

How to scrutinise a Production Sharing Agreement

A guide for the oil and gas sector based on
experience from the Caspian Region



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in Russian by the Soros Foundation–
Kazakhstan in 2009***

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Table of contents

Preface to the original report	8
Preface to the English version of the report	9
Introduction	11
1. Putting the PSA into context	13
1.1 The origins of oil development in Kazakhstan	13
1.2 Oil reserves and oil production in Kazakhstan	14
1.3 Risk and reward in the oil and gas industry	16
1.4 Oil agreements: Different types of contracts, different levels of responsibility	20
1.5 The Production Sharing Agreement	21
1.5.1 Concessions and licences	23
1.5.2 Joint ventures	23
1.5.3 Service contracts	24
2. Anatomy of a PSA	25
2.1 A bit of financial theory	26
2.1.1 Net present value	27
2.1.2 Internal rate of return	28
2.1.3 The R-factor	29
2.1.4 Payback period	30
3. A production sharing example	31
4. Taxation of oil agreements	33
4.1 A summary of the oil and gas legal regime in Kazakhstan	34
4.2 The taxation of oil in Kazakhstan	35
4.2.1 Corporate income tax	39
4.2.2 Special taxes and payments	39
4.3 Indirect taxation	47
4.3.1 Value-added tax	47
4.3.2 Excise duties	47
4.4 Tax burden ratio	48
5. What civil society can do	49
5.1 Promoting transparency in contracting: Revenue issues	50
5.2 Promoting transparency in contracting: Beyond revenues	50
5.3 Monitoring social investment	51
5.4 A final remark	51
A sampling of PSAs signed in Kazakhstan and Azerbaijan	53
Appendix 2: Useful internet resources	56
References	57

List of Tables

Table 1.	Production of hydrocarbons in Kazakhstan.....	16
Table 2.	Average upstream production costs	17
Table 3.	Net present value	27
Table 4.	An example of net present value	28
Table 5.	Rate of return and corresponding shares of production	31
Table 6.	PSA profit-sharing formula for a hypothetical project	31
Table 7.	ACG project revenue projections based on oil price (in USD billions)	32
Table 8.	Differences between the EPT and PSA taxation models	36
Table 9.	Tax definitions	38
Table 10.	Differences between royalties and mineral extraction taxes (MET)	42
Table 11.	MET rates	43
Table 12.	EPT rates	45
Table 13.	Rent tax rates	46
Table 14.	PSAs for exploration and production signed with Kazakhstan	53
Table 15.	PSAs for production signed with Azerbaijan	54
Table 16.	PSAs for exploration signed with Azerbaijan	55

List of Figures

Figure 1.	Percentage of proven oil reserves	14
Figure 2.	Percentage of daily oil production	15
Figure 3.	Oil distribution under PSAs	26

List of Abbreviations

AA	Atasu-Alasankou
ACG	Azeri-Chirag-Gunashli
BP	British Petroleum
BTC	Baku-Tbilisi-Ceyhan
CIT	Corporate Income Tax
CNPC	China National Petroleum Corporation
CPC	Caspian Pipeline Consortium
EITI	Extractive Industries Transparency Initiative
EPT	Excess Profit Tax
FDI	Foreign direct investment
IFI	International Financial Institution
FSU	Former Soviet Union
IRR	Internal Rate of Return
IOC	International Oil Company
KA	Kenkiyak-Alashankou
KCST	Kazakhstan Caspian Transportation System
KKA	Kalamkas-Karazhanbas-Aktau
KPO	Karachaganak Petroleum Operating BV
MET	Mineral Extraction Tax
NCOC	North Caspian Operating Company
NIEO	New International Economic Order
NGO	non-governmental organisation
NOC	National Oil Company
NPV	Net Present Value
OKIOC	Offshore Kazakhstan International Operating Company
PSA	Production Sharing Agreement
SOE	State Owned Enterprise
SOCAR	State Oil Company of Azerbaijan Republic
TBR	Tax Burden Ratio
TCO	TengizChevrOil LLP
UAS	Uzen-Atyrau-Samara
UK	United Kingdom
US	United States
USD	United States Dollar
VAT	Value-Added Tax

Preface to the original 2009 report

The efficacy of government's action and, as a result, the growth of society's well-being depend, to a large extent, on the degree of citizens' involvement in decision-making processes and their monitoring. Despite the relatively short history of civil society in the post-Soviet space, Kazakhstani non-governmental organisations (NGOs) have made some progress in this direction over the past five years, especially in the field of monitoring revenues in the extractives sector.

The availability and use of natural resources cannot, in itself, increase the population's well-being. For some resource-rich countries, oil revenue management has proved to be problematic. Torn by corruption and internal strife, they have entered the group of so-called 'failed states' with direct experience of the 'resource curse.'

According to many representatives of civil society, economists, lawyers and political scientists, the 'resource curse' can only be avoided by increasing the transparency and accountability of revenue management. This, in turn, helps reduce levels of corruption, and along with the participation of the general public in decision-making processes, has a positive effect on the economic efficiency of government programmes. Having information about government revenues is the first important step in assessing the efficiency of government fiscal management.

The legal relationship between the government and extracting companies is established through investment contracts for the development, extraction, and transportation of resources. These signed contracts stipulate the terms of profitmaking and distribution between the government and companies over several decades. The success of developing countries is directly bound up

with many of these terms, such as the level of local content, ecological security, government profits, etc.

Thus, oil contracts are a serious test for both those who sign them on behalf of the government, and for representatives of civil society, whose role is to ensure independent control of resource revenue management. To achieve this, NGOs must have a clear idea of what kind of interests the parties concerned have in the negotiation process, and be able to distinguish between different kinds of contracts.

Given the interest in oil contracts on the part of Kazakhstani NGOs, the authors of this guide organised a seminar, held in Almaty under the auspices of the Soros Foundation–Kazakhstan, for representatives of more than 30 NGOs from different regions of the country. Participants had many questions, such as: how can representatives of civil society monitor contract performance? and what should primarily be taken into account when examining contracts?

In view of the general public's concerns over contract transparency and fairness, the authors have attempted to answer these and other important questions. The Soros Foundation–Kazakhstan hopes that this report will be of great interest to the public, and of particular use to organisations working to increase revenue transparency in the extractive industries. It is the first publication of its kind, not only in Kazakhstan, but also in the whole post-Soviet region, and may be seen as the counterpart to the report: *Covering Oil: A Reporter's Guide to Energy and Development*, published in Russian and English by the Open Society Institute in 2005.

Anna Alexandrova

The Soros Foundation–Kazakhstan

Preface to the English version of the report

In recent years, economic liberalisation, improved transport and communication systems, and the global demand for energy, minerals, and commodities have fostered natural resource investment in many poorer countries. For some commentators, this trend provides new opportunities to promote growth, generate public revenues and create employment in countries that have limited alternative development options. Others have stressed the major risks involved in natural resource investments. For example, people may lose key livelihood assets, such as land, water, and grazing land, while environmental damage may have lasting effects on the resource base and repercussions for public health.

From the perspective of sustainable development, attracting investment should not be an end in itself for host countries, but rather a means to an end. The ultimate goal should be to improve local livelihoods while protecting the environment. Many governments have made efforts to attract more investment, some of it dubious. For the quality of investment — assessed for its core characteristics, rather than philanthropic programmes at the fringes — is as important as its quantity. This involves a thorough scrutiny of the social, environmental, and economic considerations at stake. Key issues include public participation in the contracting process, the economic fairness of the deal, the degree of integration of social and environmental concerns, and the extent to which the balance between economic, social and environmental considerations can evolve over often long project durations.

Together with applicable national and international law, contracts between investor and host government define the terms of an

investment project, and the way in which risks, costs, and benefits are distributed. The process for signing the contract greatly influences the extent to which people's voices can be heard. Therefore, scrutinising contracts is an important mechanism for ground-testing competing claims about natural resource investments, assessing the extent to which opportunities are maximised and risks minimised, and for increasing accountability in public decision-making.

Getting the contracts right requires strong capacity on the part of the host government to negotiate and manage agreements, and of civil society, parliamentarians and the media to hold governments and investors to account. Contracts for large natural resource investments are usually very complex, raising challenges for negotiators, implementers, and scrutinisers. Revenue-sharing arrangements in Production Sharing Agreements illustrate this point vividly. Together with partners in lower- and middle-income countries, IIED has been working to strengthen local and national capacity to examine contractual issues with a sustainable development lens.

This guide was originally published in Russian by the Soros Foundation–Kazakhstan. Its content proved invaluable at two training sessions on extractive industry contracts co-organised by IIED in Central Asia (with Kazakhstan Revenue Watch) and in Ghana (with the Centre for Public Interest Law). The original plan was to simply translate the Russian text, but it soon became clear that the value of the guide would be increased if its content could be adapted, in English, to target an audience well beyond Central Asia. As a result of this translation and adaptation process, the content and structure of the present English guide differ in important ways

from the original version, while preserving the core analysis and the spirit that inspired the original. We hope that this publication will be a useful contribution to efforts to improve accountability in contracting for natural resource investment.

Dr. Lorenzo Cotula

International Institute for Environment and Development (IIED)



Introduction

This guide discusses the provisions of a particular type of oil and gas contract, the Production Sharing Agreement (PSA). While the guide is aimed at a general civil society readership, it draws particularly on experience from Kazakhstan.

PSAs have emerged in the past number of decades as a popular form for structuring oil and gas contracts between resource-endowed countries and international oil companies (IOCs). While these agreements are not the only means for regulating the exploration and development of hydrocarbons, they have been used extensively in a number of producing countries. Although Kazakhstan has decided not to use the PSA model for future contracts, many major oil and gas fields in the country are still being developed under such arrangements. Therefore, understanding the key characteristics of this model remains important in Kazakhstan and elsewhere. In countries such as Uganda, Tanzania, Kurdistan and Turkmenistan, for example, new PSA arrangements are being made. We hope this guide will be useful to stakeholders in such countries.

The purpose of this guide is to give an accessible account of some key characteristics of PSAs, with a focus on revenue issues, and to suggest action points for civil society organisations involved with monitoring extractive industries. Indeed, in recent

years the public in resource-rich states has become increasingly concerned about the management of extractive industry revenues.

This concern is underpinned by a desire to avoid the so-called ‘resource curse’: a label given to a phenomenon whereby resource-rich countries are unable to benefit from their natural resource abundance. According to the ‘resource curse’ literature, the economies of resource-rich countries are dependent on fluctuations in world commodity markets; their political systems are often distorted by short-term interests in revenues and rent-seeking and by a failure to fulfil long-term development goals.

Ensuring transparency and accountability in revenue management is a key part of avoiding the resource curse. It is with a view to achieving this goal that initiatives such as the Publish What You Pay (PWYP) Campaign and the Extractive Industries Transparency Initiative (EITI) were launched in 2002. In order to ensure effective control over revenues in the oil and gas sector, citizens need to have a deeper understanding of the often complex issues concerning the industry. Thus, oil and gas contracts are of paramount importance, as they describe each party’s rights and obligations, and the main principles used to determine revenue sharing.

While the guide draws primarily on experience from Kazakhstan, a few examples from Azerbaijan will also be mentioned. Contracts are confidential in Kazakhstan, but Azerbaijan is one of the few countries where civil society has access to contract documents, and insights can be gained from comparing experience in the two countries.

The first chapter will contextualise PSAs by presenting a broad overview of the oil and gas industry in Kazakhstan and by discussing how the particularities of this sector create specific challenges for contractual arrangements. Chapter two considers the principles of oil sharing between the government and the investor: the hallmark of any PSA. Chapter three is an overview of the taxation system in Kazakhstan as it relates to the oil and gas sector. And chapter four focuses on how civil society may use the information presented in this guide to promote greater transparency and accountability.

PART 1

1

Putting the PSA into context

An introduction to Kazakhstan's oil and gas industry

This chapter sets the scene for analysing PSAs. Kazakhstan has used PSAs to structure many of its hydrocarbon development projects, and thus provides an appropriate contextual starting point for understanding PSAs more deeply. As mentioned, no new PSAs will be signed in Kazakhstan as a result of a new Subsoil Use Law adopted in 2010, but existing PSAs will remain in force to regulate major oil development operations in the country. Kazakhstan's experience is also valuable to other countries using or considering using PSAs.

The chapter provides a brief background on the history of oil and gas development in Kazakhstan, the risks prevalent in the oil and gas industry, and the various types of contractual arrangements that have been developed.

1.1 The origins of oil development in Kazakhstan

The first pages of the history of oil in Kazakhstan are set in the Atyrau region, an area bordering the northern shores of the Caspian Sea, and rich in hydrocarbons. In 1890, an expedition led by Grum-Grzhimailo undertook a very detailed geological survey of the area, and in 1899 the areas containing hydrocarbons were sold to the Russian

entrepreneurs Lemap, Doppelmayr, and Grum-Grzhimailo, founders of the Emba-Caspian Partnership. At the Karachunul field, 21 wells were drilled to depths of 38 to 275 metres, and in November 1899, oil was first produced and Kazakhstan's oil industry was born.

Gas condensate

is a mixture of liquid hydrocarbons, emitted from natural gases when the temperature is lowered and different pressures are applied. Gas condensate can be used as a fuel, or treated to become benzene, diesel or furnace oil.

The first field of industrial significance, the Dossor field, was discovered in 1911, and two years later the Makat field was discovered by the Nobel company. Infrastructure developed to keep pace with the annual increase in the volume of oil production in Kazakhstan. Pipelines were built and the port of Guryev became increasingly developed. However, until the 1970s, Kazakhstan remained a fairly small producer of hydrocarbons. This all changed in 1979 with the discovery of the super-giant Tengiz¹ field and the Karachaganak gas condensate field.

1 At the time of discovery, the Tengiz field ranked as one of the five largest oil fields in the world.

Despite these major onshore discoveries, Kazakhstan only began developing its offshore fields in the Caspian following independence in 1991. As it initially had neither the appropriate technology nor the experience to do so, Kazakhstan signed PSAs with IOCs in 1997 to explore and develop the northern Caspian Sea. The prospecting work resulted in the discovery of four gas condensate fields, one of which, the Kashagan field, ranks among the largest fields discovered in the last 30 years.

In addition to these initial PSAs, Kazakhstan made intensive efforts to encourage and expand investment in hydrocarbon exploration and development during the first years of the 21st century. To facilitate this policy, Kazakhstan concluded bilateral agreements with Russia and Azerbaijan on the division of the Caspian. Although the policy focus of Kazakhstan’s hydrocarbon industry has fluctuated in the past few decades, the main thrust of new growth in the oil industry

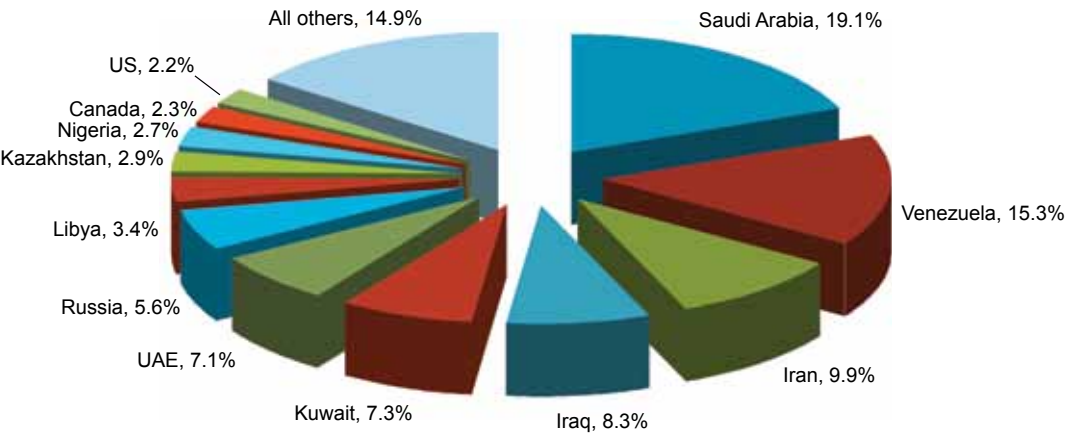
remains centred on developments in the offshore potential of the Caspian.

By 2015, Kazakhstan plans to more than double production, from 65 million tonnes in 2006 to over 150 tonnes in 2015. In 2010, production was at approximately 79.7 million tonnes.² These goals are largely consistent with statements made by the president of Kazakhstan at an international conference in October 2007, where he announced that plans for oil production were targeted at 80 million tonnes in 2010, increasing to 130 million tonnes by 2015.

1.2 Oil reserves and oil production in Kazakhstan

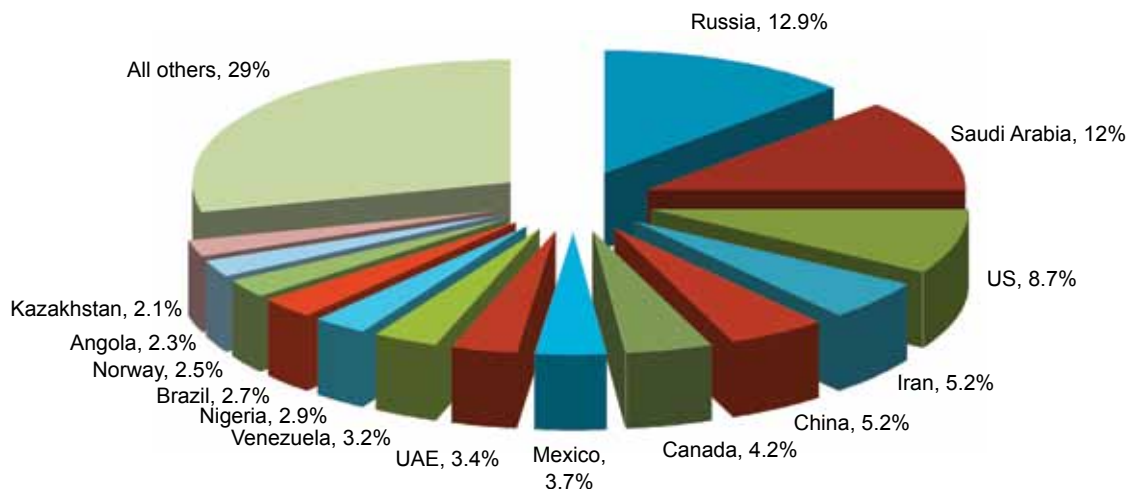
Estimating the exact volume of hydrocarbons available or accessible in any single country at any one moment is exceedingly difficult. This is especially true in the case of Kazakhstan, where intensive exploration continues through to the present. As seen in Figures 1

Figure 1. Percentage of proven oil reserves



Source: BP Statistical Review of World Energy, 2011

2 There are two methods of measuring the quantity of oil extracted: million barrels per day or million tonnes per year: 1 million barrels per day equals 49.8 million tonnes per year.

Figure 2. Percentage of daily oil production

Source: BP Statistical Review of World Energy, 2011

and 2, Kazakhstan is currently ranked ninth in the world in terms of proven oil reserves.

In the regional context, the 2.9 per cent of the world's reserves held by Kazakhstan are significantly less than the 5.6 per cent held by Russia, and significantly more than the 0.5 per cent held by Azerbaijan. For Kazakhstan, this percentage represents approximately 39.8 billion barrels of proven oil reserves. Comparatively, the reserves held by Saudi Arabia, the world's largest, stand at 264.5 billion barrels.

In addition to oil, Kazakhstan also produces gas condensate and natural gas (Table 1). Gas condensate is usually included in oil reserve statistics. Natural gas statistics, on the other hand, are determined independently. Kazakhstan holds an estimated 1 per cent of global proven reserves in natural gas. This translates into 1.8 trillion cubic metres of extractable natural gas. By comparison, the reserves of natural gas held by Russia,

the world's largest, stand at 44.8 trillion cubic metres. According to statistics from Kazakhstan's Ministry of Oil and Gas, the country has 169 fields of confirmed hydrocarbons resources: 87 oilfields, 17 gas fields, 30 mixed oil and gas fields, and 35 gas condensate fields. Moreover, two-thirds of the extractable reserves come from six fields with over 50 per cent coming from the Kashagan and Tengiz fields alone.

In terms of output, 2010 statistics show that Kazakhstan accounts for 2.1 per cent of global oil (including condensate) production. This places Kazakhstan as the 14th largest producer in the world. At current rates of production, proven oil reserves are estimated to last approximately 50 years. Natural gas production in Kazakhstan is significantly less than its oil production, accounting for less than 1 per cent of the annual global total. However, if natural gas production were to remain at its current annual rate of 37.4 billion cubic metres, Kazakh proven gas reserves (1.7

Table 1. Production of hydrocarbons in Kazakhstan

Year	Oil production + condensate (million tonnes)	Natural gas (billion cubic metres)
2003	51.4	16.6
2004	59.4	22.1
2005	61.5	25.0
2006	65.0	26.4
2007	67.1	29.6
2008	70.7	32.9
2009	76.5	35.9
2010	79.7	37.4

Source: The Agency of Statistics for Kazakhstan, 2011.

per cent of global reserves) would last for over 100 years.

While Kazakhstan aims at being a top ten oil producer by 2015, significant challenges exist. Given the difficulty in developing many of the country’s largest fields, and the suboptimal chemical composition of most of Kazakhstan’s hydrocarbons (high sulphur content and hydrogen sulphide compounds), realising large-scale development projects in Kazakhstan requires significant investment, consistent and effective governance, and specialised technological knowhow.

1.3 Risk and reward in the oil and gas industry

The oil and gas industry is based on the exploitation of natural resources, and in economic terms, this involves the management of both the receipt and distribution of rent. In the context of natural resources, economic rent is defined as any income earned from the scarcity of a finite resource. While this may state a truism with regard to natural resources, its significance

becomes apparent when placed in the context of geographic limitations. Businesses engaged in the extraction of hydrocarbons must go where those hydrocarbons are located. The combination of a finite resource and its location in specific geographic areas means that the oil and gas industry is presented with challenges that are not always present in other sectors.

As such, oil businesses can obviously only be conducted where hydrocarbons are available. Currently, there are about 50 oil-producing countries in the world, and production costs differ widely among these geographic regions. In addition, the geological characteristics of the hydrocarbons largely determine production costs. For example, offshore development tends to be significantly more expensive than onshore development. To illustrate, Table 2 below shows that costs are lower in the Middle East, where oil is pumped from onshore oil fields with relative ease, whereas pumping from offshore North Sea fields and offshore fields in the Gulf of Mexico is far more expensive.

Table 2. Average upstream production costs³

Region	2006–2008 (2009 USD per Barrel of Oil)	2007–2009 (2009 USD per Barrel of Oil)
United States	41.49	33.76
Canada	38.75	24.76
Europe	72.32	53.37
Former Soviet Union	16.70	20.96
Africa	42.24	45.32
Middle East	17.09	16.88
Worldwide	34.71	29.31

Source: EIA Performance Profiles of Major Energy Producers, 2009.

Although National Oil Companies (NOCs) now produce more of the world's oil than the once-dominant western International Oil Companies (IOCs), IOCs continue to seek lucrative deals in countries where hydrocarbon development has been a relatively new enterprise, such as West Africa and the former Soviet Union (FSU). This means that the governments of a number of low- and middle-income countries, where new oil fields have recently been discovered, face a difficult choice of either contracting out production to IOCs experienced in pumping methods and technologies, or waiting for local or state-owned companies to gain sufficient capacity to develop resources on their own. In the majority of cases, financial necessity and the desire for regional dominance have driven government policy decisions to accept cooperation with foreign companies in order to develop the fields as quickly as possible.

Given this reality, it is unsurprising that resource-rich countries often turn to foreign

oil companies for capital and expertise. But herein lies the challenge: how can the governance of relationships with foreign oil companies be sufficiently balanced so that the hydrocarbon wealth is shared, commensurate with sovereign ownership of the resource, on the one hand, and the value-added by the foreign oil company in extracting the resource on the other? Over the past few decades, governments have looked to increasingly sophisticated methods of contracting to deal with this challenge. While these various types of contracting methods will be introduced in the next section, it may be useful to highlight some of the financial reasons for needing such complex legal instruments for governing the relationship between host states and foreign investors.

The development of oil and gas fields requires capital and that capital can come from a number of financing sources. How oil companies finance operations is of great importance, and a few strategies are

³ Upstream production costs include both finding and lifting costs.

Box 1. The stages of oil project development

Negotiations

1. The government issues an invitation to tender for the exploration and development of fields.
2. The company buys geological and geophysical data from the government.
3. The company carries out a commercial assessment to choose a field.
4. The company submits a bid to the government.
5. An agreement is reached with the government by way of signing a memorandum of understanding.
6. Negotiations begin with the government to stipulate the details for agreement.
7. A protocol is signed to signify approval of the details of the agreement.
8. A contract is signed with the government.
9. The contract is ratified by the government.

Exploration

1. An operating company is set up to execute the contract.
2. The company accepts the contract area from the government.
3. Geophysical surveys are carried out.
4. Based on the results of the survey, a drilling site is chosen for an exploration well (or wells).
5. Announcements are made about the discovery of hydrocarbons or an assessment is made of commercial hydrocarbon reserves.
6. A field development programme is prepared (technical and economic feasibility analysis).
7. The government approves the field development programme.

Development

1. Technical work (construction) begins at the contract area site.
2. Infrastructure is developed for the transportation of hydrocarbons.
3. Production wells are drilled.

Production

1. Hydrocarbons are extracted.
2. Hydrocarbons are transported to the processing site.

highlighted in the next few paragraphs. The importance of financing in oil and gas projects relates to a number of underlying peculiarities specific to the industry. Oil

field development projects are not only capital-intensive, they are risky and long-term investments, taking from 25 to 40 years to fully develop, and requiring significant

investment throughout the whole of the project. Having made such huge investments, companies then plan to make a return over project duration; but this can be very long. This risky, long-term, capital-intensive nature of projects creates special challenges for financing. In turn, financing arrangements can have significant implications for investor-state contracts.

Three common ways to finance the development of oil and gas projects are self-financing, borrowing and partnering. Self-financing refers to a practice usually limited to large IOCs and NOCs. Under this arrangement, capital investment strategies are determined internally and capital is dispersed for specific projects without recourse to outside lending or cooperation with partnering companies. While only a few very large IOCs can self-finance operations, it is more typical among many of the larger NOCs in the Middle East, Latin America and Russia. For smaller companies and smaller developing countries, borrowing from banking institutions is an alternative for securing capital for oil and gas projects. From a civil society perspective, bank involvement in the development of oil and gas projects can be beneficial: international benchmarks, such as the Equator Principles, related to lending have emerged in recent years to help mitigate some of the social and environmental risks associated with natural resource projects, and may provide effective levers for civil society scrutiny.

In practice, oil companies increasingly obtain financing from a variety of sources, with combinations of self-financing and borrowing not uncommon. Also, an important risk mitigation strategy employed by oil companies is to facilitate partnerships such as joint ventures and consortia. This can include several IOCs, and/or an IOC (or a consortium of IOCs) and a State-Owned Enterprise

(SOE), such as a national oil company. This diversification of capital and expertise assists in the realisation of projects that may be too risky, either economically and/or politically, for any single entity to enter onto its books.

As contracts for the exploration and development of oil resources always involve a relationship between one or more oil company, on the one hand, and a government agency or SOE which owns the buried oil, on the other, a key question is how the rent generated by the project is divided between the parties. This has been a difficult issue for the oil and gas industry since its inception.

In recent decades, the methods and means for determining the hydrocarbon share between national governments and IOCs have shifted. A popular incarnation of this shift is the Production Sharing Agreement (PSA). Indeed, early relationships between resource-rich countries and IOCs were governed by concessions. In their original formulation, concessions are more than contracts: they vested property rights in the unproduced hydrocarbons to the IOC. This arrangement became untenable in the post-colonial era, when developing countries were promoting what was proposed as a more equitable 'New International Economic Order.' Modern concessions are actually tax-and-royalty agreements, and do not vest title in unproduced hydrocarbons. But new contract models, such as PSAs, have become increasingly common in the developing world. The next section outlines the various types of contractual arrangements that can be used to regulate the development of hydrocarbons.

1.4 Oil agreements: Different types of contracts, different levels of responsibility

In terms of capital and expertise, attracting foreign direct investment (FDI) in Kazakhstan remains as important today as in the early years of independence. Kazakhstan continues to pursue policies aimed at attracting FDI in capital-intensive and technologically challenging projects in the oil and gas sector. Where attracting FDI is a key concern, legal mechanisms for both the protection and promotion of these investments are crucial.

For the oil and gas industry, the legal structures that regulate the development of hydrocarbon resources can be divided into micro and macro governance structures. At the macro level, the government can provide legislation regulating investment in the mining and petroleum sectors and related taxation. It can also enter into a range of bilateral and multilateral investment treaties to encourage and protect foreign direct investment. At the micro level, the government can negotiate contractual arrangements that will govern specific projects.

The PSA, the provisions of which are the focus of this guide, occupy a special place in the history of oil contracts. They were developed in the 1960s and became widespread by the 1990s. While their popularity has waxed and waned over this period, they are still used in the oil and gas industry, especially among IOCs operating in low- and middle-income developing countries. As stated in the previous section, PSAs were developed after the traditional concessions become untenable in the post-colonial era. According to the late Professor Thomas Waelde (1995), the PSA produced “a

convenient marriage between the politically useful symbolism of the production-sharing contract (appearance of a service contract to the state company acting as master) and the material equivalence of this contract model with concession/licence regimes in all significant aspects...The government can be seen to be running the show – and the company can run it behind the camouflage of legal title symbolising the assertion of national sovereignty. It is for these reasons that the production sharing agreement is so important in countries where sovereignty needs to be asserted conspicuously, while the financial and managerial resources for national management are absent. This new conceptualisation of the relationship between host state and investor helped solve many of the political difficulties concerning the development of national resources.”

However, the oil and gas industry is not monolithic, and therefore the transition from concessions to PSAs can hardly be described as a universal move. Also, during the same period, NOCs have been on the rise, and often IOCs do not participate within the territories of these NOC-dominated states. As a result, PSAs govern a relatively small percentage of global oil production.

Yet PSAs have been quite popular in the former Soviet Union, and in the context of Kazakhstan and Azerbaijan, they remain influential. But Kazakhstan has recently decided that PSAs would no longer be used in future exploration and development agreements (see Box 2). This change in policy does not reflect PSAs already signed; in fact, Kazakhstan's largest fields, Karachaganak and Kashagan, are still being developed under the PSA model.

Box 2. Kazakhstan's recent criticism of the PSA model

The following extract is found in the presentation of the new law on Subsoil Use to Kazakhstan's Parliament, Majilis Administration (2009):

Applying a production sharing model to subsoil use contracts has been the common international practice in countries with developing or transitional economies lacking financial resources and technical means for independent field development. The specifics of subsoil use in Kazakhstan (high production cost, long transportation network, limited internal processing facilities) make the production sharing concept ineffective, and difficult to manage and apply. The practice of existing production sharing agreements in the Republic of Kazakhstan shows that the country does not receive adequate returns from these projects, even with the prices for raw material being high.

The vast diversity of the industry, in terms of both policy and context, means that the contractual models used in the oil and gas industry are as diverse as the industry itself. That said, four broad categories of agreements are used in the oil and gas industry today: PSAs; concessions and licences; joint ventures; and service contracts. Each type of agreement is briefly summarised below.

1.5 The Production Sharing Agreement

By the mid-20th century, resource exploitation has entered a new era, and the traditional methods of resource governance were increasingly incompatible with post-colonial reality. Early concessions were perceived as unfair, and many newly independent countries pursued nationalisation policies that cancelled IOCs' concessions. These countries, which had already been producing hydrocarbons for many decades, such as Saudi Arabia, Iran and Venezuela, focused on developing their NOCs and locking out IOCs. In low- and middle-income countries that had yet to develop their hydrocarbons, the options of setting up NOCs and excluding IOCs and their technical knowhow was not possible. At the same time, these countries could not be seen as openly giving up sovereignty over their natural resources by agreeing to traditional concessions. PSAs emerged to fill this gap.

PSAs were first used in Indonesia in the 1960s. They were signed between IOCs and Pertamina, the state oil company of Indonesia. What is characteristic of these contracts is that the parties concerned share the production of the hydrocarbons produced and leave title to the unproduced oil with the state. Today, the PSA continues to be used in relationships between IOCs and some resource-rich states (or their SOEs) for the exploration, development and production of hydrocarbons. The fundamental principle of these types of contracts is the notion of shared production. Given the time-scale of oil field developments, PSAs are often signed for a period of 25 to 30 years, although they can cover longer periods. For instance, the contract to develop the Kashagan oilfield in Kazakhstan was signed in 1997 for a period of 40 years.

After the companies have made the stipulated investments and extracted the oil, the resources are shared between the parties to the contract, with the state's share often going to the SOE designated in the contract (often an NOC). When a number of companies are involved, one of them can be delegated to assume the operational management of the project. This function is usually assigned to the largest investor, who will be in charge of the project's operational management and settle any problems and disputes that arise. There is normally a distinction between technical and commercial operational management: the technical is mainly concerned with the actual field development process, while the commercial is concerned with regulating financial settlements and relations between the parties regarding production sharing calculations.

For the purposes of PSAs, the state is usually represented by a NOC that assumes two responsibilities: first, that of contractor with a relevant share in the contract; and second, representing the state's interests and receiving its share of profit oil on behalf of the state. The share of the NOC differs from country to country, depending upon the manner in which the PSA was negotiated and how much of a stake the NOC holds in the particular project. Many PSA laws require that the NOC hold a controlling stake in the project (50 per cent + 1 share). However, owning a 50 per cent stake in a project usually requires significant investment on the part of the NOC, a consideration that can reduce the amount of profit initially seen by the state as the NOC recoups its capital investment costs. To deal with this inconvenience, PSAs are often structured so that the NOC contribution is 'carried' (i.e., paid for) by other consortium members and the government repays this contribution from its share of profit oil.

At present, PSAs have been used in a number of resource-rich countries. They have been particularly popular in the development of hydrocarbon projects in Central Asia and on the African continent. However, the complexity of the PSA, coupled with its inability to deal with the dramatic price fluctuations of oil in recent years, has led to some backlash against its future use. For example, the new Subsoil Use Law in Kazakhstan, which came into effect in July 2010, prohibits the signing of new PSAs for future development projects, leaving in force PSAs signed earlier. While PSAs differ widely in their terms and condition, a number of common principles have emerged. A few of these principles are summarised below:

- On the host state side, an NOC or other SOE can be a party to the contract.
- The state retains legal title to the unproduced natural resources and only transfers title to the IOC's share of the oil once it has been produced.
- The IOC usually bears the risk at the exploration stage (i.e., if no oil is discovered).
- PSAs, once negotiated and signed, often become part of national legislation.
- The state or the NOC grants the IOC the right to explore, develop and extract oil.
- The IOC invests capital (along with the NOC in some cases) and initial capital expenditures and on-going maintenance costs are deducted from production in the form of cost oil.
- The IOC receives a share of the produced oil in accordance with the PSA. This is normally called the profit oil.

- Cost oil and profit oil (and any other bonuses, royalties, duties, or taxes) are calculated on the basis of the amount of oil actually produced.
- The parties share profit oil throughout the duration of the contract, with taxes on profit oil only paid to the government once the oil has been received.

1.5.1 Concessions and licences

Modern concession and licensing arrangements are contracts whereby the government grants the investor the exclusive right to exploit natural resources in a given area for a specified period of time, in exchange for payment of royalties, taxation and fees. In principle, concession contracts do not involve collaboration in production activities; rather, the investor runs operations and the government receives revenues. But local partners may be involved in production under local content provisions that can be included in the concession.

Concessions, like PSAs, mean that the investor runs oil operations at its own risk, in contrast to a joint venture. But instead of a share of the petroleum produced, a concession holder usually pays a bundle of taxes and royalties on all oil produced. However, hybrids of concession and PSA-type arrangements are also possible, whereby, for example, the investor may be required to pay income tax on its share of oil and royalties based on the value of production. Unlike PSAs and joint ventures, pure concessions rarely involve an NOC or SOE in development or production. Payments of taxes and royalties are paid directly to the state.

Compared to PSAs, concessions tend to be less complicated to negotiate and administer. They require less host state capacity in terms of proper legal, financial and technical expertise. Because of their complexity, PSAs also tend

to be less amenable to public scrutiny than concession and licensing regimes. Whether PSAs can be financially more beneficial to host countries than concessions depends on their specific sharing provisions, as compared to tax and royalty rates under concessions.

1.5.2 Joint ventures

Joint ventures involve contracts between the investor and a local partner, with a view to jointly running a business venture. Contracts may entail setting up a jointly owned company incorporated in the host state and managed by a board where both parties are represented (incorporated joint ventures). Joint ventures may also be run on the basis of contracts alone, without the creation of a separate legal entity owned by the parties (unincorporated joint ventures). Unincorporated joint ventures offer greater flexibility than incorporated ones, but require additional efforts to contractually develop governance structures; incorporated ventures can rely on the generally applicable company law that is in force in the state where the joint-venture company is established.

Unincorporated joint ventures also lack legal identity and therefore limited liability, in contrast to incorporated joint venture companies, where the parties are only responsible for liabilities up to the value of their contributions in the company. Lack of limited liability may increase the accountability of the investment towards people who may suffer damage caused by it; but in large, long-term and capital-intensive investments, the lack of limited liability is clearly a major drawback from the investor's point of view.

Joint operating agreements in the petroleum sector are commonly structured as unincorporated joint ventures, and in lower- and middle-income countries, joint

ventures for natural resource projects often involve an entity owned by the host state, such as an NOC. While a main advantage of the joint development model is the diffusion of risk among all parties involved in the project, it also requires sharing the benefits earned. Like any contractual arrangement for the development of the state's hydrocarbon resources, joint ventures will stipulate the levels of obligation that each member of the project carries. Joint ventures can be structured to include production-sharing arrangements, and many modern unincorporated joint ventures with NOCs can closely resemble the PSA model.

1.5.3 Service contracts

Service contracts, like other forms of concessions and PSAs, are used to involve IOCs in the development of a country's hydrocarbon resources. Of all the types of arrangements possible for governing hydrocarbon development projects, the service contract is the most limited, and very rarely involves profit-sharing, although examples of profit-sharing service contracts are evident in such instruments as the Iranian 'buy-back' contract model. Service contracts normally govern arrangements between national and international oil companies where the technical capacity of the former is limited. NOCs often sign service contracts with IOCs to develop particularly difficult or challenging projects, where specific technical expertise is required. Essentially, service contracts are a form of sub-contracting. Payment on service contracts varies from contract to contract, but can include payments in oil produced.

2

PART 2

Anatomy of a PSA

How production sharing takes place

At the heart of a PSA is the mechanism to share profit between the host state and the oil company. This is an extremely important aspect of this type of contract, and it is impossible to assess the distribution of costs and benefits between the parties without understanding this mechanism. In PSAs, taxes and royalties are usually less important than in concessions. In concessions, taxes and royalties are a host government's primary source of revenues from its hydrocarbon resources. PSAs are different in this respect, as they create a type of partnership between company and host state whereby oil is shared. So in PSAs, the terms for sharing the oil produced is a crucial mechanism to influence what revenues the host government will receive.

In its most simple formulation, the calculation of 'profit oil' to be shared between the parties is quite simple:

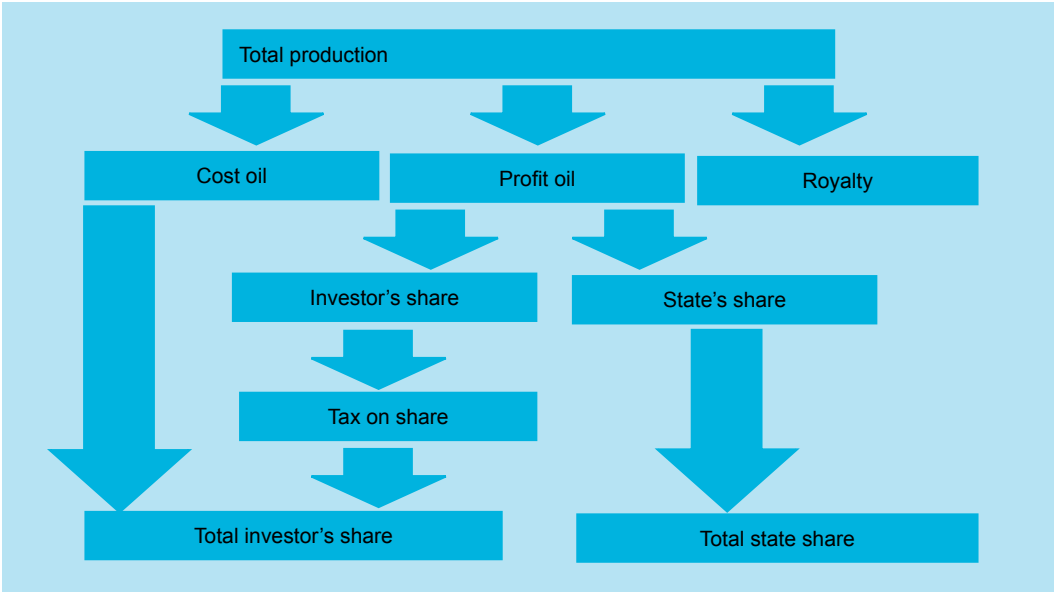
$$\text{Profit Oil} = \text{Total Oil Produced} - (\text{Cost Oil} + \text{Royalties})$$

In practice, this means that the capital investment and the on-going maintenance costs related to production can be deducted (the cost oil) before the remaining oil produced (profit oil) is split into two shares: the IOC share and the host state share. In terms of cost oil, the party or parties investing capital in a PSA project recoup their costs at a contractually stipulated rate. This rate varies

from one PSA to another. Some PSAs permit capital investors to recover 100 per cent of exploration and development costs before having to share profit oil with non-capital investing parties, such as the host state or NOC. Other PSAs permit profit oil to be generated from the very start of production. In these cases, the amount of cost oil that can go towards recovering initial capital investment costs is stipulated as a percentage of total production (Figure 3).

The parties to the PSA share the profits of production in the form of crude oil, rather than money. In other words, the state gets its share of the profits in the form of part of the extracted oil, which it then sells at its own discretion. At first glance, this makes financial relations between companies and the state easier, but as we will see later, it can sometimes become an obstacle to transparent financial relations. In a three-stage PSA process, the investor's share of the distributed oil is subject to a tax on its share of the profit oil. In a two-stage PSA process, there are no taxes on production. For example, some PSAs provide for a larger share of profit oil going to the state, but in exchange for the larger stake, all taxes are forgone.

Figure 3. Oil distribution under PSAs



Source: IMF

2.1 A bit of financial theory

The manner in which hydrocarbon production is shared under PSAs can be a complicated process. To better understand some of these complexities, a short summary of the financial theories underlying PSAs is warranted. When an IOC looks to invest in a project, there are thousands of considerations it will make in the assessment of costs and benefits. These considerations require the calculation of all risks associated with a particular project, which are not always of a purely financial character.

Long-term strategies require an assessment of political and geological risk as well. All combined, these assessments require complex analysis of all political economy considerations applicable to a proposed project. Investors want a return on their investment, but in the oil and gas industry, the long-term and capital-intensive nature of oil and gas projects — coupled with the realities

of political instability, regulatory change, geological uncertainty, and price fluctuation — lead to high level of unpredictability. To counter some of these risks, a number of financial tools are used to assess risks and returns.

In the case of hydrocarbon development projects, an investor typically invests large amounts of capital up front before generating any revenue. The longer it takes for a project to generate revenue, the higher the profits need to be. This is because the money invested in a project today is more expensive to recoup in the future. Future profits, therefore, must be calculated in terms of the current value of the investment. To do this, project analysts use a financial concept called net present value (NPV). NPV expresses the value of future revenue in relation to the value of currently invested capital. Economists call this process discounting.

2.1.1 Net present value

When looking to calculate the NPV of a project (Table 3), two key parameters must always be kept in mind: first, interest rates on monies borrowed for making capital expenditures on large-scale hydrocarbon development projects; and second, inflation: a process whereby the value of money today is worth less in the future. One need not be a financier to understand the adverse effects of inflation on money; it is sufficient to observe changes in the price for the same goods within a year. Most certainly, in a year's time, when buying the same type of product, you will have to spend more money; how much more will give an idea of the annual inflation rate.

The NPV is calculated with the following formula:

$$NPV = C_0 + \sum_{t=1}^N \frac{C_t}{(1+r)^t}$$

or

$$NPV = \sum_{t=0}^N \frac{C_t}{(1+r)^t}$$

where:

t = time

N = total length of project

r = discount rate (rate of return on investments)

C_t = cash flow

C_0 = amount of initial investment

Table 4 illustrates an example of NPV and its use in financial analysis. A corporation must decide whether to introduce a new product line. The new product will have start-up costs, operational costs, and incoming cash flows over six years. This project will have an immediate ($t=0$) cash outflow of USD100,000 (which might include machinery and employee training costs). Other cash outflows for years 1 to 6 are expected to be USD5,000 per year.

Cash inflows are expected to be USD30,000 each for years 1 to 6. All cash flows are after-tax, and there are no cash flows expected after year 6.

The required rate of return is 10 per cent. The present value (PV) can be calculated for each year

Table 3. Net present value

If ...	It means ...	Then ...
NPV > 0	The investment would add value to the firm.	The project may be accepted.
NPV < 0	The investment would subtract value from the firm.	The project should be turned down.
NPV = 0	The investment would neither gain nor lose value for the firm.	The project adds no monetary value; decisions should be based on other criteria, such as strategic positioning or other factors not explicitly included in the calculation; however, NPV = 0 does not mean that the project is only expected to break even, in the sense of undiscounted profit or loss; it will show net total positive cash flow and earnings over its life.

Table 4. An example of net present value

Year	Cash Flow	Present Value
T=0	$\frac{-100}{(1 + 0.10)^0}$	USD100,000
T=1	$\frac{30,000 - 5,000}{(1 + 0.10)^1}$	USD22,727
T=2	$\frac{30,000 - 5,000}{(1 + 0.10)^2}$	USD20,661
T=3	$\frac{30,000 - 5,000}{(1 + 0.10)^3}$	USD18,783
T=4	$\frac{30,000 - 5,000}{(1 + 0.10)^4}$	USD17,075
T=5	$\frac{30,000 - 5,000}{(1 + 0.10)^5}$	USD15,523
T=6	$\frac{30,000 - 5,000}{(1 + 0.10)^6}$	USD14,112

The sum of all these present values is the net present value, which equals USD8,881.52. Since the NPV is greater than zero, it would be better to invest in the project than to do nothing, and the corporation should invest in this project, if there is no mutually exclusive alternative with a higher NPV. NPV is especially important in the context of PSAs because it is a prerequisite to the calculation of the internal rate of return (IRR), which is discussed in the next section. In order to calculate the IRR, NPV must be known.

2.1.2 Internal rate of return

The other key tool for financial analysis in PSAs is the internal rate of return (IRR), which compares and shows the profitability of investments. Given a collection of pairs (such as time and cash flow) involved in a project,

the IRR (the value *r* in the equation below) can be calculated from an NPV that equals zero to show the minimum IRR needed for a project to be acceptable:

$$NPV = C_0 + \sum_{t=1}^N \frac{C_t}{(1 + r)^t} = 0$$

where:

- t* = time
- N* = total length of project
- r* = discount rate (rate of return on investments)
- C_t* = cash flow
- C₀* = amount of initial investment

Year	Cash flow
0	-100
1	+30
2	+35
3	+40
4	+45

Given the data to the left, it is easy to calculate that when the NPV equals zero, the value r equals 17.09 per cent. In other words, the project is profitable for the investor when the IRR equals 17.09 per cent:

$$0 = NPV = -100 + \frac{30}{(1+r)^1} + \frac{35}{(1+r)^2} + \frac{40}{(1+r)^3} + \frac{45}{(1+r)^4}$$

$$\approx 17.09$$

$$NPV = -100 + \frac{30}{(1+17.09)^1} + \frac{35}{(1+17.09)^2} + \frac{40}{(1+17.09)^3} + \frac{45}{(1+17.09)^4} = 0$$

An investment is considered acceptable if its IRR is greater than an established minimum acceptable rate of return or cost of capital (i.e., in the case above, an IRR more than 17.09 per cent).

2.1.3 The R-factor

There are different approaches to production sharing. Using the IRR to determine the production share between the investor and the state is one method. At present though, a commonly used method for determining share of production is the so-called R-factor. This is the ratio of cumulative receipts from the sale of petroleum to cumulative expenditures. It is calculated with the following simple formula:

$$R = \frac{\text{Cost recovery} + \text{Profit oil} - \text{Income tax}}{\text{Costs}}$$

An R-factor of less than 1 would mean that costs have not been fully recovered yet: total expenditures exceed total receipts. The larger the R-factor, the more profitable the operation. The royalty rate or government's share of production may increase as the R-factor increases. This is a distinct approach from the IRR, which is the inverse value of the R-factor. When this method is used, an increase in IRR would reduce the investors share in production. This is because the IRR is an indicator of the project's profitability.

The theory holds that as the investor's profitability increases, the equilibrium of the original agreement is maintained by reducing the investor's share of production commensurate with its profitability. Such an approach is slightly counter-intuitive; in normal business practice, the success of a project is rarely a good reason for reducing the benefit derived from such an investment. But in the case of resource exploitation, such a methodology is indicative of state ownership of its resources and the protective measures put in place to prevent investors from receiving windfalls in excess of their fair share of production.

Profit-sharing between government and investor is based on the principle of the investor achieving a certain level of profitability or cost recovery. Both the above-mentioned methods reveal the profitability of a particular project at the present moment. This information is then used for the subsequent identification of proportional sharing between the parties. In other words, these formulae allow for the estimation of a gradual increase in the state's share in profit oil as the investor recovers its costs and achieves the level of profit agreed to in the contract.

Obviously, in order to calculate the values of an IRR or the R-factor, it is necessary to have

complete information about the investor's capital and operating costs, the volume of production at the current moment, and the price of crude oil on the world market. Only then can a determination of the proportion of production sharing between the government and the investor be made. As a rule, information about current levels of production and world prices is easily accessible, but capital and operating costs of an investor are more difficult to obtain, unless the investor has agreed to publish these costs. This information is even more difficult to obtain if cost data is concealed by confidentiality agreements stipulated in the contract.

It is important to note that the profit-sharing normally begins after the company reimburses its current operating and capital expenses. Typically, reimbursable capital costs include the pre-investment negotiation costs, the costs of prospecting and exploration work, the payment of bonuses to the government and to social funds, and all capital investments for the development of the field, including the drilling of wells, the construction of surface facilities, pipelines, roads, power lines, and so on. Operating and maintenance costs are also recoverable prior to the calculation of profit oil share. These costs are more difficult to calculate because they occur throughout the project and are likely to vary from year to year.

2.1.4 Payback period

A final consideration when looking to calculate the financial viability of a long-term investment project is the payback period. This refers to the period of time required for the return on an investment to 'repay' the sum of the original capital expenditures. For example, a USD1,000 investment that returned USD500 per year would have a two-year payback period. The payback period intuitively measures how long something takes to 'pay

for itself.' All else being equal, shorter payback periods are preferable to longer ones. The formula used to calculate the payback period is as follows:

$$\text{Payback period} = \frac{\text{Investments}}{\text{Revenues}}$$

The payback period is considered a method of analysis with serious limitations and qualifications for its use, because it does not properly account for the time value of money, risk, financing, or other important considerations, such as opportunity costs. While the time value of money can be rectified by applying a weighted average cost of capital discount, it is generally agreed that this tool for investment decisions should not be used in isolation. Other measures of 'return' preferred by economists are net present value and internal rate of return.

PART 3

3

A production sharing example

The Azeri-Chirag-Gunashli project

Given this information about the way profit-sharing in PSAs work, an example in practice will be helpful: the Azeri-Chirag-Gunashli (ACG) PSA in Azerbaijan. The profit oil shares and how they are linked to the IRR are as follows in Table 5.

Following a number of years of development, the first oil in this project was produced in 1997. In late 1999, the production-sharing on the project began, and was initially split 30/70 with 30 per cent of production going to the state and 70 per cent going to the investors. As can be seen, at the initial stage the investors received a larger share of the oil than the government. This was justified by

the fact that these splits include cost oil in the calculation. At the beginning of the project, the investors, who had put up the capital costs for development, were being reimbursed for these costs out of its share of the production. However, once most of the capital costs had been reimbursed, the ratio changed, and in 2008, the split was 45/55 with 55 per cent of production going to the state and 45 per cent going to the investors.

Take the following hypothetical example of an offshore hydrocarbon development project in the Caspian, and how the share of profit oil could be determined using R-factor or IRR (see Table 6).

Table 5. Rate of return and corresponding shares of production

IRR	State share of oil	Investors' share of oil
Less than 16.75%	30%	70%
16.75% to 22.75%	55%	45%
More than 22.75%	80%	20%

Table 6. PSA profit-sharing formula for a hypothetical project

IRR	R-factor	Investors' share of production
IRR < 17%	R-Factor < 1.4	90%
17% ≤ IRR < 20%	1.4 ≤ R-Factor < 2.6	90 to 10%
20% ≤ IRR	2.6 ≤ R-Factor	10%

At first glance, the state’s economic interests seem protected to a greater degree in such a contract. But all is not so simple. In practice, there are always many nuances that complicate contractual terms and it is therefore difficult to say before field exploitation whether the government will be able to take the opportunity to generate such revenues.

As can be seen in the calculations in Table 7, the maximum oil price was estimated at USD60 per barrel. It is likely that these figures

were estimated in the early 1990s when this project was originally being negotiated. However, recent years have seen huge fluctuations in the price of oil. At current rates of between USD80 and 100 per barrel, these original estimations are no longer relevant. Many PSAs structured in this way have since been renegotiated to more accurately reflect the market price of oil. In Appendix 2, there is a sample list of PSAs in operation in Kazakhstan and Azerbaijan. This list includes many of the salient characteristics of PSAs, including the profit-sharing formulas.

Table 7. ACG project revenue projections based on oil price (in USD billions)

Oil price per barrel	USD60	USD50	USD40	USD20
IRR	27%	25%	24%	18%
Investor revenue from production share (including SOCAR)	44	40	32	24
Government revenue from production share	180	152	112	24
Tax on investor production	15	13	11	8
Government’s total revenue	195	165	123	32
Government’s total revenue (including SOCAR’s share)	199.4	169	126.2	34.4
Project’s total revenue	239	205	155	56

Source: PFMC

PART 4

4

Taxation of oil agreements

The example of Kazakhstan

At the beginning of this guide, we highlighted the important economic concept of rent. Some companies gain an advantage over others due to the natural characteristics of particular fields, as some fields are easier to develop than others. Whether just lucky, or savvy, operators receive substantial profit with little extra effort, whereas others must invest heavily in the extraction process. In most resource-rich countries, minerals are owned by the state, so the rent is divided between the host government and the company. The complicated mechanisms for rent sharing are normally regulated by the taxation policy of the state.

The tax burden for oil companies may vary significantly depending on the type of the contract. We have already mentioned in the previous chapter that where PSAs are in place, the state receives its share of profit oil, and taxation will not be its primary tool. However, taxation is still possible under PSAs, and in fact, PSAs often tax profit oil. There is no simple calculation for an optimal tax for the hydrocarbon industry; an appropriate level of taxation requires a contextual analysis of the particular rent distribution requirements under a particular agreement.

Under a PSA, the level of profit oil taxation is likely to be a smaller percentage than under a tax-and-royalty based concession, where the amount of tax is the state's primary revenue generator under the agreement. Taxation in

the hydrocarbon industry is a tool that can facilitate the proper balance of rent sharing between an investor and the resource-rich state. Therefore, the taxation regime has to balance a state's need to benefit from its resource wealth (i.e., to get as much income out of the resource as possible) against the need to attract investors, who likewise want to maximise returns on their investment. Favouring either party could create unwanted consequences: taxation that is overly lenient could deprive the state of potential budget revenues, whereas a more stringent tax regime could limit investment by investors in that country's hydrocarbon sector.

State policy often focuses on deriving as much benefit from its hydrocarbon wealth as possible. Where a resource-rich country requires foreign investment to develop its resources, taxation is a very important tool in deriving benefit from the natural resource endowment. A discussion of Kazakhstan's taxation system can help illustrate some key concepts and tools. The taxation system applicable to the development and production of hydrocarbons in Kazakhstan is currently governed primarily by two major pieces of legislation: first, Law No. 291-IV "On Subsoil and Subsoil Use" (Subsoil Use Law), which came into effect July 2010; and second, the revised Tax Code, which came into effect in January 2009. Both of these laws, and how they historically developed, will be outlined in the next section.

4.1 A summary of the oil and gas legal regime in Kazakhstan

The new Subsoil Use Law of 2010 replaced both the prior Subsoil Use law and the Petroleum Law of 1995. The most important aspects of this new law relates to the structure of future petroleum agreements in Kazakhstan. While the new law does not repeal the PSA Law of 2005 – a separate law enacted as a special law governing PSAs exclusively – it does require that no future contracts be structured as PSAs. For existing PSAs, the government issued a statement prior to the adoption of the revised Tax Code of 2009 stating that the tax provisions in all existing PSAs, and one concession agreement (Tengiz), would remain in effect. However, future petroleum agreements would be subject to the new Subsoil Use Law and the revised Tax Code provisions.

The revised Tax Code of 2009 governs the taxation rates for oil and gas projects in Kazakhstan. Kazakhstan's taxation system is composed of direct and indirect taxes. Taxes, levies and other compulsory payments are calculated and payable in the national currency and are reflected in the annual budget of the National Fund, in accordance with the Budget Code. Exceptions are made for cases where legislative or contractual provisions have been made to allow tax-in-kind or payment of tax in a foreign currency. Any tax exemptions or reductions are effected through supplementary legislation, or contractual provisions in accordance with the Law of the Republic of Kazakhstan on state support for direct investments.

The revised Tax Code of 2009 lowers corporate-income and value-added taxes, replaces royalty payments with a mineral extraction tax, and introduces excess profit taxes, and rent taxes on the export of crude oil and natural gas. Investors are also subject to a

signature bonus, commercial discovery bonus, and historical cost reimbursement. Therefore, when viewed in conjunction with the new Subsoil Use Law, the revised Tax Code sets a new taxation scheme for all future oil and gas projects. Under the new Subsoil Use Law, agreements with investors require separate contracts for exploration and production operations, shorter time limits on exploration contracts, and provide for enhanced government authority to terminate contracts not in compliance with the law. Further, any future tax stability clauses in contracts are subject to parliamentary approval.

For Kazakhstan, the current contractual and taxation schemes approved by the government are the result of many years of modification and adaptation. The development of the hydrocarbon industry and the legislation governing its operations can be split roughly into three periods. Each of these periods has seen a number of changes in the regulatory and legal framework for governing hydrocarbon exploration, development, and production. Following is a brief summary of these periods.

The first stage, up to 2004, was marked by the first signs of government interest in increasing its control over the oil and gas sector. Specifically, a number of amendments and supplements to the Tax Code became effective from January 2004, including a list of investors' expenses that could not be reimbursed through oil production, namely, those incurred due to non-execution or improper execution of the contract. An amendment to the Tax Code introduced triggers for calculating fixed shares in PSAs.

The second stage, from 2005 to 2008, also saw a number of tax innovations. The Supreme Court secured the right of tax authorities to exercise control over transfer pricing, including that of companies holding contracts

with stabilization clauses. Amendments introduced to the Subsoil Use Law in October 2005 were branded by the mass media as ‘rights of the first night,’ securing the state’s pre-emptive right to acquire any shares released onto the market. The state was also given power to suspend subsoil use when an investor was in breach of contract.

Also, in 2005, a new PSA law was adopted. While PSAs were permissible under previous legislation, this law was the first dedicated specifically to PSAs, and introduced a number of conditions and requirements for future PSAs. One new requirement granted SOE KazMunaiGaz the right to a 50 per cent share in all subsequent offshore PSAs. In November 2007, further amendments to the Subsoil Use Law secured the state’s right to unilaterally withdraw from a contract if the subsoil user’s actions significantly affect Kazakhstan’s economic interests and threaten national security, particularly where deposits of ‘strategic importance’ are concerned.

In the third stage, from 2009 to the present, the government has attempted to develop a new legal framework for taxation and subsoil use. Proposed in 2008, the new Subsoil Use Law came into force in July 2010 and repealed both the previous Subsoil Use Law and the Petroleum Law of 1995. The new Subsoil Use Law implements major government policy changes in contractual terms and local content requirements. This third stage also saw major changes to the Tax Code. In January 2009, the revised Tax Code came into force and provides a new regime for excess-profit taxes and for rent taxes on oil and gas exports.

4.2 The taxation of oil in Kazakhstan

In sum, the recent changes to the hydrocarbon taxation regime in Kazakhstan mean that there are essentially two ways that oil and gas operations are taxed. The first taxation model we will call the PSA model. The PSA model encompasses the taxation method used on existing PSAs in Kazakhstan. These taxation provisions, while inconsistent with the current changes in legislation in Kazakhstan, have been stabilised by tax stability clauses in the PSAs and reinforced by government statements guaranteeing that such clauses will be respected, even though the law has now changed. For all other operations, the new Subsoil Use law and the revised Tax Code will exclusively govern new oil contracts. We will call this new model the Excess Profit Tax (EPT) model. A summary of the differences in the two taxation models is highlighted in Table 8.

Table 8 clearly shows that under the EPT model, the subsoil user (investor company) is responsible for all taxes and compulsory payments stipulated in the Tax Code, with the exception of the state’s share of production. All taxes are payable by the subsoil user in accordance with the current tax system and any changes thereto. When any work is done or services are rendered outside the scope of the contract, the subsoil users will pay taxes and other compulsory payments in accordance with the Tax Code.

Under the PSA model (see Box 3 below), the subsoil user gives the state its share of production, together with payment to the budget of some taxes and other compulsory payments set out in the PSA itself. The share of production is the most significant element of the state’s profit under this model. On signing a PSA, the state and the subsoil user will stabilise the tax regime, so that any future

Table 8. Differences between the EPT and PSA taxation models

Taxes	EPC model	PSA model
1. Special taxes and payments on hydrocarbon agreements:		
a) Bonuses	Yes	Yes
b) Royalties (mineral extraction tax from 2009)	Yes	No
c) Excess profit tax	Yes	No
d) Share of production	No	Yes
e) Additional payments under PSAs	No	Yes
2. Other taxes and compulsory payments to the state:		
a) Rent tax on oil and gas condensate exports	Yes	No
b) Excise tax on oil and gas condensate	Yes	No
c) Land tax	Yes	No
d) Property tax	Yes	No
e) Environmental fees	Yes	Yes
f) Other fees (e.g., waterway navigation fees)	Yes	Yes
g) Other taxes and payments	Yes	Yes

Source: PPMC

Box 3. Taxation of PSAs in Azerbaijan

In Azerbaijan, the profit tax on PSAs varies between 25 per cent and 32 per cent, depending on the individual contract. For example, the ACG PSA stipulates a profit tax of 25 per cent. Regardless of numerous changes to the country’s tax system, since the contract was signed in 1994, none of them have been applied to taxation under the PSA. As a rule, most subsequent PSAs signed by Azerbaijan stipulate a profit tax above 25 per cent.

In addition to the profit tax payable under PSAs, companies pay a social tax to the government at the rate of 25 per cent for the Social Protection Fund, of which 22 per cent is paid by the company and 3 per cent by its employees.

changes to the state’s tax policy cannot be applied to the subsoil user, except by separate arrangement between the subsoil user and the state.

The ability to change the terms of taxation fixed in a PSA by the parties’ mutual consent is an important characteristic of Kazakhstan’s legal framework, intended to protect Kazakhstan’s economic interests. If

the government decides to abolish certain taxes or other compulsory payments to the budget, due under the terms of a PSA, the subsoil user will continue with any such taxes or compulsory payments as stipulated in the PSA until relevant amendments are agreed. In cases where more than one taxpayer (investor company) acts as a subsoil user under a PSA, the same tax regime is applicable to each taxpayer individually.

Before 2004, tax collection was supervised by the Ministry of State Revenue, which consisted of the Tax and Customs Committees, the Tax Police Committee, and a number of other institutions. In the administrative reform of 2004, the Ministry of State Revenue was abolished, and the Tax and Customs Committee (now called the Customs Control Committee) became part of the Ministry of Finance.

The Tax Committee exercises control and supervision over the budget revenue from taxes and other compulsory payments, and ensures that compulsory pension contributions and social payments to the State Social Insurance Fund are transferred in full and in a timely manner. The committee is comprised of the following local agencies:

- inter-regional tax committees
- tax committees for the regions and the cities of Almaty and Astana
- inter-district tax committees
- tax committees for districts, cities and districts within cities
- tax committees for special economic zones.

The functions of the tax committee in relation to extractive industries include:

- maintaining the state register of taxpayers
- monitoring the financial and economic activities of taxpayers, producers of oil products, oil suppliers, and sales personnel at oil depots
- maintaining a single database on the production and turnover of certain kinds of oil products
- liaising and cooperating with international organisations on issues relating to the receipt of taxes and other compulsory payments to the budget, and the production and turnover of excisable goods
- determining forms, procedures and deadlines for other state authorities to submit data on production volumes and turnover of oil products and other necessary information for a single database
- exercising state control over transfer pricing
- exercising control over the turnover of oil products through accompanying notes and declarations on the production and turnover of oil products.

In 2007, a designated agency for monitoring subsoil users was introduced under the Ministry of Finance in Kazakhstan. Its main function is to monitor subsoil users' compliance with their contractual obligations to pay taxes and make other compulsory payments. In a speech to Kazakhstan's Parliament in April 2007, the Minister of Finance noted that a number of subsoil users were regularly in breach of the tax legislation through the application of transfer pricing (see Box 4), unauthorised postponement of commercial production of minerals, and by taking unilateral advantage of the more liberal provisions of tax legislation (Expert-Kazakhstan (2007)).

Box 4. Transfer pricing

A transfer price is the price used for internal transactions between divisions of a company. The parent company can sometimes treat its office abroad as a paying customer for the goods that the company produces. Commercial relations of this nature create obvious profit opportunities, as well as giving rise to various local tax exemptions and tax avoidance schemes.

Abuse of transfer pricing enables companies to transfer profits to countries or zones with a lower tax burden, or even become exempt from (or avoid) taxation in any given state. Many countries, therefore, exercise state control over transfer pricing through competent bodies monitoring transactions between divisions of companies.

In an interview for Interfax in May 2008, Kazakhstan’s Minister of Finance estimated that “since the current legislation on state control over transfer pricing was introduced seven years ago, the share of offshore trade went down from 60 per cent to 26 per cent” (Interfax 2008).

Table 9. Tax definitions

Taxable Item	Specific item being taxed (land, income, sales, etc.)
Tax base	The sum total of the taxable items
Tax rate	Applicable percentage of the tax base payable to the state
Taxable income	Gross annual income, less permissible tax adjustments, less permissible deductions
Net income	Taxable income, less CIT and less tax on net income if payer is a permanent establishment of a non-resident entity.

The following section and Table 9 detail the different types of tax payments and duties applicable to hydrocarbon development and extraction in Kazakhstan.

They include primarily the following, which will be described in the next section:

- corporate income tax (CIT)
- special taxes and payments, which include
 - bonuses (signature, production and discovery)

- mineral extraction taxes (METs)
- excess profit taxes (EPTs)
- reimbursement of historic costs
- rent taxes on exports
- export customs duties
- additional payments.

A third category, indirect taxes and payments, will also be detailed. These include

- value-added taxes (VAT)
- excise duties.

4.2.1 Corporate income tax

In Kazakhstan, the corporate income tax (CIT) is payable by resident legal entities, with the exception of government institutions and non-resident legal entities doing business in Kazakhstan through a permanent establishment or earning income from sources in Kazakhstan.

Items taxable for the purposes of the CIT are:

- taxable income
- income taxed at source
- net income of a non-resident legal entity doing business in Kazakhstan through a permanent establishment.

CIT calculations and payment procedures are detailed in the Tax Code of Kazakhstan. For the purposes of this guide we shall only provide a brief commentary on tax-deductible exploration costs and preliminary expenses preceding field development.

The list of permissible deductions from gross annual income specified in the Tax Code for subsoil users includes exploration and field work costs as well as preliminary work expenses, including estimation and field development costs, general administrative expenses, signature and commercial discovery bonuses paid, and fixed and intangible assets expenditure incurred after the commercial discovery but prior to the start of production.

The above costs are deducted from the gross annual income in the form of depreciation allowances from the moment production begins. This occurs after the commercial discovery of minerals and allows for a procedure entitling the subsoil users to set a relevant depreciation rate (the maximum value limit is currently set at 25 per cent).

If the subsoil user receives income from his activities under an existing contract during

the period in question, any such deductions will be reduced by the amount of income received from the following:

- during exploration and preliminary work before production
- from sales of minerals extracted after commercial discovery but prior to the beginning of production, or
- from the partial sale of mineral rights.

Rates for the corporate income tax are set in the Tax Code as follows:

- 20 per cent from 1 January 2009 to 1 January 2010
- 17.5 per cent from 1 January 2010 to 1 January 2011
- 15 per cent from 1 January 2011.

It should be noted that earlier PSAs may set different rates for the CIT in accordance with the Kazakhstan tax regulations in force when the contract was signed. As most PSAs incorporate a stability clause, any innovations and amendments to the tax regulations will not apply.

4.2.2 Special taxes and payments

As outlined above, a number of special taxes and payments are applicable to all subsoil users under the revised Tax Code of 2009, and each will be detailed in subsequent sections.

Bonuses

There are three types of bonus applicable to hydrocarbon development and extraction in Kazakhstan: signature bonuses, commercial discovery bonuses, and production bonuses. Payment of exploration and development milestone bonuses to the state is integral to most hydrocarbon agreements, including PSAs. In the case of PSAs, these bonuses are

non-reimbursable and do not count towards the state's profit oil share. Bonuses often come just at the right time, as many of them are paid to the state during the contract's initial stages, when production has not yet begun and the state budget requires a cash injection. These bonuses can serve the purpose of ensuring financial stability or resolving a country's urgent socio-economic problems.

Signature bonuses: As the name implies, are fixed, one-off lump sums, paid by the company on signing the contract with the state. Article 288 of the Tax Code defines it as follows:

- The signature bonus is a one-off lump sum paid by the subsoil user to acquire the mineral rights for the contract territory.
- The initial amounts of signing bonuses shall be determined by the Republic of Kazakhstan government on the basis of an estimate that takes into account the volume of minerals involved and the economic value of a deposit.

The signature bonus differs from any other special payments applicable to subsoil users in the manner in which it is calculated. Most countries choose to grant mineral rights by tender, where the signature bonus is one of the key selection criteria: the higher the bonus offered, the greater the chance that the bidder will win the contract. In order to ensure a certain level of payments from subsoil users, the state will set a minimum limit for the signature bonus.

The starting value of the signature bonus is defined in the Tax Code. For example, hydrocarbon development contracts for territories without proven hydrocarbon reserves, the starting value will be 3000 times the monthly indicator set out in the annual National Fund budget. For hydrocarbon production contracts, the minimum value of

the bonus will be much less: approximately 300 times the monthly indicator value.

For contracts where the hydrocarbon reserves are proven, the following simple formula is used to calculate the starting value of signature bonuses is applied:

$$(C \times 0.04\%) + (C_n \times 0.01\%) = \text{Signature bonus}$$

where:

C = the value of the ultimate reserves of crude oil, gas condensate or natural gas, as approved by the State Commission for Mineral Resources of Kazakhstan, in commercial categories A, B, C1.

C_n = the overall value of the C2 inferred reserves approved and/or accounted for in the findings of the State Commission for Mineral Resources of Kazakhstan for the purposes of current estimation of potentially commercial reserves and inferred C3 reserves.

Under the Tax Code, the value of hydrocarbon reserves is calculated based on the price of the hydrocarbons in question on the International Petroleum Exchange or the London Metal Exchange on the day the bidding is announced for the hydrocarbon rights. When the stock exchange price for the hydrocarbons cannot be established, the value of extractable and inferred reserves is calculated based on the total production costs indicated in the work programme for the duration of the contract, and then multiplied by 1.2.

The starting value of the signature bonus can be increased before the bidding for mineral rights starts by the decision of the competent authority's tender committee. Signature bonuses are part of the industry's competitive process for acquiring licences and are based upon the amount of acreage offered and its perceived exploration potential.

Commercial discovery bonuses:

Considering the geological risks associated with hydrocarbon exploration, discovery of commercially viable fields is a rarity. Nevertheless, commercial discovery bonuses are a fairly common reward whenever a subsoil user makes a commercial discovery within the contract territory of an exploration contract. Under the Tax Code in Kazakhstan, this bonus is also payable when the additional exploration of fields reveals resources supplementary to the initially approved extractable reserves.

Production bonuses: These are paid upon the achievement of certain levels of production. Oil companies often give up this bonus, opting to pay income taxes instead. According to Article 317 of the revised Tax Code in Kazakhstan, production bonus payments are not applied to subsoil users. However, production bonuses are common in Azerbaijan. The largest set of production bonus payments received by the Azeri government is understood to have totalled USD300 million, accrued under the ACG PSA. The bonuses were paid in stages. The biggest bonus under the contract was paid in 1995, when the Azerbaijani government sanctioned the start of the Chirag field development.

Some of the bonus money received from IOCs was used by the Azeri government to support the national currency rate, and some went to the country's foreign exchange reserve. As had been agreed, the final bonus payment was paid in 2004, when the international consortium began construction work to develop the deepwater areas of the Gunashli field, signifying the final development stages of the project.

Mineral extraction taxes (METs): Before 1 January 2009, all companies engaged in the production of hydrocarbons (except those operating under PSAs) paid royalties

to the government, based on production. The amount of the royalty payment varied according to an applicable rate that was set by the government and was based on the volume of minerals produced — or the volume of the first commercial product manufactured from these hydrocarbons — and their taxable value (i.e., the world price of oil). The amount of royalty set by the contract was usually paid in cash, but sometimes in kind. Table 10 illustrates the distinction between royalties and mineral extraction taxes.

However, the revised Tax Code of 2009 replaced royalty payments with a mineral extraction tax (MET). The MET was introduced to offset problems relating to government claims that transportation costs, which could be deducted from royalty payments, were being overestimated by subsoil users. The MET aims to reduce this problem by applying a tax in lieu of a royalty. Both the MET and royalties are essentially volume-based taxes, with the difference between the two deriving only from the manner in which the tax is calculated. Royalties are calculated after certain costs are deducted. The MET excludes these deductions and also appears to set a higher overall variable rate on production than the previous royalty regime (see Table 10).

The calculation of the MET has been criticised by some subsoil users because of the way in which the tax is calculated. An Almaty attorney specialising in the Kazakh oil and gas sector commented:

Royalty payments took into account the specifics of the tax base calculation in the industry. For example, for the purposes of royalty calculation, the subsoil user's costs in transporting the raw material to the sales depot were factored in – which is quite logical and fair. With MET, such costs are not accounted for. Initially, one

Table 10. Differences between royalties and mineral extraction taxes (MET)

Type	Royalty	MET
Definition	A payment made for the right to use the subsoil in the process of hydrocarbon extraction	A tax paid for each type of hydrocarbon produced, and based on reserves of such hydrocarbons being approved by a specially authorised state body
Taxable item	The volume of hydrocarbons produced in the tax period	The volume of hydrocarbons produced in the tax period
Tax rate	Based on the average sales prices in the tax period, exclusive of indirect taxes and costs of transportation to the sales depot Rates for hydrocarbons calculated on a progressive scale from 2 to 6%.	Tax rates for crude oil and gas condensate are fixed on a scale (see Table 11) based on the volume of production and world market prices. Tax rates for hydrocarbons calculated on a progressive scale from 7 to 20%.

Source: Kazakh Ministry of Finance

of the reasons for replacing royalty with MET was the deliberate overstatement of transportation costs by the subsoil users alleged by the tax authorities, or, in other words, compensation for idle time to transport companies. This is, however, the problem of poor practices in tax administration. As regards reducing the MET rates for the oil production industry, I believe that this is a necessary step, at least in this low-price environment. In our estimate, the newly introduced tax regime for subsoil users is paradoxical. The problem is, for example, that the lower the oil prices, the higher the tax burden ratio will be for subsoil users. This results from the high MET rates and tightening of the rent tax regulations. Overall, one could either bring the MET rates down, or account for the subsoil user's significant costs for the purposes of its calculation (Gazeta Kapital 2009).

In February 2009, the Ministry of Industry and Trade for Kazakhstan suggested that, due to the current world market outlook, the government should temporarily reduce MET rates, and introduce a preferential tax regime for low-profit fields. However, there are already a number of safeguards included in the Tax Code regarding the application of the MET. In terms of built-in exceptions in its application, the following examples are insightful:

- For crude oil and gas condensate sold for domestic use, the Tax Code stipulates a 50 per cent reduction in the MET rate.
- The MET rates also differ for different types of hydrocarbons.
- The MET rate for natural gas is fixed at 10 per cent, with a special lower rate applied to natural gas sold on the domestic market. Reduction factors are also stipulated for

Table 11. MET rates

Annual production volume (crude oil and gas condensate)	Rate %
Up to and inclusive of 250,000 tons	7
Up to and inclusive of 500,000 tons	9
Up to and inclusive of 1,000,000 tons	10
Up to and inclusive of 2,000,000 tons	11
Up to and inclusive of 3,000,000 tons	12
Up to and inclusive of 4,000,000 tons	13
Up to and inclusive of 5,000,000 tons	14
Up to and inclusive of 7,000,000 tons	15
Up to and inclusive of 10,000,000 tons	17
Over 10,000,000 tons	20

Source: Kazakh Tax Code

low-profit, high-viscosity, marginal, and worked-out fields.

- The higher rates of the new METs (as compared to earlier royalty rates) actually balance out, when viewed in light of the entire taxation regime for hydrocarbons. Under the revised Tax Code, the CIT has been substantially reduced in comparison with earlier CIT rates.

The MET is based on world market prices, as opposed to average sale price under earlier royalties. The Tax Code calculates the market price for crude oil and gas condensate as an average of daily quotes for Urals Med or Brent Dtd crudes in a given tax period, based on information published in the Platts Crude Oil Marketwire. When quotes for the above grades are not available from this source, quotes from Petroleum Argus are used.

Box 5. Oil property benchmarks

Properties of oil (such as density, sulphur content, etc.) can vary from country to country and even from well to well. This is why the so-called oil benchmarks were introduced for the purposes of price formation: Urals and Siberian Light (Russia), Brent (UK), Light Sweet (US). Brent grade oil is used as the benchmark for trading on the London ICE Futures exchange.

Prices for other oil grades, which are not listed separately, are tied to the Brent oil price and calculated by application of the reduction or scale-up factor. Brent Dtd is an international crude oil benchmark. It derives its name from the fact that the oil supplied under this quotation has been assigned a loading date, which is set 15 days prior to actual delivery.

The following formula is applied to calculate the market price of crude oil and gas condensate:

$$\frac{(P_1 + P_2 + \dots + P_n)}{n} = S$$

where:

P₁, P₂, ... P_n = daily average world market price for crude oil and gas condensate on quotation days in a given tax period.

n = number of quotation days in a given tax period.

S = world market price for crude oil and gas condensate in a given tax period.

To calculate the daily average world market price for crude oil and gas condensate, the following formula is used:

$$(P_1, P_2 + \dots + P_n) = \frac{C1 + C2}{2}$$

where:

P_n = average daily world market price for Urals Med or Brent Dtd crude oil grades.

C1 = average opening daily world market price for Urals Med or Brent Dtd.

C2 = average closing daily world market price for Urals Med or Brent Dtd.

The subsoil users classify crude oil and gas condensate as Urals Med or Brent Dtd standard grades in accordance with the crude oil sales agreements. When the sales agreement does not specify the grade, the subsoil user must classify the crude oil supplied under such agreement as the grade

with the highest average world market price in the given tax period.

C. Excess profit taxes: As noted above, the EPT applies to subsoil users operating under contracts covering projects in hydrocarbon development and extraction that are not classified as PSAs. This will include all agreements signed under the new Subsoil Use Law after July 2010, and all earlier concession-type (tax and royalty) contracts where the stabilisation of tax provisions has not been provided for in the contract.

The EPT applies to a specific part (the EPT tax base) of the subsoil user's net income received under each contract where the aggregate income to deductions ratio allowable for EPT purposes is more than 1.25 for the reporting tax period. The EPT tax base is the amount of net income in a given tax period that exceeds 25 per cent of deductions allowable under the Tax Code at the end of the tax period.

Deductions allowable for EPT purposes for each contract are the aggregate of: 1) the expenses deductible for CIT purposes under contracts during the reporting tax period and 2) other expenditures such as: a) costs incurred during the reporting tax period for the acquisition and/or construction of fixed assets, b) expenditures subject to deductions through amortization charges, and c) tax losses carried forward from earlier periods.

The EPT is calculated by applying the respective EPT rate to the tax base (Table 12). The tax base is calculated in accordance with the provisions of the Tax Code and any applicable adjustments. Accumulated income is the subsoil user's aggregate annual income from the contract inception date. Accumulated expenditure is the subsoil user's aggregate deductible expenses from the contract inception date.

Table 12. EPT rates

Ratio of aggregate annual income to deductions	Tax base	Rate %	Tax payable to the budget
1.25 or less	not taxed	0	
1.25 to 1.3 inclusive	part of net income for which the ratio is 1.25 to 1.3	10	calculated based on the rate of 10%
1.3 to 1.4 inclusive	part of net income for which the ratio is 1.3 to 1.4	20	calculated based on the rates of 10% and 20%
1.4 to 1.5 inclusive	part of net income for which the ratio is 1.4 to 1.5	30	calculated based on the rates of 10%, 20% and 30%
1.5 to 1.6 inclusive	part of net income for which the ratio is 1.5 to 1.6	40	calculated based on the rates of 10%, 20%, 30%, and 40%
1.6 to 1.7 inclusive	part of net income for which the ratio is 1.6 to 1.7	50	calculated based on the rates of 10%, 20%, 30%, 40% and 50%
over 1.7	part of net income for which the ratio is over 1.7	60	calculated based on the rates of 10%, 20%, 30%, 40%, 50% and 60%

Source: Kazakh Tax Code

Reimbursement of historical costs

These are payments to reimburse the state's historical geological study and field development costs with respect to the contract territory. It is a fixed payment the subsoil user makes to reimburse the state for the aggregate costs incurred for geological study and field development of the relevant contract territory, prior to the signing of a contract on subsoil use. Payment for reimbursement of historical costs is not applicable to contracts that only cover the exploration of mineral fields without the production of minerals.

The aggregate historical costs incurred by the state for geological study and field development on the relevant contract territory are calculated by a specially authorised government body, in accordance

with the legislation of Kazakhstan. Pursuant to the law of Kazakhstan, part of the reimbursable historical costs is paid into the budget for geological information owned by the state. The remaining amount goes to the budget as a payment for the reimbursement of historical costs.

Rent tax on exported crude oil

Rent tax on exported crude oil and gas condensate is payable by individuals and legal entities carrying out export sales of crude oil and gas condensate. Importantly, companies operating under PSAs are exempt from this tax. The rent tax base is the value of exported crude oil and gas condensate, calculated on the basis of the volume of exported crude oil and gas condensate and the world market price (Table 13). The government may decide

Table 13. Rent tax rates

World market price of crude oil (and gas condensate)	Rate %
Up to USD20 per barrel, inclusive	0
Up to USD30 per barrel, inclusive	0
Up to USD40 per barrel, inclusive	0
Up to USD50 per barrel, inclusive	7
Up to USD60 per barrel, inclusive	11
Up to USD70 per barrel, inclusive	14
Up to USD80 per barrel, inclusive	16
Up to USD90 per barrel, inclusive	17
Up to USD100 per barrel, inclusive	19
Up to USD110 per barrel, inclusive	21
Up to USD120 per barrel, inclusive	22
Up to USD130 per barrel, inclusive	23
Up to USD140 per barrel, inclusive	25
Up to USD150 per barrel, inclusive	26
Up to USD160 per barrel, inclusive	27
Up to USD170 per barrel, inclusive	29
Up to USD180 per barrel, inclusive	30
Up to USD190 per barrel, inclusive	32
USD200 and higher	32

Source: Kazakh Tax Code

to replace the payment of rent tax in money with payment in kind.

Export customs duty on crude oil

In May 2008, the government of Kazakhstan announced the introduction of export customs duty on crude oil and gas condensate. Export customs duties on crude oil and gas condensate are part of the revised Tax Code regime of 2009. The duty is calculated as a percentage of the world market price when the duty is assessed. When first introduced

in May 2008, the duty was set at 109.91 per tonne. This was calculated based on a world market price at that time, which then stood at USD714 per tonne.

Subsoil users operating under PSAs with a customs duty stability clause were not affected by the introduction of the export customs duty. The situation with Karachaganak Petroleum Operating (KPO) consortium is a good illustration of this point, as the PSA they had signed with the state stipulated tax stability, but not the stability of

customs duties. KPO were therefore forced to pay the export customs duty on the same basis as everyone else. It is difficult to say why the company failed to fully safeguard its interests and foresee such developments, but this example shows the economic relevance of payment stability clauses in contracts.

The government explained the introduction of the new duty as being necessary to protect the domestic oil products market and secure additional revenues. Between May and December 2008, the government was hoping to secure an additional USD1 billion, but oil prices crashed two months after the Export Customs Duty was introduced, making the influx of such significant revenues unrealistic. When the revised Tax Code took effect in January 2009, subsoil users became liable for the Rent Tax (described earlier). Although the Export Customs Duty was not repealed, the Rent Tax replaced it. In late January 2009, the government announced that the Export Customs Duty rate for crude oil and gas condensate would be set at zero.

Additional payments

The prior Tax Code in Kazakhstan, which was in force between January 2004 and January 2009, stipulated a so-called additional payment from subsoil users for companies operating under PSAs. This payment was introduced to stabilise the state's revenue under PSAs, so that a minimum share of production in any given tax period could be guaranteed:

Five to 10 per cent of production volume from the moment production begins until a return is received on investment, and 40 per cent of production volume in subsequent periods.

In this context, the state's revenue share under a PSA is equal to its production share plus taxes and other compulsory payments

to the budget, exclusive of VAT and taxes for which the subsoil user acts as a tax agent. The additional payment from the subsoil user is not stipulated in the revised Tax Code of 2009.

4.3 Indirect taxation

In addition to the standard direct taxes described in the previous section, there are also two types of indirect taxes that are worth mentioning: a) VAT and b) Excise Duties.

4.3.1. Value-added tax

Pursuant to the revised Tax Code, crude oil, natural gas, and gas condensate sold within the country are subject to a 12 per cent VAT. The same tax rate is applied to goods and equipment imported for the oil and gas sector. Some contracts contain clauses exempting the subsoil users from VAT charged on imported goods, usually specifying a list of such goods. In Kazakhstan, export sales of crude oil, natural gas, and gas condensate are not subject to VAT. Geological exploration and reconnaissance services are also VAT exempt. It is notable that in neighbouring Azerbaijan, all equipment and materials imported for the purposes of field development under PSA contracts are VAT exempt.

4.3.2. Excise duties

Both domestically manufactured and imported goods are subject to an Excise Duty in Kazakhstan. For example, an Excise Duty is applied to petrol (with the exception of aviation fuel) and diesel fuel sold on a wholesale and retail basis. However, the Excise Duty rate for crude oil, including gas condensate, is zero. Rates for Excise Duties are set by the government and charged as a percentage of the price of goods and/or in absolute terms (per unit of measure). The Tax Code clearly distinguishes between wholesale and retail. For example, the shipment of non-aviation and diesel fuel to a company's

own divisional structures for further sales is classified as wholesale, whereas using manufactured or purchased non-aviation fuel for the company’s own production needs is classified as retail.

4.4 Tax burden ratio

The tax burden ration (TBR) is usually defined as the ratio of aggregate taxes and other compulsory payments to the budget (exclusive of debt repayments) to the company’s aggregate annual income in the reporting period. This ratio is usually measured as a percentage. The TBR is useful for the purpose of measuring the attractiveness of a country’s tax regime to investors. From the public point of view, a subsoil users’ TBR may be an important indicator of how fairly the rent is shared between the subsoil user and the state.

The Executive Director of the KazEnergy Association says that the “TBR for KazMunaiGaz Exploration and Production is 35 per cent when calculated by the Ministry of Finance, and 51 per cent when the international calculation method is employed”(Panorama 2007). The Vice-Minister of Finance for Kazakhstan says that “at present, the tax burden for the natural resources sector in Russia varies between 60 and 65 per cent depending on the field. We have compared our taxation to that of Alaska, Mexico, Bolivia and Venezuela, and Kazakhstan today looks like an absolute tax haven for oil companies. Certainly no-one is going to die if we were now to introduce a little tax increase” (Panorama 2008).

Nevertheless, one should be cautious when comparing TBRs for different countries and sectors. There are, in fact, a large number of TBR calculation methods, which differ in both the taxes taken into account, and the TBR base, which can include sales proceeds, company profits or even added value.

Depending on the method used, the TBR value can vary by a factor of two or more. Therefore, before conducting any comparative analysis, it is important to make sure that the TBRs compared have been calculated by the same method. In terms of macroeconomics, the TBR can be used in accessing the proper amount of GDP should go to the state through taxation and other payments. The relative tax burden can be calculated by the following formula:

$$\frac{\text{Sector's share in the state's aggregate tax revenue} \times 100\%}{\text{Sector's share of the GDP}}$$

This method of calculating the relative tax burden is best for international comparative analysis as it precludes any dispute as to the TBR base.⁴

4 Summaries of Kazakhstan revenues from the oil and gas industry are available at the Ministry of Finance website. See www.minfin.kz.

5

PART 5

What civil society can do

It is widely accepted that, through informed scrutiny of state-investor deals, civil society can provide the ‘checks and balances’ needed to improve governance and outcomes in the oil and gas sector. Even though contracts are commercial transactions, they have a public element that creates a strong argument for transparency and public scrutiny. A primary aim of this guide is to increase public awareness about oil contracts and how their terms and conditions affect the distribution of the risks, costs and benefits involved in oil projects. A good understanding of the complex issues involved in oil and gas contracts adds a powerful tool in the civil society toolbox. This section briefly discusses the roles that civil society can play to increase accountability and public scrutiny in the extractive industries, with a focus on oil contracts. Civil society can help improve transparency of extractive industry contracting in a number of ways, including:

- assisting the public in accessing contractual terms and conditions⁵
- providing the public with state-of-the-art legal, economic and financial analyses of the terms and conditions reflected in the contracts
- providing the public with information about the parameters needed to monitor contract performance

- providing independent revenue calculations and monitoring compliance with contractual obligations
- disseminating information to the broader public, including the results of revenue monitoring activities.

These activities concern not only the contract itself, but more generally the contracting process, from negotiation through contract management. In terms of pre-contract negotiations, for example, the following aspects can be independently monitored:

- the preliminary conditions of the tender
- the entry list
- the transparency and openness of the whole cycle of licence acquisition
- whether the criteria of the selection process have been met by the winner.

As to the contract itself, both revenue and non-revenue issues can form the object of independent monitoring by civil society. These aspects are discussed in the next two sections.

5 In Azerbaijan, for example, all PSAs have the force of law, and are thus publically accessible.

5.1 Promoting transparency in contracting: Revenue issues

In oil contracts, the distribution of oil revenues is a key issue. It must be borne in mind that the end profits for both the government and the IOC are measured not by the estimates factored into contracts, but by actual revenues over project duration. In other words, it is necessary to establish whether there is any difference between contractual terms and actual practice as it evolves during project implementation. That said, the terms of the contract, and the terms of the pre-contractual tender process remain a primary indicator for actual practice; therefore, these terms and conditions are a vital aspect of financial analysis.

Below are several examples of actions that civil society can take to monitor revenue issues in oil contracts:

- obtaining and analysing data on revenue distribution
- making recommendations to governments and IOCs, for instance as part of public consultations, multi-stakeholder dialogues, published reports or bilateral meetings
- comparing government and IOC revenue distribution
- comparing government take in different resource-rich states
- making recommendations for long-term revenue management
- conducting opinion polls to assess public perceptions of the oil and gas sector's impact on people's lives, or to understand public expectations for the oil and gas sector
- disseminating information and engaging the general public, for example by publishing alternative statements of revenues

and other project benefits, organising conferences, assisting the media in reporting on transparency and effectiveness of revenue management, or holding public consultations on spending oil and gas revenues.

5.2 Promoting transparency in contracting: Beyond revenues

While this guide has focused on revenue issues, other contract provisions are also important and can form the object of civil society scrutiny. These provisions are not directly tied to tax liability or production sharing requirements, but have to do with social or environmental considerations. For example, contracts may require companies to implement social investment projects, or companies may implement such projects voluntarily. Contracts may also contain local content requirements to promote local participation in project activities through employment or procurement; these requirements are seen as a way of maximising local economic benefits. Also, oil companies are typically required to adhere to standards for the protection of the environment or human health. Monitoring compliance with these provisions can be as important to civil society as those obligations relating solely to tax liability and rent distribution.

As mentioned earlier, social investment projects may be contractual or voluntary. Contractual social investment projects can be stipulated in the hydrocarbon agreement itself (the PSA, for example), or in a separate agreement with local groups. Where social investment requirements are included in a PSA contract, IOC expenditures relating to social investment (for example, construction of public buildings such as hospitals and schools) may be considered as part of the company's cost recovery. In other words, the

government effectively then reimburses the company for these expenses. In contrast, voluntary initiatives are not contractually stipulated, but are often initiated by IOCs as part of their corporate social responsibility policy or to build relations with local stakeholders.

5.3 Monitoring social investment

A key issue is the extent to which social investment projects genuinely respond to local needs. A 2008 documentary film, *Money Thrown to the Wind* highlights some of the problems related to social investment programmes. According to the documentary, “over the last ten years, oil companies have invested more than half a billion dollars in the development of social infrastructure in Kazakhstan.” And yet, expenditure patterns would seem to cast some doubt about the extent of genuine community participation in the process. Five of the most expensive projects include: an indoor swimming pool in Atyrau (USD14.5 million), a health and fitness complex in Zhanaozen (USD14 million), the electrification of Atyrau (USD 12 million), a theatre in Uralsk (USD10.5 million), and a technical training college in Kulsary (USD9 million) (Soros Foundation Kazakhstan 2010).

IOCs can finance social projects directly or by investing in special funds set up for the local community. The arrangements for deciding what social investments to prioritise are crucial. In some cases, local government bodies decide, excluding or marginalising representatives of the local community. In others, inclusive and well thought out social investment projects can provide important benefits for local communities. Even relatively small amounts of money can foster social development in the area, but this requires genuine community participation and effective monitoring. So the key question is

often not how much money is spent on social investment programmes, but how well that money is spent.

Local content provisions require oil companies to include local labourers or locally sourced materials in project implementation. The provisions can be included in oil contracts or in national legislation. For example, Kazakhstan’s new Subsoil Use Law, which came into effect in July 2010, includes clear requirements on local content. It requires mandatory contractual terms relating to the percentage of Kazakhstan personnel, goods and services. All new oil contracts must include local content targets, and all projects must comply with the new Subsoil Use Law in regard to local content. Through a phased process, this also includes contracts that are already being implemented. The new law also requires equal conditions and remuneration for Kazakhstan personnel, including those engaged in subcontract work. The law also contains fines and penalties for failure to meet local content requirements.

5.4 A final remark

Sustainable development is not guaranteed by big profits alone. Revenues are of little use if they are spent unwisely. Social and environmental considerations are as important as economic ones. And in managing the oil and gas sector, it is important to remember that the oil wealth of a country belongs to both present and future generations.

The government of Kazakhstan has set the goal of becoming a top-ten oil-producing country by 2015. If we take into account Kazakhstan’s relatively small population, its high levels of literacy, a highly skilled workforce, and the government’s commitments to democratic reform, then it is clear that Kazakhstan is in a good position

to benefit from its oil wealth. However, it remains critical to learn lessons from positive and negative experience in other resource-rich states. Transparency, accountability and public scrutiny emerge as key shapers of social, economic and environmental outcomes in the extractive industries.

Civil society can play an important role in ensuring that a resource blessing does not become a resource curse. NGOs have had to learn by doing, and there are no one-size-fits-all methods to increase transparency and accountability. In Kazakhstan, civil society has made significant efforts in this direction, and the experience of successful cooperation on the part of both government and companies in the country shows evidence of great promise for the future.

Appendixes

A sampling of PSAs signed in Kazakhstan and Azerbaijan

Table 14. PSAs for exploration and production signed with Kazakhstan

Operator	Field	Comment	Participant
Karachaganak Petroleum Operating	Karachaganak	Signed in 1997 for a 40-year term.	BG (32.5%) ENI (32.5%) Chevron (20%) KazMunaiGaz (20%) LukArco (5%)
NCOC	Kashagan	Signed in 1997 for a 40-year term, but amended in 2008.	KazMunaiGaz (16.81%) ENI (16.66%) Exxon (16.66%) Shell (16.66%) Total (16.66%) Inpex (8.28%) ConocoPhillips (8.28%)
JV Kurmangazy-Petroleum	Kurmangazy	Signed in July 2005.	Kazmunai-Teniz (KazMunaiGaz subsidiary) (50%) LLP RNKazakhstan (Rosneft subsidiary) (25%) Zarubezh-Neft (25%)
Tyb-Karagan Operating Co.	Tyub-Karagan	Signed in December 2003.	Lukoil Overseas (50%) KazMunaiGaz (50%)

Table 15. PSAs for production signed with Azerbaijan

Operator	Field	Comment	Project manager
AIOC	Azeri, Chirag and Gunashli	Signed on 20 September 1994; Ratified by Parliament on 15 November 1994; enacted as a Presidential decree on 12 December 1994.	BP
BP Exploration (Shah-Deniz)	Shakh-Deniz	Signed on 4 June 1996; ratified by Parliament on 4 October 1996; enacted as a Presidential decree on 9 October 1996.	BP
Salyan Oil	Kyursengi and Garabagly	Signed on 15 December 1998; ratified by Parliament on 16 April 1999; enacted as a Presidential decree on 27 April 1999.	CNPC
Karasu Operating Co.	Kelametdin and Mishovdag	Signed on 12 September 2000; ratified by Parliament on 25 October 2000; enacted as a Presidential Decree on 5 November 2000.	Nations Energy
Gobustan Operating Co.	South West Gobustan	Signed on 2 June 1998; ratified by Parliament on 13 November 1998; enacted as a Presidential Decree on 1 December 1998.	CNPC
Kura Valley Co.	Padar	Signed on 27 April 1999; ratified by Parliament on 25 June 2000; enacted as a Presidential decree on 25 July 2000.	Nations Energy
AzShengli Operating Co.	Pirsaat	Signed on 4 June 2003; ratified by Parliament on 2 December 2003; enacted as a Presidential decree on 26 December 2003.	Shengli Oil
Binagadi Oil Operating Co.	Binagadi Block	Signed on 18 June 2004; ratified by Parliament on 29 April 2005.	AZEN Oil
Garachukhur Oil Operating Co.	Garachukhur Block	Signed on 29 September 2004; ratified by Parliament on 29 April 2005.	Noble Sky
Surakhani Oil Operating Co.	Surakhani Block	Signed in August 2004; ratified by Parliament on 29 April 2005.	RAFI Oil
Absheron Operating Co.	Zykh and Govsany	Signed on 3 November 2005; ratified by Parliament in April 2007.	RussNeft

Table 16. PSAs for exploration signed with Azerbaijan

Operator	Field	Comment	Project manager
LUKARCO Operating Co.	D-222	Signed on 4 July 1997; ratified by Parliament on 4 November 1997; enacted as a Presidential decree on 5 December 1997.	LUKoil
BP Exploration (INAM)	Inam	Signed on 21 July 1998; ratified by Parliament on 1 December 1998; enacted as a Presidential decree on 28 December 1998.	BP

Appendix 2: Useful internet resources

Energy Information Administration (EIA) information on Kazakhstan

<http://www.eia.doe.gov/emeu/cabs/Kazakhstan/kazaproj.html>

The Foreign Investors' Council of Kazakhstan

<http://www.fic.kz/>

International Monetary Fund (IMF)

<http://www.imf.org>

The Kazakhstan Oil and Gas Ministry

<http://mgm.gov.kz>

Kazakhstan Tax Code

http://www.kazembassy.org.uk/legislation_of_kazakhstan.html

JSC NC KazMunaiGaz

<http://www.kmg.kz>

The Agency of Statistics for Kazakhstan

<http://www.stat.kz>

Barrows Company: A legal library for the extractive industries

<http://www.barrowscompany.com>

The Tax Committee of the Kazakhstan Ministry of Finance

<http://www.salyk.kz>

Platts: Information for the energy sector

<http://www.platts.com>

Extractive Industries Transparency Initiative

<http://www.eitransparency.org>

Revenue Watch Institute (RWI)

<http://www.revenuewatch.org>

Publish What You Pay (PWYP)

<http://www.publishwhatyoupay.org>

Kazakhstan Revenue Watch (Soros Foundation–Kazakhstan)

<http://www.krw.kz>

Oil Revenues – Under Public Oversight! Coalition

<http://www.publicoversight.kz>

Public Finance Monitoring Centre (Azerbaijan)

<http://www.pfmc.az>

IIED's energy pages

<http://www.iied.org/theme/6/Energy/projects>

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Kazakhstan Parliament, Majilis Administration (2009) “*Majilis energy presented the draft law on “subsoil and subsoil use”*” (our translation) Press release: 15 January. See <http://www.nomad.su/?a=3-200901160525> Panorama. (2007) “*KazEnergy believes the Government’s tax initiatives to be ‘incompatible with international practice’*” (our translation) 11 July.

Panorama (2008) “The Ministry of Finance suggests replacing the royalty with a rent tax and a tax on hydrocarbon extraction. Experts suggest negotiating with oil companies on oil processing in-country” (our translation) 29 December.

Soros Documentary Kazakhstan (2010) “*Money thrown to the wind*”. Documentary. 3rd June. http://www.soros.kz/en/press_room/audio_and_video/money-thrown-wind-documentary

Waelde, T. (1995) The current status of international petroleum investment: regulating, licensing, taxing and contracting. *The Centre for Energy, Petroleum and Mineral Law and Policy (CEPMLP) Journal*, Vol. 1(5). <http://www.dundee.ac.uk/cepmlp/journal/html/Vol1/article1-5.html>

This guide discusses the provisions of a particular type of oil and gas contract, the Production Sharing Agreement (PSA). While the guide is aimed at a general civil society readership, it draws particularly on experience from Kazakhstan. Its purpose is to give an accessible account of some key characteristics of PSAs, with a focus on revenue issues; and to suggest action points for civil society organisations involved with monitoring extractive industries. Indeed, in recent years the management of extractive industry revenues has become of growing concern to public opinion in resource-rich states.

Key issues include public participation in the contracting process, the economic fairness of the deal, the degree of integration of social and environmental concerns, and the extent to which the balance between economic, social and environmental considerations can evolve over often long project durations.

Now available in English, the guide was originally published in Russian by the Soros Foundation – Kazakhstan. Its content proved invaluable at two training sessions on extractive industry contracts co-organised by IIED in Central Asia (with Kazakhstan Revenue Watch) and in Ghana (with the Centre for Public Interest Law).

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The International Institute for Environment and Development (IIED) is an independent policy research organisation. IIED works with partners in middle- and low-income countries to tackle key global issues – climate change, urbanisation, the pressures on natural resources and the forces shaping markets. IIED's work on energy aims to address poverty and energy security issues by supporting access to sustainable, affordable energy services for the poorest, as well as promoting responsible practice in larger-scale energy sector development, including biofuels, oil and gas, and stimulating debate around energy policy reform.

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