physical method allocates most of the costs to the production of heat energy and less costs to the production of electric power. The exergy method, on the contrary, allocates most of the costs to the production of electric power. Thus by exaggerating the cost of power production the plants artificially bring the cost of heat energy generation down. The reason for using both methods (which have been in use since 2005) lies in the physical nature of power and heat generation as well as the economics of the power plants (though the actual cost allocation is rather subjective). Nevertheless, since in practice the tariffs for heat energy are set at levels that fail to cover production costs and stimulate sufficient reinvestment in heat energy assets (as a result of government policy of suppressing heat energy tariffs), the methodology of redistribution of costs between the heat and power sectors legalizes the "cross-subsidization" of heat energy by electric power.[34]

TETs remain a major source of heat energy supply, and taking into account that the TETs' ratio of fuel utilization is higher than that of condensing plants and boiler houses, they are physically more efficient.[35] Nevertheless, in practice due to heat tariff suppression (for social reasons) the profitability of TETs could be worse than that of condensing plants and boiler houses. TETs' efficiency dependence on heat load and the administrative restriction to the heat energy tariff methodology prevents TETs from demonstrating the advantage of cogeneration from an economic point of view. A decrease in heat load from designed levels has been an additional factor that has impacted TETs' economics. As a consequence of the global economic slowdown that began in the late 1990s, industrial consumers, as well as small and medium-sized businesses, have drastically curtailed their heat energy (steam) consumption, making state budget–funded and residential household consumers key off-takers of heat energy (the consumer categories that traditionally are characterized by low payment discipline). However, TETs supplying heat energy to industrial consumers have demonstrated economically healthy revenues (such as the Pavlodar TETs-3 that supplies steam to the Pavlodar oil refinery).

The reasons behind the high level of costs and heat losses in the heat energy sector lie in the depreciation of equipment and infrastructure as a result of past underinvestment. The lack of investment interest in the heat energy sector now is a result of investors' fear of not getting a return on their invest-

[33] In the physical method, all fuel savings from the combined output of heat and electric power are allocated to the production of electric power, and the majority of other current costs (with the exception of fuel) are distributed between the heat and power output proportionally to the fuel use. However, the resulting inflation of the heat energy prices makes centralized heat supply uncompetitive. The method is based on the concept of exergy (a measure of the work potential or quality of different forms of energy in a given environment). It tells how much of the usable work potential (exergy) supplied to the system has been consumed (lost) by the process. The loss of energy is a quantitative measure of process inefficiency.

[34] The cost of heat energy is suppressed so the asset owners attempt to recapture lost revenue by inflating power prices. This, in turn, changes the economics of TETs and makes their wholesale power price uncompetitive.

[35] The efficiency of TETs is highest when operating in heating mode, enabling them to achieve optimal load for their main and auxiliary equipment, as well as realizing the best fuel efficiency. Given the importance of TETs for heat provision, during the heating season the system operator must give them loading priority in scheduling electricity generation—alongside hydropower—over other thermal generators. Yet even in heating mode many TETs fail to be economically successful.

ment under the current tariff methodology for heat energy tariff calculation. The basic tariff methodology is "cost-plus," but the growth of heat energy tariffs is limited to a predetermined factor based on inflation growth at a predetermined level. Therefore, TETs and boiler houses have been reluctant investors, as any improvement in efficiency or cost would result in a tariff reduction in the upcoming tariff-setting period rather than translating into increased operating margins.[36]

What the heat energy sector needs is a new long-term methodology for calculating heat tariffs, set at a fair level based on what the heat energy sector needs to recover costs and put in new investment.[37] Such a methodology would calculate the fuel utilization costs for the production of electric and heat energy using two or more methods individually for every TETs to identify the optimal prices and increase TETs' profitability (taking into account the regional aspects). Such an approach would make it possible to set optimal tariffs for heat (and electric power) for each TETs. However, this methodology will not improve the competitiveness of TETs operating in heating mode (when compared to power plants operating in condensing mode) due to TETs' power output dependence on the heat load.[38] The use of non-market mechanisms for supporting TETs operating in heating mode (for example, a guaranteed purchase of electric power from TETs with no guarantee of purchasing power from condensing plants) would defeat the purpose of the market to support the most efficient generation.[39]

Irrespective of the obvious arguments in support of centralized heat power supply, and co-generation in particular, the selection of the most efficient source of heat energy and electric power generation (taking into account the severe wear and tear of TETs' main electric and heat production equipment as well as loss of heat load) would force the market to make a choice—either to support TETs at any cost or to decommission inefficient TETs. The artificial support of TETs' operation poses a risk that in the end would deter them from improving efficiency (particularly if there is a guaranteed purchase of power and/or capacity, when the capacity mechanism is launched). Simultaneously, TETs' preferential treatment would postpone investment in other plants, as efficiency would no longer be a criterion for selecting generation. A fair heat tariff under the circumstances would help to avoid non-market methods of TETs support and stimulate efficiency.

When weighing the arguments for and against inefficient TETs, decommissioning 10–15% (technical and economic parameters rather than overall co-generation benefits) should be considered, as well as the availability of alternative sources of power and heat energy production. The choice in favor of heat supply by modern (highly technological) boiler houses would provide a strong argument if the economics of end-consumer heat (even when power is supplied by a different source) over the long term would be more beneficial. Subject to gas pipeline development, gas-fired steam TETs (abbreviated in Russian as PGU) technology could be considered.

The methodology of an "alternative boiler house" developed in Russia restricts heat energy production and supply growth to the tariff (a minimum price) that would ensure a return on investment for modern boiler house construction (which is to replace a source of centralized heat supply). Here the generating plants' heat tariff cannot be higher than that of an "alternative boiler house" acting as a tariff growth restrictive measure. In a situation in which the economics of heat generation and reliability of supply favor TETs, the TETs' heat tariff is expected at a minimum to reflect the cost of heat generation (e.g., breakeven). A preferential and guaranteed TETs' loading during a heating season would improve TETs economics further.

The differentiation of the heat tariff according to different consumer groups (to increase TETs' profitability) could further exacerbate cross-subsidies between consumer groups while not addressing the issues of sector modernization and efficiency. Therefore the government of Kazakhstan is presented with the challenge of reforming the heat energy market simultaneously with the changes to the wholesale market and capacity mechanism.

What Is Heat Energy?

Heat production consists of the provision of steam for industrial use and/or hot water for the needs of hot water supply and space heating or industrial processes; in Kazakhstan its output is reported in gigacalories (Gcal). Heat is similar to electricity in that it is a more flexible form of energy transformed from other (primary) fuels.

A significant difference between heat and power is that though both use a network, unlike electric power heat energy does not possess similar universal parameters. Heat energy parameters vary subject to source (temperature and pressure), and there is no physical ability for consumers to purchase heat energy over a distance

[36] The cost-plus methodology and short-term tariff-setting means that heat energy generating and supply companies are restricted in their access to financial markets to borrow funds. And for the same reason it is difficult to secure funding for heat energy efficiency projects.

[37] The government policy of suppressing heat tariff growth for the population and similarly subsidized categories is an obstacle to setting a fair heat energy tariff. However, the resolution of this issue lies outside the framework of market-related issues.

[38] TETs' power output efficiency is less than that of condensing plants. The anticipated launch of Kazakhstan's capacity mechanism and changes to the wholesale power market, without changes to the heat energy market regulation, present further risks to TETs' competitiveness, owing to the large excess capacity of condensing plants in the northern part of the country.

[39] The findings of a survey conducted jointly by IHS Energy and Power Center KING showed that of the 35 TETs responding to the survey, 10 (or 29%) were loss-making in 2014.

from the heat source even when a centralized heat network is in place.

The CIS countries employ a definition of heat generation that is different from Western statistical practices. The approach is to classify the transformation of primary fuels by industrial enterprises into heat on-site as heat production (a transformation activity) rather than as industrial consumption as the International Energy Agency (IEA) does; in the IEA methodology such activity is only considered heat production if it is for sales/distribution to third parties. At the same time the IEA does not include within final consumption of industry any losses occurring in the transformation of these fuels into heat in industry. The reason for this difference is historical: industrial enterprises in the CIS provided heat from their generating plants not only for industrial processes in the manufacturing facility, but typically also for surrounding districts of apartment blocks and commercial buildings or even entire cities or towns.

10.6.3. Heat energy consumption and consumer tariff policy considerations

According to the KazNIPIEnergoprom Institute, heat energy consumption will grow about 20% by 2030. Consumption of heat energy in Kazakhstan is concentrated mainly in three sectors: commercial-municipal, residential (households), and industry; minor amounts are shown as being consumed by agriculture, construction, and transportation, but this appears to represent heating of buildings and terminals. According to Kazakhstan's statistical agency, industry has accounted for 47–53% of heat consumed in Kazakhstan in recent years, households consume 28–34%, and commercial-municipal uses account for about 18–22%.

Heat energy tariffs for consumers (population) are calculated based on the size of the premises occupied rather than actual heat consumption, so any individual improvement in efficiency by a resident would not result in a heat tariff reduction. The installation of individual metering devices in apartments together with the simultaneous installation of a single house meter (for a block of apartments) could provide a way to address this problem. However, large scale installation of meters in apartments could be complicated due to technical, technological, and regulatory issues.[40]

Nonetheless, metering on its own cannot guarantee cost savings without insulation of common entrances, windows, flow control in the heating system, etc. Heat suppliers are compensated for the total volume of heat energy released to the consumer (at the point of the power plant), rather than the actual delivered volume. The central heating system methodology also envisages compensation of heat losses occurring en route from the TETs to the consumer's radiator. A greater effect from metering would be achieved by improving the heat supply control system and tightening requirements for the heat supply/house management company for the upkeep of the heating pipelines. In other words, a single meter for a block of apartments would enable consumers to control the quality of services delivered to them by the heat supply and house management companies (inclusive of expenses related to the upkeep of management, accountants, engineers, specialists, etc.)[41]

Any elimination of intermediary parties between a producer and a consumer of heat energy through the creation of a centralized heat supply company (CHSC) also could contribute to increasing the efficiency of the entire heat energy sector. A CHSC could take charge of its respective area and be in a position to optimize expenses, replace pipelines, and install meters. However, a CHSC's interest in increasing efficiency is viable only in an environment with strong technical regulations and economically justified tariffs, with an appropriate return on investment incorporated into such tariffs.[42]

[40] The technical issues for meter installation in blocks of apartments relate to the routing of heating pipes. The most common piping layout (particularly in Soviet-era apartment blocks) is vertical, with floor-to-ceiling pipes in each room. In other words, radiators in each room are linked with radiators in the apartments above and below and not with the other radiators in the same dwelling.

The calculation of consumed heat energy is based on the volume of delivered hot water and the difference in temperatures at the entrance and exit points of the pipes. Although metering each radiator is possible, it would be challenging, as the difference in temperature at any given radiator could fall within the measurement accuracy of the temperature measurement device. In addition, the high cost of individual radiator meters and relatively short working life expectancy of four to five years (taking into account more than two vertical pipes in an apartment) make installing individual meters economically dubious (particularly if the payment for individual meters as a rule becomes the responsibility of a tenant).

The installation of a single building meter (one meter for all apartments in a block) makes the task of heat metering much cheaper. The ultrasound flowrate meter, with a life expectancy of 25 years, makes greater economic sense taking into account the installation costs, given that the distributed cost is more affordable for every apartment (if heat meter installation is the responsibility of tenants, rather than the heat supplying company). As an alternative (to accelerate metering), the cost of installing single house metering could be undertaken by the management company.

[41] More efficient heat consumption planning by building residents could be another factor driving the heat load down, which would have a negative impact on the economics of TETs operating in the heating mode.

[42] Unlike electric power, heat energy distribution and supply in Kazakhstan are handled by one and the same companies. During the first stage of privatization, heat supply companies ended up in private hands; however, restricted by heat tariff growth (mainly due to social factors), meant that investment into the heating network upkeep was insufficient (10-15% of required volumes). Consequently, this has forced the government to repossess and transfer heat supply companies into municipal ownership (and to increase spending on heat network maintenance through state funding).

Centralized District Heating in Kazakhstan

The wide use of combined heat and power (CHP) plants to provide centralized heat reflected several dictums of Soviet central planning. The ability to capture waste heat via the special turbines installed in TETs allowed such stations (especially the larger ones) under the right conditions to attain higher average conversion efficiencies of up to 70% compared with 40% for modern steam plants supplying only electricity; hypothetically, this meant that the additional value of the recovered heat offset the extra costs of the additional equipment. Another major advantage of district heating is that it can use low-grade sources of energy such as waste heat, biofuels such as wood or straw, or solid fuels such as peat or lignite. Thus to central planners, these dual-purpose plants provided more flexible, cleaner, and convenient forms of electricity and heat than could be made available to final consumers through direct fuel combustion. While this is certainly an advantage when most thermal generation is coal fired, it becomes much less compelling with increased penetration of natural gas.

Geographically Kazakh market planners expect the biggest growth in heat demand to be in northern Kazakhstan (58%), presumably reflecting Astana's continued growth, followed by southern Kazakhstan (27%), with demand in western Kazakhstan growing 15% by 2030. By 2030, if the planned construction of gas-fired generation in the west of the country materializes, then the share of gas-fired plants involved in heat energy production in Kazakhstan as a whole will grow significantly, while the share of coal-fired heat-generating plants will decline slightly.

Finally, in the absence of effective centralized planning of heat energy supply in the past few years, the segment has evolved somewhat haphazardly without due consideration for best practices or pursuing optimal technological solutions, as well as consideration for the long-term consequences. Current legislation for the sector does not take into account the problems of the heat market nor does it offer a practical development path going forward.[43] Although the government recognizes that a separate law for heat energy should be developed, there is little indication that the government has formulated a succinct action plan that ties in with broader energy sector reform.

Nevertheless, Kazakhstan's desire to improve the efficiency of heat energy production means that policymakers should introduce measures that allow heat energy production to remain economically viable. Policymakers have several options to change Kazakhstan's heat tariff methodology from a cost-plus basis (as it is now) so as to establish a more reliable market value of heat energy.

These options include:

- Regulated asset base (RAB [also referred to as RAV])
- Benchmarking against boiler houses
- Benchmarking of cost redistribution methodologies
- Appropriate indexation.

However, these methods can create conditions that drive unwelcome hikes in heat tariffs for end-users. Lessons from neighboring Russia show that an unreformed heat energy market presents a major obstacle for policymakers as they attempt to move forward on overall power sector reforms, particularly in the face of anticipated power and heat energy consumption growth.

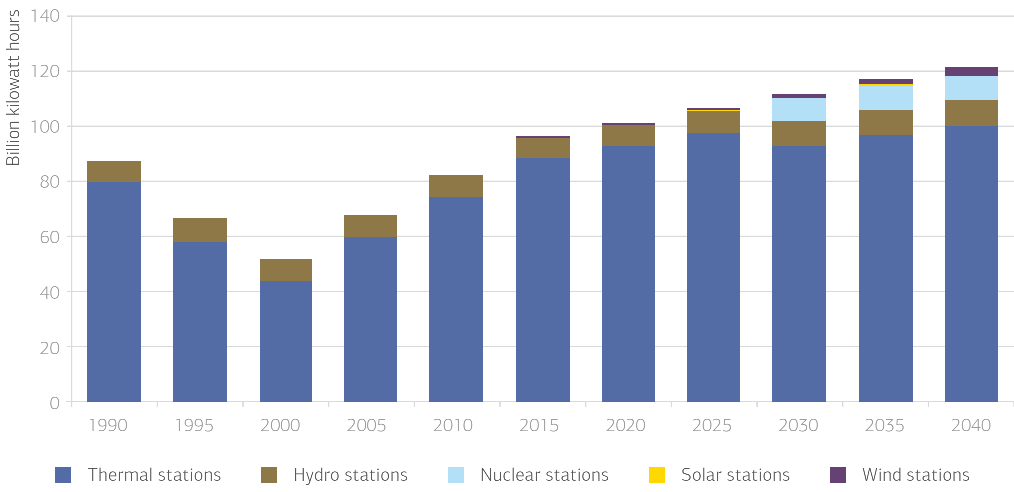
Due to significantly fewer TETs in Kazakhstan (than in Russia) Kazakhstan could be in position to develop individual heat energy tariff-setting models and come to an optimal solution drawing on the experience of heat energy markets in Europe. Support mechanisms together with TETs and centralized heat supply have been devised in Germany, Denmark, Austria, Sweden, Finland, Poland, and the Baltic states. They have achieved a variable level of success and as a rule include: stimulating tariffs for power supply into the grid, tax and investment benefits, as well as an obligation to purchase TETs' electric power output.

10.7. Production and Capacity Outlook

Electricity generation growth in Kazakhstan is projected to average about 1.0% out to 2040, essentially mirroring the expected growth in consumption. Thus, by 2040 total electricity generation in Kazakhstan is projected to be about 121 billion kWh (and 117 billion kWh by 2035), compared with 94.6 billion kWh in 2014.[44] Of total production in 2040, 83% is expected to be from thermal (fossil fuel–fired) plants, 8% hydro, 7% nuclear, and about 2% from renewables (wind and solar) (see Figure 10.24). Importantly, during 2015–2035, overall thermal production is likely to remain stable. In contrast, hydropower will grow by about 1% a year over the same period. However, hydropower generation in eastern Kazakhstan may see production levels threatened as growing water use upstream across the border in China impacts water volume downstream in Kazakhstan. In the IHS Energy's base-case scenario, we expect nuclear generation to come online by around 2026, which will mainly offset thermal generation, and in particular coal, even if the nuclear plant is built in the South Zone. The first unit would likely be around 1200 MW (see the analysis below). Oil use in power generation is expected to remain negligible.

[43] Law No. 588-II, "On the Electric Power Sector" of 9 July 2004.

[44] For IHS Energy's production outlook, historical data is based on Kazakhstan's National Statistical Agency. For 2014, KEGOC registered production at 93.9 billion kWh (versus 94.6 billion kWh).



Source: IHS Energy

Figure 10.24 Outlook for electricity production in Kazakhstan

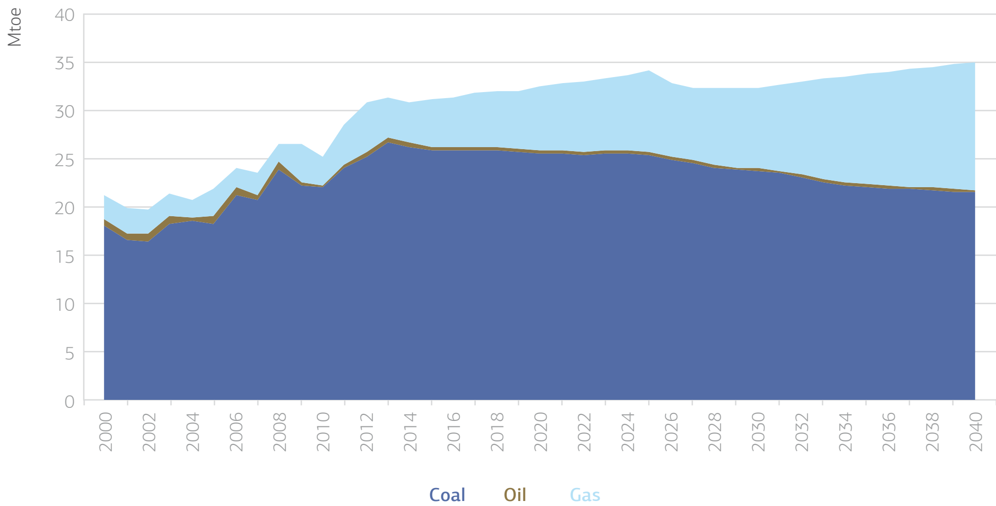
Thermal fuel mix to reflect a greater use of gas

Currently fuel use for electric power generation in Kazakhstan is dominated by coal; the share of gas is relatively small (see Figure 10.25). But this will gradually shift toward gas over the outlook period, owing partly to expanded oil and gas production in western Kazakhstan that creates a geographic shift in the country's overall economic activity toward this region, where gas is a natural fuel of choice for power generation. As discussed above, coal currently accounts for around 76% of fuel for thermal power production, and about 20% is gas.[45] But by 2040, this is expected to swing to about 61% coal and 38% gas (from 65% coal and 34% gas in 2035). Although coal will remain the dominant fuel for power generation in Kazakhstan, IHS Energy expects total coal consumption in electric power to remain relatively flat, albeit mildly declining, at about 20–25 million tons of oil equivalent (MMtoe) annually out to 2040. Kazakhstan's shift to more gas use in power generation is described in a later section; however, it can be summarized as follows:

- **Almaty City switching from coal to gas.** Almaty City has already started to switch from coal to gas, although the pace is set to quicken. First, Almaty is committed to improving its air quality, which at the moment is poor. Essentially, this means that if logistically viable all of Almaty's coal-fired power generating units will be converted, or replaced by new power plants. However, it is not exactly clear how and when this transformation will take place.
- **Zhambyl GRES upping power production.** Currently the gas-fired Zhambyl GRES is deeply underutilized, with power plant's load factor (utilization rate) consistently below 25%, but this situation is likely to change as gas supplies become more widely available from western Kazakhstan and Aktyubinsk Oblast. Export opportunities to Central Asia also exist and are likely to improve (perhaps provoked by the CASA-1000 project).
- **Continuing growth of autoproducers.** Construction of on-site power plants at oil and gas fields to generate own electricity and heat power for the production needs will continue. These projects are also driven by the need to increase associated gas utilization and reduce the share of flaring. The total installed capacity of these plants to date is over 1,000 MW. In Eastern Kazakhstan a number of industries are reviewing the option of autonomous (on-site) power supply using gas.

Essentially these developments will be encouraged by local electricity demand growth in the southern and western parts of Kazakhstan, coupled with increased gas availability as the country's gas network gradually expands.

[45] Including gas turbine power production.



Source: IHS Energy; KEGOC

Figure 10.25 Fuel use in the Kazakh electric power sector

10.7.1. Generating capacity outlook: Replacement of aging plants needed

KEGOC reported that total official installed (nameplate) capacity in Kazakhstan was 20.8 GW on 1 January 2015, which is up from 18 GW at the end of the Soviet period. Notably, the available capacity was 16.9 GW (on 1 January 2015). Actual usable capacity is typically less than nameplate capacity owing to depreciation, grid congestion, water restrictions for hydropower plants, and other factors including equipment maintenance. Kazakhstan's utilization of overall power plant capacity (or capacity factor) in 2014 was about 52%, which has steadily increased from 48.7% in 2010. The capacity factor for thermal power plants grew from 49.7% in 2010 to 54.2% in 2014 while gas-turbine power plants have grown from 51.7% in 2010 to 54.9% in 2014. However, hydropower plants have gradually declined from 40.3% in 2010 to 36.4% in 2014 partly owing to worsening hydrological conditions.

The bulk (88%) of installed capacity is thermal plants, while 12.4% is hydroelectric facilities. A small amount (about 0.5% of the total, or less than 1 GW) is wind and solar. Of the 18 GW of installed thermal capacity, about 31% (5.2 GW) is in cogeneration facilities (TETs). Officially, Kazakhstan currently lists 76 power plants connected to Kazakhstan's UES, grouped into three general categories for purposes of dispatch and operation: plants of national significance, plants of regional significance, and industrial-owned facilities.

Notable Capacity in Kazakhstan

Kazakhstan's largest single thermal condensing plant is the coal-fired Ekibastuz GRES-1, with an installed capacity officially listed as 4,000 MW.[46] This station comprises eight 500 MW units; the station began producing power in 1980 when its first unit was installed and reached its designed capacity of 4,000 MW with the installation of the last unit in 1984. However, since the disintegration of the Soviet Union, followed by a drastic drop in demand in the early 1990s, the plant's operational capacity has not exceeded 2,500 MW. Even with the loss of one of its 500 MW units in an explosion in 2003, a drop in the plant's available capacity was averted by starting up an idle unit. Since then Ekibastuz GRES-1 has undergone a substantial investment program, currently operating at 3,500 MW. The modernization of the last unit is scheduled for 2017, which will bring the plant's operational capacity to 4,000 MW.[47] The plant's key consumers are AlmatyEnergoSbyt, KazPhosphate, Temirzholenergo, and others. The plant produced 13.5 billion kWh in 2013, accounting for nearly 14.6% of total national production.

Other major thermal stations include:

[46] Thermal plants that produce only electricity were traditionally referred to as state regional electric stations (GRES), as opposed to the TETs designation for combined heat-and-power plants (although the general designation of thermal electric station [TES] is becoming more widely used to denote both types of plants); hydroelectric stations are referred to as GES.

[47] Investment into the plant's expansion and modernization became possible as a result of the "tariff in exchange for investment" scheme that was launched in Kazakhstan in 2009 to stimulate investment in generating assets.

- **Aksu GRES (formerly Yermak GRES), with a current installed capacity of 2,425 MW.** Aksu GRES was the first of the large stations to be built in northern Kazakhstan (Ekibastuz-Pavlodar-Yermak area), using Ekibastuz coal. The station comprises eight 300 MW units. The first went online in 1968, with one unit added each year in 1969, 1970, 1971, and 1973, then two in 1974, and the last unit in 1975. By 2015, the units will get an upgrade, increasing their capacity by 25 MW each.

- **Zhambyl GRES, with an installed capacity of 1,230 MW.** The gas-fired Zhambyl GRES (ZhGRES) supplies power to the major industrial centers of southern Kazakhstan and comprises three 200 MW units and three 210 MW units.[48] After running predominantly on gas for 15 years, it had to switch to also use fuel oil (mazut) in the 1990s because of difficulties in importing gas from Uzbekistan (according to the plant's design, the share of mazut in the plant's fuel balance is 5% and it is used as a boiler start-up fuel).[49] The plant's ratio of installed capacity utilization as of 1 January 2014 was only 14.8%. Even though in 2014 the plant's electric power output increased by more than 63% and the use of gas doubled, it was driven by the need to export power to Kyrgyzstan. The cost of Zhambyl GRES power in Kazakhstan remains high. Even with the plant's access to the Bozoy-Shymkent segment (since 2014) of the Beyneu-Bozoy-Shymkent gas pipeline (which should resolve the issue of gas supplies to the plant), the cost of gas for the plant makes the cost of its power uncompetitive. According to government decree, Zhambyl GRES has been compensated by the state for the difference between the price of mazut and the price of gas. However, the high cost of gas has negated this benefit and has prevented a decrease in the power price. More importantly, with the changes to the law on "Gas and Gas Supply" in 2015, consumers of gas will have to purchase gas from a distribution company rather than from a gas pipeline operator. Essentially this means a hike in the gas price by the distribution company tariff. Therefore, with its low ratio of installed capacity utilization and high maximum power tariff, Zhambyl GRES will remain loss-making and uncompetitive irrespective of its position in an energy-deficient area.

- **Ekibastuz GRES-2 (1,000 MW) is one of the newest coal-fired condensing plants.** The planned construction of the third 630 MW ultra-critical capacity unit has been put on hold due to lack of sufficient power demand.

- **Karaganda TETs-3 (560 MW [coal])**

- **Karaganda TETs-2 (400 MW [coal])**

- **Almaty TETs-2 (560 MW [coal])**

- **Pavlodar TETs-3 (440 MW [coal])**

Kazakhstan's major hydroelectric stations are in the east and south, mainly on the Irtysh River. The largest, Shulba, located at Novobazhenovo on the upper Irtysh River, comprises six 225 MW units. Its listed capacity when completed was 1,350 MW, although its units are now rated at only 117 MW each, for a total of 702 MW, and the actual capacity available is only about 585 MW. Shulba is the third hydroelectric producer on the Irtysh River in eastern Kazakhstan. The first was the Ust-Kamenogorsk GES (the city now known by its Kazakh name of Oskemen), on which construction began in 1939; the first of its four 82.8 MW units was installed in 1952 and the last in 1959, with nameplate capacity of 331 MW.[50] The second, the Bukhtarma GES, also above Shulba, was built in the 1960s (its first 75 MW unit went online in 1960 and the ninth in 1966, for a total installed capacity of 675 MW). Over the last decade, the plant's units have been revamped, bringing their individual capacity to 82 MW and overall installed capacity to 738 MW. Kazakhstan's newest large hydro plant, the Moinak GES on the Charyn River in Almaty Oblast, began operation in December 2011; its two 150 MW units provide a total rated capacity of 300 MW. The country's other large hydropower station, the Kapchagay plant, in Almaty Oblast on the Ili River, has an installed capacity of 364 MW.

Plans exist for the construction of two counter-regulating hydropower plants below the Shulba and Kapchagay stations (Bulak and Kerbulak, respectively). These will allow peak power generation at Shulba and Kapchagay to be increased by 432 MW and 110 MW, respectively. Commissioning of the 33 MW Kerbulak hydropower plant is scheduled for 2020, while construction of the 68 MW Bulak plant is not listed in the Concept for Fuel and Energy Sector Development to 2030.

[48] The first 200 MW unit opened in 1967, the second in 1968, and the third in 1969. In the second stage of construction, one 200 MW unit was added in 1975 and two in 1976, bringing total capacity to 1,230 MW. In 2008 three units were increased by 10 MW each.

[49] Except for Zhambyl, fuel oil is used at Kazakh power plants only during boiler start-up and some coal-combustion stabilization.

[50] The plant's current available capacity is 312 MW.

The earlier years of underinvestment in Kazakhstan's power sector have left it technologically behind (according to KazEnergy's National Energy Report 2013, the power generating sector is experiencing a "substantial technological 20-year lag relative to the best international practices"). As a result, the plants are inefficient, environmentally harmful, and worn out. The 2014 Concept of Fuel and Energy Sector Development to 2030 (hereinafter the 2014 Concept) estimates the overall wear and tear of power plants at 70%; and that 57% of power plants have been in operation for more than 30 years. According to the Concept, a total of 5.8 GW of new coal, gas, and hydropower capacity will be put online by 2030; in addition, the capacity of existing thermal generation will be increased by 2.3 GW (through revamping). By 2030, Kazakh policymakers also plan for Kazakhstan to generate 30% of its power from renewable or alternative sources, which policymakers hope to increase to as much as 50% by 2050.

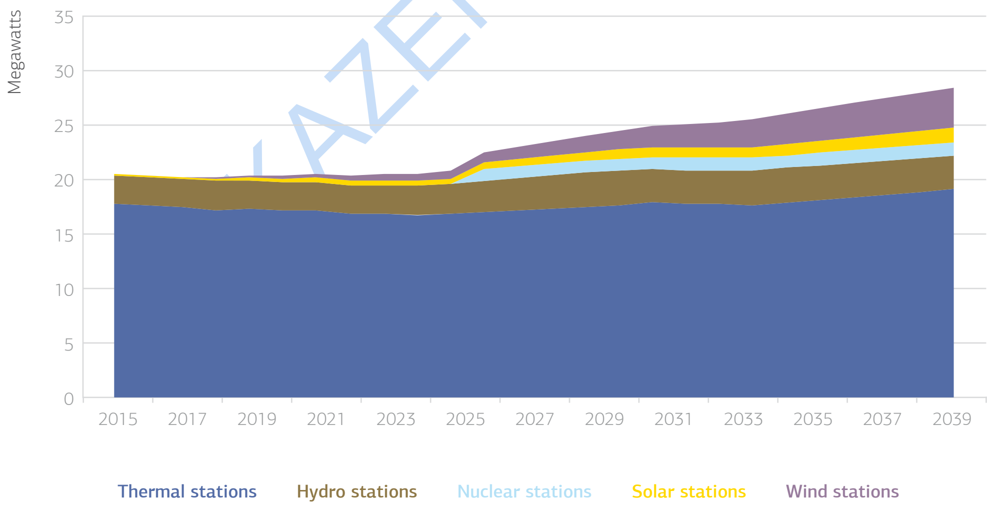
As per the official plan, the bulk of investment is designated for the northern regions of the country, and thus will be coal-fired generation. According to the 2014 Concept, 3.3 GW of new generating capacity and 1.9 GW of increased existing capacity will be put on line in the North Zone by 2030. Expansion of generating capacity in the north remains important in resolving the problem of power supply in the south. At the same time, the government planned that the South Zone will see the construction of 1.7 GW of new generating capacity and 50 MW of increased existing capacity. The scheme expects that demand in southern Kazakhstan by 2030 will still exceed import potential by an estimated 470 MW (including reserve capacity) even with a modernized north-south transmission line (the third stage of construction on the north-east-south transmission line will be completed by 2018). The development of a number of small hydropower projects, amounting to 208.6 MW out of the 1.7 GW total planned, is part of the overall "green economy"; all these developments will be important in the south.

The country's much smaller West Zone will remain self-sufficient through 2030, with the installation of 892 MW of new thermal capacity and 347 MW of expansion of existing capacity planned to be commissioned by 2030. By 2025 the West Zone is planned to be linked with the North Zone by a 500 kV line. The government has discontinued plans for building a nuclear power plant in the West Zone (by 2030), opting for new thermal generation to meet anticipated demand instead.[51]

In IHS Energy outlook (see Figure 10.26), new thermal additions will largely negate decommissions, meaning that thermal capacity is likely to remain relatively unchanged through 2040. In Figure 10.26 additions and decommissions might appear to be equal (because our model spreads out capacity additions and decommissions). But in reality there will be some annual capacity swings (for instance, additional capacity such as the Balkhash [Ulken] GRES or an additional unit at Ekibastuz GRES-2 may appear as a stepped increase in overall thermal capacity before other capacity is decommissioned).

IHS Energy outlook also assumes units that have run past their designed operational hours or failing to meet technical criteria will be decommissioned.[52] In reality, Kazakh policymakers may choose to keep these units in service.

The bulk of new capacity additions will be made up of nuclear, hydropower, and renewables. But nuclear will be the most important for generation owing to a typically higher load factor and predictability of supply.



Source: IHS Energy

Figure 10.26 Capacity outlook for Kazakh electric power sector

[51] In particular, CCGT units are to be installed as part of the MAEK upgrade.

[52] Potential technical criteria for the decommissioning of generating equipment include: power output of less than 24 hours in a calendar year (as a result of maintenance, conservation, or absence of demand by the Kazakhstan power system); generating equipment that has exceeded a double term of its initial designed life; equipment with a working steam pressure of 9 MPa or less; and equipment in production for over 50 years.

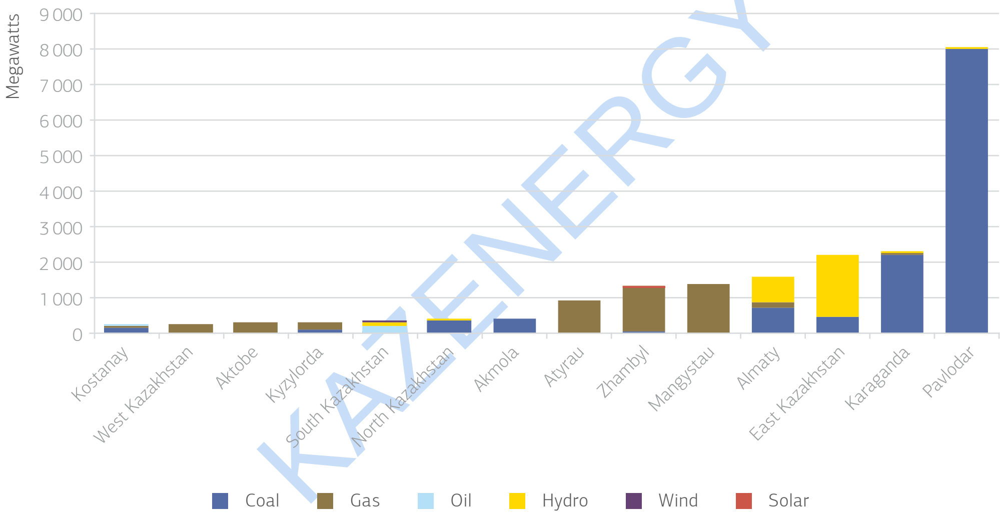
10.7.2. The dominance of coal in Kazakhstan's power production

The importance of coal in Kazakhstan's power sector is best viewed in a geographic context. As mentioned previously, about 63% of Kazakhstan's total installed capacity is coal-fired; the bulk of this is situated in central, northern, and eastern Kazakhstan, the main coal-producing region. To illustrate the weight of coal in Kazakhstan, provinces with only coal generation in them (e.g., provinces without a gas network or significant hydropower capacity), such as Pavlodar, Karaganda, Akmola, and North Kazakhstan, account for 56% of the country's total installed capacity and 65% of the country's generation (see Figure 10.27).[53]

As late as 1960, Kazakhstan's total hydropower capacity actually held a small lead over coal, while gas capacity was negligible; but during the 1960s and 1970s, the situation changed dramatically in favor of coal-fired capacity. Between 1961 and 1990, out of total capacity launched, 75% was coal, 14% was gas, and 9% was hydropower.

In 1990, coal accounted for over three-quarters (77%) of the fuel balance at Kazakhstan's thermal power plants (for the production of both electricity and heat), with residual fuel oil (mazut) accounting for 13% and natural gas 10.5%. At that time, residual fuel oil was used primarily at smaller generating facilities (often in isolated locations), while the large Zhambyl GRES in southern Kazakhstan (operating on Central Asian gas) accounted for the bulk of gas consumption.

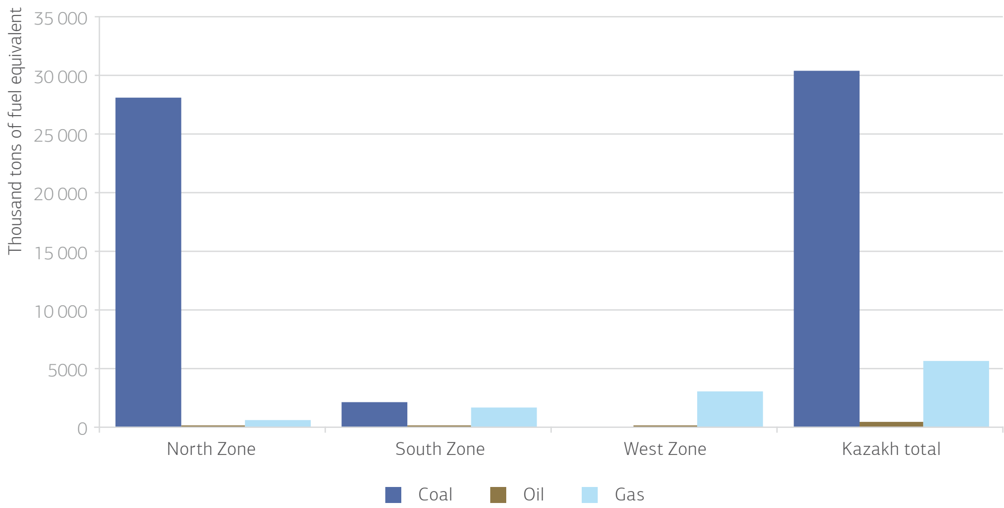
During the 1990s, the share of gas declined, mainly because of supply difficulties in southern Kazakhstan, where gas had to be imported from Uzbekistan. By 2000, the gas share had stabilized at about 12%, while coal's share was around 85% of the fuel balance, and mazut accounted for 3% (Figure 10.25). As of 2014, according to aggregated data submitted by power plant operators, the share of fuel used by power and heat generation, or steam turbines (e.g., excluding of gas turbines), for coal was about 83%, mazut 2%, and gas had grown to 15% (see Figure 10.28 and Figure 10.29). The locus of gas consumption in the power sector also shifted somewhat to the west of the country with the rise of gas turbines, where locally produced gas had become more available as a by-product of oil production, such as in Aktobe, Mangistau, and Atyrau oblasts. So when accounting for gas turbines into the production mix, coal accounts for around 76%, gas rises to about 22%, and mazut remains around 2% (see Figure 10.30).



Source: SEEPX Energy

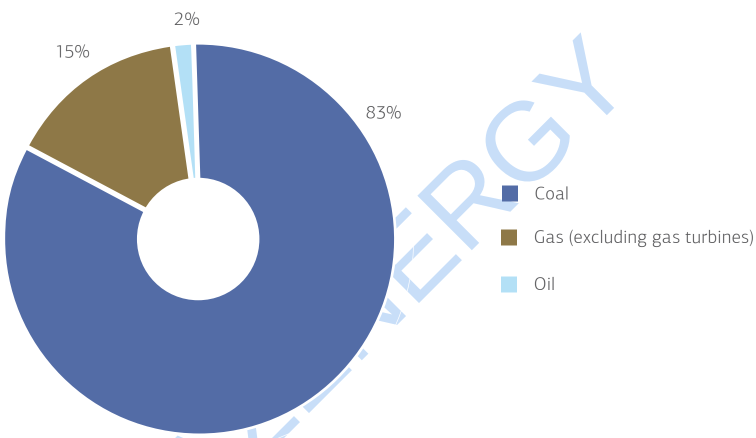
Figure 10.27 Installed capacity in Kazakstan oblast and by type (2015)

[53] This figure excludes Kostanay, Almaty, and East Kazakhstan oblasts, which combine coal generating capacities with other generating sources, including some gas and significant hydropower.



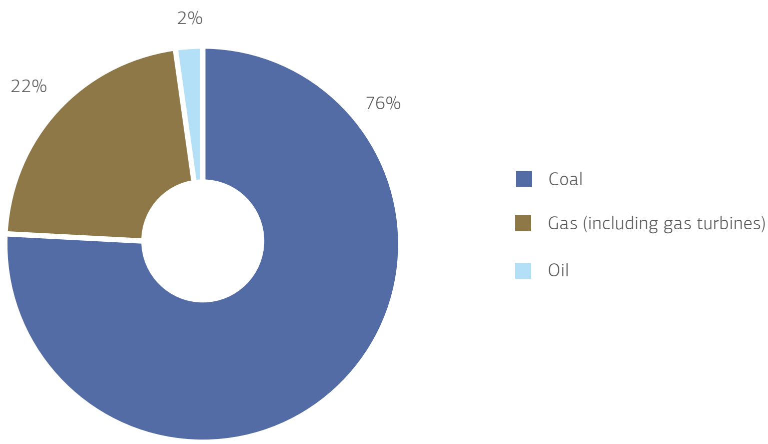
Source: IHS Energy, KEGOC

Figure 10.28 Share of fuel consumed generating power and heat energy in 2014 (excluding gas turbines)



Source: IHS Energy, KEGOC

Figure 10.29 Share of fuel use by power and heat generation in 2014 (excluding gas turbines)



Source: IHS Energy, KEGOC

Figure 10.30 Share of fuel use in thermal generation in 2014 (including gas turbines)

With abundant and relatively low-cost coal being the fuel of choice, the big coal-generating provinces in Kazakhstan have few other available options. In particular, Pavlodar Oblast's position as Kazakhstan's largest electricity-producing province remains secured for the foreseeable future by considerable local open-pit coal reserves to feed its large local power plants. These plants also have important power exports to Russia.[54] So a shift away from coal in the largest power-producing regions will require persuasive shifts either on the cost and/or policy fronts, which are not yet evident.

By contrast, western Kazakhstan is gas driven, owing to the oil and gas extraction industries active in the Caspian littoral. And more Kazakh gas from the Caspian is bleeding into other parts of Kazakhstan, and will continue to do so with the expansion of the national gas network; in southern Kazakhstan, gas-fired generation is capturing ground from coal. Moreover, the swing toward gas in power generation could accelerate subject to encouragement in the gas transportation tariff methodology. Yet in spite of such infrastructural investment for gas to replace coal, policymakers still face considerable constraints in expanding generating options. Despite considerable growth in Kazakhstan's gas regions, much of the country's vast power consumption remains focused in the country's gasless areas where power transmission is most developed—the staunch coal-producing provinces.[55]

Even with growth in gas-fired generation, coal capacity is still on the rise in Kazakhstan and is set to remain the primary fuel of choice for some time. For example, one of Kazakhstan's largest power plants that is under construction, the Balkhash power plant on the shore of Lake Balkhash, is to be coal fired (it is slated to ultimately reach a capacity of 2,640 MW). The Balkhash power plant is positioned close to the YKGRES (also referred to as Ulken) substation, at a strategic junction in the electric power transmission network where two 500 kV transmission lines intersect, the main north-south backbone of Kazakhstan's national electric grid (see Figure 10.1).

To avoid challenges with frequency control issues, predominantly in the southern grid area—owing to a complex relationship with the power grids of neighboring states—the Balkhash power plant could be a crucial asset in balancing the county's growing power demand. Coal is the natural fuel option for the first stage of the Balkhash power plant (1,320 MW), for several reasons:

- The gas pipeline system does not reach this location, and there are no plans for this to occur anytime in the foreseeable future
- Frequency control is important, and a nuclear power plant could not perform this function
- Renewables cannot respond to fluctuations in demand, so they cannot perform the system-balancing role demanded for this particular facility
- A modern efficient coal plant would positively improve coal plants' overall efficiency ratio country wide.

In other developments, in the Kazakh capital of Astana, coal will also continue to play a central role in future capacity refurbishments despite its undesirable effect on air quality. The Astana TETs-2 and TETs-3 plan to add 480 MW of coal-fired capacity, but there are also plans to build gas capacity even though much depends on the plan to bring a gas pipeline to the city (the so-called Kartaly-Astana pipeline, which now appears to be postponed).

To date, total new coal-fired generation announced (or in the construction stage) amounts to around 3,120 MW, significantly overshadowing the 500 MW announced for gas.[56] Coal's obvious role was echoed by then-Minister of Industry and New Technologies, Asset Issekeshev, in 2012. He stated that with the abundance of coal, the country's coal-fired power plants would remain as its core generation source through 2030.

10.7.3. Role of gas generation to grow

Owing to Kazakhstan's abundance of coal-fired capacity, the country has a severe shortage of peaking capacity. Thus far, Kazakhstan's overall strategy does not appear to address this shortfall aggressively. Naturally, gas-fired generators are best suited to provide peaking capacity and as a result may begin to play this role in parts of Kazakhstan.

Kazakh provinces that have access to both gas and coal are expected to shift, or increase, some of their gas use for thermal generation, particularly as older coal units are eventually replaced or upgraded. A shift from coal to gas is likely to be most pronounced in Kazakhstan's South Zone for the following reasons:

- At least one trunk pipeline development, the **Beyneu-Bozoy-Shymkent pipeline** (described in detail in Chapter 7) should enhance the country's gas-fired options in the south over the medium term.[57] Although some of Kazakhstan's gas moving through this new line ultimately is earmarked for export to China (as it joins with the larger Central Asia–China pipeline system at Shymkent), this line improves the stability and reliability of gas supply to

[54] Adverse changes in currency values and Russia's power pricing (particularly in Siberia) could further disrupt Kazakhstan's current level of power transfers going forward.

[55] Another issue to consider is tariff policy on transportation through trunk gas pipelines. The cost of transportation from the field to the end consumer in the south nearly doubles the cost of gas, although trunk gas pipelines capacity remains underutilized.

[56] Actual construction of gas-fired plants is likely to be higher, however, because these announcements appear to cover only major facilities of national importance. For example, total planned new construction, according to the sector's overall action plan to 2020, is 1,980 MW of coal-fired capacity, 830 MW of gas-fired capacity, 374 MW of hydropower capacity, 600 MW of nuclear capacity, 793 MW of wind, and 77 MW of solar.

[57] The first phase of this new pipeline, which links the western gas production centers with southern Kazakhstan, was completed in 2013. This major new trunk (1,475 km) is being constructed as part of a 50-50 joint venture between KazTransGaz, the national pipeline operator, and a Chinese partner.

existing domestic power plants, mainly in South Kazakhstan and Zhambyl oblasts. But in time, as gas supplies increase, the pipeline build-out continues, and Kazakhstan's environmental standards become stricter, Kazakh generators and investors may replace coal in areas that become accessible to gas supplies.

- **Almaty is expected to replace its coal-fired generation for gas.** Due to its topography (a piedmont basin), Almaty suffers greatly from pollution, which is a considerable political issue for Kazakhstan. For Almaty, Kazakhstan's largest city, pollution is particularly problematic because airflows do not allow pollution to disperse efficiently. Therefore almost purely for ecological reasons Almaty is already undergoing a shift toward cleaner fuels in power and other sectors. Taking into account consumption growth projections for Almaty, the city should expect to replace its current coal-fired capacity with up to 800–1000 MW of gas fired capacity by 2022. This capacity should be funded through a capacity mechanism. Taking into consideration expected utilization of around 50–55%, annual gas consumption by the power industry in Almaty could grow by about 2 billion cubic meters (Bcm).

- **Zhambyl GRES (1240 MW) is expected to increase production.** Zhambyl GRES has a history of being dramatically underutilized (less than 25%) owing to physical constraints and comparative economics of burning oil and gas (see above). But as access to gas improves, particularly during winter, Zhambyl should increase power production. A second important factor is economics. Market conditions are likely to eventually encourage more gas use in the power system, particularly during peak demand periods.

- **Significant rise in autoproduction by industry.** Collectively oil and gas producers are utilizing significantly more associated gas in power production. This is a high growth industry that has proven to have developed particularly quickly in Russia as well (for similar reasons). Certain changes to gas pricing policy and regulations, to encourage gas use by the power sector, might help stimulate gas-to-power usage (gas flaring is prohibited by law). But in many situations, power produced by associated gas is often restricted or isolated from the grid network, and thus may play only a minor role in the overall balancing of the electric power system. Moreover, another limiting factor is that the Kazakh state will need to find a way to encourage the oil and gas majors to invest into their own generation development for capacity output for third parties.

Naturally, Kazakhstan's West Zone will make more use of gas in its power production as the oil and gas industry increases autoproduction, and in response to overall population growth (see Figure 10.13).

10.7.4. Prospects for nuclear generation

For several years, Kazakhstan has been considering building nuclear capacity. The main argument for constructing a nuclear power plant is to diversify Kazakhstan's energy mix and bolster its green credentials. But the final location, size, technology, and source of funding remain unclear. Talks have been going on with several international players, but in particular with Russia's Rosatom (including the option to build and help finance the plant). In 2014, Japan's Toshiba, JAPC, and Marubeni companies proposed construction of a nuclear power plant using a Westinghouse reactor.

Notably, Kazakhstan inherited a BN-350 sodium-cooled fast neutron reactor (launched in 1973 in Aktau in Mangistau Oblast) from the Soviet era, but it has since stopped operation (in 1999). The plant dedicated 150 MW for powering Aktau city but was mainly used for desalination to supply fresh water. For several years, Kazakh policymakers considered revisiting this site for a second nuclear power plant (see below).

Given the isolation of the Western Zone and limited transmission capacity in Mangistau Oblast, the government considered an innovative plan of building a medium-sized nuclear reactor (up to 600 MW). After considering a number of options, Kazakhstan suggested developing and building a WWR-300 reactor based on a marine design together with Russia; however, due to project share and copyright issues this location has been dropped.

In 2013, the government of Kazakhstan took a strategic decision to develop nuclear in Kazakhstan and build nuclear power capacity (NPP). The choice of site has to account for many factors, including approval by the local inhabitants.

In 2013–2014, a dedicated government commission conducted a study benchmarking a number of sites and configurations for nuclear power in Kazakhstan. The site benchmarking criteria included environmental conditions, threats to nuclear-related security linked to the industrial activity, social factors, and the impact of nuclear power on the environment, including exposure of the population to radiation in the event of a radiological accident. Kazakhstan has employed IAEA criteria for site suitability in building nuclear power capacity.

According to the findings, the preferred sites have been identified as: near Kurchatov (East Kazakhstan Oblast), and near Ulken settlement on Lake Balkhash in Almaty Oblast.

- **Near Kurchatov (close to the Semipalatinsk test site) in East Kazakhstan.** The Semipalatinsk test site, best known for nuclear weapons testing in Soviet times, is currently a leading venue for building Kazakhstan's next nuclear power plant. A strong argument for choosing this site rests on negating Kazakhstan's growing use of coal in its northern power systems. But given the atomic history of Semipalatinsk, building a nuclear power plant on this site still presents the risk of local opposition.[58]

- **Near Lake Balkhash in Almaty Oblast.** Positioned between the north and south energy systems, strategically, a nuclear power plant that intercepts the double 500 kV north-south transmission lines would allow for considerable flexibility for power deliveries. The plant might

[58] Construction of a large scale (1000 MW) nuclear power plant in Kurchatov in the power capacity rich North Zone does not seem to be an optimal decision. Nevertheless, Kurchatov is home to a unique scientific and research center. The uniqueness of a research base and skills would enable Kazakhstan conduct research on "fourth generation" reactors.

serve to offset coal generation in Kazakhstan's north while playing an important role filling the capacity shortfall in southern Kazakhstan. If the Lake Balkhash location is chosen, then it may end up displacing the second stage of the Balkhash GRES (planned at 1320 MW).

Kazakh policymakers initially advocated building a reactor with a capacity of around 300 MW, and then later 600 MW; however, Kazakhstan's government is likely to commit to a 1200 MW unit (or 1150 MW), which is the standard international size. In particular, if the government settles on Rosatom to build (and operate) its next nuclear power plant, it is most likely that Kazakhstan will need to commit to Rosatom's standard-size reactor. If Rosatom or any other company selected by the government were to build a smaller customized unit for Kazakhstan (the government is still considering construction of a 600 MW reactor), the cost per kilowatt would rise significantly, largely eliminating the political justification.

Most estimates place the cost of building a 1000 MW unit at around $4–5 billion. Since there is significant pressure to keep end-user power prices in check, the Kazakh government may find it difficult to pay for a nuclear power plant through the electricity tariff alone. This will mean that either the state would need to provide financial support to build a nuclear power plant or another funding mechanism would have to be found. Rosatom may offer its build, own, and operate scheme (BOO), whereby the company would financially support the project and control the majority of the plant's operation. But the BOO model places significantly more risk with Rosatom, making settling on the plant's final location and guarantees for dispatch and tariffs more contentious in negotiation.

Despite Kazakhstan's relatively cheap and abundant fossil fuels, the country wants to add nuclear to its mix and improve its green energy credentials. But a commitment to press forward on the nuclear option is further complicated by the recent economic headwinds. Kazakhstan is likely to keep the nuclear discussions moving forward should favorable terms with providers and investors arise. Notwithstanding, we expect nuclear to enter the mix by 2026.

Proposed Sites for Nuclear Power Plants That Have Not Received Government Approval:

- **Near the site of the original BN-350 reactor in Aktau.** Aktau was originally earmarked (in 2006) to be the leading location for Kazakhstan's new nuclear power plant. However, despite being one of the fastest growing regions for power consumption (in percentage terms) in Kazakhstan over the last 10 years, Mangistau is still a relatively small power consumer with weak transmission links, in particular with no link to Kazakhstan's main grid system. Furthermore, a nuclear power plant near Aktau would only offset potential gas-fired capacity.

- **Near Taraz in Zhambyl Oblast.** To meet local demand in the South Zone, southern Kazakhstan depends greatly on two 500 kV lines from central and northern Kazakhstan, and has in the past imported power from Uzbekistan or Kyrgyzstan. However Kazakhstan now has become a net exporter. A nuclear power plant could go some way to help meet baseload demand and bolster seasonal power exports. Even as more gas reaches the power sector in southern Kazakhstan—as expected (see above), a nuclear power plant in the south is unlikely to threaten local gas-fired power production significantly. It is more likely that nuclear production would offset coal-fired production imported from Kazakhstan's North Zone. If Russia's state-owned nuclear company, Rosatom, were to become a partner in building Kazakhstan's new nuclear power plant, the preference of the Russian corporation would be to build a plant in the south of Kazakhstan rather than in the north.

10.7.5. Renewables to play a modest role owing to technical and market hurdles

The global trend for encouraging renewable energy has not escaped Kazakhstan's policymakers. Arguably, Kazakhstan's renewable policy has evolved well ahead of other market and technical considerations. As a result, the momentum of Kazakhstan's renewable drive has divided opinion among power sector participants (due to such characteristics of renewable generation as a diffused resource, chaotic generation pattern, and low use of installed capacity). Consider the following:

- **Technical integration.** Kazakhstan, in many areas, lacks appropriate infrastructure to balance power. If left unchecked, a sharp rise in renewables could make KEGOC's role as system operator particularly challenging, as generators need to stand ready to balance rapid load fluctuations. Generally speaking, Kazakhstan's system plants (GRES) or hydropower plants can technically step in to perform this service, but this would also require several layers of system services' market solutions and investment in the grid. In Kazakhstan's southern regions, gas-fired capacity could be used to support the system.

- **Competitive market integration.** Under current technological conditions, renewable generation (wind and solar particularly) requires preferential treatment (in the form of special tariffs, loans, government support, and load order) to be a part of the power market driven by cost and efficiency; Kazakhstan is no exception (the legislation on renewables in Kazakhstan already accounts for the above provisions). But even then, Kazakhstan's wholesale power market is undeveloped and as a result illiquid. There is no provision for renewables in the system services market. The economic consequences of renewable energy's integration and its impact on wholesale and retail price formation have not been accounted for.

- **Cost.** The anticipated growth in the share of renewable generation (particularly wind and solar) would have power price cost implications for end-consumers. With an increase of market output by renewable sources above 5% of Kazakhstan's total output, the price would be inflated further by the cost of all complementary services necessary to balance supply and demand over all time scales, as well as investment in strengthening of grid infrastructure.

The government has officially committed to its own renewable targets in the Strategic Plan for the Republic of Kazakhstan Development by 2020 and "Strategy Kazakhstan 2050." In the official strategy, energy from renewable sources should account for 1% of power production by 2014, 3% of power production by 2020, and 11% by 2030. Longer term, and according to the recent Green Economy Concept, approved by President Nazarbayev, the Kazakh government hopes renewables and alternative sources of power could grow to 50% of its power production by 2050. However, since these plans were announced, policymakers have moderated the official expectations for renewables.

Kazakhstan has ambitiously embraced the notion of renewable energy, and importantly the country has considerable potential for renewables that can be developed. A recent addition includes a small wind facility (1.5 MW) that went into operation in North Kazakhstan Oblast in 2013; and a pending launch of Kazakhstan's first major wind farm (45 MW) was recently completed at Yereimentau in Akmola Oblast (the project is at the pre-commissioning stage). Four renewable projects (wind, solar, and small hydropower plants), with a total capacity of 165 MW, are being implemented in Zhambyl Oblast, which, according to the regional akim (governor) aims to be a pioneer in the use of renewable energy in Kazakhstan. The national action plan on developing alternative and renewable sources in Kazakhstan for 2013–20 envisages the launch of 106 renewable facilities with a total installed capacity of 3,054.6 MW.[59] This includes 34 wind generating farms (1,787 MW), 28 solar power facilities (713.5 MW), 41 small hydropower plants (539 MW), and 3 biofuel power plants (15.05 MW).

Subject to implementation, by 2020, Kazakhstan's planned projects will amount to about 15% of installed capacity of conventional generating facilities, and by 2030 to 14.2%. In developed power markets, with strict regulation and deep penetration of modern technologies, integration of about 15% of renewable production into an energy system is possible but still challenging for system operators, given the impact of high levels of intermittency on the power system. For Kazakhstan's power sector, where overall rules and regulations are yet to mature, and generating assets and grid infrastructure still require considerable technological upgrade, integrating a sizable volume of renewable production (versus installed renewable capacity) will be technologically and economically problematic and overly complicated to adopt into competitive market mechanisms.

If Kazakh policymakers continue to pursue a high share of renewables in the overall capacity mix, then the country will need to adapt Kazakhstan's power infrastructure and market to cope.

Given the unpredictable supply patterns, common with partially dispatchable renewables, Kazakhstan still needs conventional capacities to support system reliability.[60] For instance, the main renewable sources (wind and solar photovoltaic [PV]) lack the flexibility and predictability crucial for meeting power demand (after all, electricity production is totally demand driven and must be made, transported, and delivered almost instantaneously): in contrast, depending on the source, renewables produce power when the wind blows or when the sun shines. They are also quickly disrupted if the wind suddenly drops or changes direction, or in the case of solar the sun is obscured by a cloud.[61] Thus wind and solar generation output is unpredictable and can change rapidly, so Kazakhstan's energy system needs to be able to tolerate intermittent power. These are not ideal energy sources for Kazakhstan's large industries, with their high fixed loads. Moreover, renewable output can fluctuate across an entire system, complicating frequency control, voltage, and capacity utilization. Subject to timeframe and location, renewables could be dispatched only partially. Also consider that, in the case of Kazakhstan, during certain times over the heating season combined heat and power plants must take priority and their power output is inextricably linked to their heat load.[62]

The global experience in integrating intermittent renewables into energy systems offers some insight into the challenges facing KEGOC. In some countries with a high penetration of wind generation, excess production is sometimes exported. However, this is not always an option, as this opportunity is limited in scope. Other options include curtailing wind generation or investing in flexible loads. Denmark, for instance, which has a particularly high penetration of wind generation in relation to its system size (about 20% according to the IEA), reportedly solves imbalances by exporting surplus wind generation and importing Norwegian hydropower. Interestingly, Denmark also flexes its heat and power plants to support the system. For Kazakhstan, its heat and power plants' power output is constrained by their heat load and thus not flexible at present; however, investing in this particular sector ultimately may provide the best technological solution. Despite the cost implications, it would be down

[59] Government provision No. 45 of 25 January 2013 with amendments of 28 July 2014.

[60] Renewable sources of generation cannot be fully controlled (dispatched) since they reflect the time-varying nature of the resource. The main way in which they can be controlled is through reduction of output. This is in contrast to dispatchable generation that can be controlled by increasing or reducing fuel supply.

[61] Kazakh renewable legislation does not envisage the responsibility of renewable plant operators for the precision of renewable output forecasts day ahead. Therefore, the operators of renewable assets are not motivated to obtain precise weather forecasts to improve the predictability of their output.

[62] The output of different renewable sources is not generally well correlated in time, so if a power system includes a wide range of renewable sources, their aggregate output will be smoother, thus easing the challenge of electrical power system balancing (Source: IPCC Special Report on Renewable Energy Sources and Climate Change, Chapter 8, "Mitigation Integration of Renewable Energy into Present and Future Energy Systems").

to market mechanisms to find the right incentives, but the system will be costly to maintain. For example, the capacity mechanism with strict technical regulation could be used to support investment in flexible heat and power plants and a system services market could be used to reward availability and response.[63]

The high share of renewable output may also challenge short-term system balancing (frequency response), as the pressure to constantly maintain frequency would increase with the growth of renewable production (unless there are additional frequency control mechanisms in place). The majority of renewable technologies are incapable of fulfilling such service.

Kazakhstan's reserve capacity requirements will increase with the growth of renewable output in power production. The IPCC Special Report on Renewable Energy Sources and Climate concluded that global experience showed that for 10% wind penetration up to a 15% short-term reserve is also required, and for 20% penetration up to 18%. Essentially, experience from both Denmark and Spain supports this point: upon reaching penetration levels of 5–10%, an increase in the use of reserves is needed. In particular, the report points out the importance of reserves capable of reacting within 10 to 15 minutes. Here Kazakhstan's technological and economic issues will have to be addressed first. Technological issues relate to the availability of flexible generating capacity as well as grid reliability and capacity restrictions. Even though traditionally Kazakhstan's system plants (GRESs) are not primarily designed for system balancing, from a technological point of view, in case of a sudden outage of other generating units in the system, Ekibastuz GRES-1 and -2, for example (following the system operator's "emergency" order) would be in position to ramp up their load quickly. Foreign experience shows that power plants similar to Ekibastuz GRES-1 flex their load not only during an emergency but for the needs of system balancing, in part as a result of renewables integration.[64]

Taking into account the Ekibastuz power plants' recent upgrades (mainly with foreign equipment) and subject to the availability of capacity, within a very short period of time, Ekibastuz GRES-1 could increase its load by as much as 100 MW using units in operation.[65] Larger amounts might require start-up of reserved capacity and launch of additional units (which will be more time consuming, and will take hours rather than minutes).[66] Either of these scenarios raises issues of compensation for the costs of flexing power plants' capacity—for keeping equipment on stand-by, negative ramifications for the plants' equipment as a result of a sharp increase and decrease of load to account for renewables (maintenance fund), as well meeting the system operator's orders on load flexing. As a rule, payment for costs relating to the system operator's orders is covered by the mechanism of the system services market. However, Kazakh policymakers plan to introduce payments for balancing services (dynamic changes of power production by power plants upon the system operator's request) as part of a capacity regulation agreement within a mechanism for a new balancing market that is scheduled to start operation in real time on 1 January 2016. However, there are no provisions for the compensation of costs relating to either reservation of capacity or funding for additional maintenance as a result of flexing under current legislation.[67] Although the rules of the capacity market envisage payments to power plants for "capacity readiness" (subject to passing the unit capacity assessment), the capacity reservation fee to compensate fluctuations from renewable production is not envisaged because, currently in Kazakhstan, the share of renewable production in the overall output of electric power is insignificant (less than 1% of total power output in the country). With the growth of renewable output expected (subject to implementing planned projects), in order to compensate renewable production fluctuations, a new provision should be adopted in the capacity market rules on payments for reserved capacity.[68] A maintenance fee could either be included in power costs or accounted for via the planned capacity market as well. However, payment for all these additional services (capacity reservation fee, maintenance, and load flexing following the system operator's orders) will inevitably drive up end-users' power costs.

Grid infrastructure also needs to adapt to renewables (to protect grid equipment and overhead lines in particular and transformers from overloading). The best wind conditions dictate where a wind farm can be built. This is not usually conveniently located near the existing network or sites of consumption. This means more investment in grid improvements. It is not clear whether Kazakhstan's grid planning has fully accounted for the adoption of large volumes of power from awkwardly positioned wind farms.[69]

Large solar photovoltaic (PV) parks that are not located close to demand may also have to address the grid upgrading needs. But they will mostly have considerable impact on distribution networks (as small and medium-size solar PV are typically installed near to demand and get connected at the distribution level). Moreover, additional network infrastruc-

[63] A plan to reward power plants for availability and response is slated to be introduced as part of the new balancing market scheduled to launch on 1 January 2016. Nevertheless, prompt balancing and changing of the load (in particular of private plants) would require incentives to motivate generating companies and large consumers to respond. Such incentives are realized through a system services market.

[64] For example, the UK's coal-fired Drax power plant does this (http://www.drax.com/) .

[65] Obligatory installation of energy storage units with wind generating plants also could help to smooth out sharp fluctuations in the power system load.

[66] As a rule, a system operator is mainly concerned with significant load fluctuations (fluctuations within 100 MW are not significant). However, with the growth of regional electric system output, load fluctuations will increase.

[67] RK Law No. 165-IV of 4 July 2009 on "Support of Renewable Sources of Energy Use" (latest changes 29 December 2014), Chapter 3, article 9, clause 8. Financing of system balancing as a result of renewable plants' operation is made through the tariffs set for renewable sources of energy under the balancing market rules.

[68] Government provision of the Republic of Kazakhstan No. 43 of 25 January 2013, with changes from 28 July 2014 on development of alternative and renewable energy in Kazakhstan in 2013–2030.

[69] P.S. Georgilakis, Renewable and Sustainable Energy Reviews 2008.

ture is likely to be needed to enable power to flow from the distribution feeder back to the transmission system without incurring large losses.

Considering that the methodology on estimating renewable transmission capacity is different from that of a conventional power plant, it is probable that in Kazakhstan grid strengthening to meet the expected renewable output has not yet been fully taken into account.

Global experience also demonstrates that integrating wind and solar impacts upon operational costs of power systems. As a rule, to compensate for the variations in wind and solar output, conventional power plants fluctuate load to balance the system and as a result deviate from operating standards that are set to maximize overall system efficiency and minimize costs. The increased output of renewable generation will place downward pressure on heating plants' output, thus resulting in heating plants lowered load, increased fuel use, and decreased efficiency. Various studies show an increased economic impact on power system costs when the share of wind generation exceeds 5%. The economic impact on power system operational costs is insignificant if the share of wind output is less than 5%; it becomes moderate with the growth of wind output to 20%, and is high when wind output exceeds 20%.

An increased economic impact on power system operational costs relates to the additional services required for integrating wind and solar production into power systems. These include:

1. Unit commitment, start, and stop within a timeframe from one week to one day with a pace of one hour when it is impossible to predict precise volume and time of power generation (while maintaining system reliability and minimizing costs).

2. Load fluctuations within each hour with a pace of 5–10 minutes, when it is difficult to forecast adequate reserve capacity to ramp units up and down to follow the load shape resulting from random fluctuations in the combined load and renewable output.

3. Load–frequency control: the challenge is to have sufficient volume of regulating capacity to hold fluctuations within the set range from 1 minute to 1 hour within a pace of 1–5 seconds.

The power system size, generation capacity mix (inclusive of system flexibility), and changes to load will have an effect on how to integrate variable production into Kazakhstan's power system. Nevertheless, it would be essential for Kazakhstan to make provisions such as mechanisms to reward conventional power plants for additional services related to renewable output balancing via the market or alternative mechanisms.[70]

Despite the intermittency of renewable power production, research shows that diversity of renewable generation and its dispersion over a large area can have a smoothing effect on the variability of renewable production and reduce some element of unpredictability in the power system. Nevertheless, the technical state and overall condition of grid and distribution network would remain key both from the point of view of power delivery from a power plant to the end-consumer as well as regional balancing. Supply and demand balancing would require access to assets that can flex their capacity accordingly and without undue technical stress (flexible generation, demand response, power storage), as well as use advanced techniques for demand and supply forecasting and plant scheduling.

Summarizing the role renewables play in Kazakhstan

Considering the intermittent nature of renewable generation, as well as technical and economic issues relating to integrating renewables with Kazakhstan's UES, the country's heavily industrialized economy may struggle to adopt renewables in the quantities announced in the official forecasts without a significant stepped change in technical reliability in either renewable production (wind and solar in particular) or in grid operation. It is highly unlikely it would be in position to support consumption growth in southern Kazakhstan either, in part because of a dearth of reserve flexible local capacity.

That being said, the legislation on renewables in Kazakhstan remains geared toward attracting investment through favorable conditions for, including:

- A preferential fixed tariff prior to renewable generation commissioning
- Obligations to purchase renewable power in full
- Preferential treatment when connecting to the electric grid, or on the point of supply
- Priority on renewable power supply to the grid
- Expansion and upgrade of the existing electric grids (as necessary for the connection of renewable plants) at the expense of a power transmission/distribution company
- No charge for power transmission from a renewable plant to the grid.

Moreover, Kazakh legislation does not set a quota for renewable generation while fixed tariffs ensuring investment attractiveness of new renewable projects are fixed (once) for three years ahead. Should policymakers fail to make amendments to the legislation on renewable generation, Kazakhstan risks the possibility of too much construction of renewable generation (wind and solar plants, in particular).

Therefore, summarizing the above, and taking into account the risks associated with integration of renewable generation into Kazakhstan's energy system, IHS Energy would suggest by 2030 limiting total renewables penetration to around 3–5% of total power output (15% of installed capacity). Naturally the situation could change dramatically should various technological solutions—such as super-efficient battery power storage—become a convincing part of the overall solution.

[70] Current legislation does not have a provision on reserving capacity or rewarding conventional power plants for balancing renewable output.

10.8. Kazakhstan's Reinforced Transmission Grid

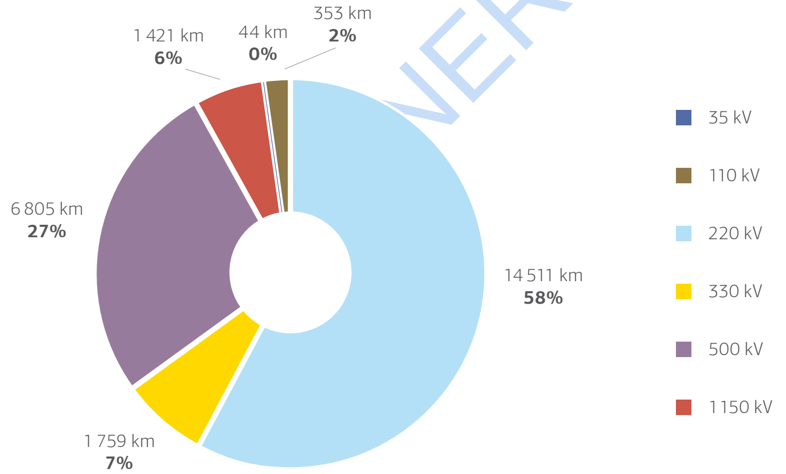
10.8.1. Kazakhstan's high-voltage grid

By 1990, Kazakhstan's transmission network comprised 412,700 km of overhead lines; low-voltage distribution lines made up the largest component (lines of 35–110 kV) at 111,300 km (or 27% of the total). Currently, Kazakhstan maintains over 71,600 km of high-voltage transmission lines over 110 kV, mainly in voltages of 110 kV and 220 kV (see Figure 10.31). But the 220–500 kV lines form the backbone of the national system. Of this total, KEGOC owns and operates 24,849 km of power lines (ranging in capacity from 35 kV to 1150 kV) as well as 77 substations (with a total transformer capacity of 36,245 mega volt ampere [MVA]).

A special note must be made of Kazakhstan's unusual extra-high voltage (EHV) 1150 kV lines (see Figure 10.1).[71] The coal reserves of the Ekibastuz Basin gave rise to two projects for long-distance transmission of electricity over EHV lines, from what were planned to be four 4,000 MW mine-mouth stations (although only Ekibastuz GRES-1 was built with a nameplate capacity of 4,000 MW). This project involved the construction of a 1150 kV (alternating current [AC]) line to Russia's Urals region. This was envisioned as part of a larger project, involving a 2,600 km, 1150-kV link extending all the way from the Kansk-Achinsk coal basin in East Siberia through Ekibastuz to Kostanay and then Chelyabinsk in the Urals. The 1150 kV line was designed to carry 4,000 MW.

The Siberia-Kazakhstan-Urals project was split into three stages. The first stage—a 1150 kV line between Ekibastuz and Kokshetau—was launched in 1985, and then in 1988 the Kokshetau-Kostanay segment was raised from 500 kV to 1150 kV. However, due to changes in the economic environment the final segment between Kostanay and Chelyabinsk was not powered to 1150 kV. The 1150 kV line was also extended eastward, reaching Barnaul in West Siberia (Russia), and construction was completed in the late 1990s on the connection between Barnaul and Itat in the Kansk-Achinsk coal basin (southern East Siberia).

A further ambitious transmission project that was conceived, but later abandoned, involved the construction of a 1500 kV direct-current (DC) line of 2,400 km to the Tambov area south of Moscow from the Ekibastuz stations. The DC line had a projected carrying capacity of 6,000 MW and ability to transmit 40 billion kWh annually. Construction on the line began in 1978, but a host of problems (technical, economic, as well as political) led to the eventual abandonment of the project in early 1990s.



Source: IHS Energy, KEGOC

Figure 10.31 Total length of transmission lines operated by KEGOC in 2014 (total km = 24,894)

[71] Although currently operating as 500 kV lines.

10.8.2. New transmission links to unlock latent value for Kazakh power plants

Kazakh policymakers continue to focus on strengthening the national power transmission network as well as revitalizing generating capacity. Several major transmission developments have been completed in recent years, allowing Kazakhstan's electricity to flow more freely without relying on transfers from neighboring countries as it was during the Soviet period.

The original Soviet-built grid relied heavily on power transfers between neighboring republics, as each individual republic's self-sufficiency was not a consideration. This was particularly true in southern Kazakhstan, where power transfers were intimately entwined with hydropower and irrigation politics in Central Asia. Also, Kazakhstan's power assets to the west (e.g., Atyrau, West Kazakhstan, and Mangistau oblasts) remained isolated from the rest of Kazakhstan and are linked only via the Russian grid system (see Figure 10.1).

Aside from refurbishing its existing infrastructure in recent years, Kazakhstan has added several major power lines of national significance to its network. For example, the power system has gained:

- A 500 kV line (485 km) linking Aktobe with Kazakhstan's main grid network at Zhitikara (completed in February 2009). By circumnavigating Russian territory with this link, Kazakhstan has significantly improved its overall power independence.
- A second north-south 500 kV line (1,097 km) running from Ekibastuz in Pavlodar Oblast to Shu in Zhambyl Oblast (completed in 2010). This new line was important in strengthening power-system connectivity between north and south, reinforcing an existing key artery, as well as increasing reliability of power supply in southern Kazakhstan. This project has been executed in three stages: stage one— construction of a 500 kV line YKGRES-Shu; second stage—construction of a 500 kV line Ekibastuz-Agadyr; and the third stage—construction of a 500 kV line Agadyr-YKGRES.

By 2025, KEGOC plans to implement 15 projects developing Kazakhstan's National Power Grid (NPG) as part of its long-term development strategy.[72]

Among KEGOC priority projects is to complete construction of a third North-East-South 500 kV transit by 2018. The new line will bolster's the national grid's North-South and North-East capacity and will bolster power transit from generating assets in the north of Kazakhstan to meet a growing demand in the south (including strengthening the connections of the Shulba and Bulak hydropower stations with Almaty). It will also allow for the parallel operation of East Kazakhstan Oblast's power system with UES Kazakhstan irrespective of existing power connections via the Russian power grid. This line is planned to create conditions for electrification of parts of the Aktogai-Almaty, Aktogai-Dostyk, and Aktogai-Moyinty rail lines, as well as provide a power supply for energy-intensive mining companies (Aktogai MEC) and the development of border territories.[73]

To increase national power transit as well as to improve power export potential, KEGOC is working on "strengthening the connection between the Pavlodar power node and UES Kazakhstan," and also plans to start work on the following projects:

- 500 kV line YKGRES-Zhambyl (about 400 km) instead of earlier planned cross-border 500 kV line between Kazakhstan and Kyrgyzstan[74]
- 500 kV Atyrau-Ulke transmission line, connecting West Zone to UES Kazakhstan
- 220 kV Uralsk-Atyrau and Kulsary-Tengiz transmission lines
- 500 kV substation in Astana connecting to the national grid 500 kV lines to improve reliability of power supply to Astana and Akmola Oblast as well as grid rehabilitation (2,200 km of 220 kV lines, 404.3 km of 500 kV), which will enable the technical characteristics of these lines to be restored
- 500 kV Aktau-Beyneu-Kulsary-Atyrau transmission line.

10.9. Power Investment Spending Accelerates, but Considerable Investment into Modernization Still Needed

Over the past decade, significant investment has reached Kazakhstan's power sector, an achievement that many market

[72] Including following developments:
- Modernization of Kazakhstan's NPG (phase one). Construction and connection of 500 kV Alma substation in Almaty Oblast to the NPG via 500 kV and 220 kV lines; 500 kV line Almaty-Alma, 500 kV line YKGRES-Alma, and connection of Alma substation to the existing 220 kV lines
- Moinak GES (hydropower plant) transmission line (two 220 kV lines to Almaty). Moinak GES is a newly completed 300 MW hydropower plant situated in southern Almaty Oblast
- Construction of a 500 kV line Zhitikara-Ulke and connection of Aktobe power node to UES Kazakhstan
- Final stage of 220 kV Osakarovka line rehabilitation (220 kV lines serving Astana)
- As part of the second phase of "NPG modernization and rehabilitation plan," Kazakhstan will modernize 55 substations and fully overhaul existing overhead power lines.

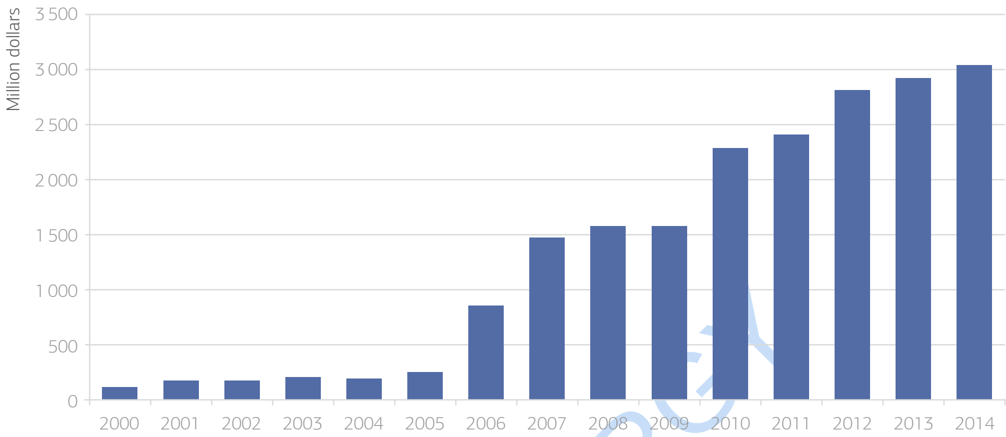
[73] Wind power plants at the Dzungarian Gate are likely to be characterized by a high installed capacity utilization factor (more than 45%).

[74] KEGOC's decision not to build a cross-border line to Kyrgyzstan was based on the results of a due-diligence report commissioned by KEGOC in 2013–2014.

observers have largely overlooked. This is chiefly because much of the investment has been channeled into refurbishing, reinstating, and upgrading existing plants and equipment rather than supporting new "greenfield" construction that tends to garner more attention.[75]

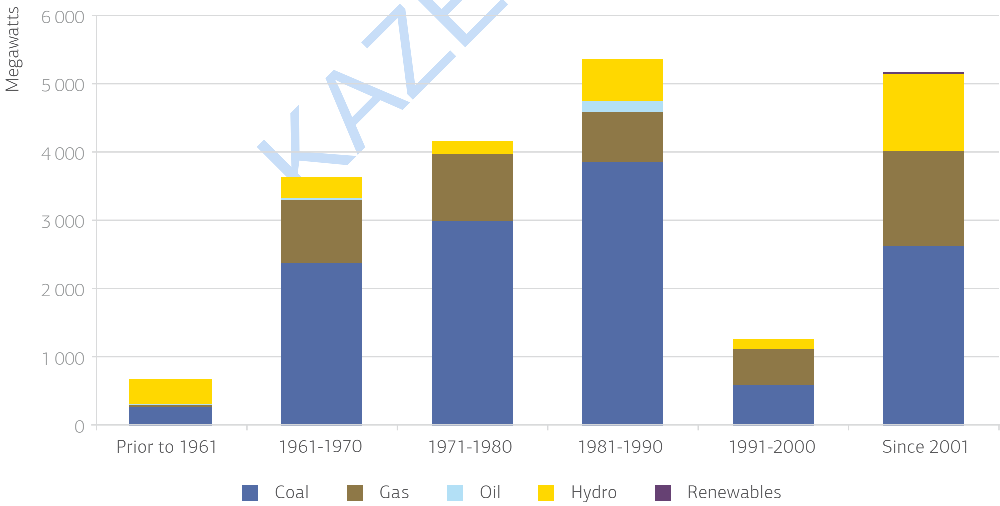
Annual investment outlays in the sector have increased from the equivalent of a mere $123 million in 2000 to $3 billion in 2014; cumulatively, investment in the sector during the past decade (since 2000) amounts to about $20 billion (see Figure 10.32). Even so, a sizeable share of Kazakhstan's existing generating capacity still needs to be either revitalized or replaced. For example, some 20% of the country's capacity in operation today was launched prior to 1970, with 4% installed prior to 1961 (see Figure 10.33).

As noted above, the "2014 Concept" estimates the overall wear and tear of power plants at 70%, with 57% of power plants having been in operation for more than 30 years. Thermal plants on average have been operating for 28.8 years, and hydroelectric plants for 35.7 years. According to this Concept, 5.8 GW of new coal, gas, and hydropower capacity will be put online by 2030, while the capacity of existing thermal generation would be enlarged by 2.3 GW. Both represent a slight downgrade from the estimation by Chokin KazNII presented in the KazEnergy's National Energy Report 2013.[76]



Source: IHS Energy, Statistical Committee of Republic of Kazakhstan

Figure 10.32 Investments into the Kazakh power sector



Source: SEEPX Energy, Platts

Figure 10.33 Age distribution of generating capacity in Kazakhstan

[75] A total of 1341 MW of new capacity has been commissioned as part of the State Program to boost industrial and innovative development of the Republic of Kazakhstan through 2014, raising the total number of power stations in Kazakhstan from 63 in 2009 to 76 at the end of 2014.

[76] According to Chokin KazNII Energy, the plan in 2013 was for 5 GW of existing coal-fired capacity, 152 MW of existing gas-fired capacity, and 947 MW of existing hydropower to go through a technical upgrade between 2013 and 2030. At the same time the capacity of coal-fired units would be enlarged by 2 GW, and the capacity of gas-fired units by 980 MW.

A similar situation has been observed with respect to investment in the country's transmission and distribution network. At the beginning of 2013 the wear and tear of Kazakhstan's transmission and distribution network was estimated on average at 57%. Aged equipment and the network's topology were the major contributors to losses reaching as high as 18.6% (compared to 2.3–6.0% in Europe).[77] Though a number of grid assets were built between 2009 and 2012, in 2013, Chokin KazNII estimated that transmission and distribution grid infrastructure needed about $26.3 billion in investment (of which $9.3 billion was earmarked for transmission and $17 billion for distribution). Similar to generation, the final figure of grid investment needs has been revised downward in the final version of the 2014 Concept when compared to KAZENERGY 2013 National Energy Report.

10.9.1. Aggregate investment needs of Kazakhstan's power sector

According to the 2014 Concept, the Kazakh power sector requires 7.57 trillion tenge (in 2011 prices) or some $51 billion of fresh investments in 2016–2030.[78] The Ministry estimated that 5 trillion tenge (or some $33.8 billion) will need to be spent on generation (of which 0.9 trillion will be directed to renewables) and 2.5 trillion ($16 billion) on transmission and distribution.[79] In addition to the $51 billion investment in generation and grid, the government estimates that $4 billion would be required for its energy efficiency program. This official forecast is based on higher estimations of power consumption and peak demand. Based on IHS Energy's consumption, peak demand, and production and capacity outlooks, we estimate that the power sector requires only about $37 billion by 2030, or an average of $2.5 billion annually, which is about what is currently being spent.

This figure is based on estimated overnight capital costs. The estimate breaks down as follows:

- $16.6 billion for overall grid and distribution refurbishments and additions
- $12 billion for refurbishing and new coal generating capacity
- $5 billion for nuclear power plant
- $2 billion for refurbishing and new gas capacity
- $1 billion for refurbishing and new hydropower capacity.

This estimate does not include:

- Renewables, which on a modest scale could cost about $8 billion
- Energy saving/efficiency initiatives of about $4 billion in line with official estimates.

This estimate does not envisage a full overhaul of the country's heat energy sector, but has accounted for some investment in that sector. It is noteworthy that the cost of revitalizing the heat energy sector, and the impact on the end-consumer, is likely to be quite substantial and requires further analysis (taking into account that the social factor restrains heat tariff growth for the population). This is because the overall wear and tear for the country's heat energy infrastructure is fairly high (70%), while a cross-subsidy between the heat energy and power tariffs distorts the economic performance of the power assets.

The government recognizes that tariff growth alone would be insufficient to financially support the envisioned scale of the power sector upgrade, and plans are being prepared to attract additional private funding by establishing a favorable environment for investors to return to Kazakhstan's power sector. In the 2014 Concept of Fuel and Energy Sector Development to 2030, the government lists the anticipated deliverables of the upcoming changes in 2015–2030. These include launching new models for the wholesale power and capacity markets, a new system of long-term transmission/distribution tariffs, and new heat energy market legislation.

Even though the above changes are positive, and could boost investor confidence, both institutional and private investors still could be reluctant to invest because the government intends to suppress end-user tariffs for both the population and industry for the foreseeable future (until 2030). With restrictions placed on tariff growth, the return on investment might be insufficient, forcing the state to either review its policy regarding the trajectory of end-user tariff growth or provide more direct state funding. Failing to meet the pace and depth of the sector upgrade, the government might feel compelled to reassess launches of generating and grid assets, as well as support for renewables or energy-saving initiatives, etc.

In addition, the government may face yet another challenge. The bulk of anticipated new investment by the government of Kazakhstan (estimated at more than 60%) is planned for construction and upgrade of coal-fired generation. The drive to minimize the effects of coal generation on the environment in Europe means there is a significant risk that certain European investors would be averse to invest (even if the plants are equipped with the latest clean coal technologies). Naturally, Asian investors are less constrained by these standards, but as Russia's experience has demonstrated, while negotiations with Asian investors often lead to genuinely rich opportunities, they can be relatively limited and take considerable time to find a mutual agreement.

Nevertheless, as Kazakhstan faces a steep investment curve for modernizing its aged generating capacity and grid network, policymakers are keen to promote diversification into other types of generation: gas, renewables, and nuclear (see the box "Kazakhstan's 'Green Economy' Concept").

[77] According to Chokin KazNII Energy, as presented in the National Energy Report 2013, 50–60% of the basic transmission and distribution infrastructure is in disrepair, increasing losses.

[78] The estimate of 7.57 trillion tenge was presented in the August 2014 (final) version of the Concept of Fuel and Energy Sector Development to 2030. It was reduced from the Ministry's earlier estimate of 9.5 trillion tenge (the equivalent of $60 billion) from July 2013.

[79] The figure of 7.57 trillion tenge (in 2011 prices) conflicts with the Ministry's estimate of investment needs over 2020–2030. The same Concept refers to 8.3 trillion tenge (in 2011 prices) needed in 2020–2030.

Kazakhstan's "Green Economy" Concept

Kazakhstan's official energy plan ambitiously calls for a major shift toward renewable energy sources and away from coal longer term. Part of the broad "Strategy Kazakhstan 2050," the energy plan uses the country's sizable natural gas reserves as a bridge between coal and alternative sources (renewables and nuclear) for electricity generation. According to the decree signed by Kazakhstan's President Nursultan Nazarbayev on 30 May 2013, renewable and alternative energy sources are slated to provide 50% of all electricity produced in Kazakhstan by 2050.[80]

The goal is part of the broad "Strategy Kazakhstan 2050" initiative designed to modernize and diversify the nation's carbon-reliant economy. The plan calls for the aggressive development of Kazakhstan's alternative energy generation as well as water resources, agriculture, and the waste management sector. It also contains measures to reduce carbon emissions and increase energy efficiency in the industrial, housing, utilities, and transport sectors.

This ambitious "green" plan targets 11% of electricity generation to come from wind and solar sources, 10% from hydro, and 8% from nuclear by 2030, with the remainder coming from coal (49%) and natural gas (21%). By 2050, the plan calls for 50% of power generation from alternative and renewable sources. By 2050 the share of wind and solar sources to increase to 39%, nuclear and hydro (combined) to account for 14%, and gas to fall to 16%, with the remaining 31% to come from coal-fired stations (albeit upgraded facilities using cleaner-burning technologies).

The "Green Economy" messages have been integrated into the 2014 Concept of Fuel and Energy Sector Development to 2030. According to the Concept, installed capacity of renewable plants will increase from 2.7 GW (in 2012) to 8 GW in 2030.

10.10. Changes to the Power Market Mechanism to Drive Efficiency and Investment

According to "the 2014 Concept," the ultimate goal of power sector development is to increase the efficiency of Kazakhstan's power resources in support of economic growth and improving living conditions for the country's population. Among the strategic priorities, to be achieved by 2030, are energy security, development of the resource base, and lessening of the power sector's impact on the environment. Kazakhstan was first among the CIS countries to embark on a power market reform, but progress has since been slow. While the initial goal of preserving the power sector after the break-up of the Soviet Union has been met, the changes to the power market have not brought about the anticipated rejuvenation of the sector.

Kazakhstan's power market combines a wholesale and retail power market. The model of the wholesale market, while sharing some similar characteristics to the Scandinavian and US power markets, has failed to live up to expectations. Of all its segments, only decentralized power trade has had some measure of success (bilateral agreements account for 95% of wholesale power sales). In contrast, no power is sold at a balancing market, and the centralized sale of power represents less than 5% of the market (trading power at a centralized market is voluntary rather than obligatory), making price transparency decidedly opaque. Kazakhstan's industrial holdings that tend to dominate the decentralized segment buy and sell power internally (in other words, they are vertically integrated) and have no incentive to sell power using a centralized auction. As a result, this market segment is illiquid, and devoid of pricing signals (this issue has also been a major challenge for some more developed power markets in the West, where power producers owned large sales businesses). Essentially, this situation presents a challenge when considering power price transparency, trade volumes, and terms of power supply, as terms of bilateral agreements are confidential and the volumes traded centrally are insufficient for analysis.

Almost 50% of wholesale power is traded by a handful of power plants, which means wholesale consumers are restricted in choosing power suppliers, as well as negotiating terms of supply. Furthermore, the power supply companies affiliated with these generators get priority in signing power supply agreements.[81] The situation is exacerbated by the fact that consumers have to pay higher prices for power as part of the "tariff in exchange for investment" scheme that was launched six years ago.

[80] "Concept of Transition of the Republic of Kazakhstan to a Green Economy," approved by Presidential Decree No. 577 of 30 May 2013.

[81] An oligopoly in power generation, supply, and trade is not unique to Kazakhstan. For example, only a handful of companies generate and sell power even in France and Germany.

Change is coming but details are yet to be released

President Nazarbayev outlined several key power sector objectives in a recently published "100 tangible steps" plan. In steps 50–52 the President refers to reorganizing the electric power sector, the launch of a single buyer, integration of regional power companies, and changes to the tariff policy stimulating investment (see box below for more detail). At the point of writing, no further details were made available.

President Nazarbayev's "100 Tangible Steps" Plan

The "100 tangible steps" plan was announced by President Nazarbayev during a government meeting in Astana on 6 May 2015 and published in the KazPravda newspaper on 20 May 2015. The 100 steps plan is Kazakhstan's "response to global and internal challenges, as well the nation's ambition to be among the 30 leading developed countries in a new historic environment." It consists of five institutional reforms:

- Professional government
- The rule of law
- Industrialization and economic growth
- Identity and unity
- State accountability.

The electric power sector is a part of the "industrialisation and economic growth" reform and has three steps dedicated to it.

- **Step 50.** Reorganization of electric power sector. Launching of a "single buyer" model. This approach will make it possible to level out the difference in tariffs by region.
- **Step 51.** Integration of regional electric grid companies. This approach will make it possible to increase the reliability of power supply, decrease power transmission costs in the regions, and reduce power costs for the end-consumers.
- **Step 52.** Introduction of a new tariff policy in the power sector to stimulate investment. This involves changes to the tariff structure. The overall tariff is to consist of two essential parts: a fixed part to finance capital costs and a fee for consumed power to cover variable costs of power production. This approach will replace the current "costs-plus" methodology.

10.10.1. Finding a power market model that fits Kazakhstan

In 2009, Kazakhstan divided its generating capacity into 13 groups; each is considered a separate maximum tariff subject according to fuel, type of plant, and distance to the fuel base. The "tariff in exchange for investment" scheme made the tariff high enough to allow for meaningful investment. The lack of transparent control mechanisms over generators' investment obligations largely meant that the high tariff increased asset-owners' profits but did not necessarily translate into useful power sector upgrades. According to KOREM (the operator of the centralized wholesale power market), after the introduction of the maximum tariffs, generators' power prices increased by 30–50%, resulting in about a 20% increase in the end-user power price, yet the overall sector witnessed a slower than hoped for uptick in overall investment.[82] The government recognizes that Kazakhstan's power sector will need to create incentives that would attract investment and secure return on investment. Capacity markets are viewed a means to guarantee targeted investments in the power sector.

According to the 2014 Concept, the launch of a new power and capacity market in 2016 is crucial for overall market rejuvenation, and is viewed as one of the top priorities for Kazakhstan's economic development. Although the exact details are currently being refined, market participants understand the overall concept of the new power and capacity market reasonably well.

First, Kazakhstan has opted for the model based on two market structures—power and capacity (something already widely practiced in the US, South America, Russia, and now several European states). While power is a traded product, capacity is a service. The benefits of running a separate capacity mechanism range from creating long-term pricing signals for consumers and investors, mitigating sharp power

[82] According to government provision No. 392 of 29 March 2009 on "Maximum Tariffs," the annual increase in end-user power tariffs should not exceed 7%.

price spikes (particularly for peak generation with limited opportunity to cover costs fully, as the capacity price covers most fixed costs and helps keep the power price down), to creating a mechanism for ensuring continued modernization and construction of new generating assets.

Second, the changes to the power market aim to shift power trading from individual bilateral agreements to a centralized platform. A new regulation will make it obligatory for all wholesale market participants to sell and buy electric power centrally, and will limit bilateral trade to the industrial groups only, thus creating better transparency and equal access to the market. The market participants will have an option to trade power: short term (day-ahead), medium term (week and month ahead), and long term (quarter, biannually, annually). Despite this, the new model does not envisage the launch of a power derivatives market to hedge price, volumes, or other market risks.

Market participants will not be able to adjust or trade power sale or purchase volumes within the same day, but instead imbalances will be settled in a balancing market. In other words, excess physical power volumes will trade at the balancing market. The balancing market will balance physical volumes and settle financial differences relative to the hourly consumption and production of the market participants. In addition, there is a discussion about the launch of a new system-services market that shall compensate for any services relevant to technical dispatch, regulation, or reservation of capacity by consumers, generators, and grid upon the request of a system operator.

Essentially, the power price will cover generators' variable costs, while the capacity price will cover fixed costs. Although the price of power will be driven by the economics of each plant, it cannot exceed a maximum price set by the regulator. This particular nuance tends to mean that the power plants sell at the regulated cap. Still, the actual process for plant selection (dispatch) into the market is unclear. Issues to consider are:

- What will be the criteria for selecting the plants during the auction (price only or technical efficiency)? In other words, how will the selection process encourage efficiency in power generation whilst minimizing the cost of power for the end consumer?
- How will the regulator deal with inefficient generation that fails to be selected on price/technical criteria but is still required to run because of crucial heat energy production?
- What instruments would be available for generators to hedge volume and price risks, particularly those relating to long-term power purchase agreements?

Consider the sale and purchase of power at the wholesale power market, including power sales companies that purchase power on behalf of retail consumers. But:

- There is a difference in the purchase price at the wholesale market and the regulated price at a retail market. How will the regulator deal with the cash imbalance that could occur in this case?
- What mechanism would protect retail consumers from volumetric risks associated with the sales companies? In other words, what would stop the sales company from passing the costs directly on to retail consumers in the event of short buying power at a wholesale day-ahead market and purchasing the additional volumes from a balancing market?
- What instruments would be available for consumers to hedge volumetric and price risks, particularly when it comes to long-term power purchase agreements?
- What mechanism of financial guarantees is envisaged to protect the interests of wholesale generators in case of payment default by wholesale consumers?

The new capacity mechanism is to become a key ingredient in planning future capacity needs and bringing new investment into generation. Kazakhstan does not envisage mimicking a Russian-type capacity mechanism to secure investment for the construction of new capacity. Both old and new capacity will be traded at a long-term auction. Key issues include:

- What mechanism would ensure transparency of capacity price formation, particularly for the new capacity (standardized costs for the construction of a unit subject to fuel; anticipated rate and terms of return of investment, etc.)?
- What incentives would the system operator have for more accurate planning of capacity needs? As a legacy from Soviet planning, there seems to be a tendency for overestimating capacity needs, particularly for reserve capacity. Consequently it increases consumers' financial burden.

The capacity selection process will be driven by price. This means that over time the majority of older generation should be forced to upgrade or shut down. Issues to consider here include:

- Will restrictions imposed on consumer tariff growth and the maximum capacity price impact capacity price formation and investment attractiveness of this segment?[83]
- How would decommissioning inefficient generation work if it remains a critical source of heat energy supply?
- Will there be a different procedure of auctioning and paying for nuclear, renewable, and hydropower capacity?
- Will payment of reserved capacity and equipment maintenance for the needs of supporting renewable generation be accounted for via a capacity mechanism?
- Will payment for capacity be differentiated by zone or province to avoid an uneven capacity payment burden in certain geographical areas?

Kazakhstan plans to launch a long-term capacity auction from the very start. Issues to consider:

- Will generators be able to define the price of capacity three years ahead under changing economic conditions?

[83] The government plans to introduce a maximum capacity price as a control mechanism. The draft of the law "On Changes to Legislation in the Power Sector" is scheduled to be approved on 1 January 2016.

- What instruments would be available for consumers and generators to hedge capacity price risks, particularly considering long-term capacity supply agreements?
- What mechanism would insure generators' accountability for investor obligations?

All other organizational aspects of the operation of future power and capacity markets seek to improve transparency and smoothness of power and capacity market operation. For example, a new Single Market Operator will be created, in charge of trade in all segments of the market: power, capacity, balancing, system services, and export/import. In addition, the Single Market Operator will:

- Certify capacity
- Maintain the registry of certified capacity and approve its readiness for supply
- Plan future development of the grid network and infrastructure (together with the grid and distribution companies)
- Forecast consumption
- Forecast demand for capacity by type of generation (flexible and non-flexible)
- Execute a financial guarantee system in the capacity market
- Grant access to trade
- Execute trade
- Arrange financial settlements.

The Single Market Operator will have an overwhelming influence over the operation of the power and capacity market, so policymakers may need to consider the issues of transparency and accountability over the body's decision making. This means that information (raw data, analysis, and reporting) should be readily available to both market participants and outsiders: it will have to be ample, consistent, and disclosed regularly in an electronic format.

In addition to the wholesale market, there is a plan for further development of a retail market as well as an intention to address complex social issues in the heat energy and retail markets. Nevertheless, policymakers do not appear to be launching simultaneous reforms of the heat energy or retail markets (beyond addressing the tariff formation issue). Any delay with reforming these markets is likely to present a major hurdle for Kazakhstan's policymakers as they attempt to advance power sector reforms.

10.10.2. The future of Kazakhstan's heat energy market

By 2030 the government aims to "create a new system of legal and economic relations between producers and suppliers of heat energy," that is, a new heat energy market model. Although the 2014 Concept provides no details about the new scheme, the "possibility of developing a long-term tariff for the production and delivery of heat energy by 2030" (as an anticipated result of upcoming change) indicates that the government intends to address the issue of heat sector funding. Yet actual changes are likely to be very slow due to technical, technological, and social aspects of heat energy market operation.

Years of overall neglect have meant that heat energy generating capacity and the network are in dire need of revitalization. While the new long-term tariff might be sufficient to support the eventual overhaul over 15–20 years (although there are no details on the methodology for new tariff formation), it may be inadequate to spur near-term investment. In this case, over the next decade, the government is likely to face severe funding challenges for replacing some of the country's most dilapidated generating equipment and heat energy networks. This means a new investment mechanism for the heat energy sector needs to be introduced alongside a long-term tariff (particularly if the government hopes to attract private funding).

There are a number of methodologies available that are practiced globally, as well as in neighboring Russia, that range from tariff indexation, RAB (regulated asset base), and benchmarking against new construction (known in Russia as "alternative boiler house"). The final choice of a single method, or a combination of methods, will depend on each power zone or area in Kazakhstan. However, whatever method(s) chosen should be based on a realistic cost of heat energy generation and supply. Essentially, this means establishing a more realistic market value for providing heat energy. It could also unintentionally drive out combined heat and power plants from the system over the long term.

One way to unlock market value for heat energy production and supply might be through creating reliable and transparent conditions for competition between various providers of heat energy generation and supply based on economics, technology, and efficiency. However, this method rarely finds an equal footing among different types of heat energy sources (often TETs are the sole source of heat energy generation and supply within a designated area, with no alternative sources of heat energy). Importantly, centralized heat energy generation had become the dominant method of heat energy supply in all of Kazakhstan's cities, towns, and large settlements by 1990 (according to KazNIPIEnergoprom, 70% of urban residents use the services of centralized heat energy supply), and the combined heat-and-power plants (TETs) are a primary source of heat energy. Of the total installed thermal capacity of some 40 TETs nationwide, 64% of heat energy is supplied in the North Zone, 19% in the South Zone, and 17% in the West Zone. Yet, for heat energy supply to remain centralized and for TETs to continue to be the source, the economics and efficiency for heat energy generation must become viable.

The drop in heat energy demand (particularly by industry and by small and medium business) has changed the economics of heat energy production by TETs, and so the net cost of heat and power production has risen. According to KazNIPIEnergoprom, TETs already fail to compete with large condensing plants located close to a fuel base (mainly coal mines in Kazakhstan), and though the competition from existing boiler houses has not been evident, Kazakhstan might see an unexpected growth in new and more efficient independent gas-fired (mainstream gas or LPG) boiler houses in the future.

But importantly, average heat energy prices from independent boiler houses in neighboring Russia have proven to be significantly more expensive than heat produced by TETs. But the argument remains that in the future Kazakh urban areas should be able to choose the most economically and technologically efficient source for heat energy supply. Therefore, if the economics of long-term heat energy production from a boiler house in certain areas proves to be more beneficial than that of TETs, the regulation should support and encourage construction of an efficient boiler house versus a power plant. To assess the end-consumer heat energy price, the costs associated with building and operating the most efficient source of heat energy supply should be comparable to the market operational and capital costs of an existing power plant. This approach provides greater flexibility as well as market transparency.

A similar approach for attracting investment into heat energy supply would require setting a long-term tariff for operating the heating network. But unlike generation, the return on investment will depend on the tariff (the most common methodology of calculating a heating network tariff is RAB). However, there will be a need to create a single body that would ensure accountability of investment and increased efficiencies. A so-called "Single Heat Energy Supply Company" would be responsible for the replacement of heating pipelines, metering, optimization of costs, etc.

The combination of a new non-regulated long-term tariff (reflecting a true cost of heat energy production and supply) that will help minimize the practice of costs redistribution between heat and electric power production, and an investment mechanism would attract funding, promote efficiency, and create conditions for long-term strategic planning and access to long-term funding in the sector. But it would inevitably drive up heat energy costs for the end-consumer. However, an uninterrupted and reliable supply (particularly during long, cold winters) at suppressed prices has become an expected social benefit. The question is, will the government be willing to reconsider its fundamental view on heat energy tariff growth for consumers, and in particular residential consumers? A gradual medium-term shift from a regulated price to a market value tariff for all heat energy consumers will smooth the overall transition and would diminish the need for heavy-handed countermeasures.

Naturally, any changes to Kazakhstan's heat energy sector bringing efficiency and investment would be welcome. However, there is a need for a single master plan (a road map) for launching a new heat energy market model covering all aspects of market regulation and planning. There is an urgent need for a dedicated law on heat energy production and supply, price formation, efficiency, quality and reliability of supply, accountability of investment, information disclosure, and overall sector planning and regulation.

Any changes to the heat energy sector should be assessed from the point of view of investment and its impact on the end-consumer heat energy bill (including the changes to consumer parity as a result of a heat energy price increase). At present, the cost associated with changing the heat energy sector, its investment needs, or the impact on the overall end-user electricity price have not been fully factored into the government's strategy. In other words, Kazakhstan's policymakers will need to address the issue of heat energy sector funding separately, but in parallel with other market reforms.

10.11. Conclusion and Key Recommendations

10.11.1. Coal to remain dominant but opportunities exist for gas and nuclear

Kazakhstan's ongoing power sector refurbishment allows policymakers some scope for encouraging specific technologies. It is evident that gas and renewables (inclusive of large hydropower plants), and potentially nuclear, will find some traction. But new transmission developments also will go some way toward unlocking more capacity, and increasing system reliability and flexibility. It is particularly important that Kazakhstan's transmission development policy continues strengthening the northern and southern grid connection, but also connects the main grid with the West Zone. Moreover, Kazakhstan's distribution network needs modernizing so to improve overall efficiency.

In terms of capacity, Kazakhstan's capacity mix is clearly shifting, albeit at a slow pace because the economics and logistics of coal-fired generation in Kazakhstan remain indisputably persuasive. Therefore, coal-fired generation is set to remain Kazakhstan's dominant fuel for power over the next two decades. But coal's share of the thermal mix will give way to more gas, particularly in the southern part of Kazakhstan where a switch to gas is logistically possible and when it is economically viable. The incremental growth in renewables is likely to play a small role in Kazakhstan's power production, but genuine market and technical issues limit their integration and thus acceptance. The nuclear power option represents the single largest newcomer to the capacity mix and, given its loading priority, also to future production. Moreover, nuclear power will dramatically improve Kazakhstan's overall carbon credentials by offsetting coal-fired power production (flowing from the North Zone), even if the nuclear power plant is built in southern Kazakhstan.

10.11.2. Key recommendations

Infrastructure

- Given IHS Energy power consumption expectations, Kazakhstan's entire electric power infrastructure requires an estimated $36.6 billion in investment for the period 2016–2030, of which grid and distribution should account for about 40%. It should also be kept in mind that in percentage terms, over this period, power consumption growth is growing more strongly in the southern and western parts of the country, meaning that capacity and grid additions will need to adequately support the future load profile.

- Moreover, in order to bolster Kazakhstan's utilization of existing capacity and overall energy independence, investment priority needs to remain aggressive on grid development. Other than general grid reinforcements and modernization throughout the system, one obvious area to focus on is to connect Kazakhstan's West Zone with the North and South zones (which is already in KEGOC's long-term development plan). A slight nuance with IHS Energy's recommendation is to bring forward the western grid connection with the rest of Kazakhstan earlier than originally planned (by some 10 years). A key objective is to focus on unlocking greater value for Kazakhstan's existing generation fleet.

- Given Kazakhstan's abundance of low-cost coal, and underdeveloped gas pipeline network, part of the capacity solution will remain coal. Therefore, outright prejudice toward coal is not helpful, but measures to support capacity modernization or replacement should be of high importance. Naturally IHS Energy recommends the upcoming capacity support mechanism accounts for modernizing and replacing coal capacity rather than just supporting its existence. In other words, solid technical regulatory policy supported by a financial guarantee mechanism if properly monitored would gradually improve the average efficiency of Kazakhstan's coal-fired fleet.

- Nuclear power should play a role in the country's capacity mix, and specifically as an additional measure to support Kazakhstan's green credentials. Nuclear power typically has a high utilization rate, and thus would make an important contribution to future base load production. Positioning nuclear generation near to the Ulken 500 kV substation (southwest of Lake Balkhash, which dissects two important 500 kV lines connecting north and south Kazakhstan), or in southern Kazakhstan has significant strategic merit. Essentially, nuclear could be used to fill the growing capacity gap in southern Kazakhstan, reducing a growing reliance on (coal-fired) power transfers from Kazakhstan's north.

- As another important means to control carbon-emitting generators, where logistically possible, gas capacities need clear policy support—mainly through market-based (differentiation of gas prices) and/or indexing incentive systems. Moreover, Kazakhstan clearly needs to add more peaking generation to its overall mix. This will become more prevalent as consumer power demand, in particular in western and southern Kazakhstan, becomes more dynamic. A market-based system or indexing to reward gas generators is an important measure to encourage their participation in the power production for the system through a well-conceived capacity mechanism and a mechanism of a system services market.

- In line with progress in revitalizing Kazakhstan's infrastructure, policymakers need to draw up robust rules and procedures for decommissioning unreliable and inefficient capacities.

- Finally, Kazakhstan's renewables policy needs further work to prevent potential runaway development, which if not properly policed, could lead to some disruption to grid stability in certain locations. Renewables must be technically viable in order to work symbiotically with the market, including a system services market providing financial incentives for conventional generators capable of reactive and replacement power; parts of Kazakhstan will need to adapt traditional technology to respond to this upcoming need. Until the full technical and economic ramifications of a varying share of renewables in Kazakhstan's grid are better understood, a more controlled approach is recommended. For instance, based on current regulations and technology, until 2030 Kazakh policymakers should allow for a total renewable production growth of up to 3–5% in the overall power production.

Power-sector financing

- Along with sound forecasts and technical regulations, investment in Kazakhstan's power sector can only be solved with predictable financial mechanisms offering reliable forward pricing signals; but this is not to be confused with unleashing full market liberalization. It would be unhelpful to recommend liberalization given the obvious constraints that currently exist. For example, Kazakhstan's rigid heat energy sector and tariff imbalances in the retail sector severely limit efforts to liberalize (efforts tested in many Western power markets). Understandably, Kazakh policymakers seek to find a stable and predictable commercial environment, but naturally we still recommend that the power sector rewards reliability, availability, and efficiency. Essentially, key goals of the power market are to reward investment and drive out inefficiencies. Many countries have a different view on how to organize a power market to achieve these goals, but crucially Kazakh policymakers should aim for policies to remain consistent to avoid confusing investors.

Market recommendations

President Nazarbayev outlined a number of key power sector objectives in a recently published "100 tangible steps" plan. Listed steps 50–52 address the reorganizing of the electric power sector, the launch of a single buyer, the integration of regional power companies, and changes to the tariff policy stimulating investment. The following should be considered:

- The wholesale power mechanism needs to be fully representative, reflecting the real cost of power production, and place an emphasis on efficiency; it therefore needs to possess market attributes. A trustworthy wholesale power market should account for all power production, consumption, and trade on a level playing field. This should be organized in an auction format. A secondary balancing market should function to settle unscheduled production and consumption.

- President Nazarbayev's proposed single buyer model appears to refer to the capacity market only. However, should it expand to include power as well, it could be construed to perform like a physical power exchange to improve trade transparency, liquidity, and regional consistency. Structured as such, it could install financial trust and buffer the risk of financial liabilities. Moreover, a financial forwards market can play a secondary role to reduce long-term financial risk.

- The market should reflect supply and demand so as to reflect the cost of producing incremental power during times of higher demand, thus rewarding capacity to flex output accordingly. This will encourage more peaking capacity.

- Current electricity sales companies' tariff differentiation relates to two consumer groups only: population and small-to-medium commercial consumers. At that the tariff differentiation policy should predominately target large consumers (particularly, industry). The goal of such tariff differential policy is to stimulate large consumers that purchase power via bilateral agreements to optimize daily load (maximum power consumption at night and drop in power consumption during peak hours).

- A further system services market should be established to reward generators who respond to rapid changes in output (including a separate provision on mitigating the effects of renewable generation). Additionally, a demand response market should be devised for consumers who can change consumption and demand requirements.

- The capacity mechanism should be thought of as a system guaranteeing capacity reliability, and thus a service, rather than a tradable product. Power-only markets tend not to work well in encouraging new capacity. So a capacity mechanism is a tool for policymakers to introduce a politically desired capacity mix—in other words, not necessarily the cheapest—in a timely manner. It is also a tool for insuring maintenance—or technical reliability—of existing assets. With that in mind, in order to get the best out of a capacity mechanism, policymakers should develop technical regulation and guidelines for the future. Moreover, the capacity mechanism should also be tied into the heat market reform and overall heat capacity objectives. In other words, financial support must guarantee a minimum technical standard from all assets.

- Since about 40% of power production comes from district combined heat and power plants (TETs), a good reform of the heat energy market is crucial to spark investor interest in refurbishing or replacing these assets, and should not be delayed. Investment should also be channeled into gaining more flexibility between heat and power provision and should be an important ingredient in the overall capacity plan. Currently, heat pricing does not reflect the real cost of heat energy provision, and raising tariffs is politically undesirable. Therefore the reform should outline a transparent long-term tariff transition plan. Liberalizing the heat energy market has serious practical limitations—because the lack or absence of competition and the state's social obligation to the people—and thus heat energy provision should remain quasi-regulated.

- The retail market needs to begin the long journey to reflect the real cost of power for different consumer groups. Clearly, the speed of this process should consider the bottom range of consumer income levels, and overall inflation. But the overall direction should ensure a pricing dynamic that encourages consumption efficiency on all levels.

ENERGY EFFICIENCY AND RESOURCE SAVING

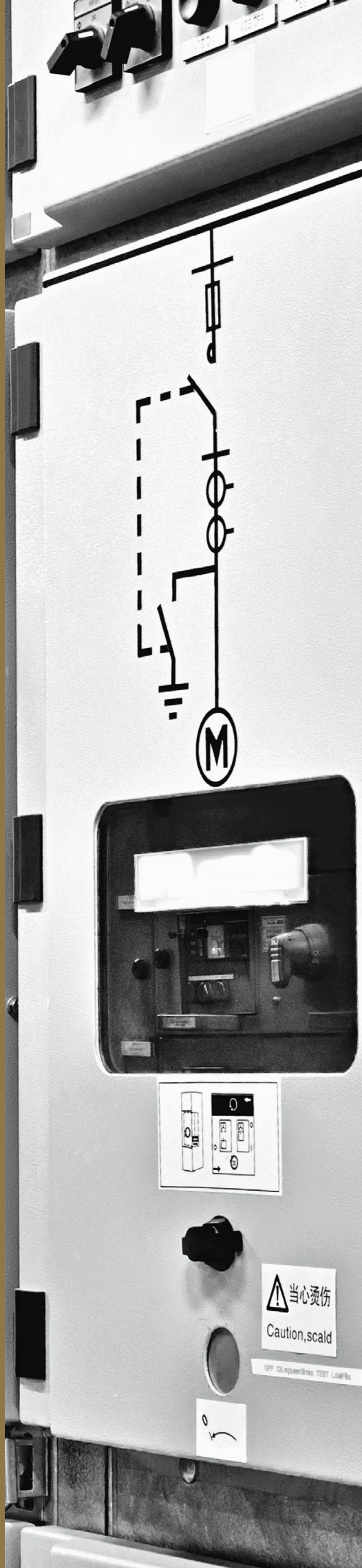
11.1 KEY POINTS

11.2 IMPORTANCE OF ENERGY SAVING AND ENERGY EFFICIENCY FOR KAZAKHSTAN'S ECONOMY

11.3 ENERGY INTENSITY OF KAZAKHSTAN'S ECONOMY VERSUS OTHER COUNTRIES

11.4 CURRENT ENERGY INTENSITY OF ECONOMY AND ENERGY EFFICIENCY GROWTH POTENTIAL

11.5 REGULATORY OVERVIEW/GOVERNMENT POLICY TO SUPPORT ENERGY EFFICIENCY



11. Energy Efficiency and Resource Saving

11.1. Key Points

- In terms of GDP energy intensity (the amount of energy consumed per unit of GDP) Kazakhstan is ranked 28th among the countries of the world.[1] This is due to a number of objective reasons such as the severe continental climate with long and cold winters, prevalence of energy-intensive sectors of the economy in the structure of GDP, the overall size of the country (its large territory), and the length of transport infrastructure (oil and gas pipelines, electricity transmission lines, water ducts).

- One of the key factors underlying Kazakhstan's high energy intensity relates to how energy is consumed in the sectors of its economy. The industrial sector, with the exception of new major projects, is characterized by a high degree of fixed asset depreciation and an inefficient energy accounting and management system. Housing stock depreciation and the technical condition of heat supply systems result in a high level of heat loss. Poor quality of motor fuel and prevalence of motor vehicles that have been in service for more than 10 years affect energy efficiency in transportation.

- Availability of cheap coal and relatively low regulated energy tariffs (heat, gas, electricity) are, undoubtedly, Kazakhstan's competitive advantages; however, at the same time, the investment attractiveness of energy-saving projects remains quite low. It should be noted that energy-saving measures may be of small economic benefit for individual companies, but may result in significant energy savings for the country as a whole through a synergistic effect.[2]

- In recent years, energy saving and energy efficiency have become one of the top priorities of state policy in Kazakhstan.[3] However, the established legal framework is characterized by the significant predominance of restrictive mechanisms, with a virtual absence of investment-encouraging provisions or incentives. A number of legislative requirements (energy consumption standards in industry, capacity factor requirements, ban on incandescent lighting fixtures) adopted in the sphere of energy consumption in industry have not yet yielded substantial positive results.

- Establishment of the National Energy Register (NER) of industrial enterprises consuming more than 1,500 tons of energy in coal-equivalent standard fuel units (1,050 tons of oil equivalent) annually as well as local government agencies and state (public) enterprises may be the most effective mechanism of managing energy consumption efficiency in the current environment. The entities on the NER are to undergo regular energy audits as well as formulate and implement energy-saving plans based on the results of such audits.

- The Energy Efficiency 2020 National Program adopted in 2013 sets a rather ambitious target of a 40% reduction of the GDP energy intensity by 2020. However, it seems unlikely that this target will be achieved within the indicated period. The IHS base-case forecast envisions an improvement of about 17% in Kazakhstan's aggregate energy intensity by 2020, and about a 48% decline by 2040.

11.2. Importance of Energy Saving and Energy Efficiency for Kazakhstan's Economy

On the national economy level, increased energy efficiency can slow down energy consumption growth and, therefore, reduce the need for construction of new energy sources as well as increase potential energy exports. Growth of energy efficiency in industry makes it more competitive. In addition, reduced consumption of many forms of energy (including solid fuels) has an environmental benefit, including curtailing the volume of greenhouse gas emissions and contaminants. For example, consuming one less coal-generated megawatt-hour of electricity results in a decline in emissions of 276 kg of CO_2 and prevents formation of 250 kg of ash waste.[4]

However, the availability of readily accessible energy resources and their relatively low cost in the domestic economy considerably reduce the investment attractiveness of energy-saving initiatives in Kazakhstan. Moreover, the competitiveness of Kazakhstan's economy depends, among other things, on the level of energy consumption, even with relatively cheap energy. For these reasons, government leadership may be important in providing the necessary incentives for increasing the investment attractiveness of energy-saving and energy efficiency programs.[5]

[1] According to IHS 2014 data with GDP estimated at market currency exchange rates. According to Key World Energy Statistics, IEA 2014, Kazakhstan is ranked 25th among the countries of the world by energy intensity of the economy based on 2012 GDP measured in 2005 constant dollars, estimated on a purchasing power parity (PPP) basis (i.e., based on the consumer basket of goods).

[2] For example, reactive power compensation at an entity has an impact on the external electric grid, resulting in reduction of electricity losses and an increase in throughput capacity.

[3] Two laws and more than 22 regulations have been adopted since 2012.

[4] The calculations are based on Ekibastuz GRES-1 generating data.

[5] For more information see the Review of the National Policy of Republic of Kazakhstan in the area of energy saving and energy efficiency from 2014.

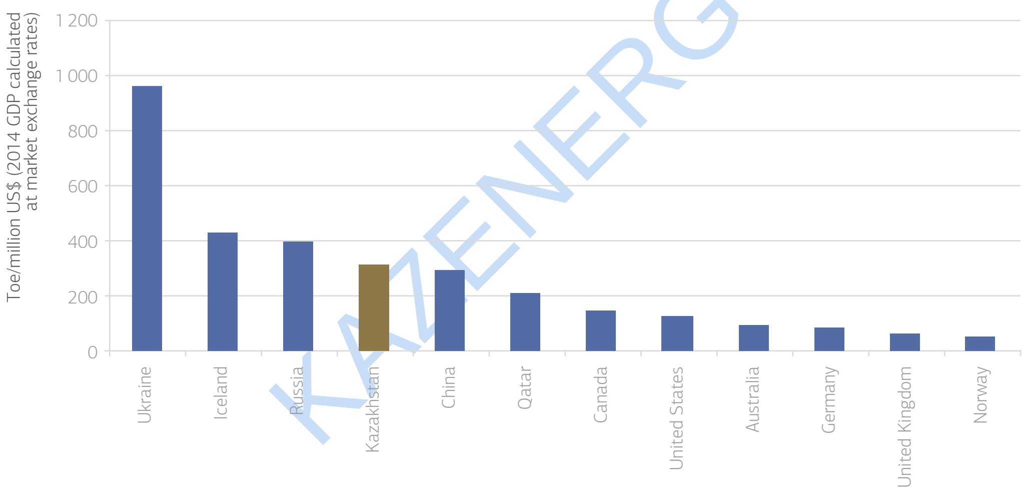
11.3. Energy Intensity of Kazakhstan's Economy versus Other Countries

As noted in Chapter 2, in 2014 Kazakhstan consumed 314 tons of oil equivalent (toe) to produce each million dollars of gross domestic product (GDP) (in 2014 dollars, with GDP measured at the market exchange rate). This level of aggregate energy intensity is widely understood to be among the world's highest,[6] but should be viewed in the broad context of the structure of Kazakhstan's economy, its geographical location, and other factors. Industry (which accounts for almost 30% of Kazakhstan's GDP) and the power sector together account for almost two-thirds of primary energy consumption. Thus, Kazakhstan's energy intensity will definitely be higher than in the EU countries, whose economic profiles are characterized by higher shares of less energy intensive sectors such as processing industry, services, and finance as well as IT and research.

Kazakhstan's high-latitude location and continental climate ensure that greater amounts of energy must be consumed for heating than in countries with milder winter climates (e.g., EU countries). Further, Kazakhstan's vast land area (ninth largest in the world) and relatively low population density mean that energy (as well as goods and people) must be dispatched across greater distances between sites of production and consumption, leading to greater losses in transmission. The share of expenditures on transportation in the end product cost is relatively high, amounting to 8% and 11% for domestic rail and motor vehicle transportation, respectively (twice [or more] the level in the European countries and other developed market economies).

Another factor contributing to Kazakhstan's relatively high energy intensity is its heavy reliance on coal (60% of the total energy consumption, see Chapter 8), which has a lower efficiency than oil and natural gas.

All of these factors should thus be considered in international comparisons of Kazakhstan's energy intensity, with the most relevant reference countries being major natural resource producers with large territories and rather severe climates like Australia, Canada, and Russia. In recent years Kazakhstan's energy intensity is comparable to that of Russia, but high relative to other "analog" resource-rich countries such as Canada and Australia (see Figure 11.1). At the same time, Kazakhstan's energy intensity is much higher than in the countries with completely different economic structures, such as the United States and the EU member states. Notably, it is comparable with that of China (with a 5% difference) where the energy sector is also dominated by coal.



Source: IHS Energy

Figure 11.1 Energy intensity in 2014: Kazakhstan versus selected other countries

Overall, energy intensity has its limits as an indicator because of its aggregate nature, and it can be somewhat misleading, primarily due to different GDP calculation methodologies as well as differences in climate, and the economic conditions of the underlying countries. However, in a qualitative comparison between countries, GDP energy intensity proves quite informative.

[6] As noted in Chapter 2 of this report, Kazakhstan now ranks 28th in the world in energy intensity according to this measure of GDP at market exchange rates. Estimates of GDP in purchasing power terms were revised upward substantially for two oil-producing countries in the former USSR, Kazakhstan and Azerbaijan, by the OECD for 2014 as part of the International Comparison Programme (ICP) exercise. GDP estimates for these two countries for every year over the period 1990–2011 were revised upward by 60%. Raising GDP, while keeping energy consumption levels unchanged, has resulted in a substantial reduction in these two countries' energy intensity levels. However, the differential treatment of various OECD and CIS countries during the ICP re-estimation (e.g., the GDP of Russia, another major oil producer, did not change) and the uniform treatment (60% increase) of Azerbaijan and Kazakhstan's GDP for each year over the period 1990–2011 have led some observers to question the underlying methodology, unless it can be demonstrated that services were seriously underpriced in the two countries.

Figure 11.1 shows that Kazakhstan's energy intensity is more than twice that of the United States and Canada and three times the level of the EU. These data are calculated based on 2014 GDP at market exchange rates. However, if we look at Kazakhstan's GDP energy intensity based on GDP calculated at purchasing power parity (PPP) the difference relative to the level of developed countries is not as significant (Table 11.1). For example, Kazakhstan's energy intensity is less than twice that of the USA. The difference in the levels of energy intensity of GDP (PPP) between Canada and Kazakhstan in 2012 is about 20%. Qualitative comparison of Kazakhstan's GDP energy intensity with Canada thus suggests that Kazakhstan has an achievable energy intensity reduction potential of at least 20%. Canada is most similar to Kazakhstan of all the OECD countries in terms of climate, land area, population density, and GDP profile.

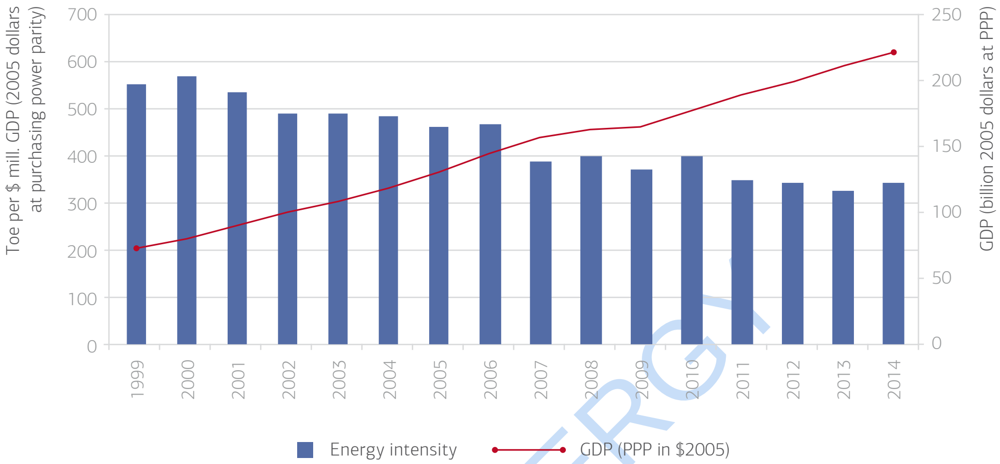
Country	Population (millions)	GDP (billion $2005 at PPP)	Primary energy consumption (TPES) (million tons of oil equivalent)	GDP per capita (thousand $2005 in PPP)	Energy intensity (toe per $1000 GDP)	Energy consumption per capita (toe per person)
World average	7 037	82 901	13 371	11.781	0.161	1.90
OECD	1 254	39 202	5 250	31.262	0.134	4.19
Middle East	213	4 184	681	19.643	0.163	3.20
China	1 358	13 289	2 909	9.786	0.219	2.14
Australia	23	872	128	37.718	0.147	5.55
Azerbaijan	9	132	14	14.156	0.104	1.47
Belarus	9	142	31	15.043	0.214	3.22
Brazil	199	2 532	282	12.747	0.111	1.42
Canada	35	1 291	251	37.017	0.194	7.20
France	65	1 959	252	29.941	0.129	3.86
Germany	82	2 951	313	36.027	0.106	3.82
Iceland	0	11	6	33.906	0.524	17.78
India	1 237	5 567	788	4.502	0.142	0.64
Iran	76	1 053	220	13.783	0.208	2.87
Japan	128	3 994	452	31.312	0.113	3.55
Kazakhstan	17	322	75	19.172	0.233	4.46
Kyrgyzstan	6	14	4	2.537	0.290	0.74
Poland	39	706	98	18.309	0.139	2.54
Russian Federation	144	2 178	757	15.178	0.347	5.27
Tajikistan	8	17	2	2.069	0.137	0.28
Turkey	75	1 015	117	13.557	0.115	1.56
Ukraine	46	339	123	7.428	0.362	2.69
United Kingdom	64	2 069	192	32.473	0.093	3.02
United States	314	14 232	2 141	45.283	0.150	6.81
Uzbekistan	30	125	5	4.193	0.037	0.16

Note: GDP is measured at purchasing power parity (PPP) in 2005 constant dollars; primary energy consumption (total primary energy supply [TPES]) from IEA's energy balances.
Source: IEA, Key World Energy Statistics, 2014.

Table 11.1 Kazakhstan's energy intensity versus other selected countries in 2012

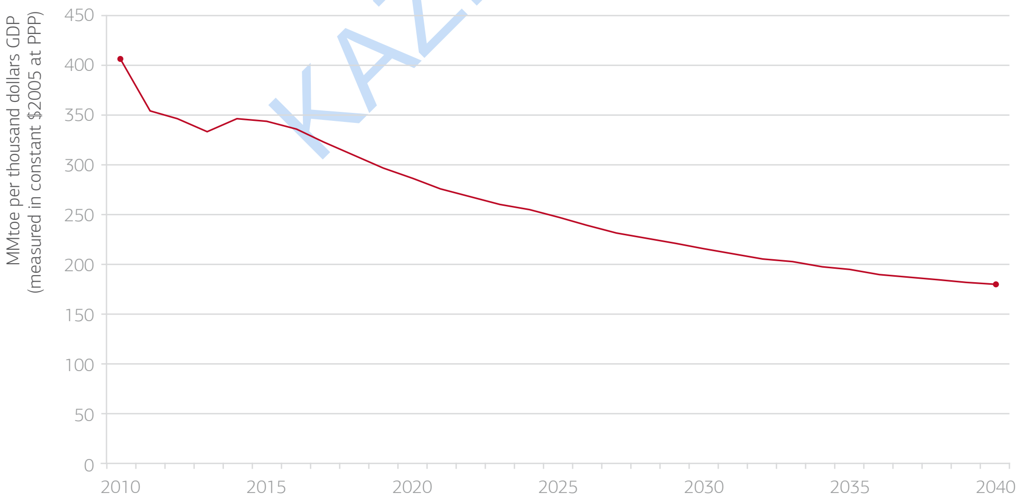
11.4. Current Energy Intensity of Economy and Energy Efficiency Growth Potential[7]

It is also important that Kazakhstan's energy intensity has decreased over time: energy intensity has fallen by more than half since 1999 (see Figure 11.2), demonstrating improved capacity utilization with higher levels of production, and growth of the services sector as a share of GDP, as well as ongoing progress in increasing the efficiency of energy use. Still, there is ample room for further improvement in the future. The IHS base-case outlook envisions a decline of about 48% in Kazakhstan's aggregate energy intensity between 2015 and 2040 (see Figure 11.3). Average annual [aggregate] energy efficiency growth rates are expected to be moderate over the forecast period to 2040, amounting to 1.7%. This reduction will be due to structural changes, implementation of new process technologies, improvements in construction sector standards, and transition from the existing district [central] heating system to a more efficient one involving direct combustion of fuel by consumers. However, it is expected that even in 2040 the economy will remain relatively energy-intensive by global standards.



Source: IHS Energy

Figure 11.2 Kazakhstan's aggregate energy intensity



Source: IHS Energy

Figure 11.3 Outlook for Kazakhstan's aggregate energy intensity

[7] For more information see the Review of the National Policy of Republic of Kazakhstan in the area of energy saving and energy efficiency from 2014.

Although broad[8] geographical factors have a certain impact, the key reason for high energy intensity in Kazakhstan is inefficient energy use. Specific fuel consumption for electricity generation is rather high at combined heat-and power (TETs) plants due to depreciation and obsolescence of equipment. Kazakhstan also suffers from a relatively high share of electricity losses in distribution networks (less than 110 kW). Losses in district heating systems sometimes reach 40%. Due to obsolete technology and worn-out equipment, energy intensity in industry per ton of output is significantly higher than in industrially developed countries. Housing stock depreciation and thermal insulation that is inconsistent, for the most part, with modern requirements result in high levels of heat loss.

11.4.1. Electric power

The electric power sector receives approximately one-third of total primary energy consumed in Kazakhstan. One of the primary obstacles to overall efficiency in Kazakhstan's power sector is a geographic imbalance in generation capacity. Most of the generating assets (72%) and transmission capacity are located in the North Zone, which generates a surplus of power that is used to meet demand in the South Zone. As a result, large amounts of electricity are moved southward along Kazakhstan's north–south transmission system.

These imbalances increase the need for long-distance transmission of electricity, which is associated with various types of losses and inefficiencies. Simple transmission losses along power lines that can stretch for 500 to 1500 km between sites of production and consumption are higher than in, for example, European countries, which have much smaller land areas. Corona losses (discharges due to ionization of a fluid in contact with an electrically charged conductor) aggravated by extreme winter temperatures can account for up to 30% of total transmission losses. High transmission losses are also due to the age and dilapidated condition of much of the grid equipment (the degree of its wear and tear sometimes reaches 60%).

In terms of generation, it should be noted that despite the asset (core equipment) depreciation figures (70%), the average rate of specific fuel consumption at coal-fired condensing plants in Kazakhstan (252.3 goe [grams of oil equivalent]/kWh) is 4.35% lower than at US coal-fired plants (263.8 goe/kWh in 2013).[8] Interestingly, in 2003 the average specific fuel consumption by coal-fired generation in the USA was 2% lower than in 2013 as a result of decreased load for coal generation due to the increasing shares of gas generation and renewable energy. Therefore, a key issue for the optimal level of specific fuel consumption at plants is long-term load planning and adjustment of capacity construction plans aimed at maintaining an acceptable level of power plant load and preventing formation of significant excess capacity amounts.

Losses in the distribution of electric power also are substantial (on the order of 11%–13%). Challenges include worn-out equipment and the absence of a uniform technical policy for grid-company development. Many of the high-voltage transmission lines operated by regional power grid companies (RECs) were built more than 40–50 years ago. Transformer capacity operation is not always efficient: the load on some transformers is no more than 15–20% even in winter.

An important factor influencing electricity loss in the distribution network is a high proportion of reactive power. High consumption of reactive power is typical for many production enterprises in Kazakhstan, which ultimately affects the level of reactive power in the distribution network. Reducing the share of reactive power in electricity networks through implementing measures for its compensation allows a significant reduction of electricity losses as well as an increase of network capacity (throughput) and stabilization of voltage fluctuation. However, reactive power compensation is currently not sufficiently profitable for the majority of enterprises in Kazakhstan, as customers pay for active power consumption only.[9] Although legislation in Kazakhstan provides for penalties for failure to comply with regulatory requirements with regard to the share of reactive power, the audits and penalties are applied mainly to RECs and sometimes (rather seldom) to industrial enterprises.

Therefore, key energy-saving measures in the electric power sector may include: achieving geographical balance in generating capacity through new generating capacity commissioning in the south of the country; core equipment modernization and implementation of advanced technologies (e.g., ultra-supercritical steam cycle, fluidized bed combustion) at coal-fired power plants; and increasing the efficiency of generation through diversification of the generation mix to include more natural gas, hydroelectricity, nuclear, and renewable power. All of these measures require significant new investment and are thus not likely to be implemented until existing capacity must be replaced. More feasible in the immediate term are more low-cost measures: optimizing the operation of boilers at TETs, further distribution network modernization, replacing obsolete and underutilized transformers, and reactive power compensation. All these measures should be supported by the tariff policy in order to ensure stability for attracting investment and providing a return on investment.

11.4.2. Heating

More than 80% of the district heating capacity in Kazakhstan is coal-fired, 13% uses gas, and about 7% uses heating oil. As in the housing sector, heat generation capacity is aged (e.g., 41% of TETs have been in service for over 30 years), and nearly two-thirds is in need of some type of repair or modernization. Some TETs plants in Kazakhstan operate at a heat load lower than the design value,[10] which leads to increased specific fuel consumption. A significant number of boiler houses in Kazakhstan (886 boiler houses with a capacity less than 100 Gcal/hour and 10 large boiler houses) that

[8] http://www.eia.gov/electricity/annual/html/epa_08_01.html. Included in the calculation for coal, petroleum, and natural gas average operating heat rate are electric power plants in the utility and independent power producer sectors. Combined heat and power plants, and all plants in the commercial and industrial sectors are excluded from the calculations.

[9] In some EU countries payment for both active and reactive power components has been introduced.

[10] Heat consumption in industry decreased significantly compared to the Soviet period.

are part of the centralized heat supply system operate at low efficiency rates, primarily due to equipment wear and tear, non-optimal modes of operation, insufficiency of metering equipment, and different (non-design) fuel burning operation.

Moreover, the high share of TETs plants in the centralized heat supply system in Kazakhstan means that construction and maintenance of the long-distance heat supply network is a "bottleneck" in overall cogeneration use. The standard operational life of heat pipelines is 25 years, and 70% of the length of the entire network consists of pipelines that have been in service for more than 20 years. After the collapse of the Soviet system, the heat supply sector was poorly managed for over 10 years until the majority of heat supply companies were returned to state control. Currently a part of the network pipelines in centralized heat supply systems are being repaired and replaced, using mainly budget funds, but these costly and time-consuming measures do not provide full renovation of heat networks.

Actual losses in heat distribution are unknown at present due to insufficiency of metering equipment, but estimates indicate that they range from 18% to 42% depending on the region and the technical condition of heating systems.[11]

Introduction of long-term heat production and transmission tariffs, which take into account heat supply networks' modernization and renovation costs, although also leading to tariff increases, will greatly increase the potential for upgrading heating system assets and will eventually result in a stabilization and then significant reduction in heat losses and in heat production costs.

11.4.3. Industry

The industrial sector is the second largest consumer of primary energy after the electric power sector (taking in roughly 25% of total consumption). The focus here is on heavy industrial enterprises that consume large quantities of energy: mining and metallurgical facilities, crude oil and gas production, oil refineries and gas processing plants, chemical plants, and machine-building and construction materials enterprises. Audits which are now being conducted reveal significant capacities for energy savings at industrial enterprises ranging from 5% to 20%.

Despite the fact that ferrous and non-ferrous metallurgical enterprises are the most energy-intensive in Kazakhstan's economy, more than 90% of their energy consumption is directly related to process technologies. The main potential for energy saving thus lies in a full upgrade or replacement of the process equipment, which is actually equivalent to construction of a new plant. Therefore, the potential for energy savings in metallurgy is very limited.

In the mining sector, except for enterprises that only began operations recently (e.g., uranium deposits), energy efficiency improvements can be achieved mainly through asset (core equipment) modernization and introduction of systems for optimizing fuel consumption during ore extraction, handling, and processing.

As it is a large energy consumer, the energy savings potential in the oil and gas industry is considerable, especially in direct oil extraction (pumps) and in gas processing, as these two activities account for a large share of the total energy consumed by the industry. Energy efficiency improvements are often associated with introduction of new equipment and technologies, new management systems resulting from energy audits, and waste heat recovery systems. In terms of overall energy conservation, further efforts to reduce gas flaring also remain important.

In addition, efficiencies can be achieved in the transportation of oil and gas. Much of Kazakhstan's trunk pipeline systems were built in the Soviet period, and are now fairly aged, with much of the equipment becoming obsolete. Improvements in pipeline insulation and replacement of key components, such as pipeline pumps and compressor units, can yield additional reductions in energy consumed during transportation.

Also, because, some oil produced in Kazakhstan is characterized by a high paraffin content, this raises energy consumption not only during production but also during transportation (because of the need for heating). For example, oil flowing through the Uzen-Atyrau-Samara trunk pipeline needs to be kept above 40–50°C, which means significant consumption of gas for heat. At the same time, lack of thermal insulation of oil tanks at oil pumping stations leads to high energy losses (up to 15% of total usage). On the gas side, the drop in gas transit from Central Asia to Russia reduced the gas trunk pipeline system's efficiency: all strings remain in operation while throughput is quite low. So closing some of the individual strings in the trunk gas pipeline system, and consolidating existing flows into the remaining strings, would significantly raise the energy efficiency of gas transportation (energy used per Bcm-km of transportation).

11.4.4. Housing and utilities sector

The housing and utilities sector, which accounts for roughly one quarter of primary energy consumption, includes the housing stock as well as networks and systems that provide heating, water supply, lighting, small boiler houses, and waste management.

Average residential energy consumption (270 kWh/m²) in Kazakhstan exceeds that in Europe (100–120 kWh/m²) as well as in Russia (210 kWh/m²). The reason, apart from climate, is the dilapidation of the housing stock (32% of which is in need of repair and 2% requires demolition). Roughly 70% of the buildings in Kazakhstan were constructed between 1950 and 1980 and do not meet modern requirements for thermal insulation, which results in considerable heat losses. For new residential construction, the Law on Energy Saving and Energy Efficiency specifies that modern energy-saving materials must be used, and automated heating systems and utility metering devices installed. For existing residential structures, the Law requires that such materials, heating systems, and devices be installed

[11] KazEnergy, The National Energy Report 2013, p. 184.

during capital repair or reconstruction. However, due to the shortage of funds for repair and reconstruction of buildings and structures, such measures are implemented on a very limited scale.

Another promising area in the housing and utilities sector that affords considerable potential for energy savings is lighting [artificial lighting systems]. The share of lighting in total electricity consumption in Kazakhstan is about 13% and the share of lighting in electricity consumption in the residential sector is about 39% (the share of lighting in the commercial and municipal sectors is 19% each).

Kazakhstan does not currently have a domestic capacity to manufacture lighting fixtures: it imports more than 60 million fixtures mainly from Kyrgyzstan, Russia, and China annually. Of these, 80% are more than 25 W incandescent (filament) lighting fixtures. The share of incandescent lighting has been gradually decreasing in recent years, but still remains quite high despite the introduced legislative ban.[12]

Discontinuation of incandescent lightning use is impeded mainly by the high cost of energy-saving lighting fixtures and partly by the absence of a system for recycling mercury-containing lighting fixtures. While the issue of organizing and funding the recycling of mercury-containing fixtures remains unclear and the cost of LED lighting fixtures remains high, it would be advisable [as a preliminary measure] for the housing and utilities sector to install lighting control systems (light sensors [photo relays], motion sensors) in the lighting systems of residential and public buildings.

Overall, a continuous and gradual movement away from incandescent lighting fixtures (using fluorescent, sodium-vapor, and diode fixtures) has the capacity to reduce energy consumption in lighting systems of the housing and utilities sector by as much as 30%.[13]

11.4.5. Transportation

The transportation sector in Kazakhstan also accounts for a large part of energy consumption (10-15%). It is noteworthy that in terms of both freight and passenger traffic, the automobile (vis-à-vis rail, maritime, and river transport) dominates.[14] Energy consumption in motor vehicle transportation has been growing in absolute terms, as the number of motor vehicles on Kazakhstan's roads has more than doubled since 2003 to reach nearly 4 million vehicles. Although there is some consumption of electricity and natural gas in Kazakhstan's vehicle fleet, by far the primary fuel consumed consists of refined oil products.

A major factor influencing energy efficiency in the transport sector is the age of the vehicle fleet and the quality of motor fuel consumed. Much of Kazakhstan's car fleet tends to be old (more than 10 years in service). According to the Committee on Statistics, 79% of the 3,678,282 vehicles registered in Kazakhstan as of 1 May 2014 were manufactured more than 10 years ago.

As for the quality of motor fuel, Kazakhstan's main refineries now in operation were designed for producing older fuel grades: (e.g., A-72 or A-76 gasoline). The refineries are being upgraded now for the first time since their launch and, presumably, a significant amount of additives is used in products, affecting the fuel quality and, thus, the efficiency of fuel combustion in vehicle engines.[15] Use of fuel not fully meeting the standards of internal combustion engines reduces their efficiency and results in incomplete fuel combustion. The current refinery modernization effort (see Chapter 7.4) will make it possible to produce fuel of higher quality in the future.

At the moment, there are several promising ways of increasing transport energy efficiency in the Republic of Kazakhstan, including:

- state support for expanding electric and hybrid vehicle use as well as incentives for wider use of natural gas as a motor fuel;
- transition to new motor fuel quality standards (Euro-5 and Euro-6), with increased state control over motor fuel quality;
- development of high-speed public transport;
- increasing the efficiency of freight truck transportation through optimizing logistics.

11.5. Regulatory Overview/Government Policy to Support Energy Efficiency

Kazakhstan's government plays important and diverse roles in supporting energy efficiency initiatives: providing legislative support, a regulatory framework, and economic incentives for energy conservation and efficiency. The key body responsible for energy policy is the Ministry of Energy, which in August 2014 assumed regulatory functions in the sector following the liquidation of the Ministry of Industry and New Technologies, while energy efficiency is the responsibility of the

[12] The ban on 100 W incandescent lights was introduced in 2012 and was extended to 75 W and 25 W fixtures in 2013 and 2014, respectively.

[13] See Overview of the National Energy Saving and Energy Efficiency Policy of the Republic of Kazakhstan.

[14] In 2013, automobile transport accounted for 85% of all freight shipments (tonnage) in Kazakhstan, although only 29% of total freight turnover (ton-km), indicating that automobile freight shipments tend to be short-haul in comparison with rail or pipelines, for example. In terms of passenger movements, automobile transport (which represents only buses and does not include movements in individual vehicles) accounted for 79% of the Kazakh passenger-kilometer total.

[15] According to the Balkhash-Alakol Department of Ecology, fuel quality tests revealed that 40% of liquid fuel samples do not meet official standards.

Investment and Development Ministry. State policy intended to increase energy efficiency is directed toward modernizing a variety of highly energy-consuming sectors of the economy.

Much of current policy is codified in two laws enacted in January 2012: (1) the Law of the Republic of Kazakhstan on Energy Saving and Energy Efficiency; and (2) the Law on Amendments to Certain Legislative Acts of the Republic of Kazakhstan Related to Energy Saving and Energy Efficiency. These two laws, among other things, provide for the following measures:

1. introduction of energy consumption standards for products and services;
2. introduction of capacity factor requirements;
3. introduction of new requirements for project (design) documentation;
4. application of mandatory energy efficiency requirements for transportation, electric motors, various classes of buildings and other structures, and in architectural design;
5. implementation of a procedure for conducting energy audits in order to assess energy efficiency and to implement energy supply management systems at major industrial enterprises and buildings;
6. establishment of facilities for the training of energy auditors and managers as well as conducting research activities;
7. introduction of energy service contracts; and
8. ban on the use of incandescent lighting fixtures and on sales of electrical products without energy efficiency grade indication.

It should be noted that Kazakhstan's extant legislation on energy efficiency relies mainly on requirements and bans, with the virtual absence of incentives. At the same time, the ban on incandescent lighting fixtures is not fully being followed, and the energy consumption standards for industrial enterprises introduced in 2012 turned out to be impracticable for a large number of enterprises. For example, specific energy consumption for ore extraction differs considerably depending on the enterprise, and practically every mine/field has its own technological (process) peculiarities as well as different dependence of energy consumption on production volumes. Comparing energy consumption at mines using uniform standards often turns out to be inaccurate (inappropriate), as the consumption is too highly dependent on the mine's geological features and the technology of its development. The same is valid for oil production; therefore, it is rather difficult to establish a single uniform energy consumption standard. As a result, application of energy consumption standards in industry is quite relative.

Development and adoption of mechanisms encouraging energy saving are becoming a priority of government policy. Although the government already provides grants for pilot and demonstration projects and selectively finances implementation of energy-saving technologies, there is ample room for expanding credits and tax breaks to promote energy conservation. Additional incentives (benefits) may be provided within the framework of the GHG emission control system and emissions trading system (see Chapter 13).

Serious consideration is now being given to energy service contracts that would allow residential consumers to finance energy efficiency improvements through regular payments incorporated into their utility bills. However, lack of proper energy metering/accounting systems will restrict the possibility of using energy service contracts.

The strengthening of incentives is important for Kazakhstan, as present legislation in general tends to emphasize prohibitions and limitations, thus limiting the possibility to achieve a significant increase in energy efficiency.

Kazakhstan's government is also able, as necessary, to directly support initiatives aimed at increasing energy efficiency by adjusting its energy tariff policy. A stepwise increase in tariffs for the purpose of attracting investment in modernization can guarantee achievement of the dual objectives of reducing consumption[16] and financing energy efficiency projects.

Key Recommendations

Any list of recommendations for increasing the energy efficiency of Kazakhstan's economy must recognize that to a large degree the ultimate solution lies in the replacement of worn-out or outmoded infrastructure with modern, "state-of-the-art" equipment and technologies. However, the magnitude of the task, the challenging current economic environment in Kazakhstan, and the limited investment resources available make anything but a stepwise, or staged tariff policy improvement or incentivizing mechanism roll-out virtually infeasible.

This section briefly reviews a number of first-priority steps that can be taken at relatively low cost to begin building a framework supporting more rigorous efficiency measures in the future.[17]

- In electric power, a focus should be on regulations that ensure the reliability and quality of electricity supply (which are necessary prerequisites for efficiency), including introduction of an electricity certification mechanism. Revising the calculation methodologies for estimating (assessing) acceptable power losses during electricity generation, transmission, and distribution can also be recommended. Steps also should be taken toward the further standardization and modernization of the work of the regional

[16] Rising energy costs will encourage energy saving; generally, the following rule applies: "The more expensive the energy resource, the more effective its consumption."

[17] For additional information also see the Review of the National Policy of Republic of Kazakhstan in the area of energy saving and energy efficiency from 2014.

electricity companies, examining the required investments and the timeframe for implementation of corresponding projects aimed at loss reduction, including tariff adjustment which is indispensable. Special attention should be paid to the recommended introduction of a mechanism of payment for reactive power by large electricity consumers.

- In industry, the implementation of energy-saving plans in accordance with the results of enterprise audits should be monitored. Another significant measure would be revision or cancellation of approved energy consumption standards due to their inapplicability to most large industrial enterprises in Kazakhstan. Finally, there is a need for innovative mechanisms of funding and providing incentives (tax incentives, subsidies, preferential loans) for initiatives in industry aimed at increasing the investment attractiveness of energy-saving and energy efficiency measures.

- In the heat and gas distribution sector, economically feasible long-term tariffs (at least for five years) should be set, taking into account the need for investment in modernization and increase in energy efficiency.

- In the housing and utilities sector, energy performance requirements should be strengthened for new buildings as well as for buildings under construction. It is also necessary to amend the existing standards with regard to the energy efficiency of the engineering systems of buildings and building units, including windows as well as heating, ventilation, cooling systems, etc. It may be recommended to introduce a system of individual apartment heat consumption metering and control in new buildings in order to incentivize the end users as well as to continue installation of automated heat consumption control systems and individual heat meters in existing apartment buildings. As a compulsory measure, it is recommended to introduce requirements for installation of automated lighting control systems in residential buildings and to adopt minimum energy efficiency standards for lighting products.

- Initiatives in transportation could involve an accelerated switch to natural gas as a transportation fuel in public transportation, long-haul trucking, urban delivery fleets, and in agriculture. Mass transit systems in major cities could be further improved as an acceptable alternative to private vehicular transportation, thereby reducing congestion and fuel consumption. Finally, it is necessary to continue implementing the policy of state monitoring and control over the quality of motor fuels[18] as well as to introduce new quality standards.

Summarizing the foregoing, Kazakhstan's government should support energy efficiency initiatives through tariff policy adjustment. Tariffs should be sufficiently high to generate an acceptable rate of economic return for energy producers and distributors, in particular, for reinvestment in new, more energy efficient production and distribution capacity. Certainly, rapid tariff hikes could be destabilizing for the market, and thus jeopardize economic growth during the current period of uncertainty, but over the longer term a gradual, controlled increase in energy tariffs to rates more closely approximating world market prices is needed. The long-term tariff policy should curb genuinely wasteful energy consumption and encourage investment in modernization and energy efficiency.

[18] On 27 June 2015, Rules and Regulations for Equipping the Tanks (Containers) of Oil Production Facilities, Oil Product Depots, and Filling Stations were adopted, in accordance with which, starting from 1 January 2016, oil depots and gas stations must install metering devices for collecting and submitting information to the competent state authority (Ministry of Finance).

THE OIL SERVICES SECTOR AND LOCAL CONTENT REQUIREMENTS IN KAZAKHSTAN

12. The Oil Services Sector and Local Content Requirements in Kazakhstan

12.1. Key Points

- **Kazakhstan's oil services activities are expanding, both in terms of physical parameters and financial expenditures; it is also becoming more localized.** Although oilfield services encompass drilling, completions, geology, surveying, various field and well analysis, and other work, this section will focus on drilling, as it is the largest component in terms of expenditure. An increasing number of meters drilled and completed wells testify to growing activity, reflecting the overall expansion of oilfield services overall. Also, an increasing share of these services is being handled by local providers in the country. However, we must distinguish between more inputs and actual results achieved.

- **One area where Kazakh oil services appear to be making significant strides forward is in drilling, particularly onshore; but the nascent offshore segment is also progressing.** Onshore, several local companies are primarily responsible for growing drilling figures, working for both domestic and international production firms. Offshore, Kazakhstan is actively developing a domestic drilling capacity by building a small fleet of offshore drilling vessels capable of operating in both the shallow and deeper waters of the north Caspian Sea.

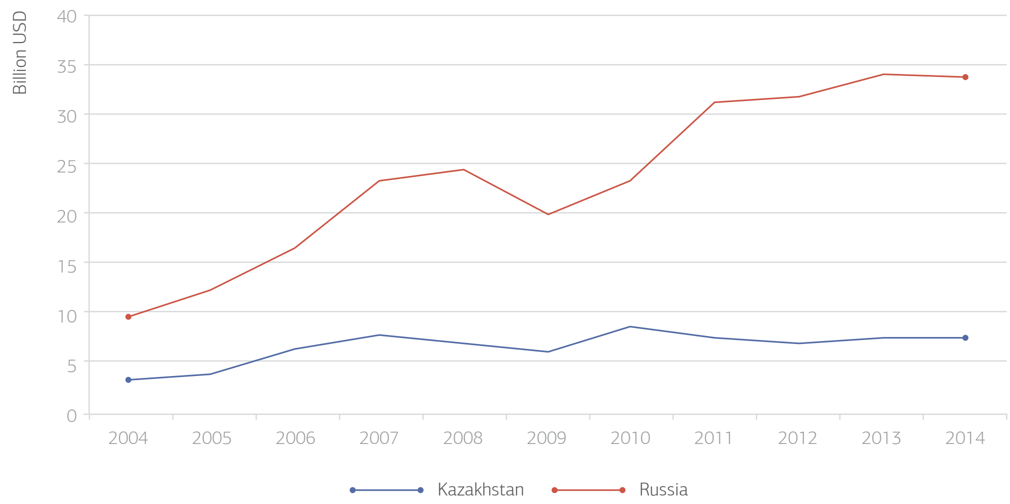
- **Growing local expertise has increased the utilization of local oil services, as the government sets targets for oil and gas producers to use domestic goods, services, and personnel.** Although Kazakhstan's services industry is competing against a large and well established international service sector, local firms are expanding their role beyond basic works and services and gaining participation in Kazakhstan's sophisticated megaprojects and acquiring new technical capacities. To acquire new technology and know-how, some Kazakh providers have formed joint ventures (JVs) with internationals to work on specific projects or to build facilities and infrastructure together, setting the stage for technology transfer from foreign actors.

12.2. Size of Kazakhstan's Oil Service Industry

Service activities in Kazakhstan have grown steadily to address increasingly challenging local technical issues, both in upstream and midstream development. In particular, drilling is a key segment of the services industry—along with associated construction and equipment—and is the key subject examined in Chapter 12. This section discusses the status, opportunities, and challenges of the country's drilling industry onshore and offshore, examines Kazakhstan's local content regulations and the successes and challenges of localization, and analyzes the means by which domestic services providers can continue to improve their technical and competitive position vis-à-vis foreign providers. However, it must be kept in mind that drilling is really an input into upstream production, and while it is important to reflect on the relative level of effort (the amount of inputs into the process), this does not always translate directly into actual results.

Kazakhstan's service sector is relatively small, but is growing steadily both financially and physically. Since 2000, fixed investment into Kazakhstan's petroleum extraction (a rough proxy for upstream expenditures for services) increased from $1.9 billion to a high of $8.6 billion in 2010, and was $7.2-7.3 billion in 2013-14 (see Figure 12.1).[1] Compared to Russia, Kazakhstan's market for upsteam services is much smaller: investment in Russia's upstream oil sector amounted to about $33.6 billion in 2014, whereas in Kazakhstan $7.2 billion was invested. Similarly, Russia's drilling portfolio, at 21 million meters in 2013-14, was more than eight times as much as in Kazakhstan.

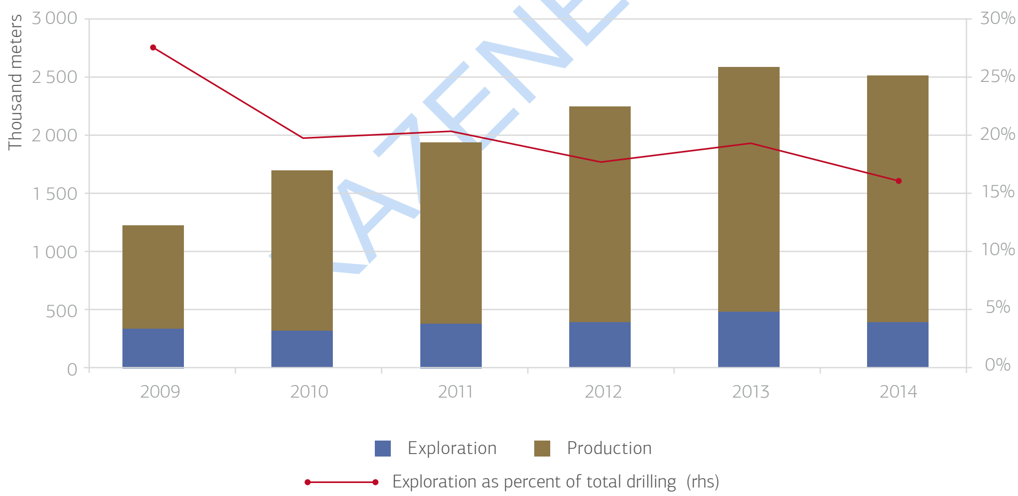
[1] Fixed capital investment by a firm is defined as investment in durable (fixed) assets such as buildings, machinery, and equipment, or other infrastructure or structures that a firm holds for at least one year.



Source: IHS Energy, Statistical agencies of Russia and Kazakhstan

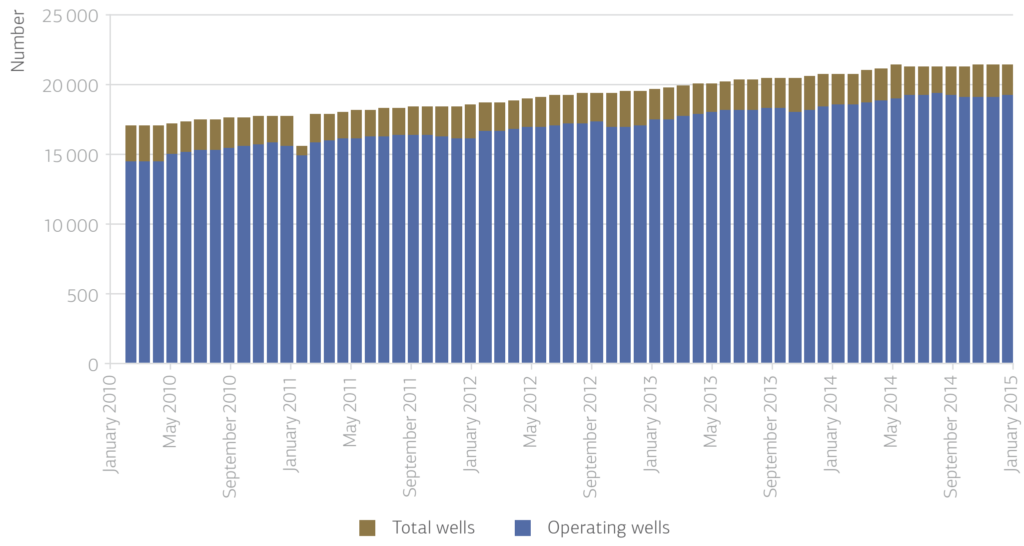
Figure 12.1 Investment in fixed capital in oil and gas extraction, Kazakhstan and Russia

Total drilling activity in Kazakhstan has recovered rapidly since the 2009 recession, however, reaching about 2.5 million meters in 2014, which is more than double the 2009 result (1.2 million meters). Development drilling has grown far more rapidly than exploratory drilling: since 2009, production drilling increased by 137% to 2 million meters, while exploration drilling expanded only by about 20% to 391,000 meters (see Figure 12.2). Consequently, Kazakhstan's operating well count has grown steadily since 2010 as well, increasing about 20% to about 21,000 wells by the end of 2014 (see Figure 12.3). Although increased drilling does generally match growing production, the presence of several other important factors also influences oil extraction trends (global prices, physical production, and transportation capacity), as well as the inevitable lag present between drilling dynamics and production growth, which conditions the translation into actual results.



Source: IHS Energy Global E&P Service, InfoTEK

Figure 12.2 Exploration and production drilling in Kazakhstan, 2009-2014



Source: InfoTEK, Ministry of Energy of the Republic of Kazakhstan

Figure 12.3 Operating well stock in Kazakhstan

Onshore, drilling is commissioned by domestic and international operators that contract out work to both domestic and international firms, including "in-house" service divisions. National company KazMunayGaz (KMG) is the single largest driller in Kazakhstan, contracting 424,000 meters in 2013, or nearly 17% of all drilling in Kazakhstan, much of it done "in-house." China National Petroleum Corporation (CNPC) is another major player, mainly through two of its Kazakh upstream subsidiaries, AktobeMunayGaz and Ai Dan Munay. The Aktobe subsidiary is larger, accounting for 396,000 meters as compared to Ai Dan Munay's 82,000 meters in 2013. Another major driller is PetroKazakhstan, an upstream JV between CNPC and KMG, which accounted for 206,000 meters, or 8.1% of all drilling in Kazakhstan.

Offshore drilling volumes are much smaller and commissioned by the international consortia that operate these projects: in 2013, NCOC, developing Kashagan, contracted around 29,000 meters. Although international firms many carry out the bulk of services needed for offshore projects currently, Kazakhstan's indigenous services sector has been proactive in expanding into that area.

12.3. Characteristics of Kazakhstan's Drilling Sector

The bulk of Kazakhstan's drilling occurs onshore, where a handful of companies, both independent and affiliated with upstream developers, hold a commanding share of the market. Similar to other CIS countries, Kazakhstan's national reporting system lacks a comprehensive statistical reporting system on the country's overall rig fleet. Still, some data exist that illustrate the current state and trends of the sector.

Kazakhstan's drilling sector leader is KazPetro Drilling (KPD), a consortium of drillers which includes a KMG subsidiary, KMG Drilling (SBC KazMunayGaz Drilling), as well as the firms Burgylau, Astra Star, and MHINDUSTRY. Drilling an estimated 538,000 meters in 2013, KPD accounted for 21% of Kazakhstan's total drilling volume. Altogether KPD employs 5,253 people (up from 3,585 in 2011) and has a fleet of 42 drilling rigs (34 in 2011), which range in drilling capability from 200 meters to 7,000 meters in depth, as well as 51 work-over rigs. The company's rig fleet has grown recently. In 2013, the consortium planned to add two new rigs, one sourced from the United States and the other built together with Discovery Industrial Services at a Ukrainian manufacturing facility. The firm also states that they have operated in cooperation with external contractors, including Schlumberger, BakerHughes, and others.

The second largest drilling firm is a Chinese-Kazakh joint venture, Velikaya Stena (Great Wall), which works primarily with CNPC's AktobeMunayGaz subsidiary. Velikaya Stena has a fleet of 27 rigs, ranging in capability from 3,000 to 7,000 meters. Most of these were sourced from China, although three rigs are reported as Russian in origin. Other principal drilling contractors in Kazakhstan include SibuKyzylorda, SmartOil (12 rigs, 96,000 meters drilled in 2013), Ontustyk MunayGas (ten rigs), Vostokneft, NeftTekhService, and China's Sinopec. Various other contractors are active, but individually comprise a small percentage of the Kazakh total drilling market; some of these are foreign operators.

Kazakhstan's contractors for the most part rely on foreign imports of equipment, as Kazakhstan does not manufacture medium and heavy duty rigs. Most likely, Kazakhstan's drillers import rigs mostly from builders in Russia and China.[2] Some drilling contractors (including KPD) also source rigs from the United States and Europe.

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[2] See the IHS Energy Insight, Russia's Rig Dilemma: Shifts in Upstream Oil Tasks Spark Search for Onshore Rig Fleet Modernization Formula, July 2014.

Domestic manufacturing and fabrication remain limited but growing. The Petropavlovsk Heavy Machinery Plant in North Kazakhstan Oblast assembles mobile truck-mounted rigs, including models with an operating depth of 2,000 meters. Other construction facilities in Kazakhstan build pumps and other associated drilling and services equipment. Kazakh service companies also operate repair facilities domestically for the maintenance of Kazakhstan's rig fleet.

In the offshore space, a key issue for some time was a shortage of rigs: at the end of 2013 there were only eleven rigs operating in the Caspian Sea (excluding Azerbaijan) with one of those rigs committed to Russia's Caspian projects. Private contractors manage ten of these, including four semisubmersibles, five jack-ups, and one barge, the Sunkar Rig 257, operated by Parker Drilling. Kazakhstan has sought to rectify this shortage by building its own offshore vessels and associated infrastructure to expand the fleet. This expansion was designed to allow Kazakh service providers to absorb skills and technology by working alongside highly experienced foreign services firms on offshore E&P. However, with the downturn in oil prices and a major retrenchment in upstream expenditures, offshore exploration is diminishing, and even local rigs have been left without much work.

The first floating drilling rig assembled in Kazakhstan was the Caspian Explorer submersible drilling barge (SDB). The SDB was built pursuant to the obligations undertaken by a consortium of Korean companies (consisting of Korean National Oil Corporation [35%], SK Innovation [25%], LG International Corp. [10%], Hyundai Hysco Co. Ltd. [10%], Samsung C and T Corp. [5%], Daesung Industrial Co. Ltd [5%], Daewoo Shipbuilding and Marine Engineering [5%], and Aju Corporation [5%]) within the framework of the Agreement on Principles signed in 2005 between JSC "NC "KazMunayGas" (KMG) and KC Kazakh BV ("KCK"), a company established by the aforementioned Korean consortium as part of the program for development of Kazakhstan's Caspian shelf. Different units, equipment, and materials of the SDB were manufactured and assembled abroad and, following their delivery to Kazakhstan through the Volga-Don Canal in 2011, the SDB's assembly began at the shipyard of Kazakhstan's ERSAI Caspian Contractor LLC and was successfully completed in June 2012. Since the date of its foundation on 26 December 2011, KC Caspian Explorer LLP (KCCE) – KCK's subsidiary in Kazakhstan – has been the owner of the SDB.

Initially the SDB was designed for drilling operations at the Zhambyl offshore structure in the shallow waters of the northern part of the Caspian Sea; therefore, it can operate in waters 2.5-5.5 meters deep and drill exploration wells to 6,000 meters below the drilling rig floor. On 27 April 2012 KCCE transferred the SDB to the trust management of Teniz Burgylau LLP (currently KMG Drilling & Services LLP) and in 2013-2014 it was used to drill two exploration wells at Zhambyl block (ZB-1 in 2013 and ZT-1 in 2014). It was planned to use the SDB in other offshore projects in the shallow waters of the Caspian Sea as well, and, taking into account its successful drilling campaign for the Zhambyl project, that would be expectable and reasonable.

However, due to falling oil prices and significant cost reductions in the oil and gas sector, offshore field exploration issues are postponed for an indefinite period and, as a consequence, the new SDB is currently on cold stack at the ERSAI shipyard. KMG Drilling & Services LLP ceased to be the SDB's operator after expiration on 31 March this year of the trust agreement validity period, which was not renewed due to the absence of plans to further use the SDB.

In 2012, KMG's service subsidiary signed agreements to construct the country's first domestically built jack-up rig on a turn-key basis, at a cost of $242 million, to be used for drilling in deeper waters. The rig, which was launched in April 2015, will operate at depths between 5 and 80 meters, with an expected drilling depth of 6,000 meters below the seafloor. It was assembled at the ERSAI shipyard at Kuryk and Keppel-KasStroyService at Aktau, involving a thousand workers. This is a FELS B model, recognized for its modernity and efficacy in operations, and will be managed by "KMG Drilling & Services" LLP.

The two shipyards that assembled the rig are located in Mangistau Oblast. Both are joint ventures: the one in Aktau is between Singapore-based engineering firm Keppel and the Kazakh EPC company KazStroyService; the other, the ERSAI Caspian Yard, is run by Italy's Saipem engineering firm and Kazakhstan- England-registered Lancaster Group (founded by a group of Kazakhs including Nurlan Kapparov). Each facility is capable of handling 12,000 tons of metal-works annually. These two facilities gave local construction firms the opportunity to work with highly qualified foreign rig builders.

12.4. Local Content in Kazakhstan

A key factor affecting Kazakhstan's service industry is the growing presence of regulations ensuring local content procurement by companies running upstream projects. Following examples set by other oil- producing states, Kazakhstan has passed rules attempting to maximize local content usage, seeking to keep funds spent on goods, works, and services (GWS) in the domestic market, expand local human capital and technology, and establish a services industry which could itself contribute to exports longer term.

Kazakhstan's initial 1995 Petroleum Law was vague on local content, but the government repeatedly amended it before passing local content regulations in 2009 and a new subsoil law in 2010 that called for domestic procurement of goods and services. After 2010, the Kazakh government began to outline programs requiring oil and gas producers to source prescribed percentages of goods, services, and personnel from local providers: by 2014, 16% of all procured goods and 85% of both works and services were to be sourced domestically, calculated according to value. The Kazakh government was fairly aggressive in pursuing companies that failed to comply, with some 80 firms in 2011 facing fines for insufficient utilization of local content.

In 2015, a new draft subsoil law ("On Subsoil and Subsoil Use") is winding its way through the legislative process, with several changes designed to increase the attractiveness of the sector to investment. One of the key changes incorporated into the draft law, partly reflecting Kazakhstan's accession to the World Trade Organization as well as the launch of the Eurasian Economic Union in 2015, is a cancelation of the state's regulation of GWS procurement in the sphere of subsoil use as well as local content requirements for goods.

To identify approved local goods providers, the Kazakh government established a system of certificates (known as CT-KZ certificates), issued annually to providers after an evaluation of the domestic origin of the products sold. Holders of the CT-KZ certificate are enabled to offer their goods at a 20% premium, while contractors that procure from firms without certificates receive zero "credit" towards achieving local content requirements. As well as products created in Kazakhstan, CT-KZ certification can be extended to local works and services firms, based on the percentage of the firms' salary expenditure going to Kazakh employees. Kazakh authorities also set quotas on foreign employment in Kazakhstan: in 2012, only 30% of top managers and 10% of other skilled workers, specialists, and mid-managers could be foreign.

Both as a result of new regulations and expansion of the domestic services sector, overall utilization of local content has grown significantly in the past five years: according to official accounting, of some 3 trillion tenge ($16.7 billion) in total spent on oilfield services in Kazakhstan in 2014, 54% went to local service providers, a significant expansion from 45% in 2010. For the national oil company KMG, local providers comprised 72% of KMG's total procurement expenditures in 2014.

Although local procurement by oil and gas companies has increased in recent years, Kazakhstan's service providers are only beginning to expand into the high-value, more sophisticated segments of the country's oil and gas projects. According to a mid-2014 interview with Kazakhstan's deputy energy minister, Uzakbay Karabalin, operators rely on Kazakh local content for procurement of basic goods, including fuels, electricity, building materials, metal, uniforms, and office furniture – instead of more technically advanced goods. In another report, Karabalin explained that Kazakh services are utilized for low-technology requirements like waste management or catering, and have also expanded into somewhat technical work (like construction of components), but that foreign contractors provide the complex technological drilling and completion services. Oil and gas producers rely on international contractors like Halliburton, Schlumberger, or Parker Drilling for sophisticated drilling, logging, and engineering work. It is in these areas that local Kazakh content providers require further experience, specialization, and technical knowledge gained through cooperation with highly qualified foreign services firms.

Kazakhstan's three mega-projects were temporarily exempt from local content regulations, with Kazakh authorities reaching local content utilization agreements as part of negotiations for next-phase expansions. For example, in 2013, TCO announced that it planned to use local content for 32% of all services involved in the $23-40 billion Future Growth Project.[3] This was estimated to create about 20,000 new jobs for Kazakh service providers. Kazakh engineering procurement and construction (EPC) firms were created to design Tengiz modules: one was comprised of international contractors FLUOR and WoodleyParsons, working together with the Kazakh Institute of Oil and Gas (KING) and KazGiproNefteTrans Engineering Company (KGNT EC). Tengiz development also offered cooperative opportunities in drilling that would tie foreign contractors with local drillers: in April 2015, KMG's services subsidiary and American firm Nabors Drilling signed a joint venture to become a key driller for the Future Growth Project.

Similarly, Kashagan's NCOC discussed increasing local services in 2014. Several Kazakh engineering companies worked on the Kashagan project, including Montazhspetsstroy—which developed steel pipe-racks, off-sites, storage, and other associated infrastructure—and Kazstroyservice, which worked on pipelines. NCOC also worked with the ERSAI shipyard, where components of Kashagan offshore infrastructure were assembled.

Karachaganak's KPO consortium is also planned to increase local content utilization, as it considers another expansion phase. In early February 2015, KPO signed a memorandum initiating the tender offer for front-end engineering design of Karachaganak's expansion. The memorandum included provisions that between 40% and 50% of front-end engineering and design (FEED) services would be executed by a Kazakh partner of an engineering JV; and that 40 and 50% of the work would be done on Kazakh territory. KPO has been proactive in gaining the services of local-foreign JVs, including a critical JV formed between domestic firm Caspian Engineering and Eni subsidiary Tecnomare, which is expected to contribute to the FEED work. KPO also signed other memoranda for contracts with several other Kazakh and foreign firms to perform a range of works involving geologic data processing, chemical re-agents acquisition, and other works. In this way, national services firms are maximizing exposure to Kazakhstan's most complex fields.

12.5. Potential Lessons from Local Content Regulation in UK, Norway, and Brazil

Examination of local content development in the UK, Norway, and Brazil may be instructive to Kazakhstan's national services sector and regulatory bodies. The UK and Norway both established institutions encouraging the usage of local content in the mid-1970s, following the discovery of oil in the North Sea. The UK, already endowed with an existing manufacturing base and an onshore services industry, eschewed hard local content regulations. Instead, in 1973 the government founded the Offshore Supplies Office (OSO) to ensure that local British companies received "full and fair" opportunity to compete with foreign firms for procurement contracts. It did so by introducing auditing and reporting mechanisms that compelled foreign firms to report non-British procurement quarterly. Only rarely did OSO request operators to review procurement plans or suppliers to make certain that British firms were fairly considered. Eventually, OSO would also facilitate investment into British services and joint ventures with foreign players. OSO's operations appear to have been sufficiently low key that this type of approach can fit within the current WTO rules on local content regulation. Therefore the British approach may remain effective for Kazakhstan and other countries seeking to develop local specialized in-

[3] With the potential to increase this to 44% local content utilization, after taking into account the required amount of heavy metal-work involved.

dustry while operating within WTO rules. Norway, desiring to maximize transfers of technology and expertise, took a more direct regulatory approach, with local content utilization becoming a key factor in the awarding of contract blocks to producers, and with the government pushing for the creation of foreign-local engineering JVs. Both methods worked: UK local service utilization climbed from 40% in 1974 to 80% in the 1980s, and British service providers became globally ubiquitous. Norway's indigenous service sector has gained 75% of the domestic market, as well as broad respect in the global services industry as it has expanded operations internationally.

The UK and Norway success stories were assisted by fortuitous timing. In the 1970s, oil prices were growing and supply was tight, with oil producers happy to invest in local content as a means of obtaining new holdings; in the current paradigm, however, with low oil prices, an ample supply of service providers globally, international integration obligations requiring market openness, and a North American unconventional revolution unfolding, foreign operators are more likely to balk at higher domestic content thresholds considered inconvenient or uneconomic. Likewise, the economic climate in the 1970s was less opposed to regulations protecting domestic industry.

Brazil is another valuable case for Kazakh consideration. Brazil's hydrocarbon resources are concentrated in complex ultra-deep offshore deposits, and Brazil sought to localize the construction and operations of offshore platforms, drillships, and the crucial floating production storage and offshoring vessels (FPSOs) necessary for Brazil's upstream development. This, when combined with aggressive oil output targets, generated construction bottlenecks as Brazil's available fabrication yards and assembly capacity was too small and underdeveloped to adequately handle incoming orders. As a result, actual ship deliveries in 2012-2021 are expected to be reduced by 40%. Although producers are meeting local content requirements, the pace of development has been dramatically slowed, and costs have been higher. The strong local content requirements have also been a key avenue for corruption in Brazil's oil sector. Brazil's case proves the importance of concise, well-timed, financially sound plans when considering policies for developing the local services industry.

Local content requirements can create long-term benefits for Kazakhstan, eventually benefitting both the Kazakh economy and energy sector. Kazakhstan's service sector should focus on developing the expertise to match the emerging operating and technical conditions found in the country's upstream sector, particularly the Caspian offshore. Kazakhstan may consider evaluating specific project capabilities that are both useful and feasible for the national sector to take over, and then create workable plans that are feasible in terms of budget and timeline. Kazakhstan may also consider strategically developing relevant industries (metallurgy, construction) to support the service sector in order to provide increasingly sophisticated goods and services to oil and gas producers that are forecast to be and remain in high demand.

One key obstacle for protectionist policies in local content will be both WTO ascension and the Eurasian Economic Union. Because of Kazakhstan's commitments to these international bodies, laws compelling utilization of local content will have to be gradually disbanded. Kazakhstan probably will still be able to create beneficial tax incentives (VAT, corporate tax) for providers of local goods and services. But Kazakhstan will need to establish a precise well-timed plan that considers the diminishing role of protectionist policies.

Key Recommendations

- To increase Kazakhstan's significance in global drilling and services, the national sector must continue developing new, technologically sophisticated structures required for next-generation projects.

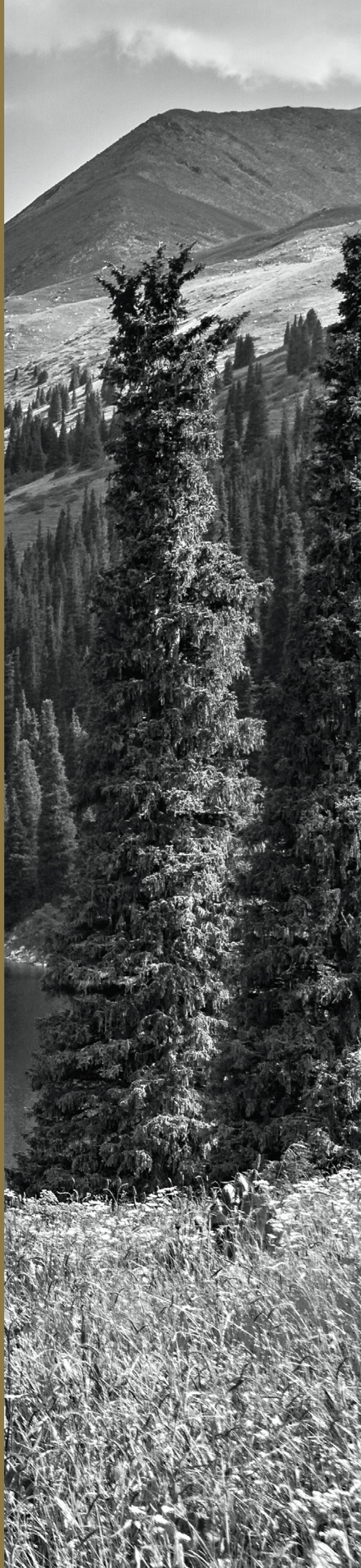
- The national sector must identify which types of work projects it can accomplish effectively and establish coherent, financially sound plans for the development of the necessary human capital and fixed infrastructure development.

- Kazakh plans for local content development should incorporate incentive structures permitted under WTO regulations, instead of relying on explicit protectionist policies that will have to be relaxed after Kazakhstan's ascension. The UK's OSO approach might be of some value in development of Kazakhstan's plans.

- Kazakh service providers must continue working closely with more experienced foreign partners on complex projects to maximally acquire the better practices.

- With the increasing shift of the hydrocarbon resource base to hard-to-recover resources in increasingly difficult geological settings, a wider use of modern technologies for exploration and other upstream services should be encouraged, particularly by the national oil company, KMG.

ENVIRONMENTAL ISSUES AND GREENHOUSE GAS EMISSIONS



13. Environmental Issues and Greenhouse Gas Emissions

13.1. Key Points

- Kazakhstan's major environmental problems include the Aral Sea desiccation and Semipalatinsk (Semey) nuclear test site. This chapter will focus mainly on environmental issues related to the energy sector. Major problems in this sphere include oil sludge contamination, radioactive contamination associated with oil production as well as uranium mining and processing (mostly waste dumps and tailing ponds accumulated in the Soviet period), virtual absence of coal-fired power plant ash and slag waste management systems, an inadequate level of ash capture in stacks of coal-fired power stations, and air and water pollution at sites of extraction and processing of mineral resources.

- Kazakhstan is a relatively large emitter of greenhouse gases, including carbon dioxide, globally, relative to the size of its economy; its emissions profile closely reflects the country's primary energy consumption pattern (dominated by coal), which in turn is shaped by its energy-intensive economic structure (primarily focused on the extraction and processing of mineral resources).

- Kazakhstan has been involved in the international discussions on the problems of greenhouse gas emissions and has made commitments to the international community to reduce its emissions. But the "Doha Amendment" adopted in December 2012 and extending the Kyoto Protocol until 2020 is unlikely to be ratified by Kazakhstan due to its obvious unsuitability for the country.[1] A successor framework to the Kyoto Protocol is scheduled to be negotiated by the parties to the United Nations Framework Convention on Climate Change in 2015 in Paris. It is expected that mandatory reductions targets will be eliminated: individual countries will enact their own plans and set their own goals for emissions reduction.

- Transition to a low-carbon economy is possible for Kazakhstan only over the long term. The first stage of such a transition is the creation of an efficient internal system of greenhouse gas emissions monitoring to support an increase of energy efficiency in industry and the broader economy.

- In 2014 the Ministry of Environment and Water Resources was abolished and its functions transferred to the Ministry of Energy, which now has primary responsibility for environmental protection.

13.2. Major Environmental Issues

Kazakhstan's environmental challenges are closely tied to the country's large size, interior location within the Eurasian landmass, and complex geological history. With a land area of over 2.7 million km², it is the world's ninth-largest state. This large area ensures a diversity of natural environments as well as an abundance of open space that can serve as a buffer between concentrations of population and dangerous or noxious activities; it was no coincidence that Kazakhstan was the USSR's primary nuclear testing site and it continues under a joint agreement with Russia to serve as the primary launch site for the latter nation's space program.

Kazakhstan's interior location means that it has a "continental" climate, featuring large seasonal temperature swings and, more importantly from an environmental perspective, a dry climate. The general dryness of the climate thus makes water (both in terms of its quantity and quality) a key environmental issue, as well as soil erosion when vegetative cover is inadequate to protect soil from wind and flash flooding.

Kazakhstan's diverse natural environments provide a rich natural resource endowment that is a "gift of nature" to the Kazakh people, but its development unavoidably is accompanied by a cost to the environment in the form of air and water pollution. The effects of pollution from resource development tend to be first concentrated locally in and near sites where the resources are extracted from the ground, but also subsequently at locations where metallic ores are smelted and otherwise processed and, in the case of hydrocarbon fuels, where they are burned to produce energy.

Kazakhstan has enacted a substantial body of legislation designed to protect the natural environment. A basic law "On Environmental Protection in the Republic of Kazakhstan," enacted in 1997, was followed by Land, Forest, and Water codes in 2003; the law "On Protection, Reproduction, and Use of Wildlife" in 2004; the law on "Specially Protected Natural Areas" in 2006; the Environmental Code of the Republic of Kazakhstan in 2007; the law "On Subsoil and Subsoil Use" in 2010; and the law "On Energy Saving and Increasing Energy Efficiency" in 2012.

What follows in this section is brief and selective overview of major environmental issues in Kazakhstan.

13.2.1. Aral Sea desiccation and transboundary water management

One of the two most prominent environmental issues with which Kazakhstan must contend is the shrinkage of the Aral Sea, a vast

[1] Paragraph 3.7-ter of the "Doha Amendment" establishes the 2008–2010 average emission level as the limit for greenhouse gas emissions in Kazakhstan in 2013–2020.

inland water body it shares with Uzbekistan. The primary cause has been the dramatic reduction of inflows into the Aral from its two major tributary rivers, the Syr Darya (via Uzbekistan and Kazakhstan) and the Amu Darya (via Turkmenistan and Uzbekistan). A vast increase in withdrawals from the flow in these two rivers began in the 1960s to support the rapid expansion of irrigated agriculture (mainly for cotton production) in the Fergana valley as well as outlying areas in downstream southeastern Kazakhstan, Turkmenistan, and Uzbekistan. Thus by the time these rivers reach the Aral they are reduced to little more than a trickle.

As a result, the surface area of the Aral Sea has been falling rapidly, to less than a quarter of its original size by 2007, separating into two and then three separate smaller bodies. The consequences have been severe. A fisheries industry based on the Aral was virtually eliminated as once-coastal communities found themselves miles inland and water salinity increased to levels toxic to aquatic life. Vast areas of the dried former sea bed, now exposed to the wind, provided the materials for massive dust storms that deposited salt on productive fields and aggravated respiratory ailments of the local population. Furthermore, the water from the two rivers that still reached the Aral contained high levels of fertilizer, pesticides, and salt leached from irrigated fields upstream, creating a serious shortage of potable water in delta communities.

An international effort is now underway to help save the vestigial Northern Aral Sea (or Small Sea), around the mouth of the Syr Darya in Kazakhstan, where salinities remain relatively low. The effort is focused on restoring local fisheries, wetland habitat, and agriculture.

Lake Balkhash, another inland terminal lake in southeastern Kazakhstan, faces a somewhat similar situation, albeit one affecting a smaller area. The lake, situated in an arid environment, experiences seasonal fluctuations in its level that are exacerbated by diversions from the rivers that empty into it. Completion in 1970 of the Kapchagay Reservoir upstream on the Ili River, one of Lake Balkhash's major tributaries, resulted in a decrease by two-thirds of the Ili's discharge, causing a significant decrease in the lake's depth. Large parts of the lake basin are now dry on a seasonal basis, creating the same problems of desiccation and blowing dust found with the Aral Sea.

Another dimension of the water management challenge at Lake Balkhash and eastern Kazakhstan more broadly is the absence of a comprehensive agreement on management of the more than 20 "transboundary" rivers that rise in northwestern China and flow into Kazakhstan. The largest of these are the Irtysh, Ili, Talas, and Korgas, and these rivers are essential to the region's population, environment, and economy. China is not a signatory to the 1997 UN Watercourses Convention on transboundary rivers and has thus far refused to enter all but bilateral negotiations with its neighbors on the joint management of transboundary rivers. In 2013 China and Kazakhstan concluded an agreement providing for an equal (50:50) allocation of the waters of the Korgas, but agreements covering the much larger Irtysh and Ili have thus far proven elusive. The rapid economic and population growth of northwestern China's Xinjiang province has resulted in increased upstream diversions to support expansion of irrigation agriculture and energy development. This has reduced the flows of rivers entering Kazakhstan in addition to having adverse impacts on water quality. The negative consequences for Kazakhstan include further damage to the water balances of lakes Balkhash and Zaysan, problems with water supply and public health concerns, degradation of the environment and of pastureland, and reduction of crop and fishery yields. Despite the challenge, the close economic relations between the two countries dictates that they work together to reach an accommodation on shared management and use, an objective that the two countries' leaders pledged to fulfill in April 2013. That Kazakhstan is the only one of China's neighbors with which it has concluded a transboundary water agreement thus far is indicative of the importance China assigns to the issue.

There is also tension among the former Soviet Central Asian countries between competing water uses in so-called "downstream" nations (Kazakhstan, Uzbekistan, and Turkmenistan) focused on irrigated agriculture and in mountainous "upstream" nations (Kyrgyzstan, Tajikistan), where the headwaters of the Amu Darya and Syr Darya arise. Here the primary use is in hydroelectric power generation. The seasonal regimes for the two uses are at odds, as electricity demand is highest in the upstream states in winter, which would dictate running more water through the dams during this period, which is precisely when heightened discharges downstream on the Amu Darya and Syr Darya are least needed (peak irrigation needs downstream are during the growing season).[2]

13.2.2. Semey nuclear testing facility

A second issue that features prominently in any discussion of environmental problems in Kazakhstan is the legacy of Soviet nuclear weapons testing at a facility in the general vicinity of the city of Semipalatinsk (now Semey), in northeastern Kazakhstan. At least 460 nuclear explosions occurred at the Semey facility between 1948 and 1989, first above ground (1948–1964), and then underground (1964–1989) following the conclusion of the Nuclear Test Ban Treaty in 1963. The facility was closed in 1991. Roughly one million people may have been exposed to radiation as a result of the tests, and the population of the region continues to experience an abnormally high incidence of immune system deficiencies and physical and mental defects. The primary environmental threat posed by the site today is a high level of residual radioactive contamination of soil and groundwater.

In addition to the tests at Semey, as many as 40 nuclear detonations may have occurred at isolated testing grounds in western and southwestern Kazakhstan. Residual radioactivity also is a byproduct of uranium mining in the country (as noted in Chapter 9, Kazakhstan leads the world in natural uranium production, accounting for over one-third of the total) as well as of past Chinese nuclear tests in Xinjiang, near the Kazakh border. The test site, at Lop Nor, was established in 1959; 45 detonations occurred between 1964 and 1996.

[2] For an analysis of the problem and its ramifications for potential future electric power exports from the region, see Christopher de Vere Walker, Central Asian Hydro Dispute Heightens Tensions between Upstream and Downstream Neighbors, IHS Energy Decision Brief, May 2013.

13.2.3. Industrial impact on ambient air quality

Kazakhstan has air quality standards in place for all major pollutants.[3] Environmental data from Kazakhstan's statistics agency indicate progress at the national level along a number of fronts. Total emissions of all major pollutants are below levels of the late Soviet period (1990), and emissions of sulfur dioxide and total suspended particulates (TSP) were much lower in 2013 than even in 2000 (see Table 13.1). Although emissions of other pollutants (e.g., nitrogen oxides, non-methane volatile organic compounds [NMVOC], and carbon monoxide) all were higher in absolute terms in 2013 than in 2000, the table shows that in relative terms (e.g., per capita and per unit of GDP) all steadily declined.[4]

However, the national-level data do not provide a complete picture, as air pollution in individual cities, especially those with metallurgical facilities, can exceed air quality standards on particular days (e.g., when meteorological conditions are unfavorable). For example, data for the iron and steel center of Karaganda show that nitrogen dioxide levels (produced by fossil fuel combustion in transport and industry) in each of the years 2011–2013 exceeded the maximum permissible concentration of 0.04 mg/m^3 on over 100 days (i.e., during roughly one-third of each year). Similarly, ground-level ozone in Karaganda (produced by the interaction of nitrogen oxides and volatile organic compounds in sunlight) exceeded the maximum permissible concentration by 79 and 89 days in 2011 and 2012, respectively. Other cities identified as locations where air pollution levels regularly exceed allowable concentrations include Taraz, Temirtau, Oskemen, Leninogorsk, Shymkent, and Balkhash.

	1990	1995	2000	2005	2010	2011	2012	2013
ABSOLUTE VALUES OF EMISSIONS. THOUSAND METRIC TONS/YEAR								
Sulfur dioxide	1483.5	1132.9	1080	1452.7	723.6	774.2	769.6	729.2
Nitrogen oxides	330.1	233.4	161.7	199	215.6	232.8	249.4	250.2
NMVOC[a]	168.1	—	33.6	41.3	49.7	53.4	58.1	92
Carbon monoxide	841.3	446	390.7	408	401.1	445.1	446.2	457.9
Hydrocarbons	139.9	—	79.2	116	132.1	137.6	170.5	96.1
TSP[b]	1683.3	1085.1	668.5	713.7	639.3	631.1	593.8	551.2
PER CAPITA EMISSIONS. KG								
Sulfur dioxide	n.a.[c]	72.2	72.5	96.2	44.4	46.6	45.5	42.6
Nitrogen oxides	n.a.[c]	14.9	10.9	13.2	13.2	14	14.8	14.6
NMVOC[a]	n.a.[c]	—	2.3	2.7	3	3.2	3.4	5.4
Carbon monoxide	n.a.[c]	28.4	26.2	27	24.6	26.8	26.4	26.8
Hydrocarbons	n.a.[c]	—	5.3	7.7	8.1	8.3	10.1	5.6
TSP[b]	n.a.[c]	69.1	44.9	47.3	39.2	38	35.1	32.2
EMISSIONS PER UNIT OF GDP. KG/THOUS. INTL. DOLLARS								
Sulfur dioxide	17.17	28.02	24.85	15.21	11.28	10.5	10	n.a.[c]
Nitrogen oxides	2.85	3.28	2.01	1.51	1.21	1.22	1.24	n.a.[c]
NMVOC[a]	1.45	—	0.42	0.31	0.28	0.28	0.29	n.a.[c]
Carbon monoxide	7.26	6.26	4.85	3.1	2.25	2.32	2.22	n.a.[c]
Hydrocarbons	1.21	—	0.98	0.88	0.74	0.72	0.85	n.a.[c]
TSP[b]	14.52	15.24	8.3	5.41	3.59	3.3	2.95	n.a.[c]

[a] *Non-methane volatile organic compounds.*
[b] *Total suspended particulates.*
[c] *Not available.*
Source: Republic of Kazakhstan Statistical Agency.

Table 13.1 Emissions of selected air pollutants in Kazakhstan

[3] It should be noted that these standards are not always as stringent as in Europe or North America. For example, Kazakhstan's standards for particulate and sulfur dioxide emissions from electric power plants are on the order of 5–10 times less strict than those in place in the European Union (KazEnergy, The National Energy Report 2013. Astana: KazEnergy, 2013, p. 134).

[4] Carbon dioxide and other greenhouse gas (GHG) emissions are discussed in later sections of the chapter.

13.2.4. Energy sector impact on the environment

13.2.4.1. Environmental impact associated with coal-fired power generation

Coal-fired power generation is a major source of emissions of greenhouse gases (discussed below) and other pollutants. Electricity and cogeneration (heat-and-power) plants together account for about 50% of Kazakhstan's total particulate emissions, 47% of sulfur dioxide pollution, and 60% of nitrogen oxides emissions.[5] Furthermore, during the period of coal-fired power generation development in Kazakhstan some 300 MMt of ash and slag waste (ASW) accumulated, and now occupy a storage area of about 8.5 thousand hectares (ha). There is virtually no commercial-scale ASW recycling at present (see below).[6]

It should be noted that although the levels of harmful emissions from most power plants in Kazakhstan comply with the standards established in the country, these levels, however, remain extremely high compared to global best practices (see Table 13.2). Allowable particulate emissions from coal-fired plants in Kazakhstan, for example, are significantly higher than the limits set for the EU's coal-fired plants (with a capacity of over 200 MW (see Figure 13.1). Therefore, in order to reduce the environmental impact of coal-fired power plants, a gradual transition to new environmental standards is necessary.

Emission type	Kazakhstan	Interim standards	EU
Particulates (ash)	1200-1600	300-600	50-100
Sulfur dioxide (SO_2)	2000-3000	1000-1500	400
Nitogen oxides (NO_x)	600	650	500

Note: Kazakahstan technical standards; EU Director 2001/80 EC.
Note: The technical regulation standards established for boilers with an output of 420 or more metric tons per hour are those reported above as the standards for Kazakhstan.
Source: Concept for Transition of the Republic of Kazakhstan to a Green Economy.

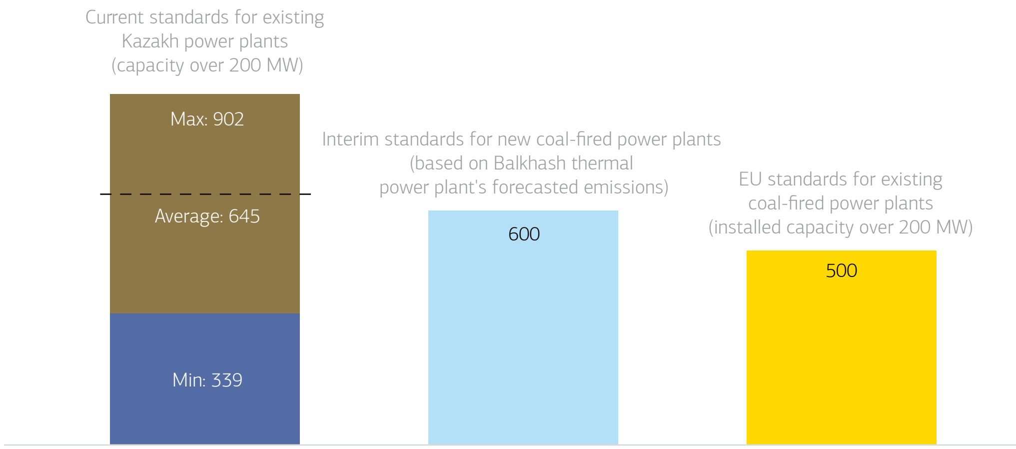
Table 13.2 Current air emission standards in Kazakhstan versus EU standards for existing power plants (milligrams per cubic meter)

Source: Concept for Transition of the Republic of Kazakhstan to a Green Economy

Figure 13.1a Particulate emission standards (milligrams per cubic meter)

[5] KazEnergy, The National Energy Report 2013, p. 133.

[6] Concept of Energy Sector Development in the Republic of Kazakhstan to 2030.



Source: Concept for Transition of the Republic of Kazakhstan to a Green Economy

Figure 13.1b NOX emissions standards (milligrams per cubic meter)

Emission type	Kazakhstan	Interim standards	EU ("clean coal" standards)
Particulates (ash)	200	30	30
Sulfur dioxide (SO_2)	780	200	200
Nitogen oxides (NO_x)	500	350	200

Note: Balkhash thermal power plant forecast emissions used as interim standards for future upgraded/improved power plants.
Source: Concept for Transition of the Republic of Kazakhstan to a Green Economy.

Table 13.3 Suggested air emission standards in Kazakhstan versus EU "clean coal" standards for future improved power plants (milligrams per cubic meter)

At the same time, due to the impossibility of an immediate transition to more stringent standards, it would be reasonable to establish some "interim" standards that would differ from the European ones only for the emissions that are currently difficult to reduce. It is important to design new power plants based on these interim standards (e.g., Balkhash power plant), preferably as close to the tougher European standards as possible (see Table 13.3).

In order to reduce negative environmental impacts, it is also necessary to introduce certain clean coal technologies at new and expanded coal-fired plants. Application of technologies such as fluidized bed combustion, supercritical and ultra supercritical steam cycles, as well as the installation of modern filters to capture sulfur oxide, nitrogen, and particulate emissions will significantly reduce the harmful environmental impact of coal-fired power plants.

However, the top priority is to solve the problem of coal-fired power plants' ash capture and handling (disposal). In order to reduce particulate emissions, it is recommended to introduce requirements for all coal-fired power plants to ensure an ash capture level of at least 99.5%. It is also recommended to arrange a system for monitoring the condition of ash and slag waste storage facilities, particularly in terms of dust control.

Within the framework of research grant funding, it is recommended to conduct research on the following issues: coal-fired power plant fly ash disposal/refining in Kazakhstan, coal loss reduction during transportation and storage, as well as establishing some pilot projects, using cutting-edge technologies, for coal ash processing and utilization. Moreover, it should be noted that coal ash can be considered a source of valuable metals (see following section), which can be considered an additional stimulus for its processing.

Another recommended step is to introduce requirements for coal-fired power plants to install modern filters capturing sulfur oxide and nitrogen emissions, facilitated by the introduction of new technical standards in this sphere (see Table 13.3).

Reducing harmful emissions at boiler houses can be achieved largely through energy efficiency improvements. Boiler houses in Kazakhstan operate with quite a low level of efficiency (e.g., 48.9% in South Kazakhstan Oblast, 52.8% in Atyrau Oblast, and 64% in the city of Astana). Therefore the sector has significant potential for reducing fuel consumption and hence emissions.[7] It is recommended that minimum requirements be established for specific fuel consumption at boiler houses, with the introduction of fines or other penalties for exceeding the established limit.

At the same time, introduction of carbon dioxide capture and

[7] Removing Barriers to Energy Efficiency in Municipal Heat and Hot Water Supply, UNDP, final publication on the project.

geological storage technologies does not seem appropriate for coal-fired power plants in Kazakhstan at the current stage of technological development. Despite the fact that modern technologies enable the capture of 85–95% of carbon dioxide, their use at coal-fired power plants is currently unfeasible from both ecological and economic points of view due to the following:

- specific fuel consumption increase by 14–40%;
- harmful emission increase (due to increase in fuel consumption);
- electricity generating costs increase by 43–90%;
- plant construction costs increase by 30–90%.

13.2.4.2. Coal fly ash, bottom ash, and boiler slag

This section examines the issue of ash and slag management in greater detail. In addition to generating emissions of carbon dioxide and other greenhouse gases (see below), the burning of coal in boilers of power plants and other industrial facilities produces combustion residuals in the form of fly ash, bottom ash, and boiler slag. Approximately 80–90% of fly ash, bottom ash, and boiler slag consists of nonradioactive minerals such as silicon, aluminum, calcium, and iron. However, the remaining material contains naturally radioactive compounds present in the coal (uranium, thorium, potassium) as well as their decay products (radium). These “technologically enhanced naturally occurring radioactive materials” (TENORM) are not highly radioactive in terms of individual dosages, but nonetheless require special procedures for recycling and disposal.

The amount of ash produced depends on the mineral content of the coal and the type of boiler in which the coal is burned. As noted in Chapter 8, Kazakh coals typically have high ash content (average 29%). One way in which utilities can reduce the ash content (by as much as 50–70%) is by washing the coal prior to combustion. However, the process itself is energy-intensive and, for Ekibastuz coal, not really technically feasible as production costs would rise three to four times. However, the cleaning technology can be implemented for most types of lignite coal.

Fly ash accounts for about half (by weight)[8] of all coal combustion residuals, and is carried upward with hot flue gases where it is trapped by stack scrubbers and other stack filtration devices. Modern, state-of-the-art filtration devices are capable of removing 99% of fly ash, practically eliminating airborne emissions. Bottom ash is too large or heavy to be carried by the flue gases and settles to the bottom of the boiler. Bottom ash that melts under the intense heat of combustion becomes boiler slag; it also collects at the bottom of the boiler as well as in exhaust stack filters.

Due to the high ash content of the coal and the limited extent of coal washing, the handling and disposal of ash and slag pose an important challenge for Kazakhstan (as noted above), and the experience elsewhere may warrant consideration. In the US, about 45% of all fly ash, bottom ash, and boiler slag is recycled, with the remainder being disposed of in landfills and surface impoundments. For fly and bottom ash, roughly two-thirds of their re-use is in concrete and blended cement (e.g., 10–40% fly ash content). The remaining use is primarily in structural fills and embankments, as road base, snow and ice control, and as aggregate. Roughly 80% of re-used boiler slag is used as blasting grit and roofing granules, and the remainder in the aforementioned uses for bottom and fly ash. The major five-year national infrastructure construction program outlined in the Nurly Zhol economic policy would appear to provide an opportunity for the increased re-use of these coal combustion residues, as it envisages extensive construction of new roads, rail lines, and airport infrastructure, with the corresponding increase in use of cement and demand for fill, road base, and embankment materials.

A final, more novel opportunity for coal ash re-use is associated with the recent increased world demand for rare-earth elements and other strategic metals such as gallium, germanium, indium, and tellurium. The concentrations of these elements in coal ash is comparable to those in many commercially mined rare-earth deposits worldwide, they do not leach from the ash like other metals, and their recovery is now believed to be economically feasible due to recent sharp price rises on world markets. The beneficiation process is complex and energy intensive, but the potential is sufficiently promising that further research is underway to optimize recovery rates and minimize negative environmental externalities. Even at present levels of knowledge and technology, coal ash storage facilities appear to constitute a source of these metals that is less expensive and environmentally hazardous than dedicated mine production.[9]

13.2.4.3. Waste coal recovery

Over many years, coal mining and enrichment activities in Kazakhstan have created large on-ground waste deposits—waste dumps and tailings ponds—consisting of the materials left over after the process of separating economically valuable fractions from those that (at the time) are not. In the case of coal, this determination is often based on the dimensions of the coal-bearing material (with below-graded-size chunks being discarded). This waste includes materials formed at high temperatures and pressures at depth. The chemical/mineralogical stability of these materials, when exposed to the physical disturbance of extraction processes and storage in the open atmosphere, may break down, releasing elements into the environment via eolian transport and fluvial processes (acid mine drainage). The environmental challenge in the management of waste dumps and tailings ponds is to dispose of the material such that it is at least inert (if not stable or contained) and to move toward finding alternative uses.

[8] "Technologically Enhanced Naturally Occurring Radioactive Materials," TENORM: Coal Combustion Residuals, Radiation Protection, US EPA.

[9] See David Mayfield and Ari Lewis, “Coal Ash Recycling: A Rare Opportunity,” http://www.waste-management-world.com/articles/print/volume-14/issue-5/wmw-special-recycling/focue/coal-ash-recycling-a-rare-opportunity.html, accessed 29 May 2015.

Another approach, not unlike that employed in older producing oil fields, is to view these wastes as new coal deposits that can be exploited through advanced technologies. Many of these wastes accumulated during periods when extraction and enrichment technologies were not as efficient as at present, and thus their reworking can afford the opportunity to access substantial volumes of coal at relatively low cost. It also provides environmental and social benefits, including the reduction of waste material subject to leaching and airborne dispersal, improvements in the visual landscape, and the creation of additional jobs. A typical recovery technology, such as that employed by US-based Coalview, blends coal waste (fines) in a slurry that passes through a series of centrifuges, cyclones, and spirals to remove water and separate out the coal fractions. Prior to processing, the company has the ability to assess, via drilling, the type of coal that is present in waste impoundments, as well as its quantity.

13.2.4.4 Impacts of oil and gas production

The environmental impacts of the oil and gas sector are significant. Among the more obvious are pipeline ruptures and spills of toxic materials transmitted to and from offshore drilling platforms.

Some fields in Kazakhstan also face the problem of oil sludge handling. In Atyrau Oblast, the estimated area of land pollution due to oil contamination of soil is over 13,000 square kilometers. One of the biggest sources of contamination is considered to be the oil storage pit (20 meters deep with a surface area of about 70 ha) in the Uzen field area (Mangistau Oblast) formed as a result of an accident on the Uzen-Samara trunk oil pipeline in 1974. Oil waste was dumped into the storage pit for over 30 years. However, in recent years, due to the gradual resolution of the sludge handling problem, the oil contamination area of the storage pit has been significantly reduced.

The solution to the problem of field oil sludge handling is enhanced oil production waste management in terms of organizing oil sludge supply to and processing at refineries. Another option to consider would be using oil sludge in production of construction materials.

Environmental problems related to oil production in Kazakhstan are also connected with high levels of radiation exposure: 267 areas of radioactive contamination with a radiation intensity of 100 to 17,000 microroentgens/hour have been identified at the 22 largest fields.[10] The problem is traced to the fact that subterranean water-bearing strata in most oil fields contain natural radionuclides (of uranium, thorium, and radium). A portion of this "formation water" is pumped to the surface during oil extraction where it is separated from the oil and gas and transferred for storage in pits or tanks (as so-called "production water") before it is ultimately disposed via reinjection into deep wells or discharged into nonpotable coastal waters. Although the radioactivity levels of produced waters are generally low, the volumes produced are large (~10 barrels of water per 1 barrel of oil).

However, when in storage, radium and its decay products (as well as certain nonradioactive chemical compounds such as silica, barium, and calcium that may be toxic) may enter into solution within the production water, and eventually may settle out to form sludges that accumulate in water storage tanks and pits (as well as oil stock tanks). Another way in which the radioactivity of production water is concentrated is through the formation of mineral scale inside pipes, drilling equipment, gas separators, heater treaters, and gas dehydrators.

In addition to water and soil contamination at producing fields, there are risks to field workers operating in direct proximity to disposal sites: exposure to at least low-level gamma radiation, inhalation of radioactive dust and radon, and ingestion of well water and/or food contaminated by radioactive dust.

At present, the decontamination of radioactive equipment is done using liquid/fluid deactivation technologies whereby more than 90% of the radioactive contamination is removed.[11] Resolution of the problem of the application and search for optimal technologies for decontamination of pipes and other field equipment is a priority for scientific research. The state must strengthen monitoring and regulation over the decontamination of oilfield equipment by establishing specific criteria for this type of decontamination.

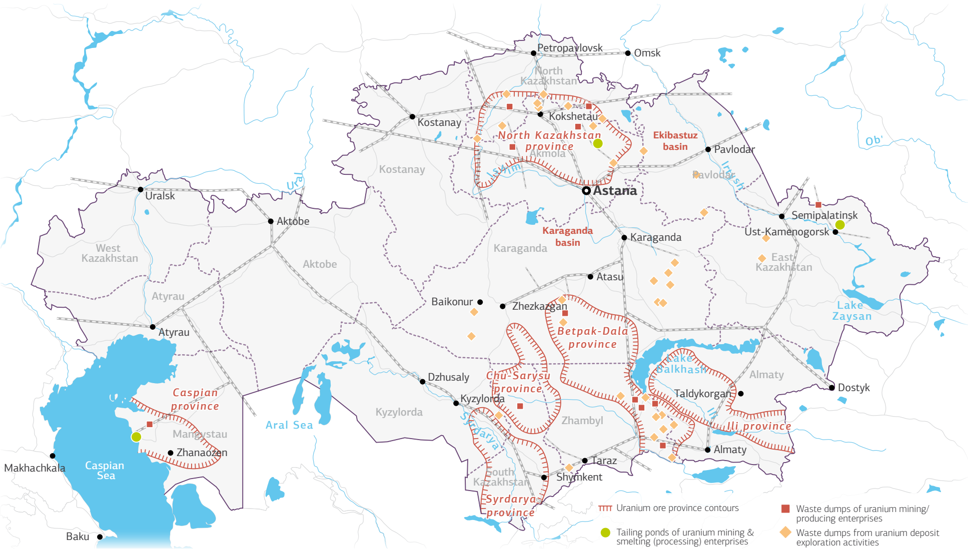
Another problem associated with oil extraction in Kazakhstan is sulfur utilization (see Chapter 7), although sulfur is no longer considered a production waste/pollutant according to the norms of Kazakh legislation.

13.2.4.5. Impacts of uranium production

Kazakhstan is a unique region rich in uranium ore, ranking among the world's top four reserve holders (see Chapter 9), which results in a high natural background radiation level characteristic for a significant (about 13%) part of the country's territory. During the Soviet period, uranium was mined in Kazakhstan using the heap leaching method. As a result, the bulk of the uranium industry waste (accumulated during the Soviet period) is waste from uranium mines and tailing ponds of enrichment plants that operated at the mines and can be classified as low- and medium-level radioactive waste (see Figure 13.2).

[10] See chapter 2 of an UNDP report on "Environmental Changes due to Economic Activity" http://www.undp.kz/library_of_publications/files/2147-19397.pdf.

[11] According to KazMunayGaz, at the Uzen field alone more than 1000 tons of radioactive pipes and equipment were decontaminated in 2014.



Source: IHS Energy, KazEnergy

Figure 13.2 Location of uranium industry waste dumps and tailings ponds

The drill-hole in situ leaching method (ISL) currently used in Kazakhstan for uranium production is characterized by a much lower level of environmental impact and a low-dose exposure of the field personnel. The negative impacts of the method are mainly related to damage to the underground hydrosphere and subsoil. Moreover, when using ISL for uranium mining, concentrations of practically all toxic components entering into solution do not exceed their initial values, as evidenced by the actual observation data for hydrochemical profiles at the Moinkum, Kanzhugan, and Northern Karamurun deposits currently being developed.[12]

However, many years of uranium mining activities in the Soviet period led to formation of 118 overburden rock and radioactive ore processing waste dumps occupying an area of 614 square kilometers with a total weight of about 50 MMt. The radioactivity level of the waste ranges from 35 to 3000 microroentgens/hour.[13] The radiation intensity at each of the abandoned dumps is more than 50 times higher than the maximum permissible level. A significant threat to public health is posed by unauthorized collection of depleted ore for use in construction.

In this regard, it may be recommended that Kazakhstan establish a system for monitoring radiation levels in uranium mining waste dumps and tailing ponds, to continue research aimed at assessing the level of impact of these facilities on the environment and public health, as well as to ensure security of the facilities in order to prevent unauthorized collection of depleted ore.[14]

13.2.5. Environmental fines and energy producers

As indicated in the section on hydrocarbon taxation in Kazakhstan, hydrocarbon producers also bear a substantial fiscal burden related to environment-related fines. Currently, three legislative acts impose financial liability for excess pollution (emissions exceeding certain established thresholds) (see Table 13.4 for an example of excess gas flaring):

- The Environmental Code and related regulations (Kazakhstan Government Resolution No. 535 from 27 June 2007) establish the principle of compensation for damage from pollution and set a formula for assessing the damage;
- The Tax Code sets fines, which are 10 times higher than the regular pollution fees set in the Environmental Code;
- The Administrative Offense Code also sets fines, which are 10 times higher than fees set in the Tax Code for emissions that exceed allowed pollution levels.

[12] I.A. Shishkov and P.G. Kayukov, "Radiation-Related Environmental Problems in the Republic of Kazakhstan Connected with Uranium Deposit Exploration and Development," Bulletin of the National Academy of Sciences of the Republic of Kazakhstan, Geology Series, 2013, №5.

[13] http://www.undp.kz/library_of_publications/files/2147-19397.pdf

[14] Shishkov and Kayukov, "Radiation-Related Environmental Problems in the Republic of Kazakhstan Connected with Uranium Deposit Exploration and Development."

Pollutants	Tax Code				Administrative Offense Code	Environmental Code. Government Resolution No. 535 of 27 June 2007
	Payment rate in Minimum Calculation Index per ton				Max. excess gas flaring fine, in Minimum Calculation Index per ton	Environmental damage calculation from gas flaring
	Stationary sources	Gas flaring, base rate	Gas flaring, max rate set by maslikhats*	Excess gas flaring, max rate set by maslikhats*		
Hydrocarbons	0.16	2.23	44.6	446	4 460	Ui = (Cfacti - Cnormi) x 360/1000000 x T x 52 MCI x Ai x 10 x K1 x K2
Carbon oxides	0.16	0.73	14.6	146	1 460	
Methane	0.01	0.04	0.8	8	80	

** The Tax Code gives local governments (maslikhats) the authority to set rates up to 20 times higher than the base rate.*

Source: Tax Code, Administrative Offense Code, and Environmental Code of the Republic of Kazakhstan.

Table 13.4 Administative charges and fees for pollution set in Kazakh legislation: example of gas flaring

The KazEnergy Association is undertaking a number of initiatives with regard to the pollution fees. These include: (1) shifting the calculation of damage from excessive emissions from the indirect method to a direct method; (2) abandoning the provision that allows local authorities to increase the base fines set in the legislation by as much as 20 times for any sort of a breach, and by another 10-fold on top of that for cases of "excessive" pollution; and (3) changing the liability set in the Administrative Code, with the amount set based on the Minimum Calculation Index (MCI), rather than on a set rate that varies based upon the extent by which allowed pollution levels are exceeded.[15]

In relation to calculation of the environmental damage, the Association has proposed revising the formulas, which now call for a broad assessment of the impact that includes an assessment of indirect as well as direct damage; this is due to the general unreasonableness and lack of transparency in the current formulae. At the same time, KazEnergy made proposals to shift the methodology for damage assessments to be based on the base rates for fines and the extent to which any actual breaches exceed the allowed pollution limit. Currently, a new draft of the damage assessment methodology has been submitted by the Ministry of Energy and other relevant state authorities for consideration.

During parliamentary hearings on 1 June 2015, which discussed this issue, the recommendation of the parliament to the Energy Ministry on environmental payments and fines was as follows:

"...in the Environmental Code - recovery of environmental damage caused by excessive emissions (should) use only direct assessment methods based on the evident fact of damage to the environment."

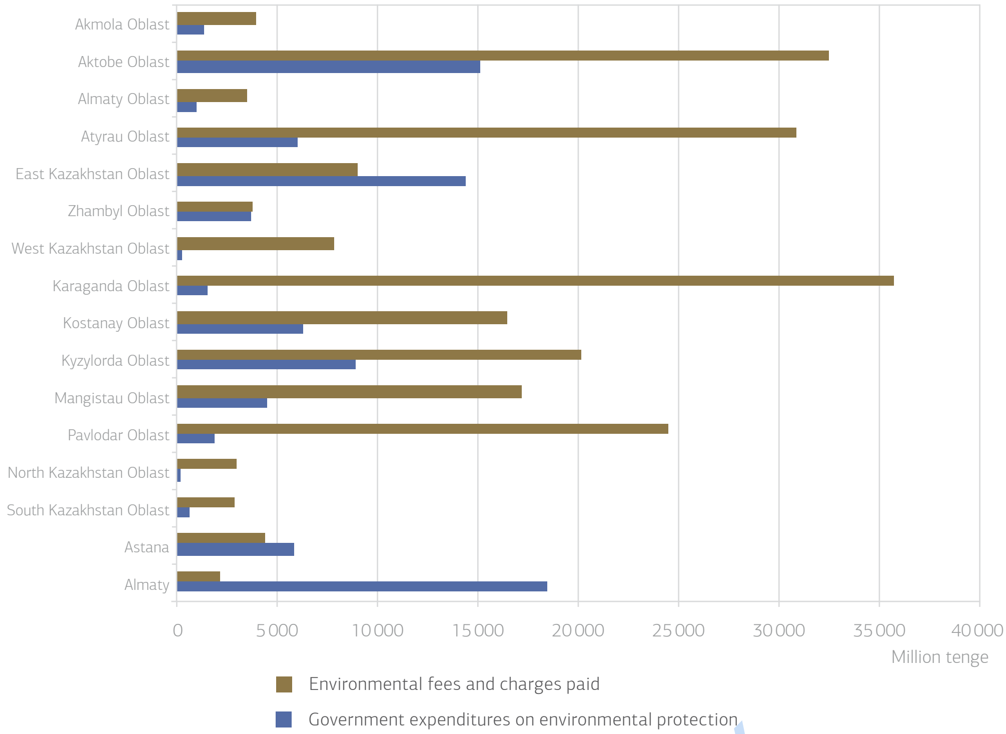
This approach also is consistent with proposals of the Ministry of Energy's Task Group. While developing a draft environmental law, the Group also recommended that the indirect method of economic damage assessment be abandoned, with only obvious and direct damage to the environment being assessed.

The Association's proposal to abandon the provision in current legislation that allows local authorities (maslikhats) to increase fees by as much as 20 times, and further by 10 times in case of excess pollution, has also been supported by state authorities, and the draft legislation on taxation was approved by the Government Commission for law-drafting activities on 30 June 2015. The draft proposes to revise the "base" rates of the environmental fees and to exclude the option that allows local authorities to increase the ratios.

In terms of the liability set by the Administrative Code, KazEnergy proposed that fines be based on the Minimum Calculation Index (MCI), rather on a set rate that varies on the extent by which allowed pollution levels are exceeded. However, this proposal was not supported by state authorities.

Related to the problem of the somewhat arbitrary and excessive fines that can be levied for pollution and environmental damage, is a strong disconnect between the funds collected by the government and the expenditures for environmental protection, remediation, and restoration, which ostensibly come from excess pollution emissions, both in aggregate and at the oblast level (see Figure 13.3). Total payments in 2011-13 amounted to about 219 trillion tenge (about $1.2 billion), while total expenditures during this period amounted to only about $91 trillion tenge ($0.5 billion). It appears that the environmental fines are largely viewed as another general government revenue source, particularly at the local level. Also, given which oblasts are the main contributors of these funds (e.g., Karaganda, Pavlodar, Aktobe, Atyrau), it appears that energy producers (coal and hydrocarbon producers) are the main payers.

[15] The MCI (or minimum calculation index) is a unit of value that is changed each year when the budget is enacted; this means that the underlying basic legislation (such as the Tax Code or Environmental Code) does not have to be. For example, on 1 January 2014 it was established in the Law on the Republican Budget for 2014–2016 No. 149-V, dated 3 December 2013, as 1,852 tenge.



Source: KazEnergy

Figure 13.3 Environmental payments versus funds allocated for environmental protection, 2011-13

13.3. Greenhouse Gas Emissions and Climate Change

13.3.1. Global warming issues

The basis for the global effort to control greenhouse gas (GHG) emissions is the 1990 report of the Intergovernmental Panel on Climate Change (IPCC), confirming the threat of global climate change due to human impact. For the purposes of the report, global warming means an increase of the average air (atmospheric) temperature of up to 3°C by 2100 (as compared to the 1990 level) and the consequences thereof. According to IPCC experts, the main factor affecting average annual air temperature rise is the increase of greenhouse gas (mainly carbon dioxide) concentrations in the atmosphere as a result of extensive use of fossil energy resources by people.

The last 50 years have seen unprecedented (in 200,000 years) growth of carbon dioxide concentrations in the atmosphere. In 2013 the CO_2 concentration in the Earth's atmosphere exceeded 400 parts per million (ppm),[16] or 0.0392%.

The greenhouse effect, which consists of the trapping of a part of the Earth's thermal radiation, is a consequence of the differential permeability of some atmospheric gases to short- and long-wave radiation and is responsible for the formation of a sufficiently warm climate on our planet for life as we know it today to exist. The main source of the greenhouse effect in the Earth's atmosphere is water vapor. If there were no greenhouse gases in the Earth's atmosphere, the average surface temperature would be -15°C, while the greenhouse effect leads to its increase by 30°C, of which 20.6°C is due to the presence of water vapor in the air and 7.2°C is due to the presence of carbon dioxide. Therefore, greenhouse gases are very important for the planet's climate formation.

The Earth's climate has been constantly changing throughout human history: periods of cold weather have given way to warmer periods, and vice versa. Research data show that the average atmospheric temperature 10,000 years ago was 2–2.5°C higher than the current value (the Atlantic Climatic Optimum) and in the 8th-12th centuries was 1° higher than the current value (Medieval Climatic Optimum).

The current physical long-term climate forecast models cannot take into account all the variety of direct and inverse effects related to an increase in greenhouse gas concentration, and therefore the accuracy of long-term climate forecasts remains quite low. However, at the moment, the theory of carbon dioxide concentration's influence on climate change is accepted as the base theory at the global level and environmental and energy policies of a number of countries are aimed at limiting greenhouse gas emissions.

[16] In the pre-industrial period, the CO_2 concentration was about 280 ppm.

13.3.2. Greenhouse gas emissions in Kazakhstan

In terms of the GDP carbon intensity (2.59 kg of CO_2 per thousand US dollars, according to International Energy Agency data), Kazakhstan is among the five top carbon-intensive countries, while the average value is 0.58 for all the countries in the world, 0.31 for the OECD countries, and 1.73 for China.[17]

As with energy intensity, individual countries' CO_2 emissions are strongly influenced by the structure of their economies. Coal accounts for over 60% of Kazakhstan's primary energy consumption, and the absolute level of its consumption is projected to hold fairly steady out to about 2025. This share is high relative to the world average—the equivalent shares are 33% for the United States, 43% in India, 47% in China, and 49% in Poland—but again is a reflection of Kazakhstan's natural resource–based economy in which large quantities of energy are expended per unit of GDP. Globally, coal combustion from all sources (including consumption in metallurgy) is responsible for some 43% of carbon dioxide emissions, and coal combustion in electric power generation accounts for 28% of global CO_2 emissions.[18]

The link between coal consumption and electric power generation in Kazakhstan is strong, as more than three-fourths of the country's generation is coal-fired (as is roughly two-thirds of total installed capacity), and in large parts of northern and central Kazakhstan coal is the only fuel available for electric power production (see Chapter 10).

The continuing importance of coal in Kazakhstan's energy balance has implications for its significant carbon dioxide emissions. Despite the increasing role of natural gas in electricity generation, at the very least coal will account for over 70 billion kilowatt-hours (kWh) of electric power generation out to 2040. At the same time, coal combustion releases 1.65 times more carbon dioxide as compared to the same amount (in calorific terms) of natural gas.[19]

According to the Kazakhstan Statistics Committee's data, absolute volumes of carbon dioxide emissions (the share of carbon dioxide in the greenhouse gas emissions profile of Kazakhstan ranges between 72 and 78%) dropped in the 1990s (from 161.5 MMt in 1995 to 140.1 MMt in 2000) and then rebounded in the 2000s, reaching about 240 MMt in 2014 (see Figure 13.4). This is considerably lower than at the end of the Soviet period: in 1990 Kazakhstan emitted about 274.8 MMt. The falling emissions recorded during the 1990s reflected the contraction of Kazakhstan's economy. Thus the slowing growth of emissions since the mid-2000s despite strong economic growth appears to be a response to structural changes in the economy (e.g., the reduced share of the metallurgical sector vis-à-vis the less energy intensive oil-gas sector in the country's overall economic output). According to a U.S. Energy Information Administration study conducted in 2010, Kazakhstan ranked 28th among world countries in terms of its absolute CO_2 emissions, an outcome that should not be viewed negatively given the size and industrial orientation of its economy, and represents a marked improvement over its 1992 ranking (17th).

Source: Kazakhstan Statistical Agency

Figure 13.4 Official estimates of Kazakhstan's CO_2 emissions, 1990-2014

[17] Key World Energy Statistics 2014.

[18] Trends in Global CO_2 Emissions: 2013 Report. The Hague: PBL Netherlands Environmental Assessment Agency and European Commission Joint Research Centre, 2013, p. 32. In Kazakhstan, according to these estimates, coal accounted for 71.9% of total CO_2 emissions in 2012, oil 15.6%, and natural gas 12.5%.

[19] Trends in Global CO_2 Emissions, 2013, p. 32.

The National Energy Report 2013 indicated that 85% of Kazakhstan's GHG emissions come from the power sector, and mainly from coal-fired power plants.[20] The program to make that sector more "green" by according priority to natural gas and renewable generation when adding new capacity and replacing outmoded capacity is discussed in Chapter 10. However, there are difficulties entailed in radically altering Kazakhstan's fuel balance in order to substantively change its carbon emissions trajectory, as the rate at which power infrastructure turns over is rather slow. Thus it would seem prudent over the near term for Kazakhstan's policymakers to focus on other measures that could be used effectively to curtail these emissions based on the existing fuel balance. These measures include energy efficiency and energy savings strategies stimulated by the recently established domestic carbon trading market.

13.4. Carbon Trading Market in Kazakhstan

In November 2010, the law "On Amendments to Certain Legislative Acts of the Republic of Kazakhstan Relating to Environmental Issues" was enacted, opening a path for the establishment of a carbon trading market by specifying general rules for emissions trading, establishing the liability of enterprises (emitting more than 20,000 tons of CO_2 annually) for GHG emissions exceeding limits outlined in an allowance certificate. This was followed on 3 December 2011 by an amendment to the country's Environmental Code: establishing a market mechanism (emissions trading system) for reducing emissions that allows both domestic and international trade in emissions allowances; and initiating the development of a domestic offset scheme. The internal emissions trading system rules were developed during 2012. As a result, the Environmental Code, including a section on greenhouse gas emissions regulation (Chapter 9.1), became the first nation-wide emissions cap-and-trade system in Asia and the CIS countries.[21] Many important elements (e.g., allocation and measurement, reporting, and verification) were modeled after provisions in the EU's emissions trading system (ETS).

During 2013 a one-year pilot phase was rolled out that included 178 major enterprises (emitting 20,000 tons or more of CO_2 annually) in the power, oil-gas, coal mining, chemicals, and metals mining/metallurgical sectors. In aggregate these enterprises accounted for 77% of the country's CO_2 emissions and 55% of its GHG emissions in 2010. Under a National Allocation Plan,[22] a cap (allowance surrender obligation) was placed on the aggregate GHG emissions of these 178 enterprises that corresponded to their 2010 emissions level (147 MMt of CO_2 equivalent). An additional reserve of allowances of 20.6 MMt was set aside for the installation of new capacity at these enterprises in 2013. The general concept is that enterprises that fail to reduce their emissions (to the 2010 level) purchase allowances from those with credits to spare, or are subject to significant fines (approximately $75 per ton of CO_2) or even loss of their business licenses.[23] No fines were imposed on enterprises during the first period (pilot phase) of functioning of the national GHG emissions regulation system.

Despite the technical and organizational challenges of the first period, the GHG emissions regulation system was launched in 2014—this time in an operating mode envisaging penalties and purchase of allocations in case of exceeding the established limit. Allocations were issued to 166 companies using 2013 emissions data as a benchmark with commitments to maintain the same level of emissions in 2014 and to achieve a 1.5% decrease in 2015 (see Table 13.5).[24] A controversial matter related to the GHG emissions regulation system in Kazakhstan is free issue by the government of additional allocations to enterprises based on applications received. Concerns have been raised about the fairness and transparency of the mechanism for allocation of free additional quotas, and that aggressive lobbying by companies for additional allocations could flood the existing system with excess quotas, making them so inexpensive as to be practically worthless. Falling quota prices due to a lack of proper market regulation system became a primary reason for the EU ETS failure.[25]

[20] KazEnergy, The National Energy Report 2013, p. 193.

[21] See EDF and IETA, Kazakhstan—The World's Carbon Markets: A Case Study Guide to Emissions Trading. Environmental Defense Fund and International Emissions Trading Association, September 2013.

[22] The ETS will be guided, at least initially, by annual National Allocation Plans that establish how many allowances enterprises will be granted based on previous years' GHG emissions. The only GHG covered to date is CO_2.

[23] However, for the 2013 pilot phase, penalties for non-compliance were suspended; the only penalties were for failure to submit the required documents and reports.

[24] Alexei Sankovski (Chief of Party, Climate Change Mitigation Program, USAID), "Using the Carbon Market to Create Modern Energy Systems in Kazakhstan." Paper presented at the American Chamber of Commerce in Kazakhstan Energy Forum, 27 June, 2014, Astana.

[25] KazEnergy, The National Energy Report 2013, p. 195.

	2014	2015
Traded volumes (tons CO_2)	1,271,289	1,246,229
Average price, tenge per ton of CO_2	301	765

Table 13.5 Volumes of internally traded CO_2 quotas in Kazakhstan

Although the average price of a quota in 2014 was 301 tenge per ton of CO_2 (Table 13.5), analysis of data provided by oil and gas companies on volumes of additional quotas purchased and their cost have shown that the cost of quotas reached as high as 1,150 tenge per ton of CO_2 in that year.

The paragraph of the Environmental Code forbidding the sale of the amounts of GHG emissions reduction (savings) obtained by reducing production gives rise to some questions. It is not clear that all quotas sold on the domestic market were not obtained at the expense of reducing production. In addition to ensuring that the trading price of allowances adequately reflects market conditions, a number of other measures could be taken in the future to strengthen the ETS and modernize Kazakhstan's energy structure. These could include, for example, extending the ETS (beyond CO_2) by testing quotas for emissions of methane; auctioning (by the state) of a portion of the allowances, with the proceeds used to finance projects for improving energy efficiency and introducing renewable energy sources; and distributing additional allowances to covered entities in as fair and transparent a way as possible.

One element of the latter policy in the EU ETS is to designate best practice in low-emission production as a benchmark when setting an enterprise's free allocation. The benchmarks are product specific to the extent possible (i.e., would be different for electric power plants, iron and steel mills, and petrochemical facilities). In a general sense, the product benchmark is based on the average GHG emission performance of the top 10% (best-performing) installations producing a specific product. Installations that meet these benchmarks in principle will receive all of the allowances they need; enterprises that do not would be required to purchase additional allowances to reach this threshold.[26] The difficulty of this approach lies in the dependence of specific emissions on the load, particularly in the case of thermal power plants. When issuing greenhouse gas emission allocations, the Ministry of Energy may face some problems in comparing the operating enterprises with best practices due to technologically different conditions of operation of some enterprises (coal mining, oil and gas production, oil refining, CHP plants [TETs]).

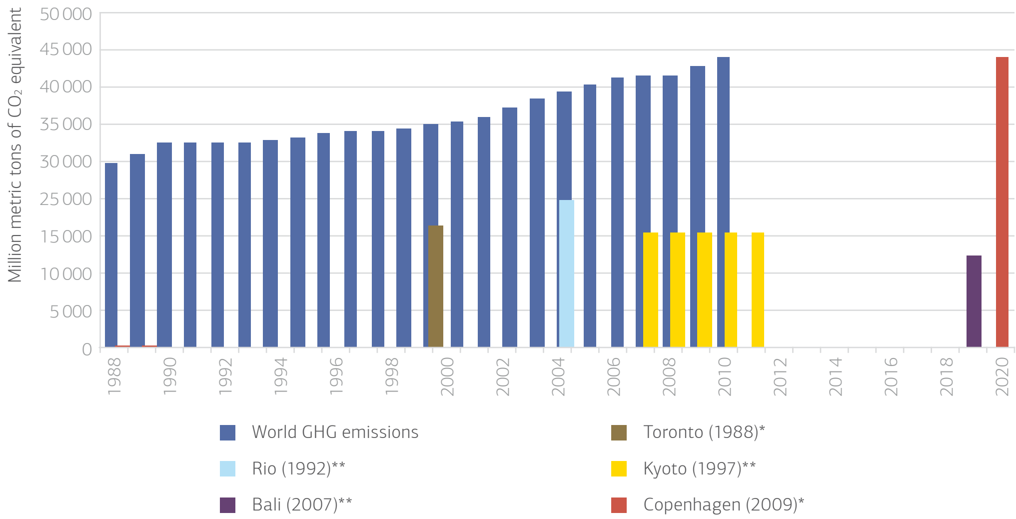
13.5. Climate Change Policy: Targets and Objectives

Although CO_2 is the most abundant greenhouse gas (not considering water vapor) in the earth's atmosphere,[27] international policies formulated to address climate change have sought for the most part to target the GHGs as a group. Thus further discussion of climate change in this chapter focuses on GHGs as a group. Global GHG emissions produced by the combustion of fossil fuels continue to rise as world population, economic activity, and consumption increase, from annual levels of below 30 gigatons in the late 1980s to well over 40 gigatons today (see Figure 13.5). The industrialized countries have been responsible for much of the past and present GHG emissions, but the recent economic growth in emerging economies (especially those with large populations such as India and China) represents a major additional source of emissions going forward. Estimates suggest that unpredictable temperatures and extreme weather damage currently cost the global economy in excess of $1 trillion annually; however, greenhouse gas emissions regulation may lead to a decrease in global GDP of 2% to 5.1% depending on the carbon policy (annual emissions limit of 500 ppm or 450 ppm).[28]

[26] For a more nuanced discussion of benchmarks, see European Commission, "Free Allocation Based on Benchmarks," http://ec.europa.eu/clima/policies/ets/cap/allocation/index_en.htm.

[27] Methane is the second most prevalent greenhouse gas (e.g., accounting for about 9% of all GHG emissions from human activity in the U.S.), although pound for pound its impact on climate change is over 20 times greater. Fortunately its lifetime in the atmosphere (12 years) tends to be much shorter than that of carbon dioxide (the lifetime of which is indefinite due to its cycling with plant life and ocean waters).

[28] Richard S.J. Tol. An Analysis of Mitigation as a Response to Climate Change. Copenhagen Consensus Center, 2010.



Source: IHS Energy

** global target; ** Annex I developed country target.*

Figure 13.5 Global CO_2 emissions and targets

Despite the growing concern, the international policy response to date has been quite inconsistent. More than 500 climate policies have been promulgated since 1997 alone, but their scope and substance have been unpredictable. The United Nations Framework Convention on Climate Change (UNFCCC), adopted in 1992, created an international framework for action on climate change, and in 1997 the Kyoto Protocol established a legally binding framework for (signatory) developed countries to reduce their GHG emissions by meeting specific reduction targets. Progress toward a coordinated international effort to reduce emissions subsequently slowed, as neither the leading CO_2-emitting country at that time (United States) nor presently (China) ratified the Protocol.

The "Doha Amendment" to the Kyoto Protocol, adopted in December 2012 in order to extend the Protocol for the period of 2013–2020, exacerbated contradictions among the countries with regard to quantitative restrictions. Russia, Japan, and New Zealand did not take on any new targets in the second commitment period of the Kyoto Protocol. Canada officially withdrew from the Kyoto Protocol in 2011. Kazakhstan and Belarus found themselves in a particularly vulnerable position. The two countries do not have a national allocation reserve for the first period and, in accordance with an amending paragraph, the GHG emissions for these countries are limited not by official commitments (Annex B to the Kyoto Protocol) but by the average level of emissions during 2008–2010.[29] Certain contradictions in positions with regard to quantitative restrictions occurred within EU countries as well.

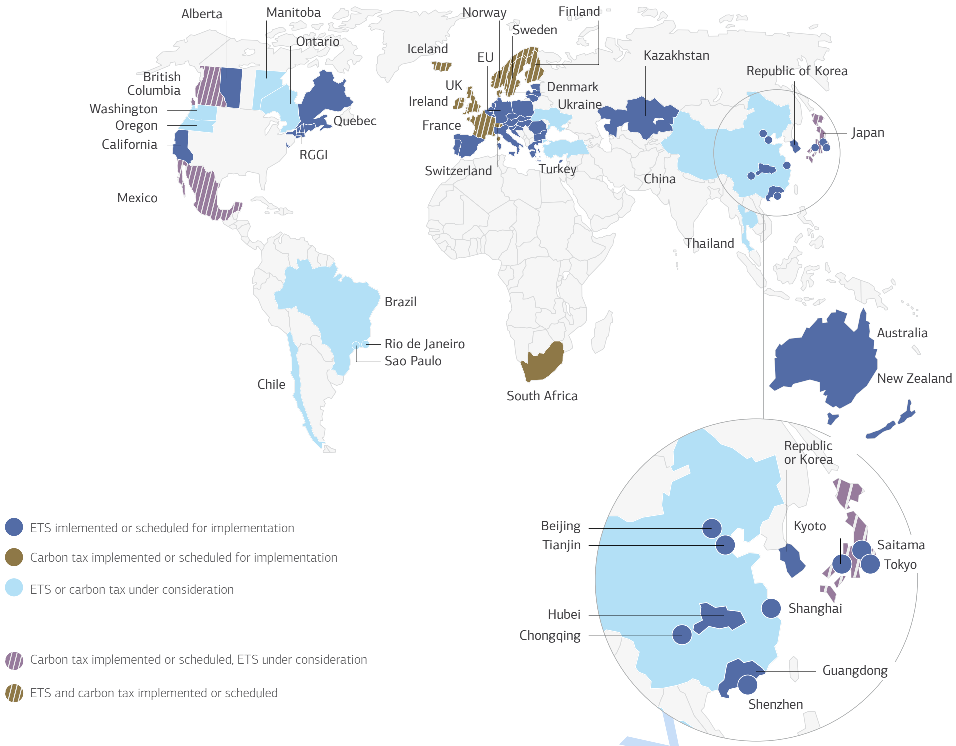
Currently, there is acknowledgement that the climate policy and the approach to limiting greenhouse gas emissions in terms of quantity are in need of major changes.

A successor framework to the Kyoto Protocol is scheduled to be negotiated by the parties to the UNFCCC in 2015 in Paris. Individual countries will enact their own plans and set their own goals for emissions reduction, beginning in 2015.

At the moment a variety of country-specific schemes exist in the international carbon market (Figure 13.6):

- EU emissions trading scheme (EU ETS) covering 28 EU countries and over 14,000 enterprises
- Swiss emissions trading scheme covering 450 companies
- Cap-and-trade system in Kazakhstan covering 166 companies with emissions of about 153 million tons of CO_2 equivalent
- South Korean cap-and-trade system covering 525 companies with emissions of about 500 million tons of CO_2 equivalent
- Regional Greenhouse Gas Initiative (RGGI) in the USA, covering 9 states and about 200 electric power plants
- California cap-and-trade system covering 500 electric power plants and enterprises
- Quebec cap-and-trade system covering 80 industrial facilities
- Australian carbon pricing mechanism covering 350 enterprises with emissions of about 285 million tons of CO_2 equivalent
- New Zealand emissions trading scheme
- Japan: Tokyo emissions trading scheme and Joint Crediting Mechanism (JCM)
- Chinese emissions trading scheme, with a pilot program functioning in seven of the country's provinces (Beijing, Guangdong, Hubei, Chongqing, Shanghai, Shenzhen, and Tianjin).

29 The "Doha Amendment" will not apply to Kazakhstan if not ratified by at least three quarters of the Kyoto Protocol member states or if Kazakhstan refuses to ratify it.



Source: State and Trends of Carbon Pricing. World Bank, Washington DC, May 2014.

Figure 13.6 Current and planned GHG emissions control mechanisms

In addition to the trading schemes listed above that involve certain GHG emissions reduction commitments (cap-and-trade schemes) necessary to create a demand for quotas, there are alternative approaches, such as carbon taxes (i.e., taxes per ton of GHG emissions). As the experience of a number of countries has shown, carbon taxes create an additional burden on the industrial sector, which may restrict economic growth to some extent, particularly in countries with energy-intensive industry. For example, the carbon tax ($23.5 per ton of CO_2 equivalent) introduced in Australia in 2012 was canceled in 2014 due to the significant burden on industry and replaced by a trading scheme.

13.5.1. Kazakhstan's GHG emissions reduction commitment

Kazakhstan is a full member of the UNFCCC, and ratified the Kyoto Protocol in 2009. In 2012, in the aftermath of the international climate summit at Doha (Qatar), Kazakhstan announced that it had joined the "Annex B" countries for the second (emissions) commitment period (2013–2020) of the Kyoto Protocol, formally committing the country to reduce GHG emissions by 5% relative to the level of 1990. In addition to this official obligation, Kazakhstan also has voluntarily set itself the goal of reducing GHG emissions by 15% relative to the 1992 level by 2020 and 25% of that level by 2050.

Parties to the Doha summit also adopted the "Doha Amendment," which would enter into force upon ratification by three quarters of the signatory parties.[30] It contains provisions (paragraph 3.7ter) for additional even more stringent GHG emissions reductions goals over the second commitment period, limiting the GHG emissions level for Kazakhstan at the average emissions level in the period of 2008–2010 (i.e., requiring it to reduce emissions by 10% per year). If the "Doha Amendment" enters into force, however, most likely it will not be ratified by Kazakhstan, and therefore the commitment to reduce greenhouse gas emissions will not apply to Kazakhstan.[31] As noted in a previous KazEnergy report, it would be "impossible [for the country] to reduce greenhouse gas emissions by 10% annually without [an] economic decline."[32] This raises the question of what rate of emissions reduction actually is feasible for the country given reasonable energy efficiency improvements and anticipated changes in its primary energy consumption. We turn to this question in the final section of the chapter.

30 This appears to be unlikely prior to the Paris 2015 climate summit, as by 7 August 2015 only 40 of the required 144 parties have ratified.

31 For example, the US signed the Kyoto Protocol but did not ratify it, so the commitments to reduce GHG emissions did not apply to the US.

32 KazEnergy, The National Energy Report 2013, p. 194.

13.5.2. New global climate change framework (INDCs)[33]

As noted above, the 2015 Paris summit will pose a chance to achieve a fundamental breakthrough.[34] A major obstacle had been the unwillingness of a bloc of both the largest developed countries (e.g., U.S., Russia, Canada, Australia, New Zealand[35]) as well as the largest developing countries (e.g., China, India, Brazil) to commit to the Kyoto emissions reduction targets. By the start of 2014, the UN process appeared to have stalled, as countries accounting for the bulk of present and future GHG emissions opted to remain outside of the regulatory framework.

However, on 12 November 2014 a signing of an agreement described as "a catalyst that could lead to a new global climate accord" and "a potentially historic deal" was announced: China and the United States, the two largest GHG emitters (accounting for 42% of the global total), agreed to jointly reduce their emissions by strengthening adherence to environmental policies already in place in the two countries.[36] In the United States, the most important policy is the 2 June 2014 executive order empowering the U.S. Environmental Protection Agency to impose new emissions restrictions on coal-fired power plants (leading to the eventual closure of many that rely on outmoded technologies), but also includes tighter vehicle emissions standards through 2025 as well as measures designed to reduce methane leakage during unconventional oil and gas extraction. Together these measures are the basis for a U.S. pledge to reduce (below the 2005 level) GHG emissions by 26-28% by 2025 (representing an annual average decline of 3%). For its part, and reflecting a mounting awareness of the outrage among its own citizens over air pollution in its large eastern cities, China has committed to continue policies of energy diversification (away from coal and toward gas, renewables, large hydro, and nuclear) that will lead to a peak in carbon emissions by 2030. Toward this goal, China's State Council has imposed a cap on coal consumption in the country (at 4.2 billion tons) by 2020.

A new agenda (and potentially a new framework/base document) is in prospect for the UN's Paris climate summit in December 2015. First, it appears that mandatory reductions targets will be replaced by less stringent, more achievable policy goals; individual countries will enact their own plans and set their own goals for emissions reduction, beginning in 2015. On 14 December 2014, officials from nearly 200 nations signed an agreement in Lima, Peru (the so-called Lima Accord) that commits their countries to submit detailed plans for emissions reduction in advance of the Paris summit.[37]

The new approach appears to reflect two basic realizations. First, the progress achieved thus far (under the old UNFCCC framework), while laudable, is no longer viewed as adequate (in the opinion of climate experts) for reaching the Kyoto goal of limiting the increase of global mean temperature to 2°C. Therefore, the objective of meeting that target now appears to have been replaced by one that seeks to avert what is viewed as truly catastrophic climate change that might occur in the absence of any widely followed accord; this weaker goal might be achieved by curbing GHG emissions at a rate only half that envisioned as necessary to stay within the 2°C threshold. The focus is therefore no longer on what is optimal, but on what is achievable.

Second, and most importantly, the new agenda reflects the realization that no framework to address climate change will be viable unless it covers the vast majority of GHG emissions generation, i.e., unless most or all of the "big polluters" agree to sign on. Thus it appears that the new agenda in Paris will sacrifice the mandatory, rigorous emissions reduction regime established in Kyoto in favor of a voluntary framework designed to mobilize those countries currently not active in the UNFCCC. Consequently, the emphasis is not on attaining a specific level of GHG emissions by 2025 and 2030, but rather on ensuring that the emissions trend line is heading in the right direction (flattening and then declining).

In addition to the shift in how countries' policy goals are formulated, the agenda in Paris is expected to include further discussion of financing arrangements for less affluent countries—both for funding emissions reductions and for mitigating environmental damage resulting from climate change (a precedent established at the Copenhagen summit in 2009). There will also be a focus on devising an international system to monitor and verify GHG emissions reduction.

Compliance with even a new, more voluntary framework that is envisaged post-Paris will come with its own headwinds. Countries, such as India and Brazil, which are struggling to bring millions of citizens out of poverty, likely will insist that "we won't sacrifice growth" (and may not be required to).[38] Others (e.g., China) may find an international monitoring and verification regime to be obtrusive. Finally, if the new climate agreement is accorded the status of a legally binding treaty (as Kyoto), it may be subjected to a tortuous ratification process in countries in which "divided government" shapes relations between the executive and legislative branches (e.g., the United States).

These challenges notwithstanding, the impending 2015 summit probably offers something approaching the best of what is possible under the circumstances. Moreover, it affords Kazakhstan an opportunity to "write its own ticket" with respect to managing its carbon footprint—to design its

[33] Intended Nationally Determined Contributions (INDCs).

[34] Fiona Harvey, "New Climate Deal Push Will Not Repeat Copenhagen Mistakes—UN Envoy," The Guardian, 22 September 2014; Coral Davenport, "With Compromises, a Global Accord to Fight Climate Change Is in Sight," The New York Times, 10 December, 2014, p. A8. See also Dan Vergano, "Paris Projected as Pivotal Climate Point," USA Today, 11 May, 2013.

[35] New Zealand has reached carbon neutrality (i.e., all carbon dioxide emissions are fully absorbed by the country's ecosystem).

[36] For background, see Henry Fountain and John Schwartz, "Climate Pact by U.S. and China Relies on Policies Now Largely in Place," New York Times, 13 November, 2014, p. A9.

[37] The programs were to be published no later than March 2015 in order to allow time to prepare for the Paris summit. However, in order to involve all countries in the process, program publication at a later date is allowed (Davenport, 2014, p. A5; see also Coral Davenport "A Climate Accord Based on Global Peer Pressure," New York Times, 15 December, 2014, p. A3).

[38] See Eduardo Porter, "In Latin America, Growth Trumps Climate," New York Times, 10 December, 2014, pp. B1, B8.

own emissions reduction strategy on the basis of its unique economic profile, energy balance, pattern of settlement, and geopolitical situation. The country has demonstrated a commitment to responsible climate stewardship through its participation in Kyoto, its enactment of domestic environmental legislation, the renewable energy initiatives outlined in the Strategy Kazakhstan 2050 and other policies, and the hosting by its capital city Astana of EXPO-2017 under the theme of "Future Energy." Kazakhstan's planned formal commitments under an INDC agreement for the period to 2030 (15% reduction in greenhouse gas emissions relative to the level of 1990), according to IHS forecasts, are excessive and difficult to achieve taking into account the structure of Kazakhstan's economy. We expect the new framework that will emerge after the Paris summit will allow Kazakhstan to reaffirm this commitment in a way that is commensurate with its historical development trajectory and status as a major energy-producing state. Actions that might form the core of such a commitment are described below.

13.6. Achieving GHG Emissions Reduction

Given that 90% of global anthropogenic emissions of the most abundant GHG (CO_2) is the result of fossil fuel combustion, the task of reducing such emissions consists either of burning smaller quantities of fossil fuels in the economy and municipal/commercial sector, altering the mix of these fossil fuels so that there is less combustion of the more carbon-rich fossil fuels, or switching to non-carbon energy sources entirely. One way of consuming less fossil fuel energy without sacrificing economic growth is to lower the energy intensity of the economy by increasing energy use efficiency. Measures for achieving this objective are outlined in detail in a 2014 KazEnergy review[39] and in Chapter 11 of this report. Indeed, considering the structure of Kazakhstan's energy industry and overall economy, the most expedient approach to reducing the country's carbon footprint is through energy savings and increased energy efficiency.

13.6.1. Focus on electric power generation

Beyond economy-wide energy efficiency measures, Kazakhstan's unique GHG emissions profile enables targeting a specific sector for attention. Unlike some countries in which contributions to GHG emissions are more or less evenly divided among major economic sectors,[40] in Kazakhstan the electric power sector, dominated by coal, accounts for over 80%. Given the slow pace at which existing power generation capacity is replaced over time (see above), it is probably best to differentiate between strategies that can be implemented relatively quickly from those that require a longer time frame (e.g., are only feasible upon the replacement of existing or the addition of new capacity). Under the rubric of short-term fixes, it would seem that attention to increasing the efficiency of coal-fired electric power generation could yield the most rapid returns.

With respect to increasing the efficiency of generation, the National Energy Report 2013 observed that Kazakhstan was consuming approximately 25–30% more fuel than the advanced economies to produce an equivalent unit of electricity. The main reasons include depreciation of equipment and low process efficiencies. It went on to note that while many steps proposed to improve efficiency in the electric power sector (e.g., the large-scale replacement of aged transmission lines and power transformers) require "extra and somewhat significant capital investments into network upgrade, plant replacement, and modernization," other measures could be undertaken to enhance the operational modes of energy equipment (e.g., optimizing the on-off cycling of boiler units) at relatively low cost and could bring about as much as a 10% reduction in fuel consumption.[41] Moreover, it appears that some additional funding could become available as part of the comprehensive Nurly Zhol (Bright Path) economic policy outlined by President Nazarbayev as part of his state of the nation address in November 2014. As part of the plan, over $1 billion annually over the period 2015–2020 would be invested in public utilities and water supply infrastructure, and would include funds from the World Bank, Asian Development Bank, Islamic Development Bank, and private investors.

An example of the type of power-sector investments that might be appropriate under such a program would be the installation of boilers utilizing the waste heat of stack gases at gas-turbine power stations. At present such boilers have been installed only at the Uralsk TETs.[42] Meanwhile, they are rather widespread worldwide.

13.6.2. Reducing consumption in the municipal/residential sector

Other measures might focus on reducing electricity consumption, and hence reducing combustion of coal intended to generate it, among end-users in the residential/commercial sector, where electricity losses are estimated to be the highest (see Chapter 11). A building-by-building approach that prioritizes such measures at new and relatively recently constructed structures (which will remain part of the housing stock longer into the future) might prove a less daunting

[39] KazEnergy, Obzor gosudarstvennoy politiki Respubliki Kazakhstan v oblasti energosberezheniya i povysheniya energoeffektivnosti [Review of State Policy of the Republic of Kazakhstan in the Area of Energy Savings and Increasing Energy Efficiency]. Brussels: KazEnergy, 2014.

[40] For example, in the United States the contributions are: electricity 32%, transportation 28%, industry 20%, commercial/residential 10%, and agriculture 10%.

[41] KazEnergy, The National Energy Report 2013, pp. 181, 183.

[42] As a part of a exhibition project of carbon investments (investor - NEDO, Japan)

task financially over the near term than a full overhaul of the power sector, and could be funded in part by incentives such as the so-called “energy service agreements” between local power distributors and residents.[43] To provide an example of the potential for energy efficiency in the residential sector, the United Nations Development Programme (UNDP) is administering a demonstration project in Karaganda involving the construction and use of a highly energy efficient house. The UNDP’s goal is to ensure the availability of 69 million square meters of affordable housing that incorporates such energy efficiency measures by 2020, providing an estimated savings of 290 million megawatt-hours annually.

13.6.3. Kazakhstan’s future GHG emissions

Kazakhstan’s high energy intensity and current energy mix (the highest dependence on coal of any of the former Soviet republics) afford both a challenge to GHG reduction and an opportunity (ample room for future improvement). Our estimates of energy-related GHG emissions[44] by fuel source for selected years for the period 1990–2040 are shown in Table 13.6. According to Kazakhstan's Committee on Statistics, greenhouse gas emissions in the energy sector have accounted for about 80-85% of total GHG emissions in the country in recent years (see Figure 13.7). The overall emissions trend line (all sources) between 1990 and the present tracks rather closely that of Kazakhstan’s economic output during that period, registering a steady decline during the recessionary 1990s, before climbing sharply as the economic recovery gathered steam after 2000 (see Figure 13.8). It is noteworthy that coal continued to account for over 70% of total GHG emissions in the economy’s energy use (all sectors) in 2014 (179 MMt out of a total of 252 MMt).

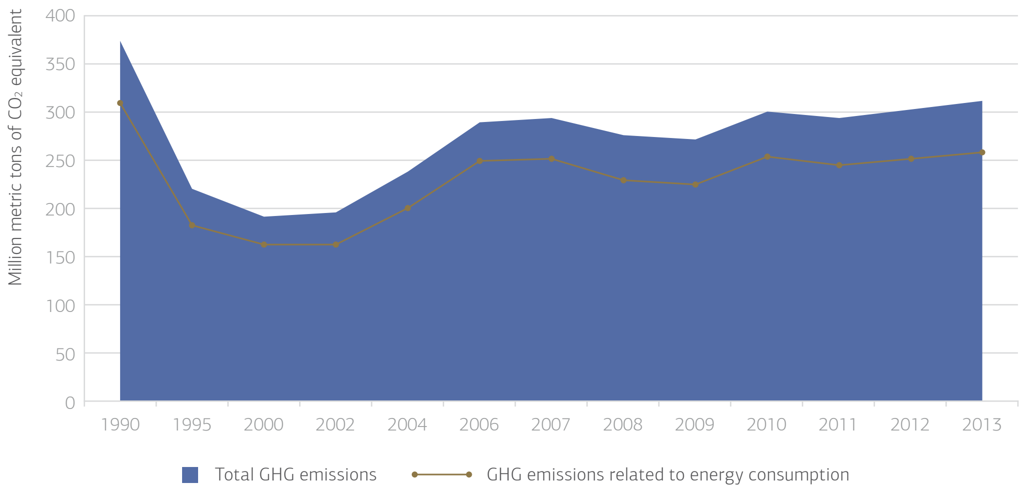
	Emission coefficient, metric tons per thous. TOE consumed	Year											Average annual pct. change, 2015-2040
		1990	1995	2000	2005	2010	2015	2020	2025	2030	2035	2040	
Total		278.9	208.5	146.4	198.3	235.0	252.9	259.2	269.8	265.5	265.4	270.1	0.3
Coal	3.81	188.7	149.5	104.3	136.7	161.0	178.2	175.3	174.7	163.3	151.5	147.3	-0.7
Oil/petroleum products	2.93	59.6	33.3	20.5	33.2	48.2	40.9	44.0	47.3	49.8	52.9	56.2	1.2
Natural gas	2.12	25.1	21.7	18.3	25.6	23.7	31.9	38.3	46.5	51.2	59.9	65.6	3.3
Primary electricity	--	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	
Other (peat, wood, etc.)	6.00	5.5	4.0	3.2	2.8	2.1	1.8	1.6	1.4	1.2	1.1	1.0	-2.4
GHG emissions/million $ GDP (2005 dollars)		2.4	2.9	1.8	1.5	1.3	1.1	0.9	0.8	0.6	0.6	0.5	-2.9

Note: Estimate only for energy-related economic activity (fuel combustion); calculated by IHS Energy.

Table 13.6 Estimated greenhouse gas (GHG) emissions for Kazakhstan for energy-related economic activity, 1990–2040 (million metric tons)

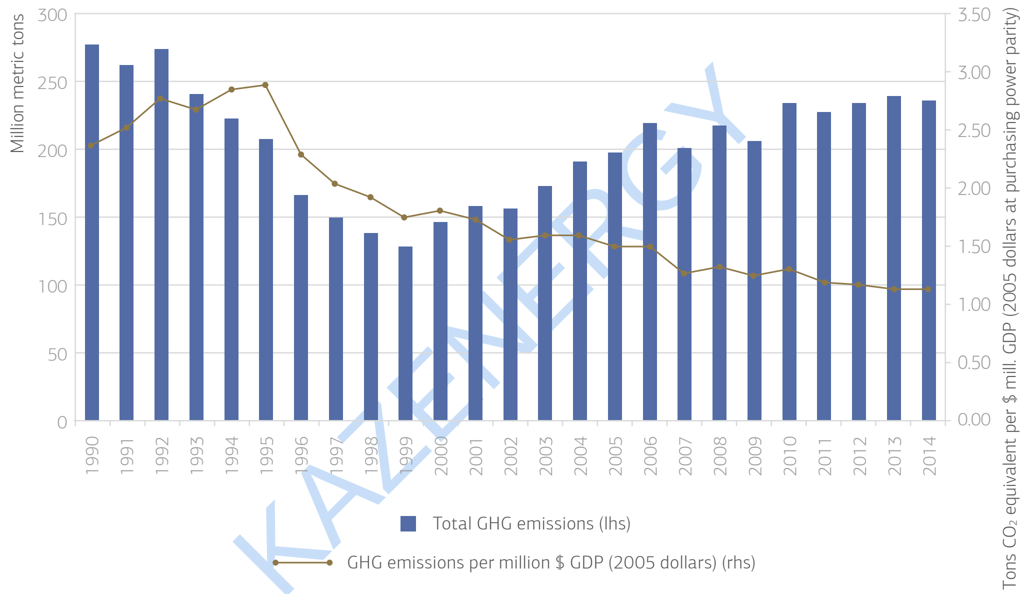
[43] KazEnergy, The National Energy Report 2013, p. 184.

[44] Emissions are calculated for energy consumption only, thus allowing for consistent historical comparison. Total GHG emissions for the country are somewhat larger, as they include emissions from all economic sectors. Greenhouse gas emissions in the energy sector have accounted for about 80-85% of total GHG emissions in the country in recent years.



Source: IHS Energy calculations

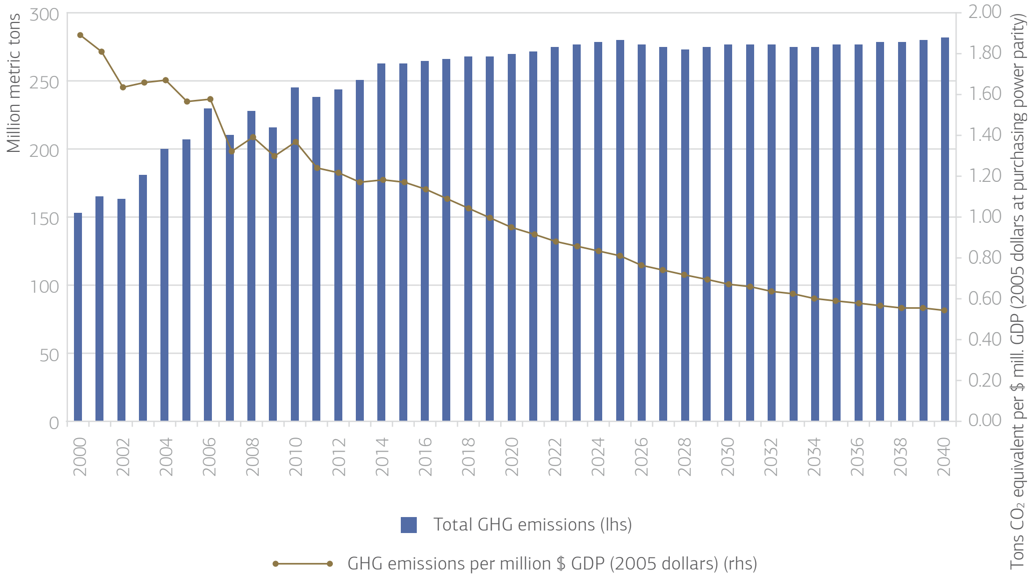
Figure 13.7 Total GHG emissions in Kazakhstan and GHG emissions related to energy consumption



Source: IHS Energy calculations

Figure 13.8 Emission of GHG gases in Kazakhstan related to energy consumption, 1990-2014

However, the link between emissions and economic growth is weakening, and this trend will continue in the future. Although Kazakhstan's GDP is projected to increase at moderate to healthy rates over the remainder of the forecast period (with an average annual GDP growth rate of 3.3% between 2015 and 2040), GHG emissions associated with energy consumption increase more gradually over this period, averaging only 0.3% per year, reaching about 270.1 MMt by 2040 (see Table 13.6; Figure 13.9). If the share of GHG emissions from energy consumption remains in the same general range as at present, then total GHG emissions for Kazakhstan would increase to about 324 MMt by 2020, to about 332 MMt in 2030 and to about 338 MMt by 2040.



Source: IHS Energy calculations

Figure 13.9 Emission of GHG gases in Kazakhstan related to energy consumption, 2000-2040

An important reason is that the energy sources used to satisfy incremental energy demand in the future will become cleaner. Natural gas—whose GHG emissions coefficient (metric tons of GHG emitted per thousand tons of oil equivalent consumed) is only 55% that of coal, 72% of oil, and 35% that of such "other sources" as peat and wood—will accommodate a significant amount of new energy demand in the economy going forward, while supplanting the "other sources." As can be seen in Table 13.6, the growth in natural gas's contribution to overall GHG emissions increases far more rapidly (3.3% annual average percentage growth between 2015 and 2040) than any of the other sources. Although at first glance, this "achievement" may seem dubious, it is accompanied by a dramatic reduction in GHG emissions (by about half) per unit of the country's economic output (lowermost row in Table 13.6; see also Figure 13.9). Such a reduction presents Kazakhstan with the opportunity to substantially reduce the carbon intensity of its economy while affording additional time to integrate new renewable and nuclear generation capacity into the electrical grid to support an even greener energy profile by mid-century and beyond.

Key Recommendations

- In order to substantially reduce adverse impacts of energy development on the environment, Kazakhstan should develop a comprehensive program aimed at reducing harmful emissions and improving waste management in the energy sector, with a gradual transition to new emission standards.

- In particular, significant changes can be achieved by introducing new standards and requirements for coal-fired power generation and in oil production (e.g., for the handling of sludge and radioactive production water and equipment). Although the levels of harmful emissions from most power plants in Kazakhstan comply with the standards established in the country, these levels remain quite high compared to global best practices. Therefore, a gradual transition to new environmental standards is necessary.

- Although it is not possible to immediately transition to stringent European standards for all types of power plant emissions, it is reasonable to establish some "interim" standards (less stringent than European ones) for emissions that currently are most difficult to reduce. It is important to design new power plants based on these interim standards.

- It is also necessary to introduce certain "clean coal" technologies (e.g., fluidized bed combustion, supercritical and ultra-supercritical steam cycles) at new and expanded coal-fired plants as well as install modern filters to capture sulfur oxide, nitrogen, and particulate emissions from coal-fired power plants. However, the top priority is to solve the problem of coal-fired power plants' ash capture and handling (disposal). It is recommended to introduce uniform requirements for ash capture systems at coal-fired power plants.

- The introduction of carbon capture and geological storage technologies cannot be recommended for coal-fired power plants in Kazakhstan at the current stage of technological development, primarily due to cost factors.

- Kazakhstan should also establish a system for monitoring radiation levels in uranium mining waste dumps (where radiation intensity can exceed by more than 50 times the maximum permissible level) and tailing ponds, to continue research aimed at assessing the level of impact of these facilities on the environment and public health, and to ensure security of the facilities in order to prevent unauthorized collection of depleted ore. It is also necessary to strengthen state control over decontamination of oil production equipment in order to decontaminate (clean) all the equipment contaminated with radiation.

- Over the near term, Kazakhstan's policymakers should focus on measures that could be used effectively to curtail GHG emissions based on the existing fuel balance. These measures include technological strategies stimulated, among other measures, by the recently established domestic carbon trading market.

- A fundamentally new framework for addressing global climate change is to be finalized in Paris in late 2015. Instead of mandatory global reduction targets, individual countries will enact their own plans and set their own goals for emissions reduction. Kazakhstan should reaffirm its commitment to emissions reduction within this new framework in a manner commensurate with its unique economic profile, energy balance, pattern of settlement, and geopolitical situation. The commitment to reduce greenhouse gas emissions currently under consideration (85% of the 1990 level by 2030) appears somewhat ambitious.

- The recently formed (2014) Ministry of Energy now has primary responsibility for environmental protection. However, because of the significant environmental problems in the country, it is recommended that a new Environmental Agency be formed, with the transfer of some of the functions now vested in the Ministry of Energy.

KAZENERGY

Appendix

IHS Energy key underlying elements in Kazakhstan's long-term energy outlook

- General global, political, and economic conditions align with IHS Energy's base-case scenario, known as Rivalry.
  - — No dramatic, market-altering disruptive forces are assumed on either the demand or supply side of the market; long-term gains in efficiency on the demand side—such as rising vehicle fuel economy and improved heat rates in electricity generation—are built into the base outlook. Rivalry also assumes sufficient investment in upstream exploration and production to meet our projections of growing global oil demand.
  - — On the geopolitical front, the scenario assumes no major wars or conflicts among major oil-producing countries.
- Average annual GDP growth for Kazakhstan for 2015–2040 is 3.3%; this is derived from the general global conditions, especially the oil price.
  - — IHS foresees relatively robust economic growth for Kazakhstan over the outlook period, although the annual growth rate declines over time after an acceleration in growth in the medium term, from a low point of 1.5% in 2015 to ~5% annually in 2018–2020. But annual growth rates naturally slow longer term as the economy becomes larger, slowing to ~3.5% in the late 2020s and to ~2.5% in the 2030s.
- The economy remains relatively industrial, with a projected average annual growth rate in industry's gross value of output of 2.4% for 2015–2040.
  - — Industrial growth is slower than GDP, illustrating a general long-term shift toward a more service-oriented economy, although Kazakhstan maintains its general industrial character owing to its mineral resource base.
- Kazakhstan's population slowly expands from 17.4 million in 2014 to 20.7 million by 2040 (exhibiting an average annual growth rate of 0.7%).
- Primary energy consumption is expected to grow more slowly than GDP, at an average annual 1.5% in 2015–2040, increasing from 76.3 million tons of oil equivalent (MMtoe) in 2014 to about 92.8 MMtoe in 2040.
- The average annual improvement in aggregate energy intensity (energy/GDP ratio) is therefore expected to be moderate, at 1.7%, over the entire outlook period to 2040.
  - — This reflects the huge opportunities for energy savings in the Kazakh economy (currently one of the most energy intensive in the world) from a combination of structural changes, new production technologies, and improved construction standards.
  - — But the economy is still expected to remain relatively energy intensive by global standards, even in 2040.
- Average annual growth in final electricity consumption in 2015–2040 is expected to be 1.2%, with growth in electricity generation averaging 1.0%.
  - — The slower rate of growth in generation versus consumption reflects reduced losses in distribution and generation as a result of improved efficiencies.

IHS Energy forecast methodology for primary energy balances

— To obtain a picture of the energy required by an economy to produce its aggregate economic output by simply adding together all sources of energy produced and consumed would entail considerable double counting of actual energy requirements. This arises through the transformation of one form of energy to another before it is consumed (e.g., from primary fuels such as coal, gas, or oil into electricity or heat, or from crude oil into refined products).

— Because of these considerations, the linkage of energy requirements to the level of aggregate economic activity is initially analyzed via the compilation of primary energy balances. Only production and consumption of primary sources of energy (e.g., those which do not result from the transformation of any other energy- carrier) are included in this balance. IHS considers five forms of primary energy in our country balances: coal (including hard coal, brown coal, and lignite); oil (including gas condensate); natural gas (including "free" and "associated" gas);[1] primary electricity (hydroelectric, wind, solar, and nuclear generation); and other (primarily wood, shale, and peat).

— These various forms of energy are aggregated in the primary balance in their energy equivalent terms. The physical volumes of fuels are converted to energy equivalent units by means of coefficients of energy content per physical unit (kilocalories per kilogram, per thousand cubic meters, or per million kilowatt-hours) specific to the fuel or energy source. We construct the balances in terms of million tons of oil equivalent (MMtoe), although alternative units such as tons of standard fuel (coal-equivalent) or barrels per day of oil equivalent (tbdoe) could have served as well.

— Our standard for oil equivalence is 10,010 kilocalories per kilogram. Thus, to convert 1 million metric tons of brown coal with an energy content of 2,400 kilocalories per kilogram (kcal/kg) to MMtoe, one would multiply the physical amount by the ratio 2,400/10,010. This particular amount of brown coal would therefore represent 0.24 MMtoe.

— It is not necessary, however, to distinguish between primary and transformed energy-carriers in considering energy trade flows in a primary energy balance. Since

[1] But by convention, this includes only gas extracted that is recovered or consumed. It excludes reinjected volumes and flared volumes of gas. These are not considered part of consumption.

imports reflect additional sources of energy available to an economy (they are based on primary energy produced in another economy), it does not involve double counting. Similarly, exports of energy reflect a decrement to the energy available to an economy. Thus, all forms of traded energy must be considered in the primary energy balance. That is, both exports/imports of refined oil products and crude oil must be included as well as imports/exports of coal and of coke as sources of energy in the primary balance.

— The concept of net exports of energy, that is, exports less imports, is particularly important when it is necessary to aggregate balances across countries. Including trade flows of various countries that trade with each other would obviously involve double counting. Net trade flows, however, may be aggregated across economies because the imports of one economy in their mutual trade are netted against the exports of the supplying country.

— The production of primary energy less net exports of energy by the economy is defined as the apparent consumption of primary energy in that economy (the consumption concept employed here). Apparent consumption differs from actual consumption of primary energy in that it includes any losses incurred in processing, transportation, storage, and use as well as any changes in stocks of energy-carriers. While data on actual consumption of energy may be difficult to obtain for a given economy (especially for more recent years, as these are typically published with a lag of several years), production data and trade data are typically among the most available and the most reliable energy statistics, and form the basis for the calculation of apparent consumption.

— IHS Energy's projections of the CIS countries' primary energy balances begin with a consideration of future developments in the aggregate output of the economies in question (GDP growth, growth in industrial and agricultural output, construction activity, personal income and spending power, etc.).

— The historical relationship between aggregate economic activity and apparent energy consumption is already established, and based on forecasts of macroeconomic developments and the anticipated changes in the relationship between the level of economic activity and the quantity of primary energy required to support it, the future path of primary energy consumption is then projected.

— The economies of the CIS have historically been far more energy intensive than those of other advanced countries, especially in Western Europe, due to the particular path of development followed under Soviet central planning. As a result, these economies are dominated by heavy industrial activity (the most energy intensive branch), and sectors' chronicle underfunding. Production, trade, and investment decisions in that system were based on special domestic prices, especially for energy.

— IHS has, therefore, incorporated substantial improvement in energy efficiency in our modeling of future energy requirements over the projection period. Thus, the historical elasticity of demand for energy with respect to GDP (that is, the percentage change in energy consumption associated with a one percentage point change in GDP) is assumed to decline toward values more typical of developed Western economies over the forecast period. The pattern of improvement is projected to be similar to the general path that took place in Western economies following the oil price shocks of the 1970s.

— This development is assumed to be the result of both the lagged adjustment to the sharp increases in the relative price of energy (the economies have been forced to bring their domestic price regimes more into line with relative prices on the world market) and from the shift in the composition of aggregate output taking place in the transition from a planned economy to a market-oriented economy. Higher relative prices of energy ultimately impact on consumer and technological choices to reduce energy consumption. The improvement in energy efficiency is projected to continue over the forecast period, but because the more readily attained gains come earlier in the period, the rate of improvement in energy efficiency is presumed to slow somewhat in the latter part of the projection, although this varies across individual countries.

— The shares among individual energy-carriers (coal, oil, gas, and primary electricity) of the projected total for primary energy consumption are determined through a consideration of the pattern of consumption of each fuel type across the major economic sectors (e.g., industry, power generation, municipal-housing [residential-commercial or the domestic sector in Western parlance], transportation, and agriculture) and the pace of expansion of the sectors themselves. Also, changes in the shares of individual energy-carriers over time in satisfying total energy requirements are constrained to relatively moderately paced shifts, given the time lags involved in the investment process required to achieve them. It is clear that this shift cannot be too drastic (barring extraordinary circumstances such as trade embargoes or armed conflict).

— The direction of changes in the shares of individual fuels over time reflects the advantages or disadvantages of the different fuels in the context of the overall economic environment. For example, a key shift throughout the region involves the gradual displacement of coal and residual fuel oil (mazut) by relatively cheaper and environmentally friendlier natural gas. To some extent, this is offset for oil by the growing motorization of the economies—rising demand for motor fuels because of expanded ownership of private automobiles and the increased role of trucking in freight transportation (these economies were traditionally overly dependent on rail transport, a legacy of the centrally planned system).

— The modeling of the share of refined petroleum products actually incorporates separate, sectorally disaggregated models of developments in petroleum product markets in each of these economies. Demand is modeled for the four major refined products: gasoline, diesel fuel, mazut (residual fuel oil), and kerosene. Demand for a specific product is linked to developments in activity indicators for the main consuming sectors (e.g., ton-kilometers or passenger-kilometers carried, vehicle fleet, sown land). Like the projected level of aggregate economic output in the energy balances, the trends in the activity variables are drawn from our macroeconomic forecasts. The projections for vehicle fleets, for example, which help to determine future demand for motor fuels, are provided by forecasts of personal income growth that drive new sales as well as retirement of older vehicles from the fleet.

— These four major refined products account for an overwhelming share of overall refined product consumption and the projected changes in their total consumption are therefore used to forecast the trends in aggregate consumption of refined products in the primary energy balances.

— To provide a sectoral breakdown of future demand for natural gas and coal, IHS Energy also employs an approach based on activity analysis. Aggregate gas and coal consumption are first projected for each country from the primary energy balance. This aggregate is then split among the major economic sectors going forward—electric power, industry, agriculture, transportation (separated into cars, trucks, airplanes, ships, and pipelines because each mostly consumes a different fuel), construction, and household and municipal use (domestic sector)—based on changes in their relative activity levels. These sectoral categories reflect the traditional accounting breakdowns employed by the statistical offices of these countries.[2] Consumption of natural gas and coal by electric power is forecast according to the methodology described below for the electric power sector.

— The activity variables used to project sectoral natural gas and coal consumption trends are derived from macroeconomic forecasts of economic expansion by sector. For example, these include forecasts of gross agricultural output, gross industrial output, and construction activity. Growth rates in these indicators are used to forecast growth in demand for electricity, refined products, natural gas, and coal in these sectors. An exception is the domestic sector (residential-commercial): its consumption is calculated as a residual.

— Efficiency coefficients are incorporated into the forecast models that determine the amount of energy (gas, coal, etc.) needed per unit of economic activity. These assume variable rates of improvements in the efficiency with which energy is used by a sector over time. These efficiency coefficients are primarily used in forecasting industrial demand, although they also apply to agriculture, transportation activities, and construction. These generally assume a fixed rate of improvement of a certain percent per annum for specific periods of time. The rate of improvement declines toward the end of the forecast period as the region's (or country's) industry and economic activity are assumed to come closer to international (or European) levels of efficiency.

— Natural gas and coal are not only consumed by these end-use sectors; they also are used by the gas or coal industries themselves. In the case of gas, this is mainly to power compressor stations on the pipeline network, and some is lost in the processes of field preparation as well as transportation and distribution. In the case of coal, this is mainly losses involved in processing. These amounts are projected from historical ratios of internal use to either total production or aggregate consumption, depending upon whether the country is mostly a producer or a (gas) consumer. It is further assumed that these ratios will decline over time as the companies reduce losses and improve efficiency.

— Production forecasts for the individual energy-carriers in the primary balances are based on expert judgment on the country-specific prospects for the respective fuels/energy-carriers. Prospects, in turn, depend on the size of economically exploitable reserves and the ability of the individual fuel to compete with domestic and imported alternatives in the region, including consideration of costs of transport and environmental protection. Many other factors may come into play as well. For example, with the exception of Kazakhstan, domestic coal in most of the economies in the region is not competitive with imported coal, much less alternative fuels (like natural gas) despite the sizable differential in transport costs (the exception in Kazakhstan is Shubarkol coal).

— In projecting developments in primary energy balances, apparent energy consumption and primary energy output are first forecast. The difference between these concepts is the projection of net energy exports from these economies.

IHS Energy forecast methodology for electric power

- To forecast future developments in the electric power sectors of the countries of the region, IHS Energy first focuses upon projecting an electricity balance (production, consumption, net exports) for each country. The starting point for the forecast for the electric power sector is a projection of electricity demand for each country. This is because underlying demand is assumed to be the driving force of any future changes in the industry concomitant with the underlying changes in these economies.

- Five general forces are driving changes in electricity demand. These include: (1) economic recession and recovery; (2) changes in relative prices; (3) changes in real incomes; (4) changes in incentives for enterprise managers and other economic actors; and (5) changes in technologies.

- To forecast future demand for electricity, IHS Energy employs a sectoral approach based on activity analysis. Electricity consumption is projected for the five major economic sectors in each country—industry, construction, agriculture, transportation (primarily electrified rail and mass transit for electricity use), and household, commercial, and municipal use (domestic sector). These categories reflect the traditional accounting breakdowns employed by the statistical offices of these countries in presenting national electricity balances. Unfortunately, demand by the commercial sector and small business is often aggregated with household or municipal use under these statistical categories. IHS Energy takes explicit account of this anomaly in the forecast methodology.

- To generate the activity variables, existing macroeconomic forecasts are used. These provide projections of growth by sector or specific activity indicators. For example, the macroeconomic outlooks provide forecasts of growth in gross agricultural output or construction activity. These

[2] But there are some differences. For example, all fuel use by vehicles is included within the transportation sector, consistent with international statistical convention, even though consumption by privately owned cars is often classified as household consumption. Similarly, fuel use in trucks employed in agricultural activities is also included in the transportation sector.

growth rates are used to forecast agricultural and construction demand for electricity. Similarly, the forecast of transportation activity (either passenger-kilometers for urban rail, ton-kilometers of freight for electrified rail, or ton-kilometers of oil and gas shipments for pipelines) is used to forecast the demand for electricity by this sector. Household and municipal demand for electricity is assumed to have a relatively high elasticity with respect to personal incomes and consumption. As this demand segment frequently includes some service sector demand, the fairly high income elasticity employed helps capture increased demand from small businesses and commercial activity.

- No attempt has been made to explicitly model price elasticities for electricity as part of the forecast methodology. It is almost impossible to estimate price elasticities from historical data for these countries. In addition, revenue collection efforts on behalf of electric utilities have been highly variable, affecting the actual effective price paid.

- Instead of modeling price elasticities, efficiency coefficients are incorporated into the models. These assume variable rates of improvements in the efficiency with which electricity is used by a sector over time. These efficiency coefficients are primarily used in forecasting industrial demand for power, although they also apply to agriculture and transportation as well. These generally assume a fixed rate of improvement of a percentage point or two per annum for specific periods of time. The rate of improvement is assumed to decline toward the end of the forecast period as the region's industry and economic activity come closer to international (European) levels of efficiency.

- Electricity is not only consumed by end-users; it is also used by power stations themselves and lost in the process of generating and transmitting electric power. To forecast these losses, historical ratios of transmission losses to domestic deliveries and of losses and self-use by power stations to total production have been estimated. It is assumed that these ratios will decline over time as the utilities reduce losses and improve efficiency. Nevertheless, even after these technical improvements, it will be a challenge for the loss ratios to converge upon current European levels even by the latter years of the forecast period due to longer distances.

- The structure of electricity consumption in the CIS countries is anticipated to increasingly resemble that of the more developed countries, which is characterized by a higher percentage of energy use by the services sector of the economy and households. Thus, the share of industrial use is expected to decline, while consumption by the domestic sector (households and the commercial and municipal sector) is projected to rise. Increased household consumption is projected to result in a rise in the ratio of peak to average load as well. This situation will necessitate increased investments in peak generating capacity or greater use of imported power for some countries.

- The extent of such a shift in electricity consumption patterns will be dependent on many factors. Energy prices for households must be high enough to cover the cost of production and delivery, while at the same time such increases cannot be excessive in comparison with rises in household real incomes. Furthermore, increased household consumption of electricity will very much depend on such factors as rates of housing construction and the pace at which electric appliances are introduced in households.

- To forecast the need for generating capacity, peak as well as average demand has to be forecast. To do so, the ratio of peak to average consumption for each major component of electricity consumption was estimated (industry, agriculture, transportation, and household and municipal demand). These ratios function as "multipliers" between average load and the amount of generating capacity needed to meet the time distribution of consumption (in kilowatt-hours) for the sector. We then employ these ratios with forecasts of electricity consumption by sector to estimate peak demand by sector. These figures are then summed to project aggregate peak demand for the country as a whole. Consequently, the forecasts of peak usage shift with structural changes in consumption.

- In projecting production, aggregate electricity generation is forecast as the sum of internal demand plus net exports. Electricity production is assumed to be largely determined by internal demand, although because of endowments of fuels or capital stock, export demand is of some importance for a few countries. The level of net exports is set exogenously, based largely on historical patterns (or these are set to show a particularly long-term trend, such as rising or declining net exports over time). For some countries, consideration is given to future plans for export projects, where these are important in the overall electricity balance, as well as import opportunities by current and potential neighboring countries.

- In turn, thermal generation is projected as total electricity production minus that by hydroelectric and nuclear stations. Hydro and nuclear production is projected into the future assuming that available capacities are run at expected utilization levels (either typical of the recent past or planned for the future).

- Installed generating capacity in future years is calculated as the sum of current capacity in the previous year minus retirements plus new capacity. For most countries, retirements are calculated by assuming existing generating plants are decommissioned after 50 years in operation, although for certain countries and categories of facilities, this is extended to 60 years. Although many plants are fully depreciated after 30 years, technological changes have frequently meant that plant life has been extended to 40 years or more. Many existing plants remain in operation even though they are older than 40 or 50 years, so we assume a somewhat attenuated retirement schedule; otherwise, there would be an excessively large contingent of retirements immediately. Many of these facilities are likely to be extensively refurbished with new equipment, a category that is considered to be "new" (replacement) capacity additions. For existing nuclear facilities, usually an official decommissioning program exists; this serves as a base for establishing our own retirement schedule, mainly dependent upon the age and condition of the facility in question.

- New capacity requirements are determined by a two-part decision rule. First, whenever average capacity utilization moves above 50% (a figure typical for Europe or the United States) or if peak load becomes more than 87% of total capacity plus (net) imports, an appropriate amount of new capacity is added. In most cases, net imports are assumed to be close to zero or the country may be a net exporter of power. However, for some countries, primarily the smaller ones, imports may provide an appreciable share of consumption. For these countries, if imports exceed a specified share of apparent consumption, generating capacity is added. These shares are fixed for the forecast period, but differ from country to country.

- In general, the limit on the percentage of apparent consumption that is provided by imports is dictated by policies concerning energy independence and security. We have taken past willingness to rely on imports as an upper bound on future willingness to rely on imports to satisfy domestic demand.

- IHS Energy projects not only total capacity additions, but also capacity additions by general fuel type. These additions are triggered by the type of capacity that has recently been retired (baseload versus peaking capacity) and the energy endowments of the individual countries. For example, all peaking capacity additions are assumed to be gas-fired. Baseload is assumed to be either gas-fired, coal-fired, or nuclear, depending on the country in question.

- Nuclear additions are based upon existing plans for construction. We also see that some countries have existing plans for new hydro capacity. Re-powering existing hydro plants (as has already occurred) will continue.

- We forecast the proportion of coal-fired units in new capacity based upon resource endowments and the overall supply of coal. The remaining base-load capacity is assumed to be gasfired units. According to our assessments, most countries of the region will find natural gas the most economic fuel because of its low cost and the region's ready access to supplies.

- Future trends in fuel use are dictated by generating capacity and utilization of particular types of generating capacity. Baseload units are assumed to operate at high capacity levels, as determined by past operating performance. For example, nuclear power stations are assumed to operate at previous output levels, as are baseload coal-fired units.

- Use of residual fuel oil has become very limited across the region in the electric power sector. It is used in areas where gas is not available, or as a start-up fuel for generating units after maintenance. Forecasts of residual fuel use in the power sector envision some further decline, although much of the displacement of fuel oil (mainly by gas) has already taken place.

- Two approaches are used to forecast gas-fired unit utilization. For countries that currently use gas only for peaking capacity, the number of kilowatt-hours consumed in peak periods is computed by assuming the system runs at peak capacity for six hours a day (two in the morning and four in the evening). The electricity produced by hydropower and residual fuel oil is subtracted from this total and we assume that the remainder is produced by gas. Residual production of electric power in this total is then assumed to be produced by shoulder and base-load units, usually coal-fired.

- For countries that use gas-fired units for shoulder or base-load capacity (as it is in Kazakhstan), production by coal-fired is estimated first, and then the residual (of aggregate thermal generation) is assumed to be produced by gas. In these cases, the average capacity utilization of coal-fired units in the past is accepted as a norm.

- Once electric power production by fuel type is computed for the historical period, the average use of fuel per kilowatt-hour (expressed in grams of oil-equivalent) is used as a coefficient to project future fuel consumption. This coefficient is assumed to improve slowly over time because of improved efficiency and newer equipment.

- Many power plants in the region produce both heat and electric power. IHS Energy has not attempted to separate fuel used for electricity generation from heat production in our national forecasts. Rather, the focus is upon projecting fuel consumption by the electric power sector as a whole (e.g., for heat and power); but the ratio of heat production to thermal electricity generation is assumed to decline over time, based upon recent historical trends that varies from country to country.