IMPORTANT NOTICE: THIS DOCUMENT IS IMPORTANT AND REQUIRES YOUR IMMEDIATE ATTENTION.

IMPORTANT: You must read the following before continuing. The following applies to the attached Prospectus, and you are therefore advised to read this carefully before reading, accessing or making any other use of the Prospectus. In accessing the Prospectus, you agree to be bound by the following terms and conditions, including any modifications to them any time you receive any information from us as a result of such access. You acknowledge that this electronic transmission and the delivery of the attached Prospectus is intended for you only and you agree you will not forward this electronic transmission or the attached Prospectus to any other person. Any forwarding, distribution or reproduction of this document in whole or in part is unauthorised. Failure to comply with the following directives may result in a violation of the applicable laws of other jurisdictions.

The Prospectus has been prepared solely in connection with the listing of ordinary shares of Nostrum Oil & Gas plc ("Ordinary Shares") as described herein. The Prospectus has been made available to the public in accordance with the Prospectus Directive.

NOTHING IN THIS ELECTRONIC TRANSMISSION CONSTITUTES AN OFFER OF SECURITIES FOR SALE.

Confirmation of your representation: By accepting this e-mail and accessing the Prospectus, you shall be deemed to have represented to the Company that you consent to delivery of such Prospectus by electronic transmission.

The Prospectus is being sent to you in an electronic form. Documents transmitted via this medium may be altered or changed during the process of electronic transmission and, consequently, none of Nostrum Oil & Gas plc, Nostrum Oil & Gas LP, Deutsche Bank AG, London Branch nor any of their respective affiliates accepts any liability or responsibility whatsoever in respect of any difference between the Prospectus distributed to you in electronic format and the hard copy version available to you on request.

The securities referred to herein have not been, and will not be, registered under the U.S. Securities Act of 1933, as amended (the "Securities Act") or the securities laws of any state of the United States. Neither the U.S. Securities and Exchange Commission nor any U.S. State securities commission has approved of the Ordinary Shares or determined if this document is accurate or complete. Any representation to the contrary is a criminal offence in the United States. The Ordinary Shares may not be offered or sold in the United States except pursuant to an exemption from the Securities Act or in a transaction not subject to the registration requirements of the Securities Act or the registration requirements or any exemptive filings under any securities laws of any state of the United States.

Certain retail investors in the Unites States, including retail investors in Minnesota, Nevada, New Hampshire, Oklahoma, Rhode Island and Utah, may not be able to receive the securities and will receive other compensation as a result of the transaction referred to herein.

Nostrum Oil & Gas plc is organised under the laws of England and Wales and Nostrum Oil & Gas LP is a limited partnership registered under the laws of the Isle of Man. Some or all of the officers and directors of Nostrum Oil & Gas plc and Nostrum Oil & Gas LP are residents of countries other than the United States. In addition, most of the assets of Nostrum Oil & Gas plc and Nostrum Oil & Gas LP are located outside the United States. As a result, it may be difficult for U.S. shareholders to enforce their rights and any claim they may have arising under the U.S. federal securities laws, since Nostrum Oil & Gas plc is located in a foreign country, and some or all of its officers and directors may be residents of foreign countries. U.S. shareholders may not be able to sue a foreign company or its officers or directors in a foreign court for violations of the U.S. securities laws. It may be difficult to compel a foreign company and its affiliates to subject themselves to a U.S. court's judgement.

The attached document comprises a prospectus relating to Nostrum Oil & Gas plc and has been prepared in accordance with the Prospectus Rules of the Financial Conduct Authority (the "FCA") made under Section 73A of the Financial Services and Markets Act 2000 (as amended) (the "FSMA"), has been filed with the FCA and has been made available to the public as required by the Prospectus Rules.

Application will be made to the FCA for all of the Ordinary Shares to be admitted to the premium listing segment of the Official List of the FCA (the "Official List") and to the London Stock Exchange plc (the "London Stock Exchange") for such Ordinary Shares to be admitted to trading on the London Stock Exchange's Main Market for listed securities (together, "Admission"). Admission constitutes admission to trading on a regulated market. It is expected that Admission will become effective, and that unconditional dealings will commence in the Ordinary Shares on the London Stock Exchange, at 8.00 a.m. (London time) on 20 June 2014.

You are responsible for protecting against viruses and other destructive items. Your use of this e-mail is at your own risk and it is your responsibility to take precautions to ensure that it is free from viruses and other items of a destructive nature.

THIS DOCUMENT IS IMPORTANT AND REQUIRES YOUR IMMEDIATE ATTENTION. If you are in any doubt as to what action you should take, you are recommended to seek your own personal financial advice immediately from your stockbroker, bank manager, solicitor, accountant or other independent financial adviser authorised under the Financial Services and Markets Act 2000 (as amended) (the "FSMA") if you are resident in the United Kingdom or, if not, another appropriately authorised independent financial adviser.

This document comprises a prospectus for the purposes of Article 3 of the European Union ("EU") Directive 2003/71/EC, as amended by the EU Directive 2010/73/EU, (the "Prospectus Directive") (the "Prospectus") relating to Nostrum Oil & Gas plc (the "Company") and has been prepared in accordance with the Prospectus Rules of the Financial Conduct Authority (the "FCA") made under Section 73A of the FSMA. A copy of this Prospectus has been filed with the FCA and has been made available to the public as required by section 3.2 of the Prospectus Rules.

If you have sold or otherwise transferred all of your global depositary receipts in Nostrum Oil & Gas LP ("**GDRs**"), please forward this document, together with the accompanying documents, at once to the purchaser or transferee, or to the bank, stockbroker or other agent through whom the sale or transfer was effected for delivery to the purchaser or transferee. However, these documents should not be forwarded or transmitted in or into any jurisdiction in which such act would constitute a violation of the relevant laws or regulations of such jurisdiction. If you have sold or transferred only part of your holding of GDRs, you should retain these documents and consult the bank, stockbroker or other agent through whom the sale or transfer was effected.

For a discussion of certain risk and other factors that should be considered in connection with an investment in the Ordinary Shares, see Part 2 "*Risk Factors*".

nostrum Oil & Gas

(*incorporated under the Companies Act 2006 and registered in England and Wales with registered number 8717287*)

Proposed issue of up to 188,182,958 ordinary shares in the Company (the "Ordinary Shares") and application for admission of up to 188,182,958 Ordinary Shares to the premium listing segment of the Official List and to trading on the London Stock Exchange's Main Market for listed securities

Sole Sponsor and Financial Adviser

Deutsche Bank

Financial Adviser in respect of the Admission and Scheme

VTB Capital

Application will be made to the FCA for all of the Ordinary Shares to be admitted to the premium listing segment of the Official List of the FCA (the "**Official List**") and to the London Stock Exchange plc (the "**London Stock Exchange**") for such Ordinary Shares to be admitted to trading on the London Stock Exchange's Main Market for listed securities (together, "**Admission**"). Admission constitutes admission to trading on a regulated market. It is expected that Admission will become effective, and that unconditional dealings will commence in the Ordinary Shares on the London Stock Exchange, at 8.00 a.m. (London time) on 20 June 2014. The Ordinary Shares issued by the Company will rank *pari passu* in all respects with each other and will carry the right to receive all dividends and distributions declared, made or paid on or in respect of the issued Ordinary Shares after Admission. The Company also intends to seek admission of the Ordinary Shares to trading on the Kazakhstan Stock Exchange (the "**KASE**") in connection with Admission.

The Company and its Directors (whose names appear on page 36 of this Prospectus) accept responsibility for the information contained in this Prospectus. To the best of the knowledge and belief of the Company and the Directors (who have taken all reasonable care to ensure that such is the case), the information contained in this Prospectus is in accordance with the facts and contains no omission likely to affect the import of such information.

This Prospectus does not constitute an offer of, or the solicitation of an offer to subscribe for or buy, any Ordinary Shares to any person in any jurisdiction in which such offer or solicitation is unlawful. The Ordinary Shares have not been and will not be registered under the U.S. Securities Act of 1933, as amended (the "**Securities Act**") or under any of the relevant securities laws of any state or other jurisdiction of the United States. Neither the U.S. Securities and Exchange Commission nor any U.S. State securities commission has approved of the Ordinary Shares or determined if this Prospectus is accurate or complete. Any representation to the contrary is a criminal offence in the United States. The Ordinary Shares will be offered in the United States only pursuant to an exemption from the registration requirements of the Securities Act. The Ordinary Shares may not be offered or sold in the United States except pursuant to an exemption from the Securities Act or in a transaction not subject to the registration requirements of the Securities Act or the registration requirements or any exemptive filings under any securities laws of any state of the United States.

This proposed issue is for the securities of a foreign company. The proposed issue is subject to disclosure requirements of a foreign country that are different from those of the United States. Financial statements included in the document, if any, have been prepared in accordance with foreign accounting standards that may not be comparable to the financial statements of the United States companies.

It may be difficult for you to enforce your rights and any claim you may have arising under the federal securities laws, since the Company is located in a foreign country, and some or all of its officers and directors may be residents of a foreign country. You may not be able to sue a foreign company or its officers or directors in a foreign court for violations of the U.S. securities laws. It may be difficult to compel a foreign company and its affiliates to subject themselves to a U.S. court's judgment.

Deutsche Bank AG, London Branch ("**Deutsche Bank**" or the "**Sponsor**") is authorised by the Prudential Regulation Authority ("**PRA**") and regulated in the United Kingdom by the PRA and the FCA and is acting exclusively for the Company and no-one else in connection with Admission, and will not regard any other person (whether or not a recipient of this Prospectus) as a client in relation to Admission. Apart from the responsibilities and liabilities, if any, imposed on the Sponsor by FSMA or the regulatory regime established thereunder, the Sponsor accepts no responsibility or liability whatsoever for the contents of this Prospectus or for any other statement made or purported to be made in connection with the Company, its Ordinary Shares or this Prospectus. The Sponsor accordingly disclaims all and any responsibility or liability, whether arising in tort, contract or otherwise (save as referred to above), which it might otherwise have in respect of this Prospectus or any such statement.

VTB Capital plc ("**VTB Capital**") has been appointed by the Company as the financial adviser in respect of the Admission and Scheme. VTB Capital is authorised by the PRA and regulated by the FCA and the PRA in the United Kingdom. The appointment of VTB Capital was not made pursuant to the requirements of the Listing Rules, and the appointment of VTB Capital is separate and distinct from the appointment of the Sponsor. The Sponsor has not relied on any of the work performed by VTB Capital in fulfilling its duties as a sponsor in connection with the Admission. VTB Capital's role is different from that of the Sponsor in that it focuses on providing general corporate finance advice to the Company on matters relating to the Admission and Scheme. VTB Capital accepts no responsibility or liability whatsoever for the contents of this Prospectus or for any other statement made or purported to be made in connection with the Company, its Ordinary Shares or this Prospectus. VTB Capital accordingly disclaims all and any responsibility or liability, whether arising in tort, contract or otherwise, which it might otherwise have in respect of this Prospectus or any such statement.

Dated 20 May 2014

Recipients of this Prospectus are authorised to use it solely for the purpose of considering the subscription for the Ordinary Shares in connection with the proposed reorganisation of Nostrum Oil & Gas LP (the "**Partnership**") and may not reproduce or distribute this Prospectus, in whole or in part, and may not disclose any of the contents of this Prospectus or use any information herein for any purpose other than considering an investment in the Ordinary Shares. Such recipients of this Prospectus agree to the foregoing by accepting delivery of this Prospectus.

Prospective investors should rely only on the information contained in this Prospectus. No person has been authorised to give any information or make any representations other than those contained in this Prospectus and, if given or made, such information or representations must not be relied on as having been so authorised by the Company, the Directors or the Sponsor. Any delivery of this Prospectus shall not, under any circumstances, create any implication that there has been no change in the affairs of the Company or its subsidiaries since, or that the information contained herein is correct at any time subsequent to, the date of this Prospectus. In particular, the contents of the Group's website (www.nostrumoilandgas.com) do not form part of this Prospectus and prospective investors should not rely on it. The contents of this Prospectus are not to be construed as legal, financial or tax advice. Each recipient of this Prospectus should consult his, her or its own solicitor, independent financial adviser or tax adviser for legal, financial or tax advice.

The distribution of this Prospectus may be restricted by law in certain jurisdictions. No action has been or will be taken by the Company or the Sponsor to permit a public offering of the Ordinary Shares or to permit the possession or distribution of this Prospectus (or any other offering or publicity materials relating to the Ordinary Shares) in the United Kingdom or any other jurisdiction where action for that purpose may be required. Accordingly, neither this Prospectus, any advertisement nor any other material relating to it may be distributed or published in any jurisdiction except under circumstances that will result in compliance with any applicable laws and regulations. Persons into whose possession this Prospectus comes should inform themselves about and observe any such restrictions. Any failure to comply with these restrictions may constitute a violation of the securities laws of any such jurisdiction.

The Ordinary Shares have not been and will not be registered or qualified for distribution under the applicable securities laws of Australia, Canada or Japan. The Ordinary Shares may not be offered for sale or subscription or sold or subscribed directly or indirectly in Australia, Canada or Japan or to, or for the account or benefit of, any national, resident or citizen of Australia, Canada or Japan.

NOTICE TO U.S. INVESTORS

The Ordinary Shares have not been approved or disapproved by the U.S. Securities and Exchange Commission (the "**SEC**"), any state securities commission in the United States or any other regulatory authority in the United States, nor have any of the foregoing authorities passed upon, confirmed the accuracy of or determined the adequacy of this Prospectus. Any representation to the contrary is a criminal offence in the United States.

Certain retail investors in the Unites States, including retail investors in Minnesota, Nevada, New Hampshire, Oklahoma, Rhode Island and Utah, may not be able to receive the Ordinary Shares and will receive other compensation in exchange for their Common Units.

THE PROPOSED ISSUE OF ORDINARY SHARES TO U.S. PERSONS IS CONTINGENT ON THE AVAILABILITY OF AN EXEMPTION FROM THE RELEVANT STATE SECURITIES REGISTRATION REQUIREMENTS (SO CALLED "BLUE SKY LAWS"). IF A U.S. PERSON IS NOT ABLE TO PARTICIPATE IN THE PROPOSED ISSUE OF ORDINARY SHARES, SUCH PERSON WILL BE INFORMED OF SUCH DETERMINATION AND WILL RECEIVE DIFFERENT TREATMENT AS DESCRIBED IN "INFORMATION ON THE SCHEME" SECTION IN THIS PROSPECTUS.

NOTICE TO NEW HAMPSHIRE RESIDENTS ONLY

NEITHER THE FACT THAT A REGISTRATION STATEMENT OR AN APPLICATION FOR A LICENCE HAS BEEN FILED UNDER CHAPTER 421-B OF THE NEW HAMPSHIRE REVISED STATUTES ("RSA 421-B") WITH THE STATE OF NEW HAMPSHIRE, NOR THE FACT THAT A SECURITY IS EFFECTIVELY REGISTERED OR A PERSON IS LICENSED IN THE STATE OF NEW

HAMPSHIRE, CONSTITUTES A FINDING BY THE SECRETARY OF STATE OF THE STATE OF NEW HAMPSHIRE THAT ANY DOCUMENT FILED UNDER RSA 421-B IS TRUE, COMPLETE AND NOT MISLEADING. NEITHER ANY SUCH FACT NOR THE FACT THAT AN EXEMPTION OR EXCEPTION IS AVAILABLE FOR A SECURITY OR A TRANSACTION MEANS THAT THE SECRETARY OF STATE OF THE STATE OF NEW HAMPSHIRE HAS PASSED IN ANY WAY UPON THE MERITS OR QUALIFICATIONS OF, OR RECOMMENDED OR GIVEN APPROVAL TO, ANY PERSON, SECURITY OR TRANSACTION. IT IS UNLAWFUL TO MAKE, OR CAUSE TO BE MADE, TO ANY PROSPECTIVE PURCHASER, CUSTOMER OR CLIENT ANY REPRESENTATION INCONSISTENT WITH THE PROVISIONS OF THIS PARAGRAPH.

TABLE OF CONTENTS

PART 1
SUMMARY

Summaries are made up of disclosure requirements known as 'elements'. These elements are numbered in Sections A-E (A.1-E.7).

This summary contains all the elements required to be included in a summary for the type of securities and issuer to which this prospectus relates. Because some elements are not required to be addressed, there may be gaps in the numbering sequence of the elements.

Even though an element may be required to be inserted in the summary because of the type of securities and issuer to which this prospectus relates, it is possible that no relevant information can be given regarding the element. In this case a short description of the element is included in the summary with the mention of 'not applicable'.

Section A—Introduction and warnings

A.1	This summary should be read as an introduction to this prospectus; any decision to invest in the securities should be based on consideration of this prospectus as a whole by the investor; where a claim relating to the information contained in the prospectus is brought before a court, the plaintiff investor might, under the national legislation of the Member States, have to bear the costs of translating the prospectus before the legal proceedings are initiated; and civil liability attaches only to those persons who have tabled the summary including any translation thereof, but only if the summary is misleading, inaccurate or inconsistent when read together with the other parts of this prospectus or it does not provide, when read together with the other parts of this prospectus, key information in order to aid investors when considering whether to invest in such securities.
A.2	Not applicable—this prospectus has not been drawn up in connection with any subsequent resale or placement of securities by financial intermediaries.

Section B—Issuer

B.1	Legal and commercial name	Nostrum Oil & Gas plc (the "**Company**" and together with its subsidiaries the "**Group**" or "**Nostrum**")
B.2	Domicile and legal form, legislation and country of incorporation	The Company is a public company incorporated under the Companies Act 2006 and registered in England and Wales with registered number 8717287.
B.3	Current operations, principal activities and markets	Nostrum is an independent oil and gas enterprise engaged in the exploration and production of oil and gas products in North-Western Kazakhstan. The Company, through its indirectly wholly-owned subsidiary Zhaikmunai LLP, is the owner and operator of four fields in Kazakhstan, the Chinarevskoye Field and the Rostoshinskoye, Darinskoye and Yuzhno-Gremyachenskoye development fields. The Group's primary field and Licence area is the Chinarevskoye Field located in the northern part of the oil-rich Pre-Caspian Basin. The Group had average daily production of 46,178 boepd and 36,940 boepd for the years ended 31 December 2013 and 2012, respectively. Based on the 2013 Ryder Scott Report, as at 31 August 2013, the estimated gross proved plus probable hydrocarbon reserves at the Chinarevskoye Field were 483.3 million boe, of which 193.2 million bbl was crude oil and condensate, 72.4 million bbl was LPG and 216.8 million boe was sales gas.

B.4a	Significant recent trends	The recent trends affecting the Group and the oil and gas industry include: • completion of the first phase of the gas treatment facility resulting in an increase in production to 46,178 boepd for the year ended 31 December 2013; • raising U.S.$400 million and U.S.$560 million in debt financing pursuant to senior bonds due 2019 issued in February 2014 and November 2012, respectively; • increased revenue and EBITDA of U.S.$895 million and U.S.$551 million for the year ended 31 December 2013, compared to U.S.$737 million and U.S.$457 million for the year ended 31 December 2012; • intention to develop second phase of the gas treatment facility which would permit doubling of production by the end of 2016; • completion of the acquisition of the subsurface use contracts in respect of the Rostoshinskoye, Darinskoye and Yuzhno-Gremyachenskoye development fields in North-Western Kazakhstan in May 2013; and • continuing volatility in crude oil and gas prices, driven by a number of factors including the condition of the world economy and geopolitical events and technical advances affecting energy consumption and extraction methods.
B.5	Description of the Group	On 20 May 2014, Nostrum Oil & Gas LP announced its intention to seek a premium listing of a public limited liability company newly incorporated in England and Wales, namely the Company, which is proposed to be the new holding company for the Group. The new corporate structure for the Group is to be implemented by way of the Scheme, pursuant to which the Company will acquire all (or substantially all) of the assets and liabilities of the Group from Nostrum Oil & Gas LP in consideration for the issue of the Ordinary Shares by the Company to the holders of Common Units (and hence to GDR holders). Following implementation of the Scheme and upon Admission, Zhaikmunai LLP, the holder of the licence for the Chinarevskoye Field, will become indirectly wholly-owned by the Company.

B.6	Interests in the Company and voting rights	The Company is aware of the following persons who, directly or indirectly, have as at the date of this Prospectus or are expected to have as at the date of Admission (assuming no changes in holdings of GDRs prior to Admission) a notifiable interest in 3% or more of the Company's issued Ordinary Shares:

Name	As at the date of this Prospectus: Number of Shares	As at the date of this Prospectus: % of issued Ordinary Shares	Admission: Number of Shares	Admission: % of issued Ordinary Shares
Claremont Holdings C.V.	—	—	51,190,476	27.2
KazStroyService Global B.V.	—	—	50,000,000	26.6
Dehus Dolman Nominees Limited	—	—	28,906,483	15.3
M&G Investment Management Limited	—	—	17,640,800	9.4
J.P. Morgan Asset Management (Korea) Company, Ltd.	—	—	8,013,400	4.3
Templeton Asset Management (Singapore) Limited	—	—	7,000,000	3.7
Nostrum Oil & Gas LP	49,999	50.0	—	—
Thomas Hartnett	50,001	50.0		

None of the Shareholders detailed above have voting rights which differ in any way from those of the Company's other shareholders. So far as the Company is aware, save as set out in the table above no person owns 3% or more of the issued share capital of the Company.

The Company is not aware of any person who either as at the date of this Prospectus or immediately following Admission exercises, or could exercise, directly or indirectly, control over the Company.

B.7	Selected historical key financial information	***Summary Audited Consolidated Income Statement***

	Year ended 31 December		
	2013	**2012**	**2011**
	(U.S.$ thousands)		
Revenue			
Revenue from export sales	765,029	630,412	284,548
Revenue from domestic sales	129,985	106,653	16,289
Total	**895,014**	**737,065**	**300,837**
Costs of sales	(286,222)	(238,224)	(70,805)
Gross profit	**608,792**	**498,841**	**230,032**
General and administrative expenses	(60,449)	(64,882)	(39,462)
Selling and transportation expenses	(121,674)	(103,604)	(35,395)
Loss on derivative financial instruments	—	—	—
Finance costs	(43,615)	(46,785)	(1,660)
Foreign exchange (loss)/gain, net	(636)	776	(389)
Interest income	764	698	336
Other expenses	(25,593)	(6,612)	(7,855)
Other income	4,426	3,940	3,365
Profit before income tax	362,015	**282,372**	**148,972**
Income tax expense	(142,496)	(120,363)	(67,348)
Profit for the period	219,519	**162,009**	**81,624**
Total comprehensive profit for the period	219,519	**162,009**	**81,624**

Summary Audited Consolidated Balance Sheet

	As at 31 December		
	2013	**2012**	**2011**
	(U.S.$ thousands)		
Non-Current Assets	1,425,977	1,251,595	1,126,897
Current Assets	334,798	351,067	179,283
Total Assets	1,760,775	**1,602,662**	**1,306,180**
Partnership capital and Reserves	832,451	695,104	585,231
Non-Current Liabilities	793,600	781,860	599,680
Current Liabilities	134,724	125,698	121,269
Total Equity and Liabilities	**1,760,775**	**1,602,662**	**1,306,180**

Except for the issuance by the Group of new bonds in a principal amount of U.S.$400 million on 14 February 2014 and the redemption of outstanding bonds due 2015 in a principal amount of U.S.$92.5 million on 14 April 2014, as at the date of this Prospectus, there has been no significant change to the financial condition and operating results of the Group since 31 December 2013.

B.8	Selected key pro forma financial information	Not applicable—the Company is a newly incorporated company which has not traded since its incorporation and, prior to the Scheme becoming effective, will not own any assets or have any liabilities. As a result of the Scheme becoming effective, the Company will become the new parent company of the Group and its assets, liabilities and earnings on a consolidated basis will be those of the Group.

B.9	Profit forecast or estimate	Not applicable—the Prospectus does not include a profit forecast or estimate.
B.10	Audit report qualifications	Not applicable—there are no qualifications in the accountant's report on the historical financial information.
B.11	Insufficient working capital	Not applicable—it is the opinion of the Company that the Group has sufficient working capital for its present requirements, which is for at least the next 12 months from the date of this Prospectus.

Section C—Securities

C.1	Type and class of securities admitted to trading and identification number	Ordinary Shares, bearing the following security identification numbers: ISIN: GB00BGP6Q951 SEDOL: BGP6Q95 London Stock Exchange trading symbol: NOG
C.2	Currency of the securities	The currency of the Company's Ordinary Shares is pounds sterling.
C.3	Number of shares in issue and par value	The aggregate nominal value of the issued ordinary share capital of the Company immediately following the Scheme becoming effective, and as at Admission, will (assuming 188,182,958 Ordinary Shares are issued in connection with the Scheme) be £1,881,829.58 divided into 188,182,958 ordinary shares of £0.01 each, all of which will be issued fully paid.
C.4	Rights attaching to the securities	Subject to the provisions of the Company's articles of association and the relevant provisions of English law, a holder of fully paid Ordinary Shares has, *inter alia*, the right to: • vote at and participate in general shareholders' meetings; • receive profit in the form of dividends; • upon the Company's liquidation, receive a proportionate amount of the Company's property after its obligations are fulfilled; • access certain of the Company's documents; • freely transfer the Ordinary Shares; • acquire the Company's newly issued shares by exercising pre-emptive rights on a *pro rata* basis; • delegate voting rights to a representative on the basis of a power of attorney; • exercise certain other rights if it holds, alone or with other shareholders, shares in excess of specified thresholds; and • in certain specified situations, demand the repurchase by the Company of all or some of the shares owned by it.
C.5	Restrictions on transfer	A holder of fully paid Ordinary Shares may freely transfer the shares without the consent of other shareholders and the Company's bodies but subject to transfer restrictions under the relevant laws in certain jurisdictions applicable to the transferor or transferee and subject to the provisions of the Company's articles of association.

C.6	Admission to trading	Application will be made for all the Ordinary Shares to be admitted to trading on the London Stock Exchange's Main Market for listed securities. The Company will also apply for admission of the Ordinary Shares to trading on the Kazakhstan Stock Exchange in connection with Admission.
C.7	Dividend policy	The Company has adopted a distribution policy with the intention of making an annual distribution of not less than 20% of the Group's consolidated net profit.

Section D—Risks

D.1	Key risks specific to the Company or its industry	• The Group's principal activities are conducted within the Chinarevskoye Field and currently its sole source of revenue comes from this field. As a result, the Group's success depends heavily on the success of its activities in the Chinarevskoye Field. Any event that adversely interferes with the Group's ability to conduct its operations in the Chinarevskoye Field could have a material adverse effect on the Group's business, prospects, financial condition and results of operations. • The Group's future hydrocarbon production profile is based principally on its gas treatment facility and to a lesser extent its oil treatment unit operating at full or near full capacity. If these facilities were not operating at full or near full capacity, the Group would have to reduce or suspend its production activities which would have a material adverse effect on the Group's business, prospects, financial condition and results of operations. • The Group's planned development projects, including a new unit for the gas treatment facility are subject to risks related to cancellation, delay, non-completion and cost overruns which could result in a reduction or suspension of the Group's production of hydrocarbons and have a material adverse effect on the Group's business, prospects, financial condition and results of operations. • The proportion of oil and gas production that must be shared with the State, as well as the Group's royalty payments to the Kazakh Government, may increase. The proportion to be delivered to the State increases as annual production levels increase, while the royalty rate payable to the State also increases as the level of oil and gas produced by the Group increases. Significant increases in the proportion of oil and gas production that the Group must share with the State and in royalty payments to the State could have a material adverse effect on the Group's business, prospects, financial condition and results of operations. • The Group depends on its key senior management and on its ability to retain and hire new qualified personnel and consultants. The loss of or diminution in the services of one or more of the Group's senior management, or the Group's inability to attract, retain and maintain additional senior management personnel, could have a material adverse effect on the Group's business, prospects, financial condition and results of operations.

		• The Group relies on transportation systems owned and operated by third parties which may become unavailable. The Group may be unable to access these or alternative transportation systems. Any reduction or cessation in the availability of rail infrastructure, whether due to serious malfunctions, security issues, political developments or other force majeure events, could have a material adverse effect on the Group's business, prospects, financial condition and results of operations. • The Group may be adversely affected by a substantial or extended decline in prices for crude oil and gas. Any decline in crude oil and gas prices and/or any curtailment in the Group's overall production volumes could result in a reduction in net income, could impair the Group's ability to make planned capital expenditures and to incur costs necessary for the development of the Group's fields, and could materially and adversely affect the Group's business, prospects, financial condition and results of operations. • The level of the Group's reserves, their quality and production volumes may be lower than estimated or expected and the Group may therefore be unable to produce its estimated levels or quality of products, which would have a material adverse effect on the Group's business, prospects, financial condition and results of operations. • The Group may be unable to comply with its obligations under the PSA and the Licence which could lead to the suspension, revocation or termination of any of the Licence, the PSA or other material permits or agreements which could have a material adverse effect on the Group's business, prospects, financial condition and results of operations. • The Group is exposed to the risk of adverse sovereign action by the Kazakh Government. Any expropriation or renationalisation by the Kazakh Government of any of the Group's assets, any adverse change to the tax regime in respect of the PSA or the invocation or application by the Kazakh Government of the New Subsoil Law in relation to the Chinarevskoye Field may have a material adverse effect on the Group's business, prospects, financial condition and results of operations.
D.3	Key risks specific to the securities.	• Share price volatility and liquidity may affect the performance of investments in the Group including the trading price of the Ordinary Shares. • Future sales, or the real or perceived possibility of sales, of a significant number of Ordinary Shares in the public market could adversely affect the prevailing trading price of the Ordinary Shares and further share issues could also dilute the interests of shareholders.

Section E—Offer

E.1	Net proceeds and estimated expenses	There is no offer of new Ordinary Shares for cash and therefore no net proceeds are being raised by the Company in connection with this Prospectus or Admission. The total costs and expenses of, or incidental to, the Scheme and Admission (exclusive of any amounts in respect of value added tax) payable by the Company are estimated to amount to approximately U.S.$32 million.
E.2a	Reasons for the Scheme and use of proceeds	The Scheme will create a new parent company for the Group registered in the United Kingdom, with its tax residence in the Netherlands. The Directors believe that the premium listing of the Company and intended FTSE index inclusion from the second half of 2014 will enable the Group to broaden its investor base and increase the liquidity of its securities. It is also anticipated that the premium listing will increase the profile of the Group and increase its exposure to a wider investor community. Not applicable—in respect of 'use of proceeds' element; the Company is not raising any proceeds in connection with this Prospectus or Admission.
E.3	Terms and conditions of the Scheme	The implementation of the Scheme is made on the following basis: **For each Existing Security (whether held as a Common Unit or as a GDR): 1 Ordinary Share** Pursuant to the Scheme, the Company will acquire all (or substantially all) of the assets and liabilities of the Group in consideration for the issue of the Ordinary Shares to the Partnership, which will distribute such Ordinary Shares to the holders of the common units representing fractional parts of the rights and obligations of all limited partners (the "**Limited Partners**") in Nostrum Oil & Gas LP (the "**Common Units**") and hence to GDR holders, followed by the dissolution of Nostrum Oil & Gas LP (the "**Partnership**"). The Scheme requires the approval of Limited Partners at a special general meeting of the Limited Partners (the "**Special General Meeting**") to (i) amend the Limited Partnership Agreement to permit the Scheme to be capable of being implemented and (ii) vote in favour of the Scheme. The Scheme is conditional upon, among other things: (a) the Scheme being approved by holders representing not less than 75% in voting rights of holders of Common Units present and voting, either in person or by proxy, at the Special General Meeting; (b) special resolutions to approve the amendment of the Limited Partnership Agreement and the dissolution of the Partnership having been duly passed at the Special General Meeting by a majority of not less than 75% in voting rights of holders of Common Units present and voting, either in person or by proxy, at the Special General Meeting;

		(c) the FCA having acknowledged to the Company or its agent (and such acknowledgement not having been withdrawn) that the application for admission of the Ordinary Shares to the premium listing segment of the Official List has been approved and (subject to satisfaction of any conditions to which such approval is expressed) will become effective as soon as a dealing notice has been issued by the FCA and an acknowledgement by the London Stock Exchange that the Ordinary Shares will be admitted to trading on the Main Market (and such acknowledgement not having been withdrawn); and (d) the receipt of relevant waivers by the Kazakh Government of its pre-emptive right and consents from the Ministry of Oil and Gas (the Competent Authority) to the acquisition of the membership interests in Nostrum Oil Coöperatief U.A. (a new intermediate holding entity of the Group) ("**Co-op**") by the Company (such consents and/or waivers being required in respect of Co-op's indirect ownership of subsoil use rights in Kazakhstan). If the Limited Partnership Agreement is duly amended and the Scheme is approved by the requisite majority at the Special General Meeting, and the other conditions to the Scheme have been satisfied, the Scheme is expected to become effective at 6.00 p.m. (London time) on 18 June 2014 and dealings in Ordinary Shares are expected to commence at 8.00 a.m. (London time) on 20 June 2014. If the Scheme has not become effective by 31 July 2014 (or such later date as Nostrum Oil & Gas Group Limited, as general partner of the Partnership, (the "**General Partner**") and the Company may agree), it will lapse, in which event there will not be a new parent company of Nostrum, Admission will not become effective and GDR holders will remain as holders of listed securities in the Partnership and the existing GDRs will continue to be listed on the Official List and admitted to trading on the Main Market.
E.4	Material and conflicting interests	Not applicable—there are no issue specific interests, including conflicting interests, that would be material to the Scheme and Admission.
E.5	Selling shareholders and lock-up agreements	Not applicable—there are no persons offering to sell the Ordinary Shares and there are no lock-up agreements.
E.6	Dilution resulting from the Scheme	Not applicable—the number of issued Ordinary Shares of the Company immediately following the Scheme becoming effective will be the same as the number of issued Common Units of Nostrum Oil & Gas LP at the Scheme Record Time.
E.7	Estimated expenses charged to investors by the issuer	Not applicable—no expenses will be charged to the investor.

PART 2
RISK FACTORS

Any investment in the Ordinary Shares is subject to a number of risks. Prior to investing in the Ordinary Shares, prospective investors should consider carefully all of the information contained in this Prospectus including, in particular, the risk factors described below, which are not presented in any order of priority and may not be exhaustive. Additional risks and uncertainties relating to the Group that are not currently known to the Group, or that it currently deems immaterial, may also have a material adverse effect on the Group's business, results of operations, financial condition and prospects. If this occurs the trading price of the Ordinary Shares may decline and investors could lose all or part of their investment. Investors should consider carefully whether an investment in the Company's Ordinary Shares is suitable for them in light of the information in this Prospectus and their personal circumstances. If investors are in any doubt about any action they should take, they should consult a competent professional adviser who specialises in advising on the acquisition of listed securities.

Prospective investors should note that the risks relating to the Group's business, the oil and gas industry, Kazakhstan, Admission and the Ordinary Shares summarised in "Summary" are the risks the Directors and the Company believe to be the most essential to an assessment by a prospective investor of whether to consider an investment in the Ordinary Shares. However, as the risks which the Group faces relate to events and depend on circumstances that may or may not occur in the future, prospective investors should consider not only the information on the key risks summarised in "Summary" but also, among other things, the risks and uncertainties below.

Risk Factors Relating to the Group's Business

The Group's principal activities are conducted within the Chinarevskoye Field and currently its sole source of revenue comes from this field.

Nostrum conducts its principal operations in the Chinarevskoye oil and gas condensate field (the "**Chinarevskoye Field**") in North-Western Kazakhstan pursuant to a subsoil use licence (the "**Licence**") and an associated production sharing agreement ("**PSA**") which expires in 2031 (with respect to the North-Eastern Tournaisian reservoir) and 2033 (for the rest of the Chinarevskoye Field). The PSA grants sole exclusive rights to the Licence area (see Part 7 "*Information on the Group—Subsoil Licences and Permits—The Licence and the PSA*"). Nostrum's activities in the Licence area (which consists of multiple reservoirs) are currently the Group's sole source of revenue. Whilst the Group has completed the acquisition of subsurface use contracts in three oil and gas fields near to the Chinarevskoye Field, the Rostoshinskoye, Darinskoye and Yuzhno-Gremyachenskoye fields, and commenced the acquisition of data on these fields in 2013 (with appraisal expected to conclude in 2015), the development of those fields has not yet commenced (and the Group will not know when development will start until the appraisal process has been completed). As a result, the Group's success depends heavily on the success of its activities in the Licence area. Any event (such as operational failures or adverse sovereign action) that adversely interferes with the Group's ability to conduct its operations in the Chinarevskoye Field or that adversely impacts production volumes or quality, or levels of reserves or resources, could have a material adverse effect on the Group's business, prospects, financial condition and results of operations and the trading price of the Ordinary Shares (see "*—The Group's future hydrocarbon production profile is based principally on its gas treatment facility and to a lesser extent its oil treatment unit operating at full or near full capacity. If these facilities were not operating at full or near full capacity, the Group may not be able to meet its strategic production objectives*", "*—The Group relies on transportation systems owned and operated by third parties which may become unavailable. The Group may be unable to access these or alternative transportation systems*", "*—Risk Factors Relating to Kazakhstan—The Group is exposed to the risk of adverse sovereign action by the Kazakh Government*" and "*—Risk Factors Relating to the Oil and Gas Industry—The Group faces drilling, exploration, production and transportation risks and hazards that may affect the Group's ability to produce oil and gas products at expected levels, quality and costs*").

The Group's future hydrocarbon production profile is based principally on its gas treatment facility and to a lesser extent its oil treatment unit operating at full or near-full capacity. If these facilities were not operating at full or near-full capacity, the Group may not be able to meet its strategic production objectives.

The Group's gas treatment facility is essential for the treatment of gas condensate to produce dry gas, condensate and LPG for sale by the Group. Until the end of 2012, the gas treatment facility operated at less than its design capacity. In October 2012, the Group successfully conducted a controlled shutdown of the gas treatment facility in order to bring the facility's production close to design capacity, which was achieved by the end of 2012 and has been maintained at approximately this level since. The Group conducted a second annual shutdown of the facility over nine days in September 2013. To date the gas treatment facility has not ceased to be operational due to operational risks or hazards. However, there can be no assurance that the Group will be able to maintain the gas treatment facility at or near design capacity or if it does, that the Group will be able to maintain it without additional expense. In addition, the Group's future hydrocarbon production profile is based on the gas treatment facility, including phase two of the gas treatment facility, which has not yet been constructed, operating at full or near-full design capacity. If the gas treatment facility fails to operate at or near design capacity, the Group would have to reduce or suspend its production activities which would have a material adverse effect on the Group's business, prospects, financial condition and results of operations and the trading price of the Ordinary Shares.

Additionally, if the gas treatment facility ceases to be operational due to operational risks or hazards, the Group would have to rely on its existing gas flaring permits to flare the associated gas that cannot be treated or, if necessary, apply for additional gas flaring permits from the Ministry of Oil and Gas of the Republic of Kazakhstan (the "**Competent Authority**") in order to flare the additional associated gas. There can be no guarantee that these permits would be issued. If the Group's existing gas flaring permits are insufficient and no such additional permits were issued, the Group might have to reduce or suspend its production activities which depend upon an operational gas treatment facility.

Any significant reduction in or suspension of the Group's production of hydrocarbons for a prolonged period of time would have a material adverse effect on the Group's revenues, cash flows, financial condition, results of operations, business and prospects, and the trading price of the Ordinary Shares. See "*—Risk Factors Relating to the Oil and Gas Industry—The Group faces drilling, exploration, production and transportation risks and hazards that may affect the Group's ability to produce oil and gas products at expected levels, quality and costs*".

The Group also relies on its oil treatment unit to process up to 400,000 tonnes per year of crude oil and if this oil treatment unit ceased to operate at or near design capacity or if it ceases to be operational due to operational risks or hazards, this would also reduce the Group's production of hydrocarbons and could have an adverse effect on the Group's business, prospects, financial condition and results of operations.

The Group's planned development projects are subject to risks related to cancellation, delay, non-completion and cost overruns which could result in a reduction or suspension of the Group's production of hydrocarbons.

An important element of the Group's growth strategy is to construct new operating facilities. The Group is in the process of designing and planning the second phase of the gas treatment facility, which entails building a third gas treatment unit in the vicinity of the first two units of the gas treatment facility. The third gas treatment unit, which Nostrum currently estimates will not cost more than U.S.$500 million (U.S.$29.7 million of which had already been incurred as at 31 December 2013) and which it currently expects to fund from cash from operations, is important for implementing the Group's strategy to increase the production of liquid hydrocarbons. Detailed engineering and procurement plans are on-going and the Group is in the process of contracting with potential suppliers for the equipment, construction and assembly of the third gas treatment unit. The final design of the third gas treatment unit has been finalised and all key permits were in place by the end of 2013. Groundworks onsite in preparation for construction were completed in early 2014 and the third gas treatment unit is expected to become operational in mid-2016. Once the third gas treatment unit becomes operational the Group expects a significant increase in its current operating capacity and production volumes.

The additional operating capacity and higher production volumes (including, specifically, production of liquid hydrocarbons) have been incorporated in the Group's long-term strategy. Any material failure or disruption relating to the gas treatment facility, including if the costs of bringing the second phase of the gas treatment facility online are significantly higher than expected (including as a result of any construction delay), could have a material adverse effect on the Group's business, prospects, financial condition and results of operations.

This project is subject to risks of cancellation, delay and non-completion. The Group may experience technical difficulties during construction, testing and commencement of operations that may not be resolved in a timely or cost-effective manner, or at all. For example, in October 2012 the Group undertook a controlled shutdown of the first phase of the gas treatment facility, consisting of two units for 12 days in order to bring it to at or near full design capacity, resulting in unexpected costs. The construction of the third gas treatment unit also will depend on the services of multiple contractors and the products of several specialist suppliers. A reduction or cessation of the performance of the contractors retained to build the third gas treatment unit, or a shortage in the necessary supplies to complete it, could also result in delays and could inflate the costs associated with this project. The Group may also incur cost overruns in connection with completing the third gas treatment unit, which it may not have sufficient financial resources to fund. The construction of the third gas treatment unit may not be completed as scheduled, or at all. Any material delays relating to the construction of the second phase of the gas treatment facility, including if the costs of bringing the second phase of the gas treatment facility online are significantly higher than expected, could have a material adverse effect on the Group's business, prospects, financial condition and results of operations.

Additionally, the Group has started seismic acquisition on the Rostoshinskoye, Darinskoye and Yuzhno-Gremyachenskoye fields near the Chinarevskoye Field and expects to incur costs of approximately U.S.$85 million by the end of 2015 in the appraisal of these fields. See "*—If the Group fails to develop the Rostoshinskoye, Darinskoye and Yuzhno-Gremyachenskoye fields successfully, or the costs of such development are greater than expected, the Group's financial condition and future performance could be adversely affected*".

The failure to complete any of the Group's planned development projects (in particular the third gas treatment unit) and/or appraisal works that lead to a reduction or suspension of the Group's production of hydrocarbons, or any delays or cost overruns in the execution of these projects, could have a material adverse effect on the Group's business, prospects, financial condition and results of operations.

The proportion of oil and gas production that must be shared with the State, as well as the Group's royalty payments to the Kazakh Government, may increase.

Under the terms of the PSA and the Licence, the Group is required to deliver a proportion of its monthly production to the State (or make a payment in lieu of such delivery). The proportion to be delivered to the State increases as annual production levels increase (see Part 7 "*Information on the Group—Subsoil Licences and Permits—The Licence and the PSA—State Share*"). In addition, as the level of oil and gas produced by the Group increases, the royalty rate payable to the State under the PSA will also increase. Increases in production will therefore result in a proportionately higher monthly royalty payment being made to the State. Significant increases in the proportion of oil and gas production that the Group must share with the State and in royalty payments to the State could therefore have a material adverse effect on the Group's business, prospects, financial condition and results of operations. Furthermore, the fiscal terms which govern the proportion of oil and gas production that must be shared with the State under the terms of the PSA may be subject to change (see "*—Risk Factors Relating to Kazakhstan—The Group is exposed to the risk of adverse sovereign action by the Kazakh Government*").

The Group sells its dry gas to two customers.

The Group currently sells its dry gas to two domestic customers under three contracts due to expire on 31 December 2014. While the Directors expect these contracts to be renewed on an annual basis, there can be no assurance that the Group will be able to execute or renew the contracts on similar terms or at all. Under one of the contracts, the Group has the right to set the quantity of the gas supplied, but is not required to sell a minimum volume of gas. Under the other two contracts, any change to the annual quantities sold has to be agreed with the buyer. Prices for gas that have been agreed in principle with these customers are currently broadly in line with domestic gas prices in the Russian Federation, but may not reflect the prevailing market prices in any given month. In the past, the Group has been able to sell as much gas as it can produce pursuant to its previous gas sale contracts, however, payment default by, reduced demand from or termination of the contracts with one or both of the customers or failure in the future to renew such contracts upon expiration may have an adverse effect on the Group's business, results of operations and financial condition and its ability to realise its expected profit margin as it may not be able to immediately enter into contractual arrangements with other purchasers on similar terms or at all.

The Group may be forced to sell its gas at prices determined by the Kazakh Government, which could be significantly lower than prices which the Group could otherwise achieve.

Since 2012, Zhaikmunai LLP has been included in a draft list prepared by the Competent Authority of subsoil users that the Competent Authority believes are subject to the Kazakhstan Law on Gas and Gas Supply No.532 IV dated 9 January 2012 (the "**Gas Law**") effective from 29 January 2012 with regards to the priority right of the Kazakh Government for the purchase of raw gas (this right became effective on 1 April 2012) at the price specified in accordance with the Kazakh Government Decree #948 dated 19 July 2012 "On approval of Rules for determination of price for raw and commercial gas purchased by the national operator under the priority right of the state" ("**Decree 948**"). Subsoil users to which the Gas Law and Decree 948 apply are required to sell their gas domestically at prices determined by the Kazakh Government calculated in accordance with a formula provided in Decree 948 (including by reference to production and transportation costs, production volumes, raw gas prices in Kazakhstan and export prices for crude oil and gas).

Decree 948 (which became effective on 29 August 2012) was issued to implement Article 15 of the Gas Law. However, according to Clause 14 of Article 15 of the Gas Law, the provisions of Article 15 of the Gas Law do not apply to (*inter alia*) raw and/or commercial gas produced (treated) by a subsoil user under a production sharing agreement which includes a tax stability clause, if the terms of that production sharing agreement include a priority right in favour of the Kazakh Government for the purchase of transferred raw and/or commercial gas.

Based on advice received from Kazakh legal counsel, the Directors believe that Article 15 of the Gas Law should not apply to Zhaikmunai LLP, as it is the intention of Article 15 of the Gas Law that the priority right contained in the PSA shall apply (to the exclusion of the priority right referred to in Article 15 of the Gas Law).

In addition, even if Article 15 of the Gas Law would otherwise apply to Zhaikmunai LLP, then application of such law to Zhaikmunai LLP would be prohibited by the general stability clause of its PSA, which provides that any changes in laws of the Republic of Kazakhstan that worsen Zhaikmunai LLP's position shall not be applicable to the PSA. To the extent that the Gas Law and Decree 948 adversely impact the position of Zhaikmunai LLP, they do not apply to Zhaikmunai LLP pursuant to the terms of the PSA as they entered into force after the PSA was signed.

Zhaikmunai LLP has consistently and repeatedly objected to its inclusion by the Competent Authority on the draft list of subsoil users to which Decree 948 is deemed to apply, but to date the Competent Authority has not yet removed Zhaikmunai LLP from the draft list. Notwithstanding that the Directors believe that the Gas Law and Decree 948 do not apply to Zhaikmunai LLP, there is a risk that Zhaikmunai LLP will be included on the list when finalised (although there is currently no date set for the draft list to be finalised and published), that the list will be attached to a further decree and that Zhaikmunai LLP will be forced to sell its gas at prices determined by the Kazakh Government in accordance with a formula provided in Decree 948, which could be significantly lower than prices which the Group could otherwise achieve. If this were to happen, whilst the Group believes that it would still be able to implement its strategy as such gas sales would form only a minority part of its overall revenues, it could have a material adverse effect on the Group's business, prospects, financial condition and results of operations.

The Group may be unable to raise additional external financing if necessary in the longer term; this would adversely affect its ability to pursue its business strategy.

The Group may in the longer term require additional equity or debt financing to satisfy its capital investment commitment and liquidity needs. The Directors may also, from time to time, seek to refinance the Group's existing external debt finance or utilise additional sources of finance if less expensive sources of financing are available. For example, in the years ended 2013, 2012 and 2011, Nostrum's cash used in capital expenditures for purchase of property, plant and equipment was approximately U.S.$201.4 million, U.S.$210.3 million and U.S.$104.7 million respectively, reflecting primarily drilling costs and infrastructure and development costs. This expenditure was funded by a combination of cash from operations and debt financing. The Directors believe that the Group's future capital expenditures will be broadly in line with recent levels. The Group's current investment programme does not foresee the requirement for additional external financing to fund its major planned capital expenditure for the construction of the third gas treatment unit. However, beyond the current investment programme, or if the investment programme were to change or if the Group undertakes potential acquisitions, the Group may be required to raise additional equity or debt financing, although this is not currently envisaged within the next 12 months.

The Group's ability to arrange external financing and the cost of financing generally depend on many factors, including:

- economic and capital markets conditions generally, and in particular the non-investment grade debt market;
- investor confidence in the oil and gas industry, in Kazakhstan and in the Group;
- the Kazakh Government's pre-emptive right in relation to any future issues of equity if such right is not waived (see "*—Risk Factors Relating to Kazakhstan—The Kazakh Government holds a pre-emptive right in*

respect of, and the Competent Authority must consent to, any transfer of subsoil use rights or direct or indirect interests in an entity holding subsoil use rights in Kazakhstan");

- the business and financial performance of the Group;
- legal and regulatory developments;
- the restriction on the incurrence of indebtedness contained in the terms of the Group's indebtedness, including the New 2019 Bonds and 2019 Bonds (see paragraph 12.3 of Part 17 "*Additional Information*");
- credit available from banks and other lenders; and
- provisions of tax and securities laws that are conducive to raising capital.

The terms and conditions on which future funding or financing may be made available may not be acceptable or funding or financing may not be available at all. If additional funds are raised by incurring debt, the Group may become more leveraged and subject to additional or more restrictive financial covenants and ratios. Although the Directors believe that they will be able to raise external financing when necessary, any inability of the Group to procure future financing if necessary in the longer term would adversely affect its ability to pursue its business strategy or capital expenditure commitments at that time and could have a material adverse effect on the Group's business, prospects, financial condition and results of operations.

The Group's leverage may, among other things, make it difficult for it to operate its business and may limit its operational flexibility.

As at 31 December 2013, the Group had U.S.$652.5 million of outstanding indebtedness in respect of the 2015 Bonds and 2019 Bonds. As at 30 April 2014, following the issuance of the New 2019 Bonds and the redemption of the 2015 Bonds, the Group had U.S.$960 million of outstanding indebtedness. See Part 13 "*Capitalisation and Indebtedness*". As a result, the risks normally associated with debt financing may affect the Group's business, prospects, financial position and results of operations. For example, the Group's leverage could:

- require the Group to dedicate a substantial portion of its cash flows from operations to payments on its debt, which may reduce the funds available for working capital, capital expenditures and other general corporate purposes;
- impact the ability of the Group to obtain future debt financing, refinance its existing debt or raise new equity capital;
- impact the ability of the Group to meet its current interest payment obligations under the New 2019 Bonds and the 2019 Bonds;
- restrict the ability of the Group to pursue acquisitions and respond to business opportunities and changes in the business environment; and
- increase the Group's vulnerability in the event of general and/or industry-specific adverse economic conditions.

In addition, if principal payments due at maturity cannot be refinanced, extended or paid with proceeds of other capital transactions, such as debt capital or by issuing additional Ordinary Shares in the Company, then the Group's cash flow may not be sufficient to repay all maturing debt.

Further, on 9 May 2014, the Group approved a distribution of U.S.$0.35 per Common Unit/GDR in the Partnership (U.S.$65.9 million in total), which is expected to be paid on 6 June 2014, and the Company plans to make distributions in the future based on a policy of making an annual distribution of not less than 20% of the Group's consolidated net profit. The obligations of the Group under its existing indebtedness could limit its ability to make future distributions. See "*—Risk Factors Relating to the Admission and the Ordinary Shares—The Group cannot assure investors that it will make dividend payments in the future*".

In addition, prevailing interest rates or other factors at the time of refinancing, such as the possible reluctance of lenders to make commercial loans in Kazakhstan, could also result in higher interest rates and the increased interest expense would adversely affect the Group's ability to service debt and to complete its capital expenditure programme.

The Group may not be able to manage its growth and expansion effectively.

The Group has experienced rapid growth and development in a relatively short period of time, and the Group expects to continue to expand its business through the development of the second phase of the gas treatment facility in the future, further appraisal and development of the Chinarevskoye field and the initial appraisal of the Rostoshinskoye, Darinskoye and Yuzhno-Gremyachenskoye fields. The Group's management of its growth and projects will require, among other things, stringent control of financial systems and operations; the continued development of the Group's management and financial control; the ability to attract and retain sufficient numbers of qualified management, technical, accounting and other personnel; the continued training of such personnel, the presence of adequate supervision and the continued consistency in the quality of its services. Failure to manage growth, development and these major projects effectively could have a material adverse effect on the Group's business, prospects, financial condition, cash flows or results of operations.

If the Group fails to develop the Rostoshinskoye, Darinskoye and Yuzhno-Gremyachenskoye fields successfully, or the costs of such development are greater than expected, the Group's financial condition and future performance could be adversely affected.

In 2013, the Group acquired the subsoil use rights to the Rostoshinskoye, Darinskoye and Yuzhno-Gremyachenskoye fields, all of which are located between 50 kilometres and 105 kilometres from the Group's existing gas treatment facility, for total consideration of U.S.$17 million. The Group intends to complete the initial appraisal of the Rostoshinskoye, Darinskoye and Yuzhno-Gremyachenskoye development fields by the end of 2015, with a view to potentially converting possible reserves to probable reserves, and probable reserves to proved reserves and commencing its production from such fields.

Appraisal results for development fields are uncertain. Appraisal and development activities involving the drilling of wells across a field are unpredictable and may not result in the outcome planned, targeted or predicted, as only by extensive testing can the properties of the entire field be fully understood. Appraisal activities are also capital intensive and their successful outcome cannot be assured. The Group currently expects to incur costs of approximately U.S.$85 million in appraising the Rostoshinskoye, Darinskoye and Yuzhno-Gremyachenskoye development fields but no assurance can be given that such expenditure will result in the discovery of commercially deliverable hydrocarbons.

The Group could experience difficulties (including geological and/or operational difficulties) in developing the Rostoshinskoye, Darinskoye and Yuzhno-Gremyachenskoye fields or the costs of developing such fields could be greater than expected, which could have an adverse effect on its business, prospects, financial condition and results of operations (See "*—Risk Factors Relating to the Oil and Gas Industry—The Group faces drilling, exploration, production and transportation risks and hazards that may affect the Group's ability to produce oil and gas products at expected levels, quality and costs*").

If the Group fails to consummate or integrate acquisitions successfully, the Group's financial condition or future performance could be adversely affected.

While the Directors believe that the Group currently maintains adequate procedures, systems and controls, if the Group acquires another company or its assets in the future, integrating operations and personnel and pre- or post-completion costs may prove more difficult and/or extensive than anticipated, thereby rendering the value of any company or assets acquired less than the amount paid. The integration of acquired businesses is likely to require significant time and effort on the part of the Group's management. Integration of new businesses can be difficult because the Group's operational and business culture may differ from the cultures of the businesses it acquires, unpopular cost-cutting measures may be required, internal controls may be more difficult to maintain and control over cash flows and expenditure may be difficult to establish. If the Group experiences difficulties in integrating future acquisitions it could have an adverse effect on its business, prospects, financial condition and results of operations.

The Group may face unanticipated increases in costs.

The oil and gas business is a capital-intensive industry. To implement its business strategy, the Group has invested in the construction of its oil and gas pipelines, and has invested, and continues to invest, in drilling and exploration activities and infrastructure, including the second phase of the gas treatment facility. The Group's current and planned expenditures on such projects are subject to unexpected problems, costs and delays, and the economic results and the actual costs of these projects may differ significantly from the Group's current estimates. For example, in October 2012 the Group undertook a controlled shutdown of the gas treatment facility in order to bring it to at or near full design capacity, resulting in unexpected costs. See "*—The Group's planned development projects are subject to risks related to cancellation, delay, non-completion and cost overruns which could result in a reduction or suspension of the Group's production of hydrocarbons*".

The Group relies on oil field suppliers and contractors to provide materials and services in conducting its exploration, appraisal, development and production activities, and may incur additional expenses if it is required to perform some of these activities directly. Any competitive pressures on the oil field suppliers and contractors, or substantial increases in the worldwide prices of commodities, such as steel, could result in a material increase in costs for the materials and services required by the Group to conduct and expand its business. The cost of oil field services and goods globally has increased significantly in recent years and is heavily linked to the price of oil and could continue to increase in the future. Future increases could have a material adverse effect on the Group's operating income, cash flows and borrowing capacity and may require a reduction in the carrying value of the Group's properties, its planned level of spending for exploration and development and the level of its reserves.

Prices for the materials and services the Group depends on to conduct and expand its business may not be sustained at levels that enable the Group to operate profitably. The Group may also need to incur various unanticipated costs, such as those associated with personnel, transportation and Kazakh Government royalties and taxes. Personnel costs, including salaries, are increasing as the standard of living rises in Kazakhstan and as demand for suitably qualified personnel for the oil and gas industry increases. Additionally, trade unions are active in Kazakhstan, particularly in the oil and gas sector. Although there have been no strikes in the history of the Group, industrial action, and the increased costs associated with such action, could occur. An increase in any of these or other costs could materially and adversely affect the Group's business, prospects, financial condition and results of operations.

The Group cannot accurately predict its future decommissioning liabilities.

The Group, through its operations, has in the past assumed certain obligations in respect of the decommissioning of the Chinarevskoye Field and related infrastructure and is expected to assume additional decommissioning liabilities in respect of its future operations. These liabilities are derived from legislative and regulatory requirements concerning the decommissioning of wells and production facilities and require the Group to make provision for and/or underwrite the liabilities relating to such decommissioning. Although the Group's accounts make a provision for such decommissioning costs, there can be no assurances that the costs of decommissioning will not exceed the value of the long-term provision set aside to cover such decommissioning costs. It is difficult to forecast accurately the costs that the Group will incur in satisfying its decommissioning obligations and the Group may have to draw on funds from other sources to bear such costs, which could materially and adversely affect the Group's business, prospects, financial condition and results of operations.

Certain major shareholders in the Company may be able to exercise substantial influence over the Company and the Group.

On Admission, Claremont Holdings C.V. (a Dutch limited partnership controlled by Frank Monstrey, the executive chairman of the Company) ("**Claremont**") and its affiliates are expected to be the beneficial owners of 27.2% of the Ordinary Shares, while KazStroyService Global B.V. (an entity which is indirectly controlled by Timur Kulibayev, Arvind Tiku, Lakshmi Mittal and Goldman Sachs) ("**KSS Global**") is expected to be the beneficial owner of 26.6% of the Ordinary Shares. Shareholders that own at least 25% of the Ordinary Shares are able to effectively block certain matters requiring approval of holders of Ordinary Shares (by way of special resolutions), including amending the Company's articles of association or approving share buy-backs. Claremont and its affiliates and/or KSS Global may therefore individually be able to exercise substantial influence over the Group's business and affairs and may potentially be able to block actions that favour the interests of the Group or interests of holders of the Ordinary Shares over their own interests. Furthermore, KSS Global is owned by a small number of shareholders. Timur Kulibayev, Arvind Tiku and Lakshmi Mittal are business associates. Timur Kulibayev and Arvind Tiku have other shared business interests.

The concentration of ownership by Claremont and KSS Global may also have the effect of delaying, deferring or preventing a change in control, impeding a merger, consolidation, takeover or other business combination or discouraging a potential acquirer from making a tender offer or otherwise attempting to obtain control.

On 19 May 2014, the Company entered into relationship agreements (the "**Relationship Agreements**"), one with Claremont and one with KSS Global, in which Claremont and KSS Global each independently undertake to allow the Company to operate its business independently from Claremont and its affiliates or KSS Global (as applicable), and to ensure that commercial transactions and relationships with Claremont and its affiliates or KSS Global (as applicable) are conducted on an arm's length basis. The terms of the Relationship Agreements also provide for Claremont and KSS Global to be represented on the Board. However, the relevant Relationship

Agreement will cease to have effect if either Claremont (together with its affiliates) or KSS Global, as the case may be, hold less than 10% of the Ordinary Shares.

If either of the Relationship Agreements were to cease to have effect or if the Company were unable to enforce its rights under the Relationship Agreements, either Claremont (together with its affiliates) or KSS Global (as applicable) would be a major shareholder unfettered by any contractual arrangement with the Company and may be able to block actions and thereby potentially favour its interests over those of the Group, which could have an adverse effect on the Group's business, prospects, financial position or results of operations.

The Group requires significant water supplies in order to conduct its business and failure to obtain such water may adversely affect its business.

Normal drilling operations and exploration activities, and the use of water injection techniques in the Group's crude oil reservoirs, require access to significant supplies of water. The Group currently extracts water pursuant to a water use permit issued on 5 December 2008 (the "**Water Use Permit**") which is valid until 31 December 2014 with certain limitations on the amounts of water that can be used. The Water Use Permit can be withdrawn if the terms of special water use specified in the Water Use Permit are breached, although there is no history of breaches or withdrawals as at the date of this Prospectus.

Such terms include monitoring the quality of underground water, submitting statistical reports and monitoring reports, complying with requirements relating to water protection during mining operations and regular checking of equipment. See also "*—Risk Factors Relating to the Oil and Gas Industry—The Group is obliged to comply with environmental regulations and cannot guarantee that it will be able to comply with these regulations in the future.*" As the Group's production increases, the amount of water required by the Group for its operations will also increase, which will require the Group to apply for additional permits to access additional water sources. The Group's current Water Use Permit allows the Group to use around half of the anticipated requirements of the Group when it reaches full production capacity. On 10 January 2014, the Group applied for a further Water Use Permit for the 2015 to 2016 period which application was granted on 17 February 2014. In the event the Group ceases to have access to the necessary amount of water, if the level of water available to it is curtailed or if the Group fails to obtain further Water Use Permits, the Group's ability to pursue its drilling and production activities may be materially and adversely affected, which would have a material adverse effect on its business, prospects, financial condition and results of operations. For more information on Water Use Permits, please see Part 8 "*Industry and Regulatory Overview—Regulation in Kazakhstan—Regulation of subsoil rights in Kazakhstan—Water permits*".

The Group depends on its key senior management and on its ability to retain and hire new qualified personnel and consultants.

The Group depends on the contribution of a number of its key senior management and personnel. For example, the Group depends on the extensive contacts and relationships of its executives and Frank Monstrey, the Chairman of the Board of Directors and the services of Mr. Kai-Uwe Kessel, Nostrum's Chief Executive, for overall management of the Group's business.

The Group's future operating results depends in significant part upon the continued contribution of its key senior management, technical, financial, operations and marketing personnel. The Group's management of its business will require, among other things, stringent control of financial systems and operations, the continued development of its management controls, the ability to attract and retain sufficient numbers of qualified management and other personnel, the continued training of such personnel, the presence of adequate supervision and continued consistency in the quality of its services.

Key personnel, such as Mr. Kessel, may not remain with the Group. The Group is not insured against damage that may be incurred in case of loss or dismissal of the Group's key specialists or managers. The loss of or diminution in the services of one or more of the Group's senior management, or the Group's inability to attract, retain and maintain additional senior management personnel, could have a material adverse effect on the Group's business, prospects, financial condition and results of operations.

In addition, the personal connections and relationships of Nostrum's key senior management, in particular Frank Monstrey, are important to the conduct of its business. If the Group were to unexpectedly lose a member of its key senior management, its business, prospects and results of operations might be adversely affected.

The Group may face difficulties in recruiting and retaining qualified personnel in Kazakhstan.

The Group's future success will depend, in part, on its ability to continue to attract, retain and motivate qualified personnel. Competition in Kazakhstan for personnel with relevant expertise is intense due to the relatively small number of qualified individuals. Currently, all Kazakh employers attracting foreign employees must obtain a work permit for such employees to work in Kazakhstan from local executive bodies (*Akimats*). The Kazakh Government establishes an annual quota on the number of foreigners who can be given such a permit and then the Ministry of Labour and Social Defence of Population of Kazakhstan allocates such quota among the oblasts, and the cities of Astana and Almaty. The quota is typically too small to permit the desired number of foreign employees and, accordingly, the process of obtaining work permits for foreign employees can be time-consuming and uncertain. Sanctions may also be imposed during the period between applying for, and obtaining, a work permit, which could include deportation of the individual concerned and an administrative fine. While 1.5% of Nostrum's staff as at 31 December 2013 were non-Kazakhs requiring a work permit, these individuals tend to serve in senior positions. As such, any changes affecting the availability of, or difficulties or costs in obtaining, work permits for these individuals could have a material adverse effect on the Group's business, prospects, financial condition and results of operations.

Factors critical to retaining the Group's present personnel and to attracting additional highly qualified personnel include the Group's ability to provide competitive compensation arrangements. Wage structures in Kazakhstan, though rising, remain lower than in more industrialised nations and it may be difficult to attract and retain experienced and skilled personnel from outside Kazakhstan at wages that are acceptable to the Group. In addition, the Group operates in areas which are subject to extreme temperatures and climate. As such, it is difficult to attract and retain skilled management personnel at affordable rates. The Group also retains external consultants to provide services that are critical to its operations and strategy, such as creating geological models used in exploration and performing hydro-fracturing and other stimulation techniques. Any failure by the Group to retain the services of its existing personnel and the services of specialist external consultants, and to successfully manage its personnel needs generally, could have a material adverse effect on the Group's business, prospects, financial condition and results of operations.

The Group relies on transportation systems owned and operated by third parties which may become unavailable. The Group may be unable to access these or alternative transportation systems.

The Group does not currently have the capacity to transport its crude oil production for export independently. Although the Group's crude oil production is currently transported from the Chinarevskoye Field to export markets via a crude oil pipeline owned by the Group to the Group's rail loading terminal near Uralsk, it still relies on third parties to transport its oil and condensate by rail car. The Group also relies on third parties to transport its LPG by truck.

The availability of sufficient rail cars affects the cost of transport of the Group's crude oil and condensate. Lack of available rail cars, or increased costs in the hiring of rail cars, could have a material adverse effect on the Group's business, prospects, financial condition and results of operations, and the trading price of the Ordinary Shares.

The viability of rail as a transport method for the Group depends heavily on Russia's transportation infrastructure since the rail cars must use the Russian railway system. The Russian government sets rail tariffs and may further increase these tariffs, as it has done in the past, generally on an annual basis. Russia has implemented the privatisation of certain state-owned railway enterprises. If the privatisation of Russia's railways or other factors result in increased railway transportation costs in Russia, this could have a material adverse effect on the Group's business, prospects, financial condition and results of operations, and the trading price of the Ordinary Shares.

The Group may also encounter various transportation risks with regards to its oil and gas products, which may affect the Group's ability to deliver its products in a timely and cost effective manner. If the Group experiences any problems with its pipeline, which connects the Chinarevskoye Field with its rail loading terminal in Rostoshi near Uralsk, as well as any other material transport disruptions (such as damage to its rail loading terminal in Rostoshi), it might be required to curtail its production activities or incur additional transportation and storage expenses from accessing alternative transport arrangements, including the use of trucks to transport crude oil and condensate to alternative rail loading terminals. At present, the Group does not currently have any alternative means to supply its gas to its customers other than via its 17 kilometre gas pipeline, which links the gas treatment facility to the Orenburg-Novopskov gas pipeline. If this pipeline or its connection to the Orenburg-Novopskov gas pipeline were materially damaged, the Group would have to cease operating the gas treatment facility until such damage is repaired. The occurrence of any of these events could have a material adverse effect on the Group's business, prospects, financial condition and results of operations.

Any reduction or cessation in the availability of rail infrastructure or other means of transporting the Group's oil and gas products, whether due to serious malfunctions, security issues, political developments or other force majeure events, could have a material adverse effect on the Group's business, prospects, financial condition and results of operations, and the trading price of the Ordinary Shares.

There are risks inherent in the Group's strategy of acquisition of new exploration and development properties.

While no material acquisitions are currently under consideration, the Group's strategies include that, from time to time as suitable opportunities arise, it may consider acquiring additional oil and gas properties. Although the Group performs a review of properties that it believes is consistent with industry practices prior to acquiring them (such as those it carried out in respect of the Rostoshinskoye, Darinskoye and Yuzhno-Gremyachenskoye fields), such reviews are inherently incomplete. It generally is not feasible to review in depth every individual property involved in each acquisition. Ordinarily, the Group will focus its due diligence efforts on higher valued properties or assets and will conduct due diligence on only a sample of the remainder. However, even an in-depth review of all properties and records may not necessarily reveal existing or potential problems, nor will it permit a buyer to become sufficiently familiar with the properties to assess fully their deficiencies and capabilities. Physical inspections may not be performed on every well, and structural or environmental problems, such as ground water contamination, are not necessarily observable even when an inspection is undertaken.

The Group may be required to assume pre-closing liabilities with respect to an acquisition, including environmental liabilities, and may acquire interests in properties on an "as is" basis. In addition, competition for the acquisition of prospective oil properties is intense, which may increase the cost of any potential acquisition. To date, the Group's exploration and development activities have been based in North-Western Kazakhstan, and the Group's lack of presence in other regions may limit its ability to identify and complete acquisitions in other geographic areas. There can be no assurance that any potential acquisition by the Group will be successful.

The Group relies and will continue to rely on the services of third parties with respect to the construction, development and maintenance of its gas treatment facility and the development of the Rostoshinskoye, Darinskoye and Yuzhno Gremyachenskoye fields.

The Group relies and will continue to rely to a large extent on external contractors to carry out construction, development and maintenance of the second phase of the Group's gas treatment facility and the development of the Rostoshinskoye, Darinskoye and Yuzhno Gremyachenskoye fields. The Group relies and expects to continue to rely on external contractors both local and external to Kazakhstan to perform major works, such as the project management, front end engineering and design, procurement, construction, engineering and commissioning of the planned second phase of the gas treatment unit (for which project, Ferrostaal Industrieanlagen GmbH, Rheinmetall International Engineering and NIPI Neftegaz have already been appointed as external contractors) as well as well drilling and maintenance, repairs and maintenance of equipment, maintaining and replacing pipe and other general building and structure maintenance. Some of the services required for the Group's operations and developments are currently only available on commercially reasonable terms from one or a limited number of providers. These operations and developments may be interrupted or otherwise adversely affected by failure to supply, or delays in the supply of services that meet the Group's quality requirements. If the Group is forced to change a provider of such services, there is no guarantee that this would not result in the Group experiencing additional costs and interruptions to production and supply continuity to its customers. There is also no guarantee that the Group will be able to find adequate replacement services on a timely basis or at all. Competition for the services of highly skilled third party contractors has increased and supply has become tightly constrained, and such competition may continue or intensify. As a result, the Group may face shortages of qualified third party contractors and significantly higher fees to retain the services of qualified third party contractors. As a result, the Group is largely dependent on satisfactory performance by its external contractors and the fulfilment of their obligations. If an external contractor fails to perform its obligations satisfactorily, this may lead to delays or curtailment of the production, transportation, refining or delivery of oil and gas and related products, which could have an adverse effect on the Group's business, prospects, financial condition or results of operations.

Harsh climate conditions may detrimentally affect the lifespan of the Group's assets and the future cost and operation of the Group's facilities.

West Kazakhstan, where the Chinarevskoye Field is located, is subject to extreme temperatures and climate. These temperature fluctuations impose additional stress on buildings and equipment and, as a result, the lifespan of buildings and equipment is not as long as in milder climates. The need to cater to extreme temperatures and climate also imposes additional costs in design, construction and maintenance. Since most of the equipment used by the Group is imported, maintenance costs are high. Supplies of spare parts and replacement parts are not locally or cheaply available and there is a shortage of skilled maintenance personnel to adequately service and maintain the Group's equipment. As a result, the increased costs of design, construction and maintenance, or delays while replacement equipment and spare parts are delivered to the Chinarevskoye Field, could have an adverse effect on the Group's business, prospects, financial condition and results of operations.

The Group is subject to risks related to fluctuations in the U.S. Dollar/Tenge exchange rate.

The products that the Group exports are sold at prices quoted in U.S. Dollars and cash payment to the Group is made in U.S. Dollars. Approximately 40% to 45% of the Group's expenses for the year ended 31 December 2013 were denominated in Tenge and not indexed to the U.S. Dollar and hence were subject to fluctuations of the U.S. Dollar/Tenge exchange rate. The Group does not maintain any currency hedging arrangements. If the value of the U.S. Dollar falls against the Tenge, then the Group will have less Tenge available to pay its Tenge expenses and its results will be adversely affected.

The Group's insurance coverage does not cover all risks and may not be adequate for covering losses arising from potential operational hazards and unforeseen interruptions.

The insurance industry in Kazakhstan is not as developed as in more advanced economies and many forms of insurance protection typically used in more advanced economies, such as business interruption insurance, are unavailable. Kazakhstan law requires oil and gas companies to insure only against certain limited types of risks, such as insurance of employees against accidents at work, environmental damage and certain civil liability, for instance civil liability of owners of objects, activities of which may cause damage to third parties, and vehicle owners' civil liability. As a result of its engagement in extraction and exploration activities, the Group may become subject to liabilities for hazards against which it either cannot obtain insurance, or which it may elect not to insure against because of high insurance premium costs. Losses from uninsured risks may cause the Group to incur costs that could have a material adverse effect on the Group's business, prospects, operating results and financial condition.

The Group's insurance does not cover business interruption, key-man, terrorism or sabotage insurance. The proceeds of insurance applicable to covered risks may not be adequate to cover increased expenses relating to these losses or liabilities. Accordingly, the Group may suffer material losses from uninsurable or uninsured risks or insufficient insurance coverage which could materially and adversely affect the Group's business, prospects, financial condition and results of operations.

The Company is subject to the Bribery Act 2010 (the "Bribery Act") and the U.S. Foreign Corrupt Practices Act (the "FCPA"), and its failure to comply with the laws and regulations thereunder could result in penalties which could harm its reputation and have a material adverse effect on the Group's business, results of operations, financial condition and prospects.

The Company is subject to the Bribery Act and the FCPA, which generally prohibit companies and their intermediaries from making improper payments to foreign officials for the purpose of obtaining or keeping business and/or other benefits. Although the Group has policies and procedures designed to ensure that the Group, its employees and agents comply with the Bribery Act and the FCPA, there is no assurance that such policies or procedures will work effectively all of the time or protect the Company against liability under the Bribery Act or the FCPA for actions taken by its agents, employees and intermediaries with respect to the Group's business. If the Company is not in compliance with the Bribery Act, the FCPA or other laws governing the conduct of business with government entities (including Kazakh laws), it may be subject to criminal and civil penalties and other remedial measures, which could have a material adverse impact on the Group's business, results of operations, financial condition and prospects. Any investigation of any potential violations of the Bribery Act, the FCPA or other anti-corruption laws by U.S. or foreign authorities also could have a material adverse impact on the Group's business, results of operations, financial condition and prospects. Furthermore, any remediation measures taken in response to such potential or alleged violations of the Bribery Act, the FCPA or other anti-corruption laws, including any necessary changes or enhancements to the Group's procedures, policies and controls and potential personnel changes and/or disciplinary actions, may materially adversely impact its business, results of operations, financial condition and prospects.

The Group's IT systems are subject to disruption which could adversely impact the Group's operations.

The Group's IT systems in Uralsk, where its operations are primarily carried out, occasionally suffer from power outages and other disruptions. The Group is in the process of implementing backup procedures and developing formal disaster recovery plans but, as at the date of this Prospectus, this has not yet been completed. While the Group's main storage data is regularly backed up, the Group does not regularly test backup copies for restoration (which may mean that the Group would be unable to restore systems when necessary). Were a severe disruption to the Group's IT systems in Uralsk to occur, it could adversely affect the Group's business, prospects, financial condition and results of operations.

Risk Factors Relating to the Oil and Gas Industry

The Group may be adversely affected by a substantial or extended decline in prices for crude oil and gas.

The Group's future revenues, profitability and cash flows depend heavily on prevailing crude oil and gas prices. Crude oil and gas sales have been and are expected to continue to be the Group's primary source of revenue and the price of crude oil and gas is affected by a variety of factors beyond the Group's control. Historically, crude oil prices have been highly volatile. According to Bloomberg, the spot price of Brent crude oil reached approximately U.S.$96.99 per barrel as at 31 December 2011, U.S.$102.32 per barrel as at 31 December 2012 and U.S. $109.02 per barrel as at 31 December 2013. Prices have varied between a low of approximately U.S.$103.99 per barrel and a high of approximately U.S.$110.01 per barrel in the first three months of 2014.

Prices for oil and gas are subject to large fluctuations in response to a variety of factors beyond the Group's control, including:

- the condition of the world economy and geopolitical events;
- changes in the global and regional supply of and demand for commodities and expectations regarding future supply and demand;
- market uncertainty and speculative activities by those who buy and sell commodities on the world markets or fluctuations in currencies, particularly the U.S. dollar;
- weather, natural disasters and general economic conditions;
- actions of the Organisation of Petroleum Exporting Countries ("**OPEC**"), and other nations exporting petroleum products, to set and maintain specified levels of production and prices;
- governmental regulation in Kazakhstan and elsewhere;
- political stability in Kazakhstan, neighbouring countries and other regions exporting petroleum products;
- technical advances affecting energy consumption and extraction methods;
- advances in shale oil and gas production in the United States, which has facilitated the monetisation of resources that were previously considered non-commercial; and
- prices and availability of alternative and competing fuel sources.

Accordingly, the Group may not continue to receive the same prices for its products as it currently receives or historically has received. Any decline in crude oil and gas prices and/or any curtailment in the Group's overall production volumes could result in a reduction in net income, could impair the Group's ability to make planned capital expenditures and to incur costs necessary for the development of the Group's business and its oil and gas fields, and could materially and adversely affect the Group's business, prospects, financial condition and results of operations.

It is the Group's policy to hedge against adverse oil price movements during times of considerable non-scalable capital expenditure. On 3 March 2014, Zhaikmunai LLP entered, at nil upfront cost, into a new hedging contract covering oil sales of 7,500 bopd, or a total of 5,482,500 boe running through 29 February 2016. However, no assurance can be given that this hedging contract or any other such hedging contracts entered into by the Group will protect the Group from adverse oil price movements fully or at all nor can there be any assurance that in the future the Group will be able to enter into hedging contracts on commercially acceptable terms.

The level of the Group's reserves, their quality and production volumes may be lower than estimated or expected.

Unless stated otherwise, the reserves data included in this Prospectus has been derived or extracted from the 2013 Ryder Scott Report, which have been prepared in accordance with the standards established by the SPE-PRMS.

There are numerous uncertainties inherent in estimating the quantity and the quality of reserves and in projecting future rates of production, including many factors beyond the Group's control. Estimating the amount and quality of reserves is a subjective process and estimates made by different experts can vary significantly. In addition, results of drilling, testing and production subsequent to the date of an estimate may result in revisions to that estimate. Accordingly, reserves estimates may be different from the quantity or quality of hydrocarbons that are ultimately recovered and, consequently, the revenue derived therefrom could be less than that currently expected. The significance of such estimates depends heavily on the accuracy of the assumptions on which they are based, the quality of the information available and the ability to verify such information against industry standards.

The reserves data contained herein are estimates only and should not be construed as representing exact quantities. These estimates are based on production data, prices, costs, ownership, geological and engineering data, and other information assembled by the Group, and they assume, among other things, that the future development of the Group's fields and the future marketability of the Group's products will be similar to past development and marketability. Many of the factors, assumptions and variables involved in estimating reserves are beyond the Group's control and may prove to be incorrect over time, and potential investors should not place undue reliance on the forward-looking statements contained herein (including data taken from the 2013 Ryder Scott Report) concerning the Group's reserves or production levels. For example, the Group's 2012 production results differed from the estimates in the 2012 production report produced by Ryder Scott as a result of slower than expected ramp-up to the full design capacity of the first phase of the gas treatment facility in 2012.

Estimates of the value and quantity of economically recoverable oil reserves, rates of production, net present value of future cash flows and the timing of development expenditures necessarily depend upon several variables and assumptions, including:

- historical production from the area compared with production from other comparable producing areas;
- interpretation of geological and geophysical data;
- assumed effects of regulations adopted by governmental agencies;
- assumptions concerning future percentages of international and domestic sales;
- assumptions concerning future crude oil and other hydrocarbon prices;
- the availability, application and efficacy of new technologies;
- capital expenditures; and
- assumptions concerning future operating costs, taxes on the extraction of hydrocarbons, development costs and workover and remedial costs.

Because all reserves estimates are subjective, each of the following items may differ materially from those assumed in estimating the Group's reserves:

- the quantities and qualities of hydrocarbons that are ultimately recovered;
- the production and operating costs incurred;
- the amount and timing of additional exploration, appraisal and development expenditures; and
- future hydrocarbon oil sales prices.

Many of the factors, assumptions and variables used in estimating reserves are beyond the Group's control and may prove to be incorrect over time. Evaluations of reserves necessarily involve multiple uncertainties. The accuracy of any reserves or resources evaluation depends on the quality of available information and petroleum engineering and geological interpretation. Exploration drilling, interpretation and testing and production after the date of the estimates may require substantial upward or downward revisions in the Group's reserves or resources data. Moreover, different reservoir engineers may make different estimates of reserves and cash flows based on the same available data. Actual production, revenues and expenditures with respect to reserves and resources will vary from estimates, and the variances may be material. The estimation of reserves may also change because of acquisitions and disposals, new discoveries and extensions of existing fields as well as the application of improved recovery techniques.

If the assumptions on which the estimates of the Group's reserves have been based are wrong, the Group may be unable to produce the estimated levels or quality of products set out in this Prospectus, which would have a material adverse effect on the Group's business, prospects, financial condition and results of operations.

Contingent and prospective resources are unlikely to be commercially productive in the short or medium term.

Unless stated otherwise, the contingent and prospective resources set forth in this Prospectus have been extracted without material adjustment from the Competent Person's Report, which has been prepared by Ryder Scott in accordance with the SPE-PRMS Standard. Special uncertainties exist with respect to the estimation of contingent and prospective resources in addition to those that apply to reserves. Contingent resources are resources estimated, as of a given date, to be potentially recoverable from known accumulations but are not yet considered mature enough for commercial development due to one or more contingencies. Contingent resources may include, for example, projects for which there are currently no viable markets, or where commercial recovery is dependent on technology under development, or where evaluation of the accumulation is insufficient to clearly assess commerciality. Prospective resources are resources estimated, as of a given date, to be potentially recoverable from undiscovered accumulations by application of future development projects. Development of contingent and prospective resources, if undertaken, may involve considerable expense, and may not result in the discovery of hydrocarbons in commercially viable quantities. The probability that contingent and prospective resources will be economically recoverable is considerable lower than that for proved, probable and possible reserves. Volumes and values associated with contingent and prospective resources should be considered highly speculative and there can be no guarantee that the Group will be able to develop these resources commercially.

Failure by the Group to gain access to additional reserves or to acquire additional reserves at commercially viable prices could materially adversely affect the Group's ability to achieve its long term growth strategy.

As with any company in the oil and gas industry, the long-term commercial success of the Group depends on its ability to explore, appraise and develop oil and gas reserves and to commercially produce oil and gas from such reserves. If the Group is unsuccessful in locating and developing or acquiring new reserves, its existing reserves (and hence production) will decline over time due to depletion by production. Future increases in the Group's reserves will depend not only on the Group's ability to develop its present properties but also on its ability to select and acquire additional suitable producing properties or prospects. The Group will need to acquire or find and develop additional reserves in order to maintain its current production levels in the long term. There can be no assurance that the Group will be able to identify appropriate acquisition opportunities or that it will be able to make such acquisitions on appropriate terms as and when they become available. Any efforts by the Group to acquire additional reserves involve a number of risks, including competition from other interested purchasers who may have larger financial resources than the Group has; unidentified historical or future liabilities of the operations that the Group may acquire; the inability to receive accurate and timely information about these operations in order to make informed investment decisions; problems in integrating acquired operations; and problems in hiring and retaining qualified personnel. Many of the Group's competitors are also actively seeking to acquire interests in Kazakh oil and gas operations. These companies may be able to pay more for exploratory prospects and productive oil and gas properties and may be able to identify, evaluate, bid for and purchase a greater number of prospects and properties, including operatorships and licences, than the Group's financial or human resources permit. Any failure by the Group to acquire or find and develop additional reserves at commercially viable prices is likely to lead to a decline in the Group's reserves and production, which may materially adversely affect the Group's business, results of operations, financial condition and prospects and the trading price of the Ordinary Shares.

The Group may not be able to develop commercially its reserves and resources.

The SPE-PRMS standards have been applied to estimate the Group's reserves and resources. Under SPE-PRMS standards, probable reserves are those additional reserves which analysis of geoscience and engineering data indicate are less likely to be recoverable than proved reserves. Possible reserves may be assigned to areas of a reservoir adjacent to probable where data control and interpretations of available data are progressively less certain. Contingent resources are those deposits that are estimated, on a given date, to be potentially recoverable from known accumulations but that are not currently considered commercially recoverable. The resources may not be considered commercially recoverable by the Group for a variety of reasons, including the high costs involved in recovering the contingent resources, the price of oil at the time and the availability of the Group's resources and other development plans that the Group may have. By contrast, prospective resources are those deposits that are estimated, on a given date, to be potentially recoverable from undiscovered accumulations. Frequently, this may be in areas where geoscience and engineering data are unable to clearly define the area and vertical reservoir limits of commercial production from the reservoir by a defined project. The Group's estimates of its possible and probable reserves, and resources, are uncertain and can change with time and there can be no guarantee that the Group will be able to develop its reserves and resources commercially.

The Group faces drilling, exploration, production and operational risks and hazards that may affect the Group's ability to produce oil and gas products at expected levels, quality and costs.

The Group's future success will depend, in part, on its ability to develop oil and gas products reserves in a timely and cost-effective manner. The Group's drilling activities may be unsuccessful and the actual costs incurred to drill and operate wells, and to complete well workovers, may have an adverse impact on the Group's profits. The Group may be required to curtail, delay or cancel any drilling operations because of a variety of factors, including unexpected drilling conditions, pressure or irregularities in geological formations, equipment failures or accidents, premature declines in reservoirs, blowouts, uncontrollable flows of hydrocarbons or well fluids, pollution and other environmental risks, adverse weather conditions, compliance with governmental requirements and shortages or delays in the availability of drilling rigs and the delivery of equipment and spare parts. The Group's current or future oil and gas appraisal, exploration projects and use of enhanced recovery techniques may involve unprofitable efforts, not only from dry wells, but from wells that are productive but do not produce sufficient net revenues to return a profit after drilling, operating and other costs. Completion of a well does not assure a profit on the investment or recovery of drilling, completion and operating costs. The Group is also exposed to drilling hazards and environmental damage that could greatly increase its operating costs or result in the deterioration of its field operations. In addition, various field conditions may adversely affect its oil and gas production. These conditions include delays in obtaining governmental approvals or consents, shut-ins of connected wells resulting from extreme weather conditions, insufficient storage or transportation capacity, and adverse geological conditions.

For example, in August 2012, the Group decided to expand its operations and agreed to acquire subsoil use rights to three new oil and gas fields in Kazakhstan, Rostoshinskoye, Darinskoye and Yuzhno-Gremyachenskoye, located approximately 50 to 105 kilometres from the Chinarevskoye Field. This transaction was completed on 24 May 2013 and the Group is currently in the process of analysing the optimal appraisal and development programme for the fields. However, appraisal and exploration activities are capital intensive and inherently uncertain in their outcome and there can be no assurance that the Group will be successful in its plans to develop these fields profitably.

The Group's production operations are also subject to risks associated with natural catastrophe, fire, explosion, blowouts, encountering formations with abnormal pressure, the level of water cut, cratering and spills, each of which could result in substantial damage to wells, production facilities, other property and the environment or in personal injury or death. Any of these risks could, among other things, result in loss of hydrocarbons or could lead to environmental pollution and other damage to the Group's properties or nearby areas, increased costs, loss of life, injury to persons and affect the ability of the Group to extract hydrocarbons, process gas and transport its products and potentially sanctions for breach of the PSA, the subsoil use agreements for the Rostoshinskoye, Darinskoye and Yuzhno-Gremyachenskoye fields (the "**Subsoil Use Agreements**"), the Licence and applicable law.

The Group's existing gas treatment facility is shut down each year for scheduled maintenance of approximately two weeks (the most recent shutdown, in September 2013, was conducted over nine days). During this period, the Group flares associated gas pursuant to a gas flaring permit from the Competent Authority. The current gas flaring permit is due to expire at the end of 2014, although the Directors expect that this will be renewed. If this permit is not renewed, the Group would either have to flare associated gas and be liable for a fine for such flaring or to reduce or suspend its production activities which depend upon an operational gas treatment facility. Any such reduction or suspension of gas production activities would have a material adverse effect on the Group's business, prospects, financial condition and results of operations and the trading price of the Ordinary Shares.

Additionally, the cost and duration of this maintenance shutdown could be greater than the Group forecasts. Any prolonged shutdown of the gas treatment facility could have a material adverse effect on the Group's business, prospects, financial condition and results of operations.

Any of these drilling, exploration, production and operational risks and hazards could have a material adverse effect on the Group's business, prospects, financial condition and results of operations.

The Group may be unable to comply with its obligations under the PSA and the Licence or under subsoil use agreements for the Rostoshinskoye, Darinskoye and Yuzhno-Gremyachenskoye fields.

The Group's exploration, mining and processing activities depend on the grant, renewal or continuance in force of the PSA, the Licence, or under subsoil use agreements for the Rostoshinskoye, Darinskoye and Yuzhno-

Gremyachenskoye fields ("**Subsoil Use Agreements**") and other licences, permits, and regulatory approvals and consents, each of which are valid for a limited time period. The PSA, the Licence, the Subsoil Use Agreements and other licences, permits and regulatory approvals and consents may not in the future be granted on terms acceptable to the Group or at all, and may not continue in force. Various provisions of Kazakh law provide that fines may be imposed and licences and subsoil use contracts may be suspended, amended or terminated if a licence holder fails to comply with its obligations under such documents, including if a licence holder fails to make timely payment of levies and taxes for subsoil use, fails to provide the required geological information or fails to meet other reporting requirements.

The Group's operations must be carried out in accordance with the terms of applicable law, the Licence and the PSA (including the production permit, the exploration permit, the Development Plans, the gas flaring permits, the technological scheme of development of the Licence area and work programmes), the Subsoil Use Agreements and other licences, permits, regulatory approvals and consents. Under the New Subsoil Law, the failure by a subsoil user to remedy more than two breaches of its obligations under a subsoil use contract or project documents within a period of time established in the notice of such breach from the Competent Authority may result in a termination of the relevant subsoil use contract. In the past few years the Competent Authority announced it had terminated subsoil use contracts of certain companies due to breaches of Kazakhstan regulations relating to goods, supplies and services from Kazakh sources. In addition, any antecedent breach under the Licence, the PSA, the Subsoil Use Agreements and other licences, permits, regulatory approvals and consents could result in the Group being ineligible for the licences, approvals and permits it needs in the future.

The State's central executive agency, designated by the Kazakh Government to act on behalf of the State to exercise rights relating to the execution and performance of subsoil use contracts, which was the Ministry of Energy and Mineral Resources of Kazakhstan until 12 March 2010, when it was reorganised into the Ministry of Oil and Gas with respect to the oil and gas industry has, on various occasions in the past, notified Nostrum of purported violations of certain provisions of the PSA and requested information from Nostrum demonstrating its compliance with its obligations under the PSA. Nostrum has responded to all such notices and requests and has provided the requested information, which Nostrum believes demonstrates its compliance with the terms of the PSA, to the relevant authorities. The Directors believe that Nostrum is in compliance in all respects with its obligations under the PSA, the Licence and the Subsoil Use Agreements. To date such authorities have not taken any further action in relation to such notices regarding the PSA following receipt of such information from Nostrum and no notices of any material adverse action on the part of the authorities have been received by Nostrum although no assurance can be given that the relevant authorities will not in the future take further action or that new allegations of violations against the Group will not be made.

However, the views of the Kazakh Government agencies regarding the development of the Chinarevskoye Field or compliance with the terms of its licences or permits may not coincide with the Group's views, which might lead to disagreements that cannot be resolved. The Group could also encounter challenges from third parties to the validity of its existing Licence and contracts, or any future permits that may be required, which could trigger suspension and subsequent termination of these contracts. The Directors regard the likelihood of either of these risks materialising as low.

Any suspension, revocation or termination of any of the Licence, the PSA or other material permits or agreements (for any of the reasons stated above) could prevent or significantly reduce the Group's production of hydrocarbons, which would have a material adverse effect on the Group's business, prospects, financial condition, cash flows and results of operations, and the trading price of the Ordinary Shares.

The Group may be unable to implement changes to its existing work programme.

As part of the tenth supplementary agreement to the PSA, the Group has replaced its annual work programme for the Chinarevskoye field by a single work programme for the 2013 to 2032 period. Any additional changes to the single work programme would require the Group to further amend the PSA. In previous years, the relevant government authorities have approved changes requested by the Group and have executed supplemental agreements to the PSA. In the future, if the Group is unable to amend the PSA for any reason, it would be required to follow the existing single work programme, which might not be sufficient to accommodate future increases in the Group's reserve base and would therefore constrain the Group's ability to diversify its sources of production.

The Group is obliged to comply with environmental regulations and cannot guarantee that it will be able to comply with these regulations in the future.

The Group's operations are subject to environmental risks inherent in oil and gas exploration and production industries. Compliance with environmental regulations may make it necessary for the Group, at costs that may be substantial, to undertake measures in connection with the storage, handling, transportation, treatment or disposal of hazardous materials and waste and the remediation of contamination.

The legal framework for environmental protection and operational safety is not yet fully developed in Kazakhstan. Stricter environmental requirements, such as those governing discharges to air and water, the handling and disposal of solid and hazardous wastes, land use and reclamation and remediation of contamination, may be adopted in the near future, and the environmental authorities may move towards a stricter interpretation of existing legislation. The costs associated with compliance with such regulations could have a material adverse effect on the Group's business, prospects, financial condition and results of operations.

The Group's environmental obligations include complying with Kazakh environmental legislation, particularly the Kazakhstan Environmental Code (dated 9 January 2007, as amended) (See also Part 8 "*Industry and Regulatory Overview—Regulation in Kazakhstan—Environmental Permits*"). The costs of environmental compliance in the future and potential liability due to any environmental damage that may be caused by the Group could be material. Moreover, the Group could be adversely affected by future actions and fines imposed on the Group by the environmental protection agencies of the Kazakh Government, including the potential suspension or revocation of the Licence or Subsoil Use Agreements and termination of the PSA. To the extent that any provision in the Group's accounts relating to remediation costs for environmental liabilities proves to be insufficient, this could have a material adverse effect on the Group's business, prospects, financial condition and results of operations.

In addition, in March 2009, the President of Kazakhstan signed the law on the ratification of the Kyoto Protocol to the United Nations Framework Convention on Climate Change (the "**Kyoto Protocol**"), which is intended to limit or discourage emissions of greenhouse gases such as carbon dioxide. The effect of such ratification in other countries is still unclear; accordingly, potential compliance costs associated with the Kyoto Protocol in Kazakhstan are unknown and may be significant. Nonetheless, the likely effect will be to increase costs for electricity and transportation, restrict emissions levels, impose additional costs for emissions in excess of permitted levels and increase costs for monitoring, reporting and financial accounting. Increases in such costs could have a material adverse effect on the Group's business, prospects, financial condition and results or operations.

Although the Group is obliged to comply with all applicable environmental laws and regulations, given the changing nature of environmental regulations, it may not be in compliance at all times. Any failure to comply with these environmental requirements could subject the Group to, among other things, civil liabilities and penalty fees and possibly temporary or permanent shutdown of the Group's operations. In the past, the Kazakh Government claimed that the operator of the Kashagan oil field (a consortium of international investors) had breached certain provisions of its licence and environmental regulations, and consequently suspended the operator's licence. The New Subsoil Law empowers the Competent Authority to terminate existing subsoil licences in certain circumstances. The PSA and the Licence or the Subsoil Use Agreements could be suspended as a consequence of non-compliance with environmental regulations. See "*—Risk Factors Relating to Kazakhstan—The Group is exposed to the risk of adverse sovereign action by the Kazakh Government*". Any such suspension or revocation of the PSA, the Licence or the Subsoil Use Agreements, or the costs associated with compliance with such regulations, could materially and adversely affect the Group's business, prospects, financial condition and results of operations.

The Group is obliged to comply with health and safety regulations and cannot guarantee that it will be able to comply with these regulations.

The Group's operations are subject to laws and regulations relating to the protection of human health and safety. Failure, whether inadvertent or otherwise, by Nostrum to comply with applicable legal or regulatory requirements may give rise to significant liabilities. The Group's health and safety policy is to observe local and national, legal and regulatory requirements and generally to apply best practice where local legislation does not exist.

Nostrum incurs, and expects to continue to incur, substantial capital and operating costs in order to comply with increasingly complex health and safety laws and regulations. New laws and regulations, the imposition of tougher requirements in licences, subsoil use agreements and permits, increasingly strict enforcement of, or new interpretations of, existing laws, regulations and licences, or the discovery of previously unknown contamination may require further expenditures to modify operations or pay fees or fines or make other payments for breaches of health and safety requirements.

Although the costs of the measures taken to comply with health and safety regulations have not had a material adverse effect on the Group's financial condition or results of operations to date, in the future, the costs of such measures and/or liabilities related to damage to human health and safety caused by Nostrum may increase, adversely affecting its operating results and financial condition.

The Group is subject to an uncertain tax environment that may lead to disputes with regulatory authorities.

The PSA provides that for the lifetime of the PSA, Nostrum shall be subject to the tax regime that was in place in Kazakhstan at the time the PSA was signed, unless the parties to the PSA agree otherwise. In addition, under the PSA, Zhaikmunai LLP is required to share a proportion of its production (in cash or kind), and make royalty payments in addition to certain other payments.

As of 1 January 2009, a new Code of the Republic of Kazakhstan "On Taxes and Other mandatory Payments into the Budget ("**Tax Code**") dated 10 December 2008, no. 99-IV, as amended became effective and introduced a new tax regime and taxes applicable to subsoil users (including mineral extraction tax and payment to compensate historical cost). While the Tax Code does not supersede the previous tax regime applicable to PSAs entered into before 1 January 2009 and which have undergone mandatory tax expertise, which continue to be effective under Articles 308 and 308-1 of the Tax Code, the Tax Code applies to the Subsoil Use Agreements.

In 2010 and 2011, the Competent Authority entered into discussions with all subsoil users who were parties to PSAs with the Kazakh Government, including Zhaikmunai LLP, with regard to potential changes to the tax regime applicable to such PSAs. Kazakh Government officials publicly expressed a desire to remove tax stability provisions from PSAs in cases where such a change was necessary to restore the balance of interests between the parties. While the Group believes that such a change would not be justified or appropriate in relation to its PSA, there is no certainty that the Kazakh Government will share this view. There is currently no indication that the Kazakh Government's stated intention to remove tax stability provisions from PSAs will result in any change in the tax regime applicable to Zhaikmunai LLP's PSA or what such change, if any, would be (see "*—Risk Factors Relating to Kazakhstan—The Group is exposed to the risk of adverse sovereign action by the Kazakh Government*").

Future tax investigations or inquiries could create tax liabilities for the Group or could result in assessments to which the Group believes it is not subject, or with which the Group believes it has complied. Tax authorities could conceivably impose material fines, penalties and interest charges that could be challenged unsuccessfully by the Group either with the tax authorities or through the courts. The uncertainty of application, including retroactive application, of tax laws and the evolution of tax laws create a risk of additional and substantial payments of tax by the Group, which could have a material adverse effect on the Group's business, prospects, financial condition and results of operations. See note 29 to the financial information set out in Part 14 "*Historical Financial Information*" for more details regarding certain contingent taxation liabilities.

The Group operates in a highly competitive industry.

The oil and gas industry is highly competitive. The Group competes with numerous other participants in the acquisition of subsoil use rights for oil and gas exploration, production and properties, and access to export transportation routes for oil and gas. Competitors include oil and gas companies that have greater financial resources, staff and facilities than the Group has. See Part 7 "*Information on the Group—Competition*". The Group's ability to increase reserves in the future will depend not only on its ability to develop existing properties, but also on its ability to select and acquire suitable producing properties or prospects for exploratory drilling. Competitive factors in the distribution and marketing of oil and gas products include price, methods and reliability of delivery and availability of imported products. The Group's failure to compete effectively could have a material adverse effect on the Group's business, prospects, financial condition and results of operations.

Risk Factors Relating to Kazakhstan

Risks associated with emerging and developing markets generally.

The disruptions experienced in the global and regional capital markets from 2007 onwards have led to reduced liquidity and increased credit risk for certain market participants and have resulted in a reduction of available financing. Companies located in emerging markets such as Kazakhstan may be particularly susceptible to these disruptions and to reductions in the availability of credit or increased financing costs, which could result in financial difficulties. In addition, the availability of credit to entities operating within the emerging markets is significantly influenced by levels of investor confidence in these markets, and, as such, any factors that impact market confidence, (for example, a decrease in credit ratings, or state or central bank intervention in one market or terrorist activity and conflict), could affect the price or availability of funding for entities within any of these markets.

Since the advent of the global economic crisis in 2007, Kazakhstan's economy has been, and may continue to be, adversely affected by market downturns and economic slowdowns elsewhere in the world. As has happened in the past, financial problems outside Kazakhstan or an increase in the perceived risks associated with investing in emerging and developing economies could dampen foreign investment in Kazakhstan and adversely affect the Kazakhstan economy. Kazakhstan's banking sector has been particularly affected by the lack of availability of international wholesale debt financing, the volatility of deposits and the fact that they have suffered significant losses, all of which led to a destabilisation of Kazakhstan's banking sector. This led to a government bail-out programme in 2009 which led to State support for Kazakhstan's four largest banks (BTA, Alliance Bank, Halyk Bank and Kazkommertsbank). This resulted in new banking legislation and, although this legislation has now been tested four times, there can be no assurance that this legislation will lead to a recovery of the domestic financial markets or the condition of Kazakhstan banks. This in turn may have further negative effects on the Kazakhstan economy.

The oil and gas sector in Kazakhstan has recently experienced significant volatility. As oil and gas production and exports, to a large degree, form the foundation of the country's economy, the Kazakhstan economy is particularly sensitive to fluctuations in the price of oil and gas on the world market. A decline in the price of oil and/or gas could therefore have a significant negative effect on Kazakhstan's economy. In turn, this could have a direct negative effect on the Group, whose primary source of revenue is sales of crude oil, gas and other hydrocarbons. See "*—The Kazakhstan economy is highly dependent on oil exports. Accordingly, the Kazakhstan economy and the Group may be affected by oil price volatility*" and "*—Risk Factors Relating to the Oil and Gas Industry—Any volatility and future decreases in commodity prices could materially adversely affect the Group's business, prospects, financial condition and results of operations*".

In addition, on-going terrorist activity and armed conflicts in the Middle East and elsewhere have also had a significant effect on international finance and commodity markets. Any future national or international acts of terrorism or armed conflicts could have an adverse effect on the financial and commodities markets in Kazakhstan and the global economy. As Kazakhstan produces and exports large volumes of crude oil and gas, any acts of terrorism or armed conflicts causing disruptions of Kazakh oil and gas exports could negatively affect the Kazakhstan economy and thereby materially adversely affect the Group's business, financial condition, results of operations or prospects.

Potential investors in emerging markets such as Kazakhstan should therefore be aware that these markets are subject to greater risk than more developed markets, including in some cases significant legal, economic and political risks. Potential investors in the Ordinary Shares should also note that emerging economies such as Kazakhstan's are subject to rapid change and that the information set out in this Prospectus may become outdated relatively quickly. Accordingly, potential investors in the Ordinary Shares should exercise particular care in evaluating the risks involved and must decide for themselves whether, in the light of those risks, their investment is appropriate. Generally, investment in emerging and developing markets is suitable only for sophisticated investors who fully appreciate the significance of the risks involved. Potential investors are urged to consult with their own legal and financial advisers before making an investment in the Ordinary Shares.

Financial instability in any emerging market could cause the trading price of the Company's Ordinary Shares to fluctuate significantly.

Financial instability in any emerging market tends to adversely affect prices in stock markets in other emerging markets as investors move their money to more developed markets that they perceive to be more stable. As has been the case in the past, financial instability or an increase in the perceived risks associated with investing in emerging markets could constrain foreign investment in Kazakhstan and adversely affect its economy. In addition, during periods of financial instability, companies operating in emerging markets may face liquidity constraints if foreign funding sources are withdrawn. Thus, even if the fundamentals of the Kazakhstan economy remain relatively sound, financial instability in other emerging markets could materially adversely affect the Group's business and/or the trading price of the Ordinary Shares.

The political environment in Kazakhstan has a significant impact on the Group.

Kazakhstan became an independent sovereign nation in 1991 following the break-up of the Union of Soviet Socialist Republics (the "**USSR**" or the "**Soviet Union**"). Since then, Kazakhstan has undergone major change as part of its transformation from a centralised planned economy to a free-market economy. Initially, this transformation was accompanied by political uncertainty and strain, where economic downturns were accompanied by high inflation, volatility in the national currency and rapid, although incomplete, changes to the legal environment.

Following the break-up of the Soviet Union, a number of the former republics of the USSR went through periods of political instability, civil unrest, military action and territorial disputes accompanied by violence. From the period of independence up to the date of this Prospectus, the political situation in Kazakhstan has generally remained calm. At the same time, no assurances can be given that the situation will not change as a result of an internal conflict or outside influence. An example of this is provided by the events which occurred on 16 December 2011 in the city of Zhanaozen in the Mangistau region of Kazakhstan. Mass riots which started in the city's main square during the celebrations of the 20th anniversary of Kazakhstan's independence resulted in dozens of people being killed or injured and significant damage being caused to the city's infrastructure. According to some sources, the riots were caused by discontent amongst oil workers, including over low wages.

The Kazakhstan economy is highly dependent on oil exports. Accordingly, the Kazakhstan economy and the Group may be affected by oil price volatility.

The economy and state budget of Kazakhstan, as with other countries in the Central Asian region, rely on the export of crude oil and oil products and other commodities, the import of capital equipment and significant foreign investment in infrastructure projects. As a result, Kazakhstan could suffer from volatility, or a sustained decline in oil and other commodity prices, or from the frustration or delay of any infrastructure projects caused by political or economic instability in countries participating in such projects. Kazakhstan's dependence on oil and oil products also has an indirect impact on its currency, the Tenge, which is indirectly correlated to the price of oil.

In addition, any fluctuations in the value of the U.S. Dollar relative to other currencies may cause volatility in earnings from U.S. Dollar-denominated crude oil, condensate and other hydrocarbons exports. An oversupply of crude oil or other commodities in world markets or a general downturn in the economies of any significant markets for crude oil or other commodities or weakening of the U.S. Dollar relative to other currencies would have a material adverse effect on the Kazakhstan economy which, in turn, could have an adverse effect on the business, prospects, financial condition and results of operations of the Group.

Uncertainty over the outcome of the implementation of economic reforms in Kazakhstan may impose risks.

There remains a need for substantial investment in many sectors of the Kazakhstan economy and there are areas in which economic performance in the private sector is still constrained by an inadequate business infrastructure. The Kazakh Government has stated that it intends to address these problems by improving business infrastructure and tax administration. Further, the significant size of the shadow economy may adversely affect the implementation of reforms and hamper the efficient collection of taxes. There can be no assurance that these measures taken by the Kazakh Government for the implementation of the economic reform will be effective or that any failure to implement them may not materially and adversely affect the Group's business, financial condition, results of operations and prospects.

Kazakhstan's tax regime and its judiciary are not fully developed and are therefore unpredictable.

Although a large volume of legislation has come into force since early 1995 (including the Law "On National Security" of the Republic of Kazakhstan dated 6 January 2012, No. 527-IV, the Tax Code, the Law of the Republic of Kazakhstan "On Competition" dated 25 December 2008, No. 112-IV (the "**Competition Law**"), laws relating to foreign arbitration and other legislation covering such matters as securities exchanges, economic partnerships and companies, state enterprise reform and privatisation), the legal framework in Kazakhstan is still in a relatively early stage of development compared to those in countries with established market economies. The judicial system, judicial officials and other government officials in Kazakhstan may not be independent of external social, economic and political forces. There have been instances of improper payments being made to public officials, and administrative decisions have been inconsistent and court decisions difficult to predict.

Further, due to numerous ambiguities in Kazakhstan's commercial legislation, in particular in its tax legislation, Kazakhstan tax authorities may make arbitrary assessments of tax liabilities and challenge previous tax assessments, thereby rendering it difficult for companies to ascertain whether they are liable for additional taxes, penalties and interest. As a result of these ambiguities, including, in particular, the uncertainty surrounding judgments rendered under the 2009 Tax Code, as well as a lack of an established system of precedent or consistency in legal interpretation, the legal and tax risks involved in doing business in Kazakhstan are substantially greater than those in jurisdictions with more developed legal and tax systems. Tax legislation in Kazakhstan may also continue to evolve, which may result in further uncertainty.

The 2009 Tax Code was adopted at the end of 2008 and came into force on 1 January 2009, except for certain provisions which came into force on 1 July 2011. The 2009 Tax Code provides for reduced rates for certain taxes, including corporate income tax, which has been reduced from 30% to 20%, and value-added tax ("**VAT**"), which has been reduced from 13% to 12%. Despite these reductions, the Group expects certain revenue-raising measures to be implemented, which may result in significant additional taxes becoming payable. Additional tax exposure could have a material adverse effect on companies operating in Kazakhstan, such as the Group.

The President of Kazakhstan, Nursultan Nazarbayev, has been in office since 1991 and should he leave office without a smooth transfer to his successor, the political and macroeconomic situation in Kazakhstan could become unstable.

The President of Kazakhstan, Nursultan Nazarbayev, is 73 years old and has been in office since Kazakhstan became an independent sovereign state in 1991. Under President Nazarbayev's leadership, the foundations of a market economy have taken hold, including the privatisation of state assets, liberalisation of capital controls, tax reforms and pension system development. President Nazarbayev was re-elected by a 95.5% majority for a new five year term in elections which took place in early April 2011. In May 2007, Kazakhstan's parliament voted to amend Kazakhstan's constitution to allow President Nazarbayev to run in an unlimited number of elections. While this amendment will allow President Nazarbayev to seek re-election at the end of his current term, there is no guarantee that he will remain in office. President Nazarbayev is also the father-in-law of Timur Kulibayev, a shareholder in KSS Global, which is one of the Company's largest shareholders.

Should President Nazarbayev fail to complete his current term of office for whatever reason or should a new President of Kazakhstan succeed him without a clear mandate, Kazakhstan's political situation and economy could become unstable and the investment climate in Kazakhstan could deteriorate, which could have an adverse effect on the Group's business, financial condition, results of operations and prospects.

All the Group's assets are located in Kazakhstan and the Group is therefore susceptible to country-specific risk factors, such as political, social and economic instability.

The Group is subject to Kazakhstan-specific risks, including, but not limited to, local currency devaluation, civil disturbances, changes in exchange controls or lack of availability of hard currency, changes in energy prices, changes with respect to taxes and royalties, withholding taxes on distributions to foreign investors, changes in anti-monopoly legislation, nationalisation or expropriation of property, and interruption or blockage of hydrocarbons or other strategic materials exports. The occurrence of any of these factors could have a material adverse effect on the Group's business, prospects, financial condition and results of operations.

The Group is exposed to the risk of adverse sovereign action by the Kazakh Government.

The oil and gas industry is central to Kazakhstan's economy and its future prospects for development, and thus can be expected to be the focus of continuing attention and debate. In similar circumstances in other developing countries, petroleum companies have faced the risks of expropriation or renationalisation, breach or abrogation of project agreements, application to such companies of laws and regulations from which they were intended to be exempt, denials of required permits and approvals, increases in royalty rates and taxes that were intended to be stable, application of exchange or capital controls, and other risks.

The Kazakh Government may attempt to modify or remove the stability of the tax regime of the PSA which could result in negative tax consequences. In January 2010, President Nazarbayev of Kazakhstan spoke out against tax stabilisation clauses stating that parties operating in Kazakhstan should work under the same legislation. Furthermore, the Minister of Energy and Natural Resources (who at that time was the head of the Competent Authority), Sauat Mynbayev, has publicly warned foreign companies that they should prepare themselves for losing their exemption from domestic taxation. Moreover, the New Subsoil Law came into force on 7 July 2010 and the application of this law is relatively new. Any complaints by the Kazakh Government or the invocation or application by the Kazakh Government of the New Subsoil Law in relation to the Chinarevskoye Field may have a material adverse effect on the Group's business, prospects, financial condition and results of operations.

The Kazakh Government holds a pre-emptive right in respect of, and the Competent Authority must consent to, any transfer of subsoil use rights or direct or indirect interests in an entity holding subsoil use rights in Kazakhstan.

Article 12 of the New Subsoil Law provides that the Kazakh Government has a pre-emptive right to purchase subsoil use rights or indirect or direct interests in companies having subsoil use rights for sale.

This pre-emptive right permits the Kazakh Government to purchase any such subsoil use rights or equity interests (including any securities convertible into equity interests) being offered for sale or otherwise being alienated, including any issuance of new shares, on terms no less favourable than those offered by the potential purchaser or transferee.

In addition to this pre-emptive right, pursuant to Article 36 of the New Subsoil Law, any transfer or pledge of subsoil use rights, including transfers of direct and indirect equity interests in a company holding a subsoil use right requires the consent of the Competent Authority. The New Subsoil Law also requires notification to the Competent Authority within 5 working days following the consummation of a transaction for which the Competent Authority's consent has been granted. The Competent Authority may terminate a subsoil use contract if a transaction occurs in violation of this law.

These provisions apply to Kazakh and overseas entities whose main activity relates to subsoil use in Kazakhstan. However, because the New Subsoil Law does not specify criteria for the determination of a company's main activity for the purpose of Article 36 of the New Subsoil Law and there is no precedent, it is not entirely clear how this law will be applied and interpreted.

In the event that the Kazakh Government exercises its pre-emption right or refuses to consent to any transfer of subsoil use rights or equity interests within or to the Group, such exercise or refusal could have a material adverse effect on the trading price of the Ordinary Shares. However, this pre-emptive right has been waived by the Kazakh Government and consent of the Competent Authority has been granted with respect to the admission of the Ordinary Shares to the premium listing segment of the Official List and to trading on the London Stock Exchange's Main Market for listed securities.

Any future issue of equity in the Company or the Group, including any issue of debt securities convertible into equity in the Company or the Group, would however be subject to the pre-emptive right of the Kazakh Government and the Competent Authority's consent and a further waiver and consent would have to be obtained. Whilst such waivers and consents have been obtained in the past, there can be no assurance that a waiver or consent will be obtained in respect of any future issue of equity. If the Kazakh Government seeks to exercise its pre-emptive right in respect of future issues of equity securities, the Company would either be unable (and would have no obligation) to issue such equity securities (as to do so would be in violation of its shareholders' pre-emption rights contained in the Companies Act, the Articles and the Listing Rules) or would have to obtain the approval of its shareholders for the disapplication of their statutory pre-emptive rights in order to issue such equity securities to the Kazakh Government. If the Kazakh Government seeks to exercise its pre-emptive right in respect of future issues of equity securities and the Company was not able to obtain such shareholder approval, or if the Competent Authority does not provide its consent in respect of such issue, the Company would be unable to proceed with the issue of equity securities and the Group would instead need to either seek alternative sources of financing or otherwise potentially not undertake the business activities for which such additional equity financing was sought. See "*—Risk Factors Relating to the Group's Business—The Group may be unable to raise additional external financing if it is necessary in the longer term; this would adversely affect its ability to pursue its business strategy.*" and "*—The Group's leverage may, among other things, make it difficult for it to operate its business and may limit its operational flexibility*."

The laws and regulations of Kazakhstan are developing and uncertain. Any changes in laws, regulations and permit requirements to which the Group is subject could require it to make substantial expenditures or subject the Group to material liabilities or other sanctions.

The laws and regulations of Kazakhstan relating to foreign investment, subsoil use, licensing, companies, procurement, customs, currency, capital markets, pensions, insurance, banking, taxation and competition are still developing and are uncertain. Many such laws provide regulators and officials with substantial discretion in their application, interpretation and enforcement. Furthermore, the judicial system may not be fully independent of social, economic and political forces. Court decisions can be difficult to predict and enforce, and the Group's best efforts to comply with applicable law may not always result in compliance as determined by regulators and/or the courts. Furthermore, because the New Subsoil Law does not define the course of action available to the Kazakh Government by reference to the gravity of a breach, a minor breach could lead to severe consequences, such as suspensions or termination of the subsoil user rights. Because the New Subsoil Law is relatively new, there are no precedents that would make the consequences of a breach more predictable. The Group is required to obtain, on an on-going basis, all permits as are required by the laws of Kazakhstan. Failure to obtain all such permits could have a material adverse effect on the Group's business, prospects, financial condition and results of operations.

Given Kazakhstan's legislative, judicial and administrative history, it is not possible to predict the effect of current and future legislation on the Group's business. Moreover, the New Subsoil Law came into force on 7 July 2010 and the application of this law is largely untested. The on-going rights of the Group under the PSA, the Licence, the Subsoil Use Agreements and other licences, approvals and permits (if applicable) and other agreements may be susceptible to revision or cancellation, and legal redress in relation to such revocation or cancellation may be uncertain. Any changes to the rights of the Group under the PSA, the Licence, the Subsoil Use Agreements and other licences, approvals and permits (and any other relevant legislative changes) could have a material adverse effect on the Group's business, prospects, financial condition and results of operations. See Part 8 "*Industry and Regulatory Overview—Regulation in Kazakhstan—Regulation of subsoil use rights in Kazakhstan*" for a summary of the New Subsoil Law, the rights of the Competent Authority thereunder and the impact of a breach of such law.

Risk Factors Relating to the Admission and the Ordinary Shares

Share price volatility and liquidity may affect the performance of investments in the Group.

The share price of listed companies can be highly volatile and their shares may have limited liquidity. The trading price for Ordinary Shares may fluctuate significantly. Investors may be unable to recover their original investment.

The market price of the Ordinary Shares may, in addition to being affected by the Group's actual or forecast operating results, fluctuate significantly as a result of factors beyond the Company's control, including, among others:

- the results of exploration, development and appraisal programmes and production operations;
- changes in securities analysts' recommendations or estimates of earnings or financial performance of the Group, its competitors or the industry, or the failure to meet expectations of securities analysts;
- fluctuations in stock market prices and volumes, and general market volatility;
- factors impacting market confidence, including the practices of other listed companies with operations in Kazakhstan;
- changes in laws, rules and regulations applicable to the Group, its operations and the operations in which the Group has interests, and involvement in litigation;
- general economic and political conditions, including in Kazakhstan; and
- fluctuations in the prices of oil, gas and other petroleum products.

Equity market conditions also are affected by many factors, such as the general economic, political or regulatory outlook, movements in or the outlook for interest rates and inflation rates, currency fluctuations, commodity prices, changes in investor sentiment towards particular market sectors and the demand for and supply of capital. Trading in the Ordinary Shares by other investors, such as large purchases or sales of Ordinary Shares, may also affect the share price. Accordingly, the market price of Ordinary Shares may not reflect the underlying value of the Group's investments and the price at which investors may dispose of their Ordinary Shares at any point in time may be influenced by a number of factors, only some of which may pertain to the Group while others may be outside the Group's control. Investors should not expect that they will necessarily be able to realise, within a period that they would regard as reasonable, their investment in Ordinary Shares. The Group's results and prospects from time to time may be below the expectations of market analysts and investors.

Future sales, or the real or perceived possibility of sales, of a significant number of Ordinary Shares in the public market could adversely affect the prevailing trading price of the Ordinary Shares. Further share issues could also dilute the interests of shareholders.

If the Company's existing major shareholders were to sell, or the Company were to issue and sell, a substantial number of Ordinary Shares in the public market, the market price of the Ordinary Shares could be adversely affected and/or result in the dilution of the interests of holders of the Ordinary Shares. Sales by the Company's existing shareholders also could make it more difficult for the Company to sell equity securities in the future at a time and price that it deems appropriate. The sale of a significant amount of Ordinary Shares in the public market, or the perception that such sales may occur, could materially affect the market price of the Ordinary Shares.

The Scheme is conditional upon the receipt of certain approvals

Pursuant to the Scheme, the Company will acquire all (or substantially all) of the assets and liabilities of the Group in consideration for the issue of the Ordinary Shares to the holders of the Common Units, followed by the dissolution of the Partnership.

The Scheme is conditional upon, among other things (a) the Scheme being approved by holders representing not less than 75% in voting rights of holders of Common Units present and voting, either in person or by proxy, at the Special General Meeting; (b) special resolutions (as set out in the notice convening the Special General Meeting in Part 7 of the Scheme Document) to approve the amendment of the Limited Partnership Agreement and the dissolution of the Partnership having been duly passed at the Special General Meeting by a majority of not less than 75% in voting rights of holders of Common Units present and voting, either in person or by proxy, at the Special General Meeting; and (c) the receipt of relevant consents and/or waivers from the Ministry of Oil and Gas in Kazakhstan and the Republic of Kazakhstan to the acquisition of the membership interests in Co-op (a new intermediate holding entity of the Group) by the Company (such consents and/or waivers being required in respect of Co-op's indirect ownership of subsoil use rights in Kazakhstan).

If holders of Common Units do not approve the amendment of the Limited Partnership Agreement or the implementation of the Scheme by the requisite majority at the Special General Meeting, or if the Scheme has not become effective by 31 July 2014 (or such later date as the General Partner and the Company may agree), the Scheme will lapse, in which event there will not be a new parent company of Nostrum, Admission will not become effective and GDR holders will remain as holders of listed securities in the Partnership and the existing GDRs will continue to be listed on the standard listing segment of the Official List and admitted to trading on the Main Market.

The Group cannot assure investors that it will make dividend payments in the future.

The Directors may be unable to declare or pay any dividends. Future dividends will depend, among other things, on the Group's future profits, financial position, distributable reserves, holding capital requirements, general economic conditions and other factors that the Directors deem significant from time to time.

The Reduction of Capital may not be implemented on a timely basis or at all

Following Admission, the Directors intend to undertake the Reduction of Capital in order to create distributable reserves in the Company. Implementation of the Reduction of Capital is conditional upon, among other things, approval by the UK Court. There are risks that approval will not be given or not given on acceptable terms and that the Reduction of Capital will not occur on a timely basis or at all. If any of these events happen, the Reduction of Capital will not be implemented and the benefits expected to result from the Reduction of Capital will not be achieved.

Exchange rate fluctuations may adversely affect the foreign currency value of the Ordinary Shares.

The Ordinary Shares will be quoted in pounds sterling on the London Stock Exchange. The Group's financial statements are prepared in U.S. Dollars. Fluctuations in the exchange rate between the U.S. Dollar and pounds sterling will affect, amongst other matters, the pounds sterling value of the Ordinary Shares.

The Company may not achieve FTSE index eligibility.

Following Admission, the Company intends to seek FTSE index eligibility. In particular, the Company will position itself for inclusion in the FTSE All-Share Index and, subject to (among other things) market capitalisation, in the FTSE 250 Index. However, as the FTSE committee exercises an element of discretion in determining whether a company is eligible for inclusion, and such discretion relates to matters outside of the Company's control, such as the liquidity of its Ordinary Shares, there is no certainty that this will be achieved or achieved within the anticipated timeline (being from the second half of 2014) or that the benefits associated with FTSE index inclusion will be available to the Group.

Pre-emptive rights may not be available to U.S. holders of the Ordinary Shares.

Under UK law and in accordance with the existing shareholder authorities, subject to certain exceptions, prior to the issuance of any new Ordinary Shares for cash, the Company must offer holders of existing Ordinary Shares pre-emptive rights to subscribe and pay for a sufficient number of Ordinary Shares to maintain their existing ownership percentages. These pre-emptive rights may, depending on the specific offer terms, be transferable during the subscription period for the related offering and may be listed on the London Stock Exchange.

U.S. holders of Ordinary Shares may not be able to receive trade or exercise pre-emptive rights for new Ordinary Shares unless a registration statement under the Securities Act is effective with respect to such rights or an exemption from the registration requirements of the Securities Act is available. The Group does not currently plan to register the Ordinary Shares or any future rights under U.S. securities laws. If U.S. holders of Ordinary Shares are not able to receive, trade, or exercise pre-emptive rights granted in respect of their Ordinary Shares in any rights offering by the Company, then they may not receive the economic benefit of those rights. In addition, their proportional ownership interests in the Company will be diluted.

There is a risk that the Company may be deemed to be a passive foreign investment company.

Based on certain estimates of its gross income and gross assets and the nature of the Group's business and certain limited administrative guidance, as discussed below, the Company believes that it will not be classified as a passive foreign investment company (a "**PFIC**") in 2014. However, as the PFIC determination is made annually and depends upon the composition of the Company's income and assets and the market value of the Company's assets from time to time, there can be no assurance that the Company will not be considered a PFIC in the future.

If the Company qualifies as a PFIC in any year during which a taxable U.S. investor owns the Ordinary Shares, such U.S. investor could be liable for significant amounts of taxes and interest charges upon certain distributions by the Company or upon a sale, exchange or other disposition of the Ordinary Shares at a gain, whether or not the Company continues to be a PFIC.

Prospective investors should review the discussion of PFICs contained in Part 16 "*Taxation—United States Taxation of Shareholders*" of this Prospectus and are strongly advised to consult their own tax advisers regarding the U.S. federal income tax consequences of an investment in an entity that potentially qualifies as a PFIC and the extent to which the mark-to-market election may be available.

Investors may be unable to enforce judgments obtained in U.S. courts against the Company.

The Company has been incorporated under English law, all of the Company's Directors and executive officers are non-residents of the United States and Nostrum's assets are located outside of the United States. As a consequence, investors in the Ordinary Shares may be unable to effect service of process on the Company or these non-U.S. resident Directors and officers in the United States, and may be unable to enforce judgments against them obtained in the United States. There is doubt as to the enforceability of certain civil liabilities under U.S. Federal securities laws in original actions in the England or in actions to enforce a judgment obtained in U.S. courts.

Risk Factors Relating to the Dual Listing

The London Stock Exchange and the KASE have different characteristics.

In connection with Admission, the Company intends to seek a listing of the Ordinary Shares on the KASE. If such a listing is obtained, the Ordinary Shares will be fungible and able to be traded on the London Stock Exchange or the KASE.

The London Stock Exchange and the KASE have different trading hours, trading characteristics (including trading volume and liquidity), trading and listing rules and investor bases (including different levels of retail and institutional participation). As a result of these differences, the trading price of the Ordinary Shares on the London Stock Exchange and the KASE may not be the same at any given time.

Furthermore, fluctuations in the Ordinary Share price on the London Stock Exchange could materially and adversely affect the Ordinary Share price on the KASE (and vice versa). Moreover, fluctuations in the exchange rate between United Kingdom pounds sterling and Tenge could materially and adversely affect the prices of the Ordinary Shares listed on the London Stock Exchange and the KASE.

As a company due to be admitted to the Official List and admitted to trading on the Main Market and listed on the KASE, the Company will be subject to both United Kingdom and Kazakhstan laws, regulations and policies.

Kazakhstan laws, regulations and policies may differ in some respects from comparable laws, regulations and policies in the United Kingdom. The differences in compliance requirements may subject the Company to additional regulatory burdens. In the event of any conflict between the applicable laws, regulations and policies in the United Kingdom and those in Kazakhstan, the Company will have to comply with the more onerous rules and may incur additional costs and require additional resources.

PART 3
DIRECTORS, SECRETARY, REGISTERED AND HEAD OFFICE AND ADVISERS

Directors

Name	Position
Frank Monstrey	Executive Chairman
Kai-Uwe Kessel	Chief Executive Officer
Jan-Ru Muller	Chief Financial Officer
Eike von der Linden	Senior Independent Non-Executive Director
Atul Gupta	Independent Non-Executive Director
Sir Christopher Codrington, Bt.	Independent Non-Executive Director
Mark Martin	Independent Non-Executive Director
Piet Everaert	Non-Executive Director
Pankaj Jain	Non-Executive Director

Company Secretary	Thomas Hartnett	
Registered Office	4th Floor 53-54 Grosvenor Street London, W1K 3HU United Kingdom	
Sponsor and Financial Adviser	Deutsche Bank AG, London Branch Winchester House 1 Great Winchester Street London EC2N 2DB United Kingdom	
Financial Adviser in respect of the Admission and Scheme	VTB Capital plc 14 Cornhill London EC3V 3ND United Kingdom	
Legal Advisers to the Company as to English, United States and Kazakhstan law	White & Case LLP 5 Old Broad Street London EC2N 1DW United Kingdom	White & Case Kazakhstan LLP Park View Office Tower 77 Kunaeva Street Almaty, Kazakhstan 050000
Legal Advisers to the Sponsor as to English and United States law	Clifford Chance LLP 10 Upper Bank Street London E14 5JJ United Kingdom	
Legal Advisers to the Sponsor as to Kazakhstan law	Kinstellar LLP Nurly Tau Business Center Block 1B, Office 503 19 Al-Farabi Avenue Almaty 050059 Kazakhstan	

Name	Position
Auditors to the Company	Ernst & Young LLP 1 More London Place London SE1 2AF United Kingdom
Reporting Accountants to the Company	Ernst & Young Advisory LLP (Kazakhstan) Al-Farabi Ave. Esentai Tower, 77/7 050059 Almaty Republic of Kazakhstan
Registrar	Capita Registrars Limited The Registry 34 Beckenham Road Beckenham Kent BR3 4TU
Competent Person	Ryder Scott Company L.P. 621 Seventeenth Street Suite 1550 Denver Colorado 80293 United States
Financial PR	Instinctif Partners 65 Gresham Street London EC2V 7NQ United Kingdom

PART 4
EXPECTED TIMETABLE OF PRINCIPAL EVENTS

Date of this Prospectus	20 May 2014
Announcement of the Scheme and publication of the Scheme Document	20 May 2014
Expected suspension of listing of GDRs	5.00 p.m. on 12 June 2014
Date of Special General Meeting	11.00 a.m. on 17 June 2014
Expected last time for transfer of Common Units	5.00 p.m. on 17 June 2014
Expected Scheme Record Time	5.00 p.m. on 17 June 2014
Expected implementation of the Scheme and issue of new Ordinary Shares	18 June 2014
Expected effective time of the Scheme	6.00 p.m. on 18 June 2014
Admission and expected commencement of unconditional dealings in Ordinary Shares on the London Stock Exchange	8.00 a.m. on 20 June 2014
KASE listing and commencement of trading in the Ordinary Shares on the Kazakhstan Stock Exchange	8.00 a.m. on 20 June 2014
Cancellation of listing of GDRs on the Official List	8.00 a.m. on 20 June 2014
Crediting of Ordinary Shares to CREST accounts	20 June 2014
Despatch of definitive share certificates in respect of Ordinary Shares (where applicable)	By no later than 4 July 2014
Reduction of Capital	As soon as reasonably practicable following Admission

Each of the times and dates in the above timetable is subject to change without further notice. References to times are to London time unless otherwise stated.

PART 5
PRESENTATION OF INFORMATION

Investors should rely only on the information in this Prospectus. No person has been authorised to give any information or make any representations other than those contained in this Prospectus in connection with the Admission and, if given or made, such information or representations must not be relied on as having been authorised by the Company, the Directors or the Sponsor. Without prejudice to any obligation of the Company to publish a supplementary prospectus pursuant to section 87G of FSMA and PR 3.4.1 of the Prospectus Rules, the publication of this Prospectus or any sale made under this Prospectus does not, under any circumstances, create any implication that there has been no change in the affairs of the Group since, or that the information contained herein is correct at any time subsequent to, the date of this Prospectus.

Cautionary Note Regarding Forward-Looking Statements

This Prospectus contains forward-looking statements which reflect the Group's current views or, as appropriate, those of the Directors, with respect to financial performance, business strategy, plans and objectives of management for future operations (including development plans relating to the Group's business). These forward-looking statements relate to the Group and the sectors and industries in which it operates. Statements that include the words "expects", "intends", "plans", "believes", "projects", "anticipates", "estimates", "will", "may", "targets", "aims", "may", "should", "would", "could", "continue", "budget", "schedule" and similar statements of a future or forward-looking nature identify forward-looking statements for purposes of the United States federal securities laws or otherwise.

Forward-looking statements are necessarily based upon a number of estimates and assumptions that, while considered reasonable by the Company, are inherently subject to significant business, economic and competitive uncertainties and contingencies.

All forward-looking statements included in this Prospectus address matters that involve risks and uncertainties. Accordingly, there are or will be important factors that could cause the Group's actual results to differ materially from those indicated in these statements. These factors include, but are not limited to, those described in Part 2 "*Risk Factors*", which should be read in conjunction with the other cautionary statements that are included in this Prospectus. Other important factors that could cause actual results to differ materially from the Group's expectations include, among others, the following:

- price fluctuations in crude oil, gas and refined products markets and related fluctuations in demand for such products;
- operational limitations, including equipment failures, labour disputes and processing limitations;
- the availability or cost of transportation routes;
- changes in governmental regulation, including regulatory changes affecting the availability of permits, and governmental actions that may affect operations or the Group's planned expansion;
- the availability of debt financing;
- unfavourable changes in economic or political conditions in Kazakhstan;
- unplanned events or accidents affecting the Group's operations or facilities;
- incidents or conditions affecting the export of crude oil and gas; and
- reservoir performance, drilling results and implementation of the Group's oil expansion plans.

Any forward-looking statements in this Prospectus reflect the Group's current views with respect to future events and are subject to these and other risks, uncertainties and assumptions relating to the Group's operations, financial condition, results of operations and growth strategy.

Investors are cautioned that forward-looking statements are not guarantees of future performance. Forward-looking statements may, and often do, differ materially from actual results. Any forward-looking statements in this Prospectus speak only as of the date of this Prospectus, reflect the Company's current view with respect to future events and are subject to risks relating to future events and other risks, uncertainties and assumptions relating to the Company's operations, results of operations and growth strategy. Investors should specifically consider the factors identified in this Prospectus which could cause actual results to differ before making an investment decision. All of the forward-looking statements made in this Prospectus are qualified by these cautionary statements. Specific reference is made to Part 2 "*Risk Factors*", Part 7 "*Information on the Group*" and Part 12 "*Operating and Financial Review*".

Any forward-looking statements speak only as at the date of this Prospectus. Subject to any obligations under the Prospectus Rules, the Listing Rules and/or the Disclosure and Transparency Rules, the Company undertakes no obligation to update publicly or review any forward-looking statement, whether as a result of new information, future developments or otherwise. All subsequent written and oral forward-looking statements attributable to the Group or individuals acting on behalf of the Group are expressly qualified in their entirety by this paragraph. Prospective investors should specifically consider the factors identified in this Prospectus that could cause actual results to differ before making an investment decision.

Presentation of Financial and Other Information

Historical Financial Information

The financial information in this Prospectus has been prepared in accordance with International Financial Reporting Standards ("**IFRS**") as adopted by the European Union. The significant accounting policies applied to the financial information are set out in Part 14 "*Historical Financial Information*" of this Prospectus.

Unaudited operating information in relation to the Group's business is derived from the following sources: (i) internal records related to production, transportation and sales of crude oil; (ii) accounting systems (based on invoices issued and/or received); (iii) internal reporting systems supporting the preparation of financial statements; (iv) management assumptions and analyses; and (v) discussions with key operating personnel. Operating information derived from management accounts or internal reporting systems in relation to the Group's business is to be found principally in Part 7 "*Information on the Group*" and Part 12 "*Operating and Financial Review*" of this Prospectus. This operating information does not relate to technological and geological information or information regarding reserves or resources, which information is derived from the 2013 Ryder Scott Report.

As presented in this Prospectus, "**EBITDA**" means earnings before interest, taxation, depreciation and amortisation, and "**EBIT**" means earnings before interest and taxation. EBITDA and EBIT are supplemental measures of the Group's performance and liquidity that are not required by or presented in accordance with IFRS. Furthermore, EBITDA and EBIT should not be considered as alternatives to net income, profit before income tax or as an alternative to cash flow from operating activities as a measure of the Group's liquidity or as a measure of cash available to the Group to invest in the growth of its business.

Although the Company does not currently employ EBITDA as a measure for internal valuations, the Company presents EBITDA in this Prospectus because the Company believes it is frequently used by securities analysts, investors and other interested parties in evaluating similar issuers, most of which present EBITDA when reporting their results. The Company presents EBIT because it believes that it provides a useful measure for evaluating its ability to generate cash and its operating performance due to the costs it incurs for depreciation. Nevertheless, EBITDA and EBIT have limitations as analytical tools and they should not be considered in isolation from, or as a substitute for, analysis of the Group's results of operations. As a measure of performance, EBITDA and EBIT present some limitations for the following reasons:

- they do not reflect the Group's cash expenditures or future requirements for capital expenditures or contractual commitments;
- they do not reflect changes in, or cash requirements for, the Group's working capital needs;
- they do not reflect the significant interest expense, or the cash requirements necessary to service interest or principal payments, on the Group's debt;
- they do not capture differences in income taxes, which may be significant even for companies operating in the same sector or country;
- in the case of EBITDA, although depreciation and amortisation are non-cash charges, the assets being depreciated will often have to be replaced in the future and EBITDA does not reflect any cash requirements for such replacements;
- they do not reflect foreign exchange gains or losses; and
- other companies in the Group's industry may calculate these measures differently from the way the Group does, limiting its usefulness as a comparative measure.

Certain figures contained in this Prospectus, including financial information and information set out in Part 14 "*Historical Financial Information*", have been subject to rounding adjustments. Accordingly, in certain instances, the sum of the numbers in a column or a row in tables contained in this Prospectus may not conform exactly to the total figure given for that column or row.

Certain Reserves Information

Cautionary Note to U.S. Investors: The SEC permits oil and gas companies, in their filings with the SEC, to disclose only proved reserves that the Company has demonstrated by actual production or conclusive formation tests to be economically and legally producible under existing economic and operating conditions. The crude oil reserves data presented in this Prospectus have been estimated at the request of the Company by Ryder Scott Company L.P., an international oil and gas consultant ("**Ryder Scott**"), according to definitions and disclosure guidelines contained in the Society of Petroleum Engineers ("**SPE**"), the World Petroleum Council (the "**WPC**"), American Association of Petroleum Geologists ("**AAPG**") and Society of Petroleum Evaluation Engineers ("**SPEE**") Petroleum Resources Management System ("**SPE-PRMS**") and thus proved reserves may differ from those estimated according to definitions used by the SEC. Further, the Company uses certain terms in this Prospectus in referring to its reserves, such as "probable" or "possible" reserves, or its resources that the SEC's guidelines would prohibit it from including in filings with the SEC if the Company were subject to reporting requirements under the United States Securities Exchange Act of 1934 (the "**Exchange Act**"). Prospective investors should read Part 7 "*Information on the Group—Operations—Oil and Gas Reserves*" and the report produced by Ryder Scott on the Group's reserves and resources as at 31 August 2013 dated 16 December 2013 (the "**2013 Ryder Scott Report**" or the "**Competent Person's Report**") included in Part 15 "*Competent Person's Report*" of this Prospectus, for more information on the Group's reserves and resources and the reserves and resources definitions that the Group uses.

Hydrocarbon Data

General

The Company uses standards established by the SPE-PRMS. Additionally, Zhaikmunai LLP is obliged to submit data according to Kazakh standards for reporting purposes to State bodies. Kazakhstan's method of classifying oil reserves is based on a system employed in the former Soviet Union and differs substantially from the standard international methodology. Since 2004, the Group has engaged Ryder Scott to conduct reviews of the Group's hydrocarbon reserves and resources. Unless otherwise stated herein, the estimates set forth in this Prospectus of the Group's proved, probable and possible reserves and resources are based on reports prepared for the Group by Ryder Scott in accordance with the standards established by the SPE-PRMS. For further information regarding these standards see Part 15 "*Competent Person's Report*" of this Prospectus.

For internal record-keeping purposes, the Group records information relating to production, transportation and sales of crude oil and gas condensate in tonnes, a unit of measure that reflects the mass of the relevant hydrocarbon, and, accordingly, the Company presents such information on the same basis in this Prospectus. References in this Prospectus to "tonnes" are to metric tonnes. One metric tonne equals 1,000 kilograms.

Presentation in the 2013 Ryder Scott Report

The 2013 Ryder Scott Report reports its estimations as follows:

- oil and condensate in standard 4.2 gallon barrels ("**barrels**" or "**bbl**");
- plant products in barrels; and
- gas in millions of cubic feet ("**mmcf**").

Presentation in this Prospectus

For information purposes only, the Company has presented the Group's estimations in this Prospectus as follows:

- oil and condensate in barrels and barrels per day. Barrel figures are extracted from the 2013 Ryder Scott Report or converted from the Company's internal records presented in tonnes at a rate of 7.36 barrels per tonne. Barrel per day figures have been obtained by dividing annual figures by 365;
- plant products are referred to as plant products including butane, propane, LPG and liquid hydrocarbons and are presented in barrels. Barrel figures are extracted from the 2013 Ryder Scott Report; and

- gas in: (i) cubic metres (converted by the Company at a rate of 35.515 cubic feet per cubic metre) and (ii) barrels of oil equivalent ("**boe**") (converted by the Company at a rate of 5.326 cubic feet per boe. These conversion rates take into account the specific calorific values of each of the Group's gas-producing reservoirs.

The actual number of barrels of crude oil produced, shipped or sold may vary from the barrel equivalents of crude oil presented herein, as a tonne of heavier crude oil will yield fewer barrels than a tonne of lighter crude oil. The conversion of data for other companies in tonnes into barrels and from cubic feet into boe may be at different rates.

In respect of the Chinarevskoye Field, the Group has presented herein total gross proved, probable and possible reserves data for the aggregate of crude oil, condensate, LPG and gas (before the terms of the Chinarevskoye production sharing agreement with the Republic of Kazakhstan). In respect of the Rostoshinskoye, Darinskoye and Yuzhno-Gremyachenskoye fields, the Group has presented herein total net probable and possible reserves data for the aggregate of crude oil, condensate, LPG and gas (after the terms of the relevant subsoil use licences). This discrepancy is because, under the PSA in respect of the Chinarevskoye Field, the Group owns the gross reserves whereas the Group is only entitled to the net reserves pursuant to the subsoil use licences in respect of the Rostoshinskoye, Darinskoye and Yuzhno-Gremyachenskoye fields. The 2013 Ryder Scott Report does not include total proved and probable reserves figures and the Group has determined these totals using the conversion rates above. Total possible reserves figures included in this Prospectus have been taken from the 2013 Ryder Scott Report.

Discrepancies in Terminology

This Prospectus and the 2013 Ryder Scott Report use different terminology. For example, the 2013 Ryder Scott Report refers to "plant products" in its reserves estimates, whereas this Prospectus refers to these reserves as LPG, including propane and butane.

Third-Party Information Regarding the Group's Market and Industry

Statistical data and other information appearing in this Prospectus relating to the oil and gas industry in the Republic of Kazakhstan have, unless otherwise stated, been extracted from documents and other publications released by the President of Kazakhstan, the Statistics Agency of Kazakhstan, the Ministry of Finance of Kazakhstan, the Competent Authority, the National Bank of Kazakhstan ("**NBK**") and other public sources in Kazakhstan, including the NBK's Annual Report, as well as from Kazakh press reports and publications and edicts and resolutions of the government of the Republic of Kazakhstan (the "**Kazakh Government**") and the World Bank and International Monetary Fund. Some of the market and competitive position data has been obtained from U.S. government publications and other third-party sources, including publicly available data from the World Bank, the Economist Intelligence Unit, the annual BP Statistical Review of World Energy, as well as from Kazakh press reports and publications, and edicts and resolutions of the Kazakh Government. In the case of the presented statistical information, similar statistics may be obtainable from other sources, although the underlying assumptions and methodology, and consequently the resulting data, may vary from source to source.

The information described above has been accurately reproduced and, as far as the Company is aware and has been able to ascertain from information published by those sources, no facts have been omitted which would render the reproduced information inaccurate or misleading. Where third-party information has been used in this Prospectus the source of such information has been identified.

This Prospectus contains illustrations and charts derived from the Company's internal information, which have not been independently verified unless specifically indicated.

No Incorporation of Website Information

The contents of the Company's website, any website mentioned in this Prospectus or any website directly or indirectly linked to these websites have not been verified and do not form part of this Prospectus and investors should not rely on such information.

Currency Presentation

Unless otherwise indicated, in this Prospectus, references to "Tenge" or "KZT" are to Kazakhstan Tenge, the lawful currency of Kazakhstan; references to "U.S. Dollars" or "U.S.$" are to United States Dollars, the lawful currency of the United States; and references to "pounds sterling", "GBP" or "£" are to the lawful currency of the United Kingdom.

On 16 May 2014, the exchange rate for U.S. Dollars on the KASE as reported by the NBK was KZT 182.03 per U.S.$1.00. For further details of applicable exchange rates, see the financial information set out in Part 14 "*Historical Financial Information*".

No representation is made that the Tenge or U.S. Dollar amounts in this Prospectus could have been converted into U.S. Dollars or Tenge, as the case may be, at any particular rate or at all. Certain amounts which appear in this Prospectus have been subject to rounding adjustments; accordingly, figures shown as totals in certain tables may not be an arithmetic aggregation of the figures which precede them.

The following table sets forth the high, low, average and period-end rates for the Tenge, each expressed in Tenge and based on the Tenge/U.S. Dollar exchange rates on the KASE, as reported by the NBK:

Year ended 31 December	**High**	**Low**	**Average**(1)	**Period End**
	(KZT per U.S. Dollar)			
2013	154.04	150.51	153.81	154.04
2012	150.52	147.79	149.11	150.42
2011	147.99	145.45	146.62	147.90
2010	148.09	146.67	147.35	147.41

Month	**High**	**Low**
	(KZT per U.S. Dollar)	
January 2014	155.54	154.06
February 2014	184.95	155.46
March 2014	184.08	181.78
April 2014	182.07	182.01

Source: NBK

(1) The weighted average rate reported by the NBK for each month or year during the relevant period.

The functional currency of the Group is U.S. Dollars. The Group's presentational currency is and has been the U.S. Dollar. The above rates may differ from the actual rates used in the preparation of the Group's financial information and other financial information appearing in this Prospectus. The inclusion of these exchange rates is not meant to suggest that the Tenge amounts actually represent such U.S. Dollar amounts or that such amounts could have been converted into U.S. Dollars at any particular rate, if at all.

PART 6
INFORMATION ON THE SCHEME

1. Introduction

The GDRs have been admitted to the standard listing segment of the Official List and admitted to trading on the main market for listed securities (the "**Main Market**") of the London Stock Exchange (together, the "**GDR Listing**") since March 2008.

On 20 May 2014, Nostrum Oil & Gas LP (the "**Partnership**") announced its intention to seek a premium listing of a public limited liability company newly incorporated in England and Wales, namely the Company, which it is proposed will be the new holding company for the Group. Following Admission, the Group intends to seek FTSE index inclusion for the Company. The Directors believe that the premium listing of the Company and FTSE index inclusion will enable the Group to broaden its investor base and increase the liquidity of its securities. It is also anticipated that the premium listing will increase the profile of the Group and increase its exposure to a wider investor community. The Company will also apply for a listing of its shares on the KASE.

Following Admission, the Group intends to maintain its robust corporate governance arrangements, which the Company has further strengthened in anticipation of the Scheme and Admission (see further Part 9 "*Directors, Management and Corporate Governance—Corporate Governance*"). As a premium-listed company, the Company will be subject to more extensive and rigorous ongoing reporting and compliance obligations than those that the Partnership is currently subject to by virtue of the GDR Listing. In particular, the Company will be required to comply with additional financial reporting and disclosure requirements pursuant to the Disclosure and Transparency Rules, the Listing Rules and the Corporate Governance Code, as well as the provisions of the City Code, which the Directors believe will provide investors with enhanced transparency.

As announced on the date of this Prospectus, the proposed new corporate structure is being implemented by way of the Scheme by the Company, pursuant to which the Company will acquire all (or substantially all) of the assets and liabilities of the Group (save for certain assets of the Partnership required to meet outstanding obligations of the Partnership and the expected costs of dissolution of the Partnership) in consideration for the issue of Ordinary Shares to the General Partner of the Partnership, and the distribution of Ordinary Shares by the Partnership to the holders of the common units representing fractional parts of the rights and obligations of all limited partners (the "**Limited Partners**") in the Partnership (the "**Common Units**") and hence to GDR holders, followed by the dissolution of the Partnership. The Scheme is conditional on, *inter alia*, the Partnership's limited partnership agreement (the "**Limited Partnership Agreement**") being amended in order to permit the Scheme to be implemented, Limited Partners voting in favour of the Scheme and Admission.

The Directors expect that the material assets and liabilities of the Group will be unaffected by the Scheme becoming effective. In addition, the Scheme will not result in any changes to the day-to-day operations of the strategy or business of the Group and, save as set out above, the Directors expect that the Group will have the same operations and business before and after the Scheme becoming effective.

Holders of the Common Units and the GDRs (the "**Existing Securities**") will continue to retain their interests in the Existing Securities for an interim period prior to the dissolution of the Partnership, but no further distribution is expected to be made in respect of such Existing Securities and holders of Existing Securities are not expected to realise any further value in respect of their interests in GDRs, in each case assuming that the Scheme becomes effective.

It is also proposed that, subject to the Scheme becoming effective, the entire amount standing to the credit of the Company's share premium account will be cancelled and the reserve arising will be re-characterised as a distributable reserve to support the payment of future dividends and share repurchases by the Company in the medium to long term, in the manner described in paragraph 3.2 below.

The formal conditions and further terms of the Scheme are set out in Part 2 "*Conditions to and Further Terms of the Scheme*" of the document describing the Scheme circulated to holders of the Common Units and GDRs (the "**Scheme Document**") and the form of proxy by which Limited Partners may appoint proxies to vote on the Scheme on their behalf.

2. Summary of the Scheme

2.1 Overview

The Scheme will create a new parent company for the Group registered in the United Kingdom, with its tax residence in the Netherlands.

The implementation of the Scheme is made on the following basis:

For each Existing Security (whether held as a Common Unit or as a GDR): 1 Ordinary Share

The Scheme requires the approval of Limited Partners at a special general meeting of the Limited Partners (the "**Special General Meeting**") to (i) amend the Limited Partnership Agreement to permit the Scheme to be capable of being implemented and (ii) vote in favour of the Scheme.

The Scheme is conditional upon, among other things:

(a) the Scheme being approved by holders representing not less than 75% in voting rights of holders of Common Units present and voting, either in person or by proxy, at the Special General Meeting;

(b) special resolutions (as set out in the notice convening the Special General Meeting in Part 7 of the Scheme Document) to approve the amendment of the Limited Partnership Agreement (to permit the implementation of the Scheme) and the dissolution of the Partnership having been duly passed at the Special General Meeting by a majority of not less than 75% in voting rights of holders of Common Units present and voting, either in person or by proxy, at the Special General Meeting;

(c) the FCA having acknowledged to the Company or its agent (and such acknowledgement not having been withdrawn) that the application for admission of the Ordinary Shares to the premium listing segment of the Official List has been approved and (subject to satisfaction of any conditions to which such approval is expressed) will become effective as soon as a dealing notice has been issued by the FCA and an acknowledgement by the London Stock Exchange that the Ordinary Shares will be admitted to trading on the Main Market (and such acknowledgement not having been withdrawn);

(d) the receipt of relevant consents and/or waivers from the Competent Authority and the Republic of Kazakhstan to (i) the acquisition by the Company of the membership interests in Nostrum Oil Coöperatief U.A. (a new intermediate holding entity of the Group) ("**Co-op**") (such consents and/or waivers being required in respect of Co-op's indirect ownership of subsoil use rights in Kazakhstan) and (ii) Admission;

(e) the issue by the KASE of its consent to the listing of the Ordinary Shares to the third category of the "Shares" sector of the official list of the KASE; and

(g) the issue by the Committee of the National Bank of Kazakhstan for Control and Supervision of the Financial Market and Financial Organisations (the "**FMSC**") of its permission for Admission.

If the Limited Partnership Agreement is duly amended and the Scheme is approved by the requisite majority at the Special General Meeting, and the other conditions to the Scheme have been satisfied, the Scheme is expected to become effective at 6.00 p.m. (London time) on 18 June 2014, the anticipated effective date (the "**Effective Date**"), and dealings in Ordinary Shares are expected to commence at 8.00 a.m. (London time) on 20 June 2014. If the Scheme has not become effective by 31 July 2014 (or such later date as NOGGL, as general partner of the Partnership, (the "**General Partner**") and the Company may agree), it will lapse, in which event there will not be a new parent company of Nostrum, Admission will not become effective and GDR holders will remain as holders of listed securities in the Partnership and the existing GDRs will continue to be listed on the Official List and admitted to trading on the Main Market.

The remainder of the conditions are customary for a transaction of this nature. Please see Part 2 "*Conditions to and Further Terms of the Scheme*" of the Scheme Document for a more detailed description of the conditions.

The Ordinary Shares will be issued to the Partnership (and then distributed to holders of Common Units) fully paid and free from all liens, equities, charges, encumbrances, options, rights of pre-emption and any other third-party rights and interests of any nature whatsoever and together with all rights now and hereafter attaching or accruing on them, including, without limitation, voting rights and the right to receive and retain in full all dividends and other distributions (if any) declared, made or payable on or after the date the Scheme becomes effective.

Further details of the Ordinary Shares are set out in paragraph 2 of Part 17 "*Additional Information*". The full conditions and further terms of the Scheme are set out in Part 2 "*Conditions to and Further Terms of the Scheme*" of the Scheme Document.

2.2 **Irrevocable Undertakings**

The Partnership and the Company have received irrevocable undertakings to vote in favour of the amendment of the Limited Partnership Agreement and the Scheme (the "**Irrevocable Undertakings**") from certain Existing Securityholders in respect of, in aggregate, 130,096,959 Existing Securities, representing in aggregate 69.13% of the existing Common Units as at the date of this Prospectus.

Further details of the Irrevocable Undertakings are set out in Paragraph 19 of Part 17 "*Additional Information*".

2.3 **Option plans**

The Partnership currently operates one option plan (the "**Phantom Option Plan**"). The Phantom Option Plan provides that, in the event of a transaction or change in the structure of the Partnership which would affect the value of any option granted under the Phantom Option Plan, the board of directors of the General Partner shall, acting reasonably and objectively, direct the Trustee to make such adjustments to the options under the Phantom Option Plan as the board considers appropriate in order to ensure that Optionholders are not prejudiced. As such, the board of directors of the General Partner has directed the Trustee to adjust, and the Trustee has so adjusted, all subsisting options, subject to and conditional upon Admission. Consequently, as from the date of Admission, each subsisting option under the Phantom Option Plan will be a right for each holder to receive on exercise a cash amount equal to the excess of (i) the market value on the date of exercise of the number of Ordinary Shares to which it relates, being the same as the number of GDRs to which it previously related; over (ii) the Base Value of the same number of Ordinary Shares which Base Value is unchanged, except that it will be stated in pounds sterling and not U.S. Dollars. Further details of the Phantom Option Plan are contained in paragraph 10.2 of Part 17 "*Additional Information*".

3. Share capital of the Company

3.1 **Ordinary Shares**

As at the date of this Prospectus, the issued share capital of the Company comprises the two Subscriber Shares, 100,000 Ordinary Shares and 410,000 Redeemable Shares. Following the issue of the new Ordinary Shares in connection with the implementation of the Scheme, the Subscriber Shares will be acquired by the Company for nil consideration and cancelled. It is expected that the Redeemable Shares will be redeemed for their paid up nominal value following Admission.

Upon Admission, the enlarged issued share capital of the Company is expected to comprise 188,182,958 Ordinary Shares plus the Redeemable Shares (assuming no new Common Units are issued between the date of this Prospectus and the Scheme Record Time).

In connection with the Scheme, the Board intends to allot and issue in aggregate 188,182,958 Ordinary Shares (being the maximum number of Ordinary Shares that would be required if the Scheme becomes effective). The Board has, to date, allotted and issued 100,000 Ordinary Shares in preparation for the Scheme and the KASE listing. The Board is authorised, inter alia, to allot up to a further 188,082,958 Ordinary Shares in connection with the Scheme. The Ordinary Shares to be distributed in connection with the Scheme have been or will be issued credited as fully paid and will rank *pari passu* in all respects with one another and will be entitled to all dividends and other distributions declared, made or paid by the Company in respect of Ordinary Shares on or after the date on which the Scheme becomes effective. The Ordinary Shares have been or will be created under the Companies Act, will be in registered form and will be capable of being held in both certificated and uncertificated form. The Ordinary Shares will, immediately following Admission, be freely transferable under the Articles.

A summary of the Articles is set out in paragraph 4 of Part 17 "*Additional Information*".

Application will be made to the FCA for the Ordinary Shares to be admitted to the premium listing segment of the Official List and to the London Stock Exchange for the Ordinary Shares to be admitted to trading on the Main Market. The Ordinary Shares will be registered with international security identification number ("**ISIN**") GB00BGP6Q951 and, when admitted to trading, Stock Exchange Daily Official List ("**SEDOL**") number BGP6Q95 and London Stock Exchange trading symbol NOG. Application will also be made to the KASE for the Ordinary Shares to be admitted to listing on the third category of the "Shares" sector of the official list of the KASE.

It is expected that Admission will become effective and unconditional dealings in Ordinary Shares will commence on or about 20 June 2014. It is expected that admission to listing of the existing Ordinary Shares on the KASE will occur on or around 13 June 2014 (prior to the implementation of the Scheme) and the further Ordinary Shares to be issued in connection with the Scheme will be admitted to listing on the KASE on or around 20 June 2014, with trading in the Ordinary Shares on the KASE commencing as soon as reasonably practicable thereafter.

The Ordinary Shares have a nominal value of £0.01 per Ordinary Share and will trade on the London Stock Exchange in pounds sterling.

3.2 Reduction of Share Capital

The Directors wish to continue the Partnership's existing dividend policy and buy-back programme in a financially and operationally efficient way. Accordingly, the purpose of the Reduction of Capital (as defined below) is to create distributable reserves in the accounts of the Company to support the payment of future dividends and share repurchases by the Company in the medium to long term.

Pursuant to the Reduction of Capital, it is proposed to cancel the entire amount standing to the credit of the Company's share premium account arising in connection with the Scheme and to re-characterise the reserve arising as a distributable reserve that will be available to the Company to be distributed as dividends or applied toward any other lawful purpose (the "**Reduction of Capital**").

By a special resolution passed at a general meeting of the Company held on 19 May 2014, the holders of the Subscriber Shares approved, conditional upon the Scheme becoming effective, the cancellation of the entire amount standing to the credit of the Company's share premium account arising in connection with the Scheme and the re-characterisation of the reserve arising as a distributable reserve.

The amount of the distributable reserves to be created by the Reduction of Capital will depend upon the price at which Ordinary Shares are issued by the Company pursuant to the Scheme. Such Ordinary Shares will be issued at a price equal to the closing price of the GDRs on the last day of dealings in the GDRs (currently anticipated to be on or about 12 June 2014) converted into sterling at the prevailing exchange rate.

Assuming that no further Common Units are issued after 16 May 2014 (being the last practicable date prior to the publication of this Prospectus), the Reduction of Capital will create a distributable reserve of approximately £61.2 million (based on an indicative exchange rate of £1.00=U.S.$1.68) in the accounts of the Company and leave the Company with paid up share capital of approximately £63.1 million (equivalent to U.S.$106,000,000).

The Reduction of Capital will only become effective if it is approved by the High Court pursuant to the Companies Act. As soon as reasonably practicable, the Directors intend to apply to the High Court to approve the Reduction of Capital, subject to the Scheme becoming effective.

As a newly incorporated company, the Company has few creditors, all of whom are expected to consent to the Reduction of Capital. It is not expected that the High Court will require any special measures to be put in place to protect creditors, and the reserves created by the Reduction of Capital will be available for distribution subject to the Company complying with the distribution provisions of the Companies Act.

Subject to Admission, the Reduction of Capital is expected to become effective in the third quarter of 2014.

4. Principal features of the Scheme

4.1 Overview

The new corporate structure is being implemented by way of the Scheme by the Company, pursuant to which the Company will acquire all (or substantially all) of the assets and liabilities of the Group (save for approximately U.S.$32 million in cash held by the Partnership which is required to meet outstanding obligations of the Partnership, including the costs of the scheme and the expected costs of dissolution of the Partnership) in consideration for the issue of the Ordinary Shares to the holders of the Common Units and hence to GDR holders. The Scheme is conditional on, *inter alia*, the Limited Partnership Agreement being amended in order to permit the Scheme to be implemented, Limited Partners voting in favour of the Scheme and related distributions of assets and Limited Partners voting in favour of the dissolution of the Partnership.

If the Scheme becomes effective, it will result in the assets and liabilities of the Partnership (save for approximately U.S.$32 million in cash held by the Partnership which is required to meet outstanding obligations of the Partnership, including the costs of the scheme and the expected costs of dissolution of the Partnership) being transferred to the Company pursuant to the acquisition by the Company (and/or its nominee) of all of the membership interests in Co-op, a new Dutch limited liability cooperative that will be the new intermediate holding entity of the Group and the subsequent dissolution of the Partnership.

Immediately following Admission, the principal assets of the Company will be the membership interests of Co-op, which will hold the existing assets and liabilities of the Group, a cash balance for the payment of fees and charges incurred pursuant to the Scheme and nominal cash balances. Immediately following Admission, the Company will have no material liabilities save for those arising in connection with Admission and the Scheme. The Directors expect that the material assets and liabilities of the Group will be unaffected by the Scheme becoming effective. In addition, the Scheme will not result in any changes to the day-to-day operations of the strategy or business of the Group and, save as set out above, the Directors expect that the Group will have the same operations and business before and after the Scheme becoming effective.

4.2 **Amendments to the Limited Partnership Agreement**

In order to implement the Scheme, a number of amendments are required to the Limited Partnership Agreement. Such amendments include, *inter alia*:

- creating a new class of limited partner interests (the "**Special Limited Partner Interest**") with priority rights to distributions of income and capital by the Partnership;
- permitting the implementation of the Scheme and the settlement of liabilities incurred in connection with the Scheme (subject to receipt of specific authorisation by Limited Partners), including entry into the Scheme Implementation Agreement (defined in paragraph 4.3 below);
- introducing provisions relating to the dissolution of the Partnership following implementation of the Scheme; and
- making various other consequential amendments to implement the Scheme consistent with the terms of the Scheme Implementation Agreement.

It is also proposed to amend the Limited Partnership Agreement to include a compulsory acquisition procedure if any person (or persons acting in concert) (other than the Depositary or its nominee) acquires Common Units representing 90% or more of the issued Common Units.

If the proposed amendments to the Limited Partnership Agreement are not approved by a special resolution at the Special General Meeting, the Scheme will not be implemented.

Full details as to the proposed amendments to the Limited Partnership Agreement are set out in the Special Scheme Document and a copy of the Limited Partnership Agreement as it is proposed to be amended may be viewed on the Partnership's website at www.nostrumoilandgas.com.

4.3 **Mechanics of the Scheme**

In order to implement the new corporate structure in a manner which is both tax-efficient and complies with relevant regulatory requirements, the Scheme is proposed to be implemented pursuant to a number of steps, which are expected to occur on the business day prior to the expected date of Admission.

If the requisite approval threshold to implement the Scheme is achieved at the Special General Meeting and the amendments to the Limited Partnership Agreement are approved, the Scheme will be implemented in full without any further action by the holders of Existing Securities and will be binding upon all holders of Existing Securities, whether or not they voted in favour of the Scheme.

Holders of Existing Securities will not need to take any action to implement the Scheme other than voting in favour of the amendments to the Limited Partnership Agreement and the Scheme at the Special General Meeting. Pursuant to the terms of the Limited Partnership Agreement (if amended), the General Partner will be authorised to execute all documents, and undertake all actions, to effect the Scheme.

In connection with the Scheme, the General Partner and/or the Company have undertaken or will undertake the following actions:

- The Partnership has formed Co-op, a new Dutch limited liability cooperative, with U.S.$1,001,000 of membership capital (with the General Partner being the second nominee member).
- Co-op will, as part of an intra-group reorganisation of the Partnership's group, acquire all of the assets and liabilities of the Partnership, other than an intra-group loan due from Zhaikmunai Netherlands B.V. (a subsidiary of the Partnership) to the Partnership (the "**Intra-Group Loan**"), which is equal in amount to U.S.$106,000,000 and certain other assets of the Partnership required to meet outstanding obligations of the Partnership (including the fees and expenses related to the Reorganisation) and the expected costs of dissolution of the Partnership (being approximately U.S.$32 million in cash). Co-op will consequently become the new intermediate holding entity for the Group.

- The Partnership and a nominee have subscribed for 100,000 Ordinary Shares as at the date of the Prospectus. Prior to implementation of the scheme, the Partnership will acquire the Ordinary Shares held by the nominee and subscribe for a further 188,082,958 Ordinary Shares, so that it will hold 188,182,958 Ordinary Shares in the Company (equivalent to the number of Common Units currently issued by the Partnership), with an aggregate subscription amount equal to U.S.$106,000,000.
- The Company, Co-op, the Partnership, the General Partner, NOGGL and VTB Capital plc ("**VTB**") have entered into an agreement to implement the Scheme (the "**Scheme Implementation Agreement**"), conditional upon all resolutions being passed by Limited Partners at the Special General Meeting. A summary of the terms of the Scheme Implementation Agreement is contained in paragraph 12.4(a) of Part 17 "*Additional Information*".
- The Company and VTB have entered into a facility agreement (the "**PLC Facility Agreement**") and NOGGL (acting in its own capacity) and VTB have entered into a facility agreement (the "**NOGGL Facility Agreement**" and together with the PLC Facility Agreement, the "**Facility Agreements**") pursuant to which VTB will lend funds to the Company and NOGGL on an intra-day basis in order to finance the acquisition of the Group pursuant to the Scheme. A summary of the terms of the Facility Agreements is contained in paragraphs 12.4(b) and (c) of Part 17 "*Additional Information*".
- Prior to the Special General Meeting, the Company will apply to the KASE for the admission of the Ordinary Shares to the third category of the "Shares" sector of the KASE's official list. Prior to or following confirmation from the KASE in respect of its consent to the KASE listing, the Partnership will issue an announcement specifying the Scheme Record Time and following the Scheme Record Time, no transfer, sale or disposal of any Common Unit will be permitted.
- The Scheme Record Time is currently expected to occur at 5.00 p.m. on 17 June 2014, the date of the Special General Meeting.
- On the business day following the Scheme Record Time, NOGGL will, pursuant to the NOGGL Facility Agreement, borrow U.S.$106,000,000 from VTB on an intra-day basis (the "**SLP Subscription Amount**") and subscribe for a new Special Limited Partner Interest in the Partnership for U.S.$106,000,000. The Special Limited Partner Interest will entitle the Special Limited Partner to distributions or returns of capital made by the Partnership, whether on a dissolution of the Partnership or otherwise, in priority to holders of Common Units (other than a distribution of Ordinary Shares in connection with the Scheme).
- The Partnership will distribute the fully paid Ordinary Shares to holders of Common Units on the basis of one Ordinary Share for each Common Unit held.
- Following such distribution the Company will, pursuant to the PLC Facility Agreement, borrow from VTB on an intra-day basis an amount (the "**Funding Amount**") equal to (i) the market capitalisation of the Partnership as at the close of business on the date of the Special General Meeting (the "**Co-op Subscription Amount**") less (ii) the SLP Subscription Amount in order to finance the acquisition of Co-op. As at 16 May 2014 (the latest practicable date before the publication of this Prospectus, the Funding Amount would therefore be approximately U.S.$1,729 million.
- The Company will make a contribution to the membership capital of Co-op in an amount equal to the Co-op Subscription Amount, becoming the holder of not less than 99.9% of the membership interests in Co-op and the new holding company of the Group.
- Co-op will make a return of membership capital to the Company in an amount equal to the Funding Amount and the Company will use such funds to repay its borrowing of an amount equal to the Funding Amount from VTB under the PLC Facility Agreement.
- The Partnership and the General Partner will sell their remaining nominal interest in Co-op to the Company (or an existing subsidiary of the Company) so that Co-op becomes a 100% subsidiary undertaking of the Company.
- The Company will purchase the Special Limited Partner Interest from NOGGL in cash for an amount equal to the SLP Subscription Amount. NOGGL will use the proceeds of such sale to repay its loan of an amount equal to the SLP Subscription Amount from VTB under the NOGGL Facility Agreement. The Company will then contribute the Special Limited Partner Interest to Co-op.
- The Partnership will subsequently make a distribution of the Intra-Group Loan to Co-op as Special Limited Partner, following which Co-op will have acquired (or be entitled to acquire) all of the assets and assumed (or be required to assume) all of the liabilities of the Partnership pursuant to the Scheme

(save in respect of certain contractual liabilities under the Scheme Implementation Agreement and funds required to meet the expected costs of the Scheme and the dissolution of the Partnership).

- **The Scheme will have become effective at this point.**
- Following the Scheme having become effective, the Company will apply to the FMSC for permission to list the Ordinary Shares on the London Stock Exchange.
- Following receipt of confirmation from the FMSC in respect of its consent to Admission, the Company will notify the FCA that all steps to implement the Reorganisation have been completed.

It is expected that all sums due to VTB from the Company and NOGGL under the Facilities Agreements will be repaid on the same day, being the second business day prior to Admission. It is expected that Admission and the admission of all the Ordinary Shares to the third category of the "Shares" sector of the KASE's official list (the "**KASE Admission**") will occur on or around the same business day.

Following Admission, and pursuant to the approval given at the Special General Meeting, the General Partner will dissolve the Partnership. It is expected that Admission and the KASE listing will occur on or around the same business day.

If the requisite approval threshold to implement the Scheme is not achieved at the Special General Meeting, or if the special resolution to approve the dissolution of the Partnership following the Scheme is not passed at the Special General Meeting, the Scheme will not be implemented.

Holders of Existing Securities will continue to retain their interests in the Existing Securities for an interim period following Admission prior to the dissolution of the Partnership. No further distribution is expected to be made in respect of such Existing Securities and holders of Existing Securities are not expected to realise any further value in respect of their interests in GDRs following Admission.

The Partnership will make announcements from time to time in relation to the progress of the Scheme, including upon the Scheme becoming effective.

4.4 Modifications of the Scheme

The amended Limited Partnership Agreement will contain a provision for the General Partner to modify or amend or impose additional conditions to the Scheme, subject to the consent of the Company pursuant to the Scheme Implementation Agreement. The General Partner shall not approve or impose any modification of, or addition or condition to, the Scheme which (with the consent of the Company) (i) might be material to the interests of Limited Partners or GDR Holders, unless the Limited Partners and GDR Holders have been given reasonable prior notice of any such modification, addition or condition or (ii) to the extent it would create or increase liabilities for the Limited Partners or GDR holders (other than pursuant to their direct or indirect participation in the Partnership) without their prior approval in general meeting by way of special resolution. It will be a matter for the General Partner to decide, in its discretion, whether or not the consent of Limited Partners should be sought at a further meeting thereof. Similarly, if a modification, addition or condition is put forward which, in the opinion of the General Partner, is of such a nature or importance as to require the consent of the Limited Partners at a further meeting, the General Partner will not take the necessary steps to enable the Scheme to become effective unless and until such consent is obtained.

The amended Limited Partnership Agreement will also contain a provision stating that in the event that such agreement is amended and restated as set out in the amended Limited Partnership Agreement, but the restructuring and re-Listing is not implemented as set out in the Scheme Circular and the Scheme Implementation Agreement, the General Partner may take such steps as, acting reasonably and in good faith, it considers appropriate, provided that the General Partner shall not take any steps which will create or increase liabilities for the Limited Partners or GDR holders without their prior approval in general meeting by way of special resolution.

4.5 Conditions to implementation of the Scheme

The implementation of the Scheme is conditional on the following having occurred:

(a) the Scheme being approved by holders representing not less than 75% in voting rights of holders of Common Units present and voting, either in person or by proxy, at the Special General Meeting;

(b) special resolutions (as set out in the notice convening the Special General Meeting in part 7 of the Scheme Document), to approve the amendment of the Limited Partnership Agreement (to permit the implementation of the Scheme) and the dissolution of the Partnership having been duly passed at the Special General Meeting by a majority of not less than 75% in voting rights of holders of Common Units present and voting, either in person or by proxy, at the Special General Meeting;

(c) the FCA having acknowledged to the Company or its agent (and such acknowledgement not having been withdrawn) that the application for admission of the Ordinary Shares to the premium listing segment of the Official List has been approved and (subject to satisfaction of any conditions to which such approval is expressed) will become effective as soon as a dealing notice has been issued by the FCA and an acknowledgement by the London Stock Exchange that the Ordinary Shares will be admitted to trading on the Main Market (and such acknowledgement not having been withdrawn) (the "**Pre-Admission Notification**");

(d) the consent of the Competent Authority to (i) the reorganisation of the Group, including the issue of the Ordinary Shares and the acquisition of the membership interests in Co-op by the Company having been received (such consent being required in respect of Co-op's indirect ownership of subsoil use rights in Kazakhstan) and (ii) the trading of the Ordinary Shares on the Main Market of the London Stock Exchange (the "**MOG Consent**");

(e) the waiver by the Republic of Kazakhstan of its right of pre-emption in respect of (i) the reorganisation of the Group, including the issue of the Ordinary Shares and the acquisition of membership interests in Co-op by the Company (such right of pre-emption arising in respect of Co-op's indirect ownership of subsoil use rights in Kazakhstan) and (ii) the trading of the Ordinary Shares on the Main Market of the London Stock Exchange (the "**RoK Waiver**"); and

(f) the issue of consent from KASE for the KASE listing and receipt of permission from the FMSC for Admission.

As at the date of this Prospectus, the Company has received the relevant confirmations from the Ministry of Oil and Gas in Kazakhstan and has therefore satisfied the conditions relating to the MOG Consent and the RoK Waiver.

The Scheme is also conditional upon certain other conditions relating to the business of the Group that are customary for a transaction of this nature. Please see Part 2 "*Conditions to and Further Terms of the Scheme*" of the Scheme Document for a more detailed description of these conditions.

The directors of the General Partner will not take the necessary steps to implement the Scheme unless the above conditions have been satisfied or (if possible) waived and, at the relevant time, they consider that it continues to be in the Partnership's and the Limited Partners' best interests that the Scheme should be implemented.

If the Limited Partnership Agreement is duly amended and the Scheme is approved by the requisite majority at the Special General Meeting, and the other conditions to the Scheme have been satisfied, the Scheme is expected to become effective at 6.00 p.m. (London time) on 18 June 2014, the anticipated Effective Date, and dealings in Ordinary Shares are expected to commence at 8.00 a.m. (London time) on 20 June 2014. If the Scheme has not become effective by 31 July 2014 (or such later date as the General Partner and the Company may agree), it will lapse, in which event there will not be a new parent company of Nostrum, Admission will not become effective and GDR holders will remain as holders of securities in the Partnership and the existing GDRs will continue to be listed on the Official List and admitted to trading on the Main Market.

4.6 Effects of the Scheme

The Company is a newly incorporated company which has not traded since its incorporation and, prior to the Scheme becoming effective, will not own any material assets or have any material liabilities save for those arising in connection with the proposed implementation of the Scheme. If the Scheme becomes effective, the Company will become the new parent company of the Group and its assets, liabilities and earnings on a consolidated basis will be those of the Group.

Under the Scheme, Limited Partners and/or GDR holders will receive an equivalent number of Ordinary Shares to the number of Common Units and/or GDRs that they hold as at the Scheme Record Time. Following the implementation of the Scheme and the dissolution of the Partnership, the holders of Common Units (including in the form of GDRs) will have effectively exchanged their interests in Common Units (or GDRs as applicable) in the Partnership for Ordinary Shares in the Company.

The proportionate entitlement of Limited Partners and GDR holders to participate in the capital and income of the Group will not be affected by reason of the implementation of the Scheme or the Reduction of Capital. Limited Partners and/or GDR holders will not receive any amount in cash pursuant to the terms of the Scheme, nor will they be required to pay any cash to receive the Ordinary Shares.

GDR holders will continue to retain their interests in the GDRs for an interim period after Admission and prior to the dissolution of the Partnership, but no further distribution is expected to be made in respect of such GDRs and holders of GDRs are not expected to realise any further value in respect of their interests in GDRs.

5. Background to and reasons for the Scheme

The Company has been incorporated in England and Wales and is intended and expected to be tax resident in the Netherlands (in line with the Partnership's current tax residency status). The Scheme, if it is implemented, will establish the Company as the parent company of the Group, with, upon Admission becoming effective, its ordinary shares admitted to listing on the premium listing segment of the Official List and trading on the Main Market of the London Stock Exchange. The board of directors of the General Partner is in agreement with the Board that this is the most appropriate structure for the Group.

The board of directors of the General Partner believes that establishing the Company as the parent company of the Group and listing it on the premium listing segment of the Official List should raise the profile of the Group with international investors, increase the liquidity of its securities, allow the Group to become eligible for inclusion in the FTSE UK Index Series in the second half of 2014 and further demonstrate the Group's commitment to the high governance and control standards according to which it operates its business.

6. Impact of the proposals on the Partnership's business, strategy, employees and management

The Scheme will not result in any changes to the day-to-day operations of the business of the Group or its strategy.

The Company (which was incorporated on 3 October 2013 specifically to become the new parent company of the Group) has no material assets or liabilities save for those arising in connection with the Scheme. Upon the Scheme becoming effective, the Company will own no material assets other than the membership interests in Co-op (the proposed new intermediate holding entity of the Group) and will have no material liabilities save for those arising in connection with the Scheme. The Directors expect that the Group's material assets and liabilities will be substantially unaffected by the Scheme becoming effective.

Save as set out above, the Directors expect that the Group will have the same business and operations in the same geographic locations before and after the Scheme becomes effective.

The existing employment rights of the management and employees of the Group will continue to be safeguarded and the accrued rights and benefits of the management and employees of the Group will continue to be protected to the same extent immediately before and after the Scheme becomes effective.

7. Suspension and Delisting of the GDRs

In order to determine the list of holders of Common Units and GDRs who will be entitled to receive the Ordinary Shares as part of the Scheme, the Partnership has applied to the FCA and the London Stock Exchange to suspend the GDR Listing in accordance with the Listing Rules and the Admission and Disclosure Standards with effect from close of trading on the London Stock Exchange three trading days prior to the Scheme Record Date. This suspension is intended to ensure that all transfers of GDRs via the London Stock Exchange prior to such suspension are appropriately reflected in the register of holders of the GDRs prior to the Scheme Record Time.

Following such suspension, holders of GDRs will able to transfer or otherwise dispose of their interests in GDRs but will not be able to effect transfers of their GDRs via the London Stock Exchange. Holders of GDRs should be aware that any transfers of GDRs after the suspension of trading of the GDRs on the London Stock Exchange may not provide sufficient time for such transfers to be appropriately reflected in the register of holders of the GDRs prior to the Scheme Record Time and thereby ensure their entitlement to the receipt of Ordinary Shares. It is expected that the suspension will last for five business days to allow the register of holders of GDRs to be updated, to allow the Partnership to implement the Scheme, to effect the Reorganisation and to obtain the remaining regulatory consents, before dealings in the Ordinary Shares are expected to commence on the second business day following the Scheme becoming effective.

The Partnership has also applied to the FCA and the London Stock Exchange to cancel the GDR Listing in accordance with the Listing Rules and the Admission and Disclosure Standards. Such cancellation is conditional upon the Scheme becoming effective and Admission occurring.

If the Scheme becomes effective, holders of GDRs will able to transfer or otherwise dispose of their interests in GDRs but will not be able to surrender their GDRs and receive delivery of the underlying Common Units, and the General Partner will not register any transfer, sale or disposal of Common Units.

Following the delisting of the GDRs, the Partnership will be dissolved in accordance with the terms of the amended Limited Partnership Agreement and the GDR programme will be terminated in accordance with the terms of the deposit agreement in respect of the GDRs and the conditions of the GDRs. Holders of existing GDRs will continue to retain their interests in the GDRs for an interim period prior to the dissolution of the Partnership, but no further distribution is expected to be made in respect of such GDRs, holders of GDRs are not expected to realise any further value in respect of their interests in GDRs and will be unable to surrender their GDRs for delivery of Common Units.

If the Scheme lapses or is withdrawn, the Partnership intends to maintain the GDR Listing and the Partnership will apply to the FCA and the London Stock Exchange to restore the GDR Listing as soon as practicable following such lapse or withdrawal.

8. Listing, dealings, share certificates and settlement

Application will be made to the FCA for the admission of up to 188,182,958 Ordinary Shares to the premium listing segment of the Official List and to the London Stock Exchange for the Ordinary Shares to be admitted to trading on the London Stock Exchange's Main Market. Application will also be made to the KASE for the admission of the Ordinary Shares to the third category of the "Shares" sector of the KASE's official list.

The last day for transfer of Common Units is expected to be on or about 17 June 2014. **The Partnership will confirm the Scheme Record Time (and the proposed suspension of the listing of the GDRs on the London Stock Exchange) pursuant to an announcement via a Regulatory Information Service.** It is expected that Admission will become effective and that dealings in the Ordinary Shares will commence at 8.00 a.m. on 20 June 2014. If Admission occurs, the listing of the GDRs will be cancelled prior to commencement of trading in the Ordinary Shares.

If the Scheme is approved at the Special General Meeting, with effect from (and including) the Scheme Record Time (expected to be 5.00 p.m. on 17 June 2014), holders of GDRs will be able to transfer or otherwise dispose of their interests in GDRs, but will not be able to dematerialise their GDRs and receive the underlying Common Units, and the General Partner will not register any transfer, sale or disposal of Common Units. Any transfer of GDRs after the Scheme Record Time will not entitle the transferee to receive Ordinary Shares pursuant to the Scheme.

If the Scheme becomes effective, all certificates representing the Common Units or GDRs in certificated form will continue to be valid and binding in respect of such holdings, and should be retained by the relevant holder pending the termination of the deposit agreement in respect of the GDRs and the dissolution of the Partnership, but no surrender of GDRs for delivery of Common Units or assignment of Common Units will be permitted after the effective time of the Scheme.

All documents, certificates or other communications sent by, to, from or on behalf of holders of Existing Securities, or as such persons shall direct, will be sent at their own risk and may be sent by post.

Application will be made for the Ordinary Shares to be admitted to CREST for settlement and transfer purposes. Euroclear requires the Company to confirm to it that certain conditions imposed by the CREST Regulations are satisfied before Euroclear will admit any security to CREST. It is expected that these conditions will be satisfied in respect of the Ordinary Shares prior to admission of the Ordinary Shares to the Official List. As soon as practicable after satisfaction of the conditions, the Company will confirm this to Euroclear.

Subject to the satisfaction of the conditions referred to in paragraph 4.5 above, to which the Scheme is subject, the Ordinary Shares to which Limited Partners and GDR holders are entitled under the Scheme (as the case may be) will be effected in the manner set out below:

(a) To the extent the entitlement arises as a result of a holding of Common Units in certificated form at the Scheme Record Time, the Ordinary Shares will be delivered in certificated form in the name of the relevant Limited Partner. Definitive certificates for the Ordinary Shares will be despatched by first-class post (or by such other method as determined by the Company) within 14 days of the Scheme Record Date to the address appearing on the Register (or in the case of joint holders, at the address of that joint holder whose name stands first in the Register of such joint holdings) or in accordance with any special instructions regarding communications, and neither the Company nor the Partnership shall be responsible for any loss or delay in the transmission of certificates sent in this way and such certificates shall be sent at the risk of the person entitled thereto.

Temporary documents of title will not be issued pending the despatch by post of the new definitive share certificates. Persons wishing to register transfers of Ordinary Shares prior to the issue of the new share certificates will be required to forward a completed transfer form to the Company's registrar for certification and registration.

(b) To the extent the entitlement arises as a result of a holding of GDRs in uncertificated form in Euroclear or Clearstream at the Scheme Record Time, the Ordinary Shares will be credited in CREST to Euroclear's CREST account, and Euroclear or Clearstream, as applicable, will credit the appropriate Euroclear or Clearstream account of each GDR holder holding Regulation S GDRs with such GDR holder's entitlement to Ordinary Shares. GDR Holders holding Rule 144A GDRs will receive the relevant Ordinary Shares in certificated form. GDR Holders holding Regulation S GDRs through DTC may, if they provide relevant details to the Depositary, elect to receive the relevant Ordinary Shares in a CREST account, and otherwise (if so elected, or no election is made or no CREST account details are provided) shall receive relevant Ordinary Shares in certificated form.

Settlement will be made through Euroclear, Clearstream or CREST on the Effective Date, or as soon as practicable thereafter, but in any case within 14 days of the Scheme Record Date, in accordance with CREST arrangements.

Notwithstanding anything above or any other provision of this Prospectus or any other document relating to the Ordinary Shares, the General Partner and the Company reserve the right to deliver any Ordinary Shares applied for in certificated form. In normal circumstances, this right is only likely to be exercised in the event of any interruption, failure or breakdown of CREST (or any part of CREST), or on the part of the facilities and/or systems operated by the Registrar in connection with CREST. This right may also be exercised if the correct details in respect of *bona fide* market claims (such as the CREST member account ID and CREST participation ID details) are not provided as requested on any application form relating to the Ordinary Shares.

GDR holders who are CREST-sponsored members intending to receive Ordinary Shares into a CREST account should refer to their CREST sponsor regarding the action to be taken in connection with this Prospectus.

9. Overseas Existing Securityholders

The implications of the Scheme for and the distribution of this Prospectus to Existing Securityholders who are resident or located in, or citizens or nationals of, jurisdictions outside the United Kingdom and Isle of Man ("**Overseas Persons**") may be affected by the laws of relevant jurisdictions. Such Overseas Persons should inform themselves about and observe all applicable legal requirements.

It is the responsibility of any person into whose possession this Prospectus comes to satisfy themselves as to their full observance of the laws of the relevant jurisdiction in connection with the Scheme and the distribution of this Prospectus, including the obtaining of any governmental, exchange control or other consents which may be required and/or compliance with other necessary formalities which are required to be observed and the payment of any issue, transfer or other taxes due in such jurisdiction.

If, in respect of any Overseas Person, the Company is advised that the allotment and issue of Ordinary Shares would or might infringe the laws of any jurisdiction outside the United Kingdom or Isle of Man, or would or might require the Company to obtain any governmental or other consent or effect any registration, filing or other formality with which, in the opinion of the Company, it would be unable to comply or which it regards as unduly onerous, the Scheme provides that the Company may determine either: (a) that the entitlement of Limited Partners or GDR holders to Ordinary Shares pursuant to the Scheme shall be issued to such person and then sold on his behalf as soon as reasonably practical at the best price which can be reasonably obtained at the time of sale, with the net proceeds of sale being remitted to the share owner; or (b) that the entitlement of Limited Partners or GDR holders to Ordinary Shares shall be issued to a nominee for such share owner appointed by the Company and then sold, with the net proceeds being remitted to the share owner concerned. Any remittance of the net proceeds of sale referred to in this paragraph shall be at the risk of the relevant holder.

Overseas Persons should consult their own legal and tax advisers with respect to the legal and tax consequences of the Scheme in their particular circumstances.

10. Dividends

The Ordinary Shares to be issued pursuant to the Scheme will rank *pari passu* in all respects with any Ordinary Shares in issue at the Scheme Record Time and shall rank in full for all dividends or distributions made, paid or declared after the Scheme Record Time on the ordinary share capital of the Company.

The Board expects to continue to follow the Partnership's current dividend pay-out policy, whilst also being progressively reviewed by the Board in line with the achievement of the Group's strategic milestones.

Accordingly, the Board has adopted a distribution policy with the intention of making an annual distribution of not less than 20% of the Group's consolidated net profit. This policy reflects the Company's desire to recognise the growth and cash generation inherent in the business.

The Scheme will only be capable of becoming effective after payment of the dividend of U.S.$0.35 per Common Unit announced by the Partnership on 9 May 2014 and accordingly the Ordinary Shares will not have any entitlement to receive this dividend payment.

11. Taxation

The attention of Limited Partners is drawn to Part 3 "*Taxation*" of the Scheme Document which contains certain statements relating to taxation. These statements relating to taxation are of a general nature only and Limited Partners who are in any doubt as to their own tax position should consult an appropriate professional adviser immediately.

12. Bond Issues

It is proposed that, on or after the Effective Date, the Company will become a guarantor of the New 2019 Bonds and the 2019 Bonds by entering into supplementary indentures in respect of each such bond issue. Implementation of the Scheme does not require consent of bondholders under the terms of either the New 2019 Bonds or the 2019 Bonds.

13. Further Information

The terms and conditions of the Scheme are set out in full in Part 2 "*Conditions to and Further Terms of the Scheme*" of the Scheme Document. The attention of Existing Securityholders is drawn to the risk factors set out in Part 2 "*Risk Factors*", the conditions and further terms of the Scheme set out in Part 2 "*Conditions to and Further Terms of the Scheme*" of the Scheme Document, the information on the Group contained in Part 17 "*Additional Information*" and certain financial information on the Group set out in Part 14 "*Historical Financial Information*" and Part 12 "*Operating and Financial Review*".

PART 7
INFORMATION ON THE GROUP

Overview

Nostrum is an independent oil and gas enterprise engaged in the exploration and production of oil and gas products in North-Western Kazakhstan. Nostrum, through its indirectly wholly-owned subsidiary Zhaikmunai LLP, is the owner and operator of four fields in Kazakhstan, the Chinarevskoye Field and the Rostoshinskoye, Darinskoye and Yuzhno-Gremyachenskoye development fields. The Group's primary field and Licence area is the Chinarevskoye Field located in the northern part of the oil-rich Pre-Caspian Basin.

For the year ended 31 December 2013, the Group had total revenue, EBITDA and net cash flows from operating activities of U.S.$895 million, U.S.$551 million and U.S.$357 million, respectively. For the year ended 31 December 2012, the Group had total revenue, EBITDA and net cash flows from operating activities of U.S.$737 million, U.S.$457 million and U.S.$292 million, respectively. The Group had average daily production of 46,178 boepd and 36,940 boepd for the years ended 31 December 2013 and 2012, respectively.

The Chinarevskoye Field, approximately 274 square kilometres in size, is located in the West-Kazakhstan oblast, near the border between Kazakhstan and Russia, and close to the main international railway lines in and out of Kazakhstan as well as to several major oil and gas pipelines. The Chinarevskoye Field has been Nostrum's only source of production from 2007 to date. Based on the 2013 Ryder Scott Report, as at 31 August 2013, the estimated gross proved plus probable hydrocarbon reserves at the Chinarevskoye Field were 483.3 million boe, of which 193.2 million bbl was crude oil and condensate, 72.4 million bbl was LPG and 216.8 million boe was sales gas. According to the 2013 Ryder Scott Report, the Chinarevskoye Field also contains approximately 76.2 million boe of gross possible hydrocarbon reserves.

Nostrum's operational facilities are located in the Chinarevskoye Field and consist of an oil treatment unit capable of processing 400,000 tonnes per year of crude oil, multiple oil gathering and transportation lines including an oil pipeline from the field to its oil loading rail terminal in Rostoshi near Uralsk, a 17 kilometre gas pipeline from the field to the Orenburg-Novopskov pipeline, a gas powered electricity generation system, warehouse facilities, an employee field camp and the gas treatment facility. The first phase of the gas treatment facility, consisting of two units, became fully operational in 2011 and has enabled Nostrum to produce marketable liquid condensate (a product lighter than Brent crude oil) and LPG from the gas condensate stream.

Following the successful completion of the first phase of the gas treatment facility, consisting of two units, Nostrum intends to build a third unit for the gas treatment facility by mid-2016. Management currently estimates that the total cost of this project will not exceed U.S.$500 million (U.S.$29.7 million of which had already been incurred as at 31 December 2013) and will be funded by cash from operations.

On 24 May 2013, the Group notified the Competent Authority of the completion of the acquisition for U.S.$17 million of three oil and gas development fields, Rostoshinskoye, Darinskoye and Yuzhno-Gremyachenskoye, also located in the Pre-Caspian basin to the North-West of Uralsk, approximately 50 to 105 kilometres from the Chinarevskoye Field. These development fields are approximately 139 square kilometres in size. According to the 2013 Ryder Scott Report, as at 31 August 2013, the estimated net probable hydrocarbon reserves at these three fields were 98.2 million boe with an additional 33.6 million boe of net possible hydrocarbon reserves.

Key Strengths

The Directors believe that the key strengths of the Group are as follows:

- *Substantial reserve base*

  According to the 2013 Ryder Scott Report, as at 31 August 2013, the estimated gross proved plus probable hydrocarbon reserves at the Chinarevskoye Field were 483.3 million boe. These estimated reserves comprise proved crude oil and gas condensate reserves of 79.5 million bbl and 113.7 million bbl of probable crude oil and gas condensate reserves, together with 90.2 million boe of proved gas reserves and probable gas reserves of 127.5 million boe and 29.5 million boe of proved LPG reserves and probable LPG reserves of 42.9 million boe. In addition, according to the 2013 Ryder Scott Report, the estimated net probable hydrocarbon reserves at the Rostoshinskoye, Darinskoye and Yuzhno-Gremyachenskoye fields were 98.2 million boe as at 31 August 2013.

- *Proven ability to develop and replenish existing reserves*

  According to management estimates based on data included in reserves reports prepared by Ryder Scott, since 1 January 2004 Nostrum has increased its gross proved hydrocarbon reserves from 28 million boe to 199.2 million boe, as at 31 August 2013, as well as increasing its probable hydrocarbon reserves from 170 million boe to 382.3 million boe (including the gross probable reserves attributable to the Chinarevskoye Field and the net reserves attributable to the Rostoshinskoye, Darinskoye and Yuzhno-Gremyachenskoye fields), as at 31 August 2013. This has been achieved through ongoing appraisal and exploration work on the Chinarevskoye Field overseen by the current management team, as well as the acquisition of the Rostoshinskoye, Darinskoye and Yuzhno-Gremyachenskoye fields. Additionally, over the past three years, the Group has been able to successfully replenish its proved and probable reserves base notwithstanding increased production during this period.

- *Strong balance sheet and cash flow generation*

  The Group has continued to demonstrate sustained revenue and significant cash flow generation. Since commencing operations in 2004, the Group has substantially grown its revenue through exploration activities and by expansion of its product base, as well as substantial growth in production and sale of hydrocarbons. The Group's EBITDA for the year ended 31 December 2013 was U.S.$551 million compared to U.S.$457 million for the year ended 31 December 2012. The Group's net debt to EBITDA ratio for the year ended 31 December 2013 was 0.7 compared to 0.8 for the year ended 31 December 2012. The improvement in operations has enabled the Group to achieve strong organic growth.

- *Strong track record of production growth within the Chinarevskoye Field with a further significant increase expected*

  Nostrum has a strong track record of successful exploration and production within the Licence area. Analysis by Nostrum personnel of 3-D seismic surveys covering the entire Chinarevskoye Field has allowed Nostrum to position wells effectively. In addition, management has deployed advanced drilling techniques to exploit the Biski-Afoninski reserves which are located in vertically and horizontally fragmented segments including drilling deep wells (between approximately 4,250-5,100 metres), drilling multiple wells and undertaking horizontal drilling (up to 1,000 metres). Further, primarily as a result of the first phase of the gas treatment facility reaching design capacity by the end of 2012, hydrocarbon production increased to an average of 46,178 boepd for the year ended 31 December 2013, an increase of 25.0% compared to an average of 36,940 boepd for the year ended 31 December 2012. Management estimates, based on the production profile of both proved and probable reserves reported in the 2013 Ryder Scott Report and assuming the successful completion of the second phase of the gas treatment facility by the middle of 2016, that annual production will more than double from the 2013 annual production by the end of 2016. Nostrum currently plans to employ the same exploration and production methods it uses within the Chinarevskoye Field at its three new development fields.

- *Advantageous location to access export infrastructure*

  Nostrum's facilities are located in western Kazakhstan approximately 10 kilometres from the Russian border, which reduces overall transportation distances from the Group's production operations to ultimate purchasers of its oil in European markets (as compared to other Kazakh oil and gas producers). In addition, Nostrum's operations are located close to various transportation routes, being 17 kilometres from the Orenburg-Novopskov gas pipeline and less than 100 kilometres from rail links and the Atyrau-Samara oil pipeline. Nostrum's oil pipeline from its field to its rail terminal in Rostoshi near Uralsk gives Nostrum direct access to the rail terminal and an option for a direct connection to the export pipeline to Samara which is crossed by the Group's pipeline. Nostrum's closer proximity to export infrastructure compared with other Kazakh oil and gas producers provides it with a competitive advantage and allows it to benefit from reduced transportation costs.

- *Stable tax and royalty payment terms under the PSA and strong relationship with regulators and authorities*

  The Group currently benefits from a relatively stable tax and royalty payment burden under the PSA for the Chinarevskoye field as the terms of the PSA have been "grandfathered" from its signing in 1997. As such, the terms of the PSA allow Nostrum to estimate the Kazakh Government's share of production revenue with reasonable certainty (although the Kazakh Government could seek to restrict or amend such "grandfathering"—see Part 2 "*Risk Factors—Risk Factors Relating to Kazakhstan—The Group is exposed to the risk of adverse sovereign action by the Kazakh Government*"). The Group has amended the terms of the PSA on ten previous occasions and the Group is regularly in discussions with regulators about the terms of the PSA and issues that impact the Group's operations.

- *Strong and highly experienced management team*

  The Group benefits from management with significant experience in the oil and gas sector in general, and Kazakhstan in particular. The current senior executive team have worked together for Nostrum since 2007 and Nostrum's Chief Executive Officer has worked since 1985 in the oil and gas industry, including approximately 13 years' experience working in emerging markets for the Gaz de France group. In addition, Nostrum has experienced senior managers in key departments, including geology, drilling, production and engineering, with an average experience of 22 years in the oil and gas industry.

- *High quality crude oil*

  The crude oil produced by Nostrum is a high quality "sweet" crude oil with an average API gravity of 42-43^{o} and a low sulphur content of approximately 0.4%. The high quality of its crude oil allows Nostrum to sell its crude oil at a smaller discount to Brent crude than other oil producers in the region.

Business Strategy

Nostrum's long-term objective is to further consolidate its position as one of the leading independent oil and gas companies in Kazakhstan. The first phase of development of the Chinarevskoye Field has now been completed. Its infrastructure, including the first phase of development of the gas treatment facility consisting of two units, is fully operational and average daily production currently runs above 45,000 boepd.

The Group is now planning to build an additional unit for the gas treatment facility by mid-2016 and commence the second phase of development of the Chinarevskoye Field. In addition, the Group intends to complete the initial appraisal of the Rostoshinskoye, Darinskoye and Yuzhno-Gremyachenskoye development fields by the end of 2015.

The constituents of the Group's strategy in delivering the future growth potential of the Group comprise:

- *Delivering Organic Production Growth*

  The Group aims to double production levels from the Chinarevskoye Field by the end of 2016. To enable this, it plans to construct a third unit for the gas treatment facility in the vicinity of the existing two units, which can currently treat a total of 1.7 billion cubic metres of raw gas per year. The Group plans for the third unit to increase production capacity by 2.5 billion cubic metres of gas, bringing the total capacity of the gas treatment facility to 4.2 billion cubic metres of gas annually once all three units are fully operational. The Group expects to benefit from the technical expertise and significant experience gained from the construction of the first two units of the gas treatment facility in the construction of the third unit.

  The development plan for the third gas treatment unit includes the front end engineering design, the selection of third parties, construction, commissioning and production ramp-up. The decision to initiate the construction is predicated on meeting Nostrum's internal macroeconomic environment conditions and financial criteria, including cash management. Nostrum has a hedging policy whereby it hedges against adverse oil price during times of considerable non scalable capital expenditure. Based on the contracts Zhaikmunai LLP has entered into with various equipment suppliers for the third gas treatment unit and the fact that further contracts will be entered into over the coming months Nostrum is closely monitoring the hedging market and may in the near future enter into a hedge to cover a portion or all of its non-scalable capital expenditure linked to the construction of the third gas treatment unit.

  The estimated capital expenditure required to build the third gas treatment unit of approximately U.S.$500 million (U.S.$29.7 million of which had already been incurred as at 31 December 2013) is planned to be fully funded from operational cash flow between 2014 and 2016, and to also cover items such as renewing and expanding the oil treatment facility. Management believes that all other existing infrastructure owned and operated by the Group, such as pipelines and rail terminals, has sufficient capacity to accommodate at least a 100% increase from current production levels.

  Under the existing oil price environment, the current drilling plan foresees approximately 50 wells during the 2014 to 2018 period. Management estimates, based on the production profile of both proved and probable reserves reported in the 2013 Ryder Scott Report and assuming the successful completion of the second phase of the gas treatment facility by the middle of 2016, that annual production will more than double from the 2013 annual production by the end of 2016.

- *Actively Pursuing Reserve Growth*

  The 2013 Ryder Scott Report reported estimated gross proved reserves of 199.2 million boe as at 31 August 2013, an increase of 17.8% compared to 1 January 2012. Over the last four years, drilling has focused mainly on production wells in order to secure feedstock for the gas treatment facility. Now that such feedstock is in place, the focus will be on a renewed appraisal drilling programme in order to transfer more of the Group's possible and probable reserves into proved reserves.

The Group's ongoing appraisal programme will focus on the Chinarevskoye Field's probable reserves (284.1 million boe as at 31 August 2013) and possible reserves (76.2 million boe as at 31 August 2013), as well as the initial appraisal of the Rostoshinskoye, Darinskoye and Yuzhno-Gremyachenskoye development fields. Nostrum's long-term target is to increase the Group's proved reserves base to up to 700 million boe, by converting existing probable and possible reserves, adding reserves from the Rostoshinskoye, Darinskoye and Yuzhno-Gremyachenskoye development fields and potential further acquisitions.

Nostrum was granted an extension of its exploration permit within the Chinarevskoye Field following the execution of a tenth supplementary agreement to the PSA on 28 October 2013. The tenth supplementary agreement extended the exploration period, other than for the Tournaisian horizons, to 26 May 2014. In April 2014, Nostrum submitted an application to the relevant authorities for a further extension of such exploration period beyond 26 May 2014. Nostrum believes that its prospects for obtaining such an extension are good, however it does not currently expect to obtain such extension from the authorities until after the current exploration period expires. In addition, Nostrum currently estimates that it will cost approximately U.S.$85 million to conduct the necessary appraisal activities for the appraisal and development of the Rostoshinskoye, Darinskoye and Yuzhno-Gremyachenskoye development fields, which commenced in 2013, initially through 3D seismic acquisition.

- *Developing a Multi-Field Model*

The Group is also pursuing a strategy of growth through value-accretive acquisitions. This is in line with its desire to leverage existing infrastructure to add further reserves at low-finding costs. The recent acquisition of the Rostoshinskoye, Darinskoye and Yuzhno-Gremyachenskoye fields, all of which are located between 50 kilometres and 105 kilometres from the existing gas treatment facility, for total consideration of U.S.$17 million, represented the first such acquisition pursuant to this strategy. The acquisition of data on these three fields commenced in 2013 and appraisal is expected to conclude in 2015.

The Group evaluates opportunities for acquisitive growth on a continuous basis, with a focus on North-Western Kazakhstan where practicable but it will also consider opportunities in the surrounding regions. Nostrum will continue to look for further acquisitions which have the potential to further improve shareholder value.

- *Making Sustainable Development a Priority*

The Group's long presence in Kazakhstan has led to a natural, gradual and ambitious involvement in sustainable development. Over the years, it has built a comprehensive corporate social responsibility roadmap comprised of employee security and welfare, investment in community building and environmental protection and reporting. Each of these priorities is now taken up in the overall yearly management plan and monitored against specific voluntary as well as compliance objectives. As such, the Group continues to strive to improve and implement new policies each year in order to integrate further sustainability in all of its operations.

The Group sees corporate social responsibility as an important indicator of non-financial risk and is regularly developing internal best practices to improve its standards. This is an important standalone part of Nostrum's strategy while it is also complementary to all of the other strategic initiatives. Sustainable development will remain a priority in 2014 and onwards.

- *Focusing on Delivering Shareholder Value*

The Group's strategy is centred on a balanced approach to investment in growth. This entails both a prudent cash management policy and returns to shareholders.

Over the next few years, the Group expects to fully fund its capital expenditure programme from its operational cash flow, current external financing and existing cash on the balance sheet. The Group's ability to maintain cash flow generation is underpinned by production growth and economies of scale and an infrastructure upgrade and corresponding operating expenditure reduction. In addition, the Group intends on hedging all non-scalable capital expenditures against oil price fluctuations. Finally, the Group will aim to keep its net debt to EBITDA ratio below 1.5 and maintain appropriate cash balances in order to mitigate any volatility in the market price of crude oil and fund its dividend policy.

The Group's current dividend policy was adopted in 2012 and will continue to be pursued over the coming years, together with a buy-back programme as appropriate, providing it does not adversely impact the Group's cash balance or growth strategy in an environment of fluctuating oil prices.

History and Corporate Structure

Zhaikmunai LLP (the "**Licence Holder**") was registered on 20 March 1997 as a Kazakh limited liability partnership and obtained the Licence from JSC Condensate (which was granted the Licence in January 1996). The Licence Holder entered into the PSA in October 1997.

In September 2004, Thyler Holdings Limited (a company beneficially owned by Frank Monstrey, the chairman of the Company) indirectly acquired 100% of the participation interests in the Licence Holder. Zhaikmunai LP was formed in August 2007 as an Isle of Man limited partnership in connection with the admission of the GDRs to the Official List and to trading on the London Stock Exchange in 2008. In March 2008, the Group effected a reorganisation which resulted in the Partnership indirectly holding all of the participation interests in the Licence Holder, with NOGGL (owned by Thyler Holdings Limited) becoming the general partner of the Partnership (the "**General Partner**"). As a result, Zhaikmunai became the parent entity of the Group.

On 29 November 2013, the limited partners of Zhaikmunai LP duly approved a change in Zhaikmunai LP's name to "Nostrum Oil & Gas LP".

The holders of the Common Units are the limited partners of Nostrum Oil & Gas LP who hold, as at the date of this Prospectus, 188,182,958 Common Units, of which 188,182,948 are held by The Bank of New York Mellon in its capacity as depositary for the holders of the GDRs, but which has no beneficial interest in such Common Units. In October 2012, Thyler Holdings BV (another company beneficially owned by Frank Monstrey) acquired 100% of the General Partner.

On 20 May 2014, Nostrum Oil & Gas LP announced its intention to seek a premium listing of a public limited liability company newly incorporated in England and Wales, namely the Company, which is proposed to be the new holding company for the Group. The Company was incorporated as an English public limited company on 3 October 2013. The new corporate structure for the Group is to be implemented by way of the Scheme, pursuant to which the Company will acquire all (or substantially all) of the assets and liabilities of the Group from Nostrum Oil & Gas LP in consideration for the issue of the Ordinary Shares by the Company to the holders of Common Units (and hence to GDR holders). Following implementation of the Scheme, the Licence Holder will become indirectly wholly-owned by the Company. See Part 6 "*Information on the Scheme—Summary of the Scheme*".

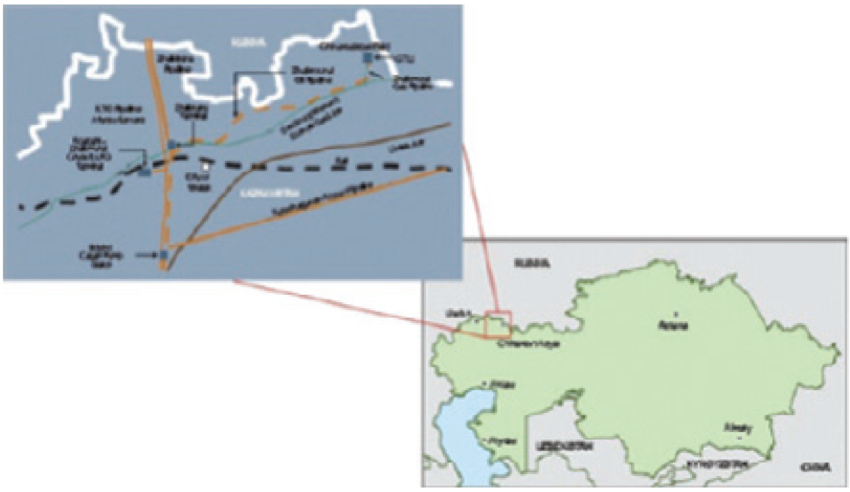
In connection with the Scheme and Admission, the Company will apply for a listing of the Ordinary Shares on the KASE. The Group is familiar with the listing requirements of the KASE, as the New 2019 Bonds and the 2019 Bonds issued by the Licence Holder are already listed on the KASE. On 29 March 2013, the KASE announced that the Licence Holder was presented with a special award for its transparency record and commitment to all of its stakeholders.

The Company's registered office is in 4th Floor, 53-54 Grosvenor Street, London, W1K 3HU, United Kingdom, and its principal offices are in Gustav Mahlerplein 23B, 1082 MS, Amsterdam, The Netherlands. The headquarters of the Licence Holder are located in Uralsk, Kazakhstan.

Operations

Nostrum's primary field and licence area is the Chinarevskoye Field. In August 2012, the Group decided to expand its operations and agreed to acquire subsoil use rights to three new oil and gas fields in Kazakhstan, Rostoshinskoye, Darinskoye and Yuzhno-Gremyachenskoye, located approximately 50 to 105 kilometres from the Chinarevskoye Field. The purchase of these fields was completed on 24 May 2013 for consideration of U.S.$17 million. The Group is currently in the process of analysing the optimal appraisal and development programme for the fields. See Part 2 "*Risk Factors—Risk Factors Relating to the Group's Business—The Group's activities are conducted within the Chinarevskoye Field and its sole source of revenue comes from this field*".

The following map sets forth the location of the Chinarevskoye Field:



Chinarevskoye Field

History of Operations

Oil and gas operations in the Chinarevskoye Field began during the Soviet era with the drilling of nine wells. Hydrocarbons were discovered in the Biski-Afoninski reservoirs in 1991. The discovery of the Tournaisian reservoir was made in 1992.

In May 1997, Nostrum was granted exploration and production licences with respect to the Chinarevskoye Field, which initially covered the entire Chinarevskoye Field. During October 1997, Nostrum entered into the PSA with the Kazakh Government which has been subsequently amended ten times. See "*—Subsoil Licences and Permits—The Licence and the PSA*". The PSA sets forth parameters for the exploration and development of the Chinarevskoye Field and the fees, profit sharing and tax liabilities payable to the Kazakh Government. To date, Nostrum has met all of its capital investment obligations under the PSA.

Three of the wells that were drilled prior to Kazakh independence were reactivated between 2000 and 2002. In 2003, Nostrum discovered the Givetian accumulation and in 2004 the Lower Permian reservoir was successfully tested. An oil treatment unit was completed in July 2006. In 2007, crude oil was discovered in the Bashkirian formation. In May 2008, commercial prospects were declared for the Mullinsky oil and gas condensate pool, the Ardatovski gas condensate pool, the Famenian oil and gas condensate pool and the Biski-Afoninski oil and gas condensate pool. New commercial discoveries were also made in the south and west regions of the Tournaisian reservoir.

In 2004, new senior management was appointed at Nostrum which instituted a strategy of increasing drilling and improving infrastructure, as well as focusing on improving the level of reserves. In the same year, Nostrum commissioned Ryder Scott to conduct an independent engineer's reserves assessment for the Licence area according to SPE-PRMS standards. According to management estimates based on data included in the Ryder Scott reserves report of 2004, Nostrum had approximately 28 million boe of proved reserves. Nostrum's primary exploration effort from 2004 to 2006 was dedicated to the Tournaisian horizon. As a result of increased drilling and improved geological data, management estimated that, as at 31 August 2013, based on the 2013 Ryder Scott Report, Nostrum had increased its gross proved reserves by 611.4% to 199.2 million boe and increased its probable reserves by 124.9% to 382.3 million boe (each as compared to 2004). Hydrocarbon production increased from an average of 2,400 boepd in 2004 to an average of 36,940 boepd in 2012 and an average of 46,178 boepd in 2013. According to the 2013 Ryder Scott Report, as at 31 August 2013, the estimated gross proved plus probable hydrocarbon reserves at the Chinarevskoye Field were 483.3 million boe.

Following successful test production from the Tournaisian reservoir during the exploration phase of the Licence, Nostrum commenced commercial crude oil production from the Tournaisian reservoir on 1 January 2007. Nostrum has obtained a production permit for the Mullinsky, Ardatovski, Famenian and Biski-Afoninski reservoirs. Nostrum expects to continue exploration activities in the North Biski-Afoninski, Lower Permian and North Tournaisian reservoirs and the Givetian accumulations until the expiry of the exploration period. Nostrum was granted an extension of its exploration permit within the Chinarevskoye Field following the execution of a tenth supplementary agreement to the PSA on 28 October 2013. The tenth supplementary agreement extended the exploration period, other than for the Tournaisian horizons, to 26 May 2014. In April 2014, Nostrum submitted an application to the relevant authorities for a further extension of such exploration period beyond 26 May 2014. Nostrum believes that its prospects for obtaining such an extension are good, however it does not currently expect to obtain such extension from the authorities until after the current exploration period expires.

In December 2008, Nostrum received an extension of its production licence. The new production licence is valid until 2033 for all horizons (other than the North-Eastern Tournaisian reservoir for which the production licence is valid until 2031) and oil or gas-condensate bearing reservoirs and covers 185 square kilometres of the Licence area. The production licence covers all proved and probable and a significant part of possible reserves reported by Ryder Scott.

In the past several years the Group has been investing significantly in the construction and development of the first phase of the gas treatment facility, which was in test production from May 2011 and came online into full production (and therefore resulting in IFRS recognition of revenue and cost of sales in the Group's income statement) in November 2011. Prior to the construction of the gas treatment facility the Group's revenue resulted solely from the sale of crude oil. Commencing in November 2011, the Group began selling condensate, dry gas and LPG in addition to crude oil. The Group is in the process of designing and planning the second phase of the gas treatment facility, which entails building a third gas treatment unit in the vicinity of the first two units of the gas treatment facility. Detailed engineering and procurement plans are on-going and the Group is in the process of obtaining the applicable permits and contracting with potential suppliers for the equipment, construction and assembly of the third gas treatment unit. All key permits and contracts were in place by the end of 2013, groundworks onsite in preparation for construction were completed in early 2014 and the third gas treatment unit is expected to become operational by mid-2016. As a result of the third gas treatment unit becoming operational the Group expects a significant increase in its operating capacity and production volumes. The additional operating capacity and higher production volumes have been incorporated in the Group's long-term strategy and operating plans. See Part 2 "*Risk Factors—Risk Factors Relating to the Group's Business—The Group's future hydrocarbon production profile is based principally on its gas treatment facility and to a lesser extent its oil treatment unit operating at full or near full capacity. If these facilities were not operating at full or near full capacity, the Group may not be able to meet its strategic production objectives.*"

Oil and Gas Reserves

The following table sets forth Nostrum's gross proved, probable and possible hydrocarbon reserves at the Chinarevskoye Field based on data included in the 2013 Ryder Scott Report:

	As at 31 August 2013
Gross Proved Reserves	
Crude oil and condensate (million bbl)	79.5
LPG (million boe)	29.5
Gas (million boe)[(1)]	90.2
Total (million boe)[(1)]	**199.2**
Gross Probable Reserves	
Crude oil and condensate (million bbl)	113.7
LPG (million boe)	42.9
Gas (million boe)[(1)]	127.5
Total (million boe)[(1)]	**284.1**
Gross Possible Reserves	
Crude oil and condensate (million bbl)	22.3
LPG (million boe)	12.3
Gas (million boe)[(1)]	41.6
Total (million boe)[(1)]	**76.2**

(1) Management has converted the dry gas reserves data from cubic feet to boepd of dry gas. See Part 5 "*Presentation of Information—Presentation of Financial and Other Information—Hydrocarbon Data—Presentation in this Prospectus*".

In accordance with SPE-PRMS reserves classifications, Ryder Scott assigned part of the volumes of crude oil that can be recovered from the accumulation through water-flooding in the Tournaisian reservoir to the category of probable reserves. See Part 2 "*Risk Factors—Risk Factors Relating to the Oil and Gas Industry—The level of the Group's reserves, their quality and production volumes may be lower than estimated or expected*". The added potential resulting from enhanced oil recovery has therefore only partly been used to estimate the amount of proved reserves.

Geological Information

The Chinarevskoye Field is a multi-formation structure. It has tested hydrocarbons at significant rates from (i) the Lower Permian horizons at depths of 2,700m to 2,900m, represented by limestone and dolomitic limestone; (ii) limestone of the Lower Carboniferous Tournaisian formation at a depth of approximately 4,200m with a gross thickness of about 200m; (iii) the middle Devonian Givetian horizons at a depth of approximately 5,000m, represented by sandstone with carbonate cement; and (iv) the middle Devonian Biski-Afoninski formations at a depth of approximately 5,000m with a gross thickness of 200m and represented by limestone and dolomitic limestone. Oil has been found in the Lower Permian, Tournaisian and Givetian Mulinski reservoirs, while gas condensate has been found in the Tournaisian, Biski-Afoninski, Givetian, Ardatovski, Famenian and Vorobyovski reservoirs.

Appraisal and Exploration

In addition to the estimated reserves calculated by Ryder Scott, management believes that there is additional exploration potential in the Licence area due to Nostrum's successful drilling record in the Chinarevskoye Field. The Group is continuing to explore parts of the Chinarevskoye Field under the terms of the Licence and the PSA. Using information obtained from 3-D seismic surveys and geological analysis, management (and consultants) review all available data and undertake individual drilling programmes.

Studies prepared by the research institute PM Lucas in 2007-2013 confirmed the possibility of significant improvement of oil recovery through water-flooding in the North-Eastern part of the Tournaisian reservoir. The Group began water injection testing at the end of 2008 and implemented the use of water-injection for improved oil recovery in 2009.

According to the 2013 Ryder Scott Report, water injection is solely required for the recovery of the probable reserves. The 2013 Ryder Scott Report analysed reservoir simulations prepared by independent third parties to understand the effect of the water injection on ultimate recovery of oil from the reservoirs. See Part 2 "*Risk Factors—Risk Factors Relating to the Group's Business—The Group requires significant water supplies in order to conduct its business and failure to obtain such water may adversely affect its business*" and Part 2 "*Risk Factors—Risk Factors Relating to the Oil and Gas Industry—The level of the Group's reserves, their quality and production volumes may be lower than estimated or expected*".

The Group has mapped several additional prospects in the Licence area, including the Biski-Afoninski (gas condensate), Tournaisian (oil and gas condensate), Lower Permian (oil) and South Tournaisian (gas condensate) reservoirs. In addition to the reported reserves as at 31 August 2013, Ryder Scott has estimated the remaining resources identified, but not yet drilled in the Chinarevskoye Field. The 2013 Ryder Scott Report estimates that the overall exploration potential of such resources through a summation of best estimates is approximately 84.3 million boe of prospective resources.

PROSPECTIVE RESOURCES ARE THOSE DEPOSITS THAT ARE ESTIMATED, ON A GIVEN DATE, TO BE POTENTIALLY RECOVERABLE FROM UNDISCOVERED ACCUMULATIONS. FREQUENTLY, THIS MAY BE IN AREAS WHERE GEOSCIENCE AND ENGINEERING DATA ARE UNABLE TO CLEARLY DEFINE THE AREA AND VERTICAL RESERVOIR LIMITS OF COMMERCIAL PRODUCTION FROM THE RESERVOIR BY A DEFINED PROJECT. SEE PART 2 "*RISK FACTORS—RISK FACTORS RELATING TO THE OIL AND GAS INDUSTRY—CONTINGENT AND PROSPECTIVE RESOURCES ARE UNLIKELY TO BE COMMERCIALLY PRODUCTIVE IN THE SHORT OR MEDIUM TERM.*"

A significant portion of the Group's reserves are classified as possible reserves, and a drilling schedule has been prepared to further appraise these accumulations. These gross possible reserves were estimated by Ryder Scott to be up to 76.2 million boe as at 31 August 2013. The Directors believe that a portion of these possible reserves, could be transferred into higher reserves categories as a result of the scheduled appraisal activities, which are planned to be performed simultaneously with the development of the existing proved and probable reserves.

Rostoshinskoye, Darinskoye and Yuzhno-Gremyachenskoye Fields

Oil and Gas Reserves

The following table sets forth Nostrum's net proved, probable and possible hydrocarbon reserves at the Rostoshinskoye, Darinskoye and Yuzhno-Gremyachenskoye fields based on data included in the 2013 Ryder Scott Report:

	As at 31 August 2013
Net Proved Reserves	
Crude oil and condensate (million bbl)	—
LPG (million boe)	—
Gas (million boe)(1)	—
Total (million boe)(1)	**—**
Net Probable Reserves	
Crude oil and condensate (million bbl)	3.8
LPG (million boe)	0.6
Gas (million boe)(1)	93.7
Total (million boe)(1)	**98.2**
Net Possible Reserves	
Crude oil and condensate (million bbl)	12.7
LPG (million boe)	0.4
Gas (million boe)(1)	20.5
Total (million boe)	**33.6**

(1) Management has converted the dry gas reserves data from cubic feet to boepd of dry gas. See Part 5 "*Presentation of Information—Presentation of Financial and Other Information—Hydrocarbon Data—Presentation in this Prospectus*".

Geological Information

The Rostoshinskoye, Darinskoye and Yuzhno-Gremyachenskoye fields are approximately 139 square kilometres in size and are located in the Pre-Caspian basin to the North-West of Uralsk, approximately 50 to 105 kilometres from the Chinarevskoye Field.

Appraisal and Exploration

Nostrum has estimated that it will cost approximately U.S.$85 million to conduct the necessary appraisal activities for the development of these fields, which commenced in 2013, initially through 3D seismic acquisition.

Production and Facilities

Oil, Gas, LPG and Condensate Production

During 2013, Nostrum produced a total of 16.9 million boe, with an average of 46,178 boepd, an increase of 25.0% compared to 2012, during which Nostrum produced a total of 13.5 million boe, with an average daily output of 36,940 boepd, and to 2011, during which Nostrum produced a total of 4.8 million boe, with an average of 13,158 boepd.

The crude oil extracted from the Chinarevskoye Field has an average API gravity of 42-43° and sulphur content of approximately 0.4%. Primary benchmark crude oils produced in Kazakhstan include CPC Blend (approximately 44.2° API with 0.53% sulphur), Kumkol (approximately 41.2° API with 0.4% sulphur) and Tengiz (approximately 47.2° API with 0.55% sulphur). The quality of the crude oil extracted allows Nostrum to sell its crude oil at a smaller discount to Brent crude than other oil producers in the region.

The stabilised condensate produced out of the gas-condensate feeds has an average API gravity of 56° with a sulphur content of less than 0.2%.

The Chinarevskoye Field contains significant gas reserves. The Group monetises these gas reserves using the gas treatment facility and by implementing a gas utilisation concept prepared by NIPI Neftegaz Institute. For more information regarding the gas treatment facility, see "*—Production and Facilities—Gas Treatment Facility*".

Gas processed by the Group's treatment units is used to produce dry gas, LPG and condensate for sale in addition to providing feed stock for power generation to cover Nostrum's power requirements.

Nostrum operates a reservoir pressure maintenance system currently consisting, *inter alia,* of seven water production wells, three water injection wells, central pumping facilities, central water treatment facilities and infield waterlines to the water well sites.

Crude Oil Facilities

Nostrum's facilities consist of an oil treatment unit capable of processing 400,000 tonnes per year of crude oil, as well as multiple oil gathering and transportation lines within the Licence area. Nostrum's storage facilities currently allow storage of 5,000 cubic metres of oil and 15,000 cubic metres of condensate on-site and 10,000 cubic metres of oil and 10,000 cubic metres of condensate at the rail terminal (equivalent in total to approximately 15 days' production of crude oil and 12 days' production of condensate). The Group plans to construct an additional oil treatment unit with a capacity of up to 400,000 tonnes per year in conjunction with the third unit of the gas treatment facility. In addition, in 2009, Nostrum completed its 120 kilometre oil pipeline through which it pumps crude oil and condensate from the field site to the railway-loading terminal in Rostoshi near Uralsk.

Drilling Facilities

The Group contracts with third parties who perform drilling operations in the Chinarevskoye Field. As at 31 December 2013, Saipem, UNGG and Xi-Bu provided drilling services to the Group and five drilling rigs were being operated by these contractors. In addition, two rigs from Kazburgaz and UNGG were employed for workover operations. The average time required to drill new deviated wells is approximately four months in the Tournaisian reservoir and five months in the Devonian, Biski-Afoninski reservoirs. Based on historical contracts, the Group has budgeted a cost per well of between approximately U.S.$10 million for oil wells and U.S.$14 million for gas condensate wells. In 2014, the Group intends to drill 11 new wells (five new exploration/appraisal wells and six new production/water injection wells) in order to maintain production above the 45,000 boepd target. See "*—Procurement Contracts material to Nostrum's Business—Drilling Contracts*".

Gas Treatment Facility

The first phase of the gas treatment facility involved the construction of two gas treatment units and cost approximately U.S.$270 million. Each of the gas treatment units has the capacity to treat approximately 850 million cubic metres of raw gas (a combination of associated gas and gas condensate). Both units are equipped with sweetening and sulphur recovery units to improve the quality of the gas. The gas treatment facility also includes a gas-fired power plant with a design capacity of 15 megawatts that provides the field site with all required electricity. The power plant has been constructed as part of the first phase of the gas treatment facility. Handover of the gas treatment facility took place in December 2011.

Nostrum is proposing to construct an additional gas treatment unit (phase two of the gas treatment facility) with a capacity to treat 2.5 billion cubic metres of gas per year. Assuming completion of the second phase of the gas treatment facility, the Group would have capacity to treat up to 4.2 billion cubic metres of raw gas per year. Management currently estimates that the total cost of this project will not exceed U.S.$500 million (U.S.$29.7 million of which had already been incurred as at 31 December 2013). Groundworks onsite in preparation for construction were completed in early 2014 and the third gas treatment unit is expected to become operational in mid-2016. Ryder Scott estimates that Nostrum's annual raw gas production will peak at 4.2 billion cubic metres per year in 2017. See Part 2 "*Risk Factors—Risk Factors Relating to the Group's Business—The Group's future hydrocarbon production profile is based principally on its gas treatment facility and to a lesser extent its oil treatment unit operating at full or near full capacity. If these facilities were not operating at full or near full capacity, the Group may not be able to meet its strategic production objectives.*"

The Group's future hydrocarbon production profile is based on the gas treatment facility operating at full or near-full capacity. If the gas treatment facility is not operating at full or near-full capacity, this may result in a reduction or suspension of the Group's production of hydrocarbons.

Oil Pipeline and Railway-Loading Terminal

The Group's pipeline and loading terminal has been fully operational since January 2009. The pipeline links the Chinarevskoye Field directly to the Group's railway loading terminal at a rail connection located at Rostoshi, near Uralsk. The oil pipeline has a maximum annual throughput capacity of 3 million tonnes (equivalent to approximately 65,000 boepd). The railway-loading terminal receives all crude oil and condensate produced by Nostrum and has a capacity of 3 to 4 million tonnes of crude oil and gas condensate per year (equivalent to approximately 65,000-87,000 boepd). Management estimates that the oil pipeline has reduced the cost of transporting crude oil and condensate from the Chinarevskoye Field to the Rostoshi rail terminal by approximately U.S.$25 per tonne (U.S.$3.1 per barrel). The construction of the pipeline and the loading terminal facilitates the Group's distribution of its crude oil and condensate internationally, where it can achieve higher prices than can be obtained within Kazakhstan.

Gas Pipeline

Nostrum's 17 kilometre gas pipeline linking it to the Orenburg-Novopskov gas pipeline has been constructed and was commissioned in February 2011, with the first sales gas being transported in May 2011. Maximum annual throughput of this gas pipeline is approximately 5.0 billion cubic metres.

Subsoil Licences and Permits

Zhaikmunai LLP, is the owner and operator of four fields in Kazakhstan, the Chinarevskoye Field and the Rostoshinskoye, Darinskoye and Yuzhno-Gremyachenskoye development fields.

Rostoshinskoye, Darinskoye and Yuzhno-Gremyachenskoye fields

On 24 May 2013, the Group notified the Competent Authority of the completion of the acquisition for U.S.$17 million of three oil and gas development fields, Rostoshinskoye, Darinskoye and Yuzhno-Gremyachenskoye. Whilst the Group has completed the acquisition of subsurface use contracts in these three oil and gas fields and commenced the acquisition of data on these fields in 2013 (with appraisal expected to conclude in 2015), the development of those fields has not yet commenced (and the Group will not know when development will start until the appraisal process has been completed).

The contracts for exploration and production of hydrocarbons from Rostoshinskoye, Darinskoye and Yuzhno-Gremyachenskoye fields require fulfilment of several social and other obligations. In particular, during the exploration period, subsurface users have the following obligations:

- Rostoshinskoye field: (i) to pay local authorities U.S.$600,000 for various social programmes and for ROK WK infrastructure development programmes; and (ii) invest at least U.S.$20.8 million for exploration of the field.
- Darinskoye field: (i) to pay local authorities U.S.$225,000 for various social programmes and for ROK WK infrastructure development programmes; and (ii) invest at least U.S.$20.4 million for exploration of the field.
- Yuzhno-Gremyachenskoye field: (i) to pay local authorities U.S.$225,000 for various social programmes and for ROK WK infrastructure development programmes; and (ii) invest at least U.S.$33.6 million for exploration of the field.

The prior operators of the Rostoshinskoye, Darinskoye and Yuzhno-Gremyachenskoye fields were not in compliance with certain of their obligations under the subsoil use contracts covering such fields. However, the Group has been able to amend such obligations (see Part 12 "*Operating and Financial Review—Current Trading and Recent Developments*"). For the year ended 31 December 2013, the Group had U.S.$5.3 million in capitalised contingent consideration under the Darinskoye and Yuzhno Gremyachenskoye acquisition agreements. The remaining deferred consideration (KZT 312.2 million for Darinskoye field and KZT 487.4 million for Yuzhno-Gremyachenskoye field) was paid to the sellers during the first quarter of 2014.

Chinarevskoye Field

Nostrum's authorisation to conduct operations in the Chinarevskoye Field was granted pursuant to the Licence issued by the Kazakh Government on 26 May 1997 which is part of an associated PSA entered into with the Competent Authority (on behalf of Kazakhstan) on 31 October 1997. The Licence and the PSA were granted under Kazakhstan's pre-1999 "licence and contract" regime described in Part 8 "*Industry and Regulatory*

Overview—Regulation in Kazakhstan". Under the PSA, Nostrum is able to undertake both exploration and production activities, subject to obtaining relevant permits. A dual-track system is available to obtain a production permit. See "*—Development Plan*".

The Licence is separated into two phases consisting of an exploration phase and a production phase. The exploration phase consists of two periods. The first exploration period lasted four years, from October 1997 to October 2001; the second exploration period, which commenced on 26 May 2001 was initially agreed to run for three years, but has since been extended four times to May 2011. The Group was granted an extension of its exploration permit within the Chinarevskoye Field following the execution of the tenth supplementary agreement to the PSA on 28 October 2013. The tenth supplementary agreement extended the exploration period, other than for the Tournaisian horizons, to 26 May 2014. In April 2014, Nostrum submitted an application to the relevant authorities for a further extension of such exploration period beyond 26 May 2014. Nostrum believes that its prospects for obtaining such an extension are good, however it does not currently expect to obtain such extension from the authorities until after the current exploration period expires.

Further to Nostrum's exploration activities in the North-Eastern Tournaisian reservoir, approval to commence commercial production in this area was initially granted by the award of a production permit for the North-Eastern Tournaisian reservoir in March 2007. When Nostrum subsequently made six new commercial discoveries (in the West Tournaisian (oil), South Tournaisian (oil and gas condensate), Biski-Afoninski (gas condensate), Givetian Ardatovski (gas condensate), Givetian Mulinski (oil and gas condensate) and Famenian (gas condensate) reservoirs) during 2007 and 2008, it entered into discussions with the Competent Authority to extend the exploration permit to appraise these discoveries. In 2008, Nostrum received a new exploration permit valid until 26 May 2011 to appraise all newly made discoveries. Once Nostrum believed that all new discoveries were sufficiently appraised in order to start production, it applied for approval of the reserves for the entire licence area (as required by the terms of the PSA) and once the approval of Nostrum's reserve estimation by the State Committee of Reserves was received in December 2008, Nostrum was issued with an extended production permit, which expires in 2033, and which now covers 185 square kilometres (including the area under the previous production permit as well as the six new commercial discoveries made by Nostrum).

In addition, Nostrum was required to submit separate development plans ("**Development Plans**") to the State Committee for Field Development ("**SCFD**") for oil and gas condensate deposits in accordance with the production permit. Both such Development Plans were approved by the SCFD in March 2009.

Nostrum's initial Development Plan for the North-Eastern Tournaisian reservoir, which was approved on 17 November 2006, has now been incorporated into the new Development Plan for oil deposits as an integral part thereof. In addition to the ongoing commercial production of oil, Nostrum's current production permit allows it to engage in the commercial production of its gas reservoirs.

Nostrum holds one gas flaring permit to flare associated gas. Nostrum flares associated gas during the periods when its gas treatment facility is shut for annual maintenance. The Directors believe that the current permit, which expires at the end of 2014 but which the Directors expect to renew for future years, is sufficient for its expected future needs. See Part 2 "*Risk Factors—Risk Factors Relating to the Group's Business—The Group's future hydrocarbon production profile is based principally on its gas treatment facility and to a lesser extent its oil treatment unit operating at full or near full capacity. If these facilities were not operating at full or near full capacity, the Group may not be able to meet its strategic production objectives.*"

In August 2012, Nostrum signed agreements to acquire 100% of the subsoil use rights related to three new oil and gas fields in Kazakhstan. The acquisition of these three fields, for consideration of U.S.$17 million, was completed on 24 May 2013. These three oil and gas fields are outside the PSA and therefore will be subject to a different set of procurement and taxation obligations than Nostrum's activities in the Licence area. Nostrum has estimated that it will cost approximately U.S.$85 million to conduct the necessary exploration activities (data acquisition for which has already commenced and which will include a seismic data analysis and the drilling of appraisal wells) for the development of the fields over the next three years. Following completion thereof, a development plan is expected to be submitted to the Competent Authority for approval. Such approval would allow Nostrum to commence the drilling of production wells. The fields, Rostoshinskoye, Darinskoye and Yuzhno-Gremyachenskoye, are located in the Pre-Caspian basin to the North-West of Uralsk, approximately 50 to 105 kilometres from the Chinarevskoye Field. The size of the three licence areas combined is 139 square kilometres.

The Licence and the PSA

The Licence and the PSA are currently valid until 2031 (with respect to the North-Eastern Tournaisian reservoir) and 2033 (with respect to the rest of the Chinarevskoye Field). To date, the Directors believe that Nostrum has met all of its obligations, including capital investment obligations, under the PSA.

The duration of the production phase, which began in 2007 in respect of the North East Tournaisian reservoir and 2008 in respect of the other Chinarevskoye reservoirs, for all reservoirs is 25 years. Nostrum must comply with the terms of the production permit and the Development Plans during this period. The Directors believe that Nostrum has fulfilled all those contractual obligations.

Although the Directors believe that Nostrum has to date met all of its obligations under the PSA, please see Part 2 "*Risk Factors—Risk Factors Relating to the Oil and Gas Industry—The Group may be unable to comply with its obligations under the PSA and the Licence*".

Amendments to the PSA

As at the date of this Prospectus, the PSA includes ten amendments. The first amendment, implemented in 2000, restated certain environmental commitments and amended the provision in the PSA regarding the share of and royalty payments to the State, in addition to specifying the manner in which Nostrum was to reimburse the State for any costs it incurred in establishing the field and the manner in which it was to contribute to an abandonment fund when it ceased its operations. The second amendment, dated 24 October 2001, extended the first exploration period for a further two years to four years and set out the requirements during the exploration phase. The third amendment, dated 29 June 2002, amended the provisions relating to tax and royalty payments. This amendment also provided that 15% of the Licence area was to be relinquished back to the State following the first phase of the exploration period (previously the PSA provided that Nostrum was to relinquish 25% of the Licence area). The fourth amendment, dated 12 January 2004, extended the exploration phase to 26 May 2006 with the term of the PSA set to expire on 26 May 2031.

The fifth amendment extended the exploration period by one year until 26 May 2008.

On 5 June 2008 a sixth amendment was made to the PSA, this time determining the Licence area and clarifying the payment and certain other obligations of Nostrum to the State. In addition, it established the production period on the North East Tournaisian reservoir as commencing on 1 January 2007.

Prior to the expiry of the exploration phase on 26 May 2008 (as per the provisions of the fifth amendment of the PSA), Nostrum declared six new commercial discoveries, pursuant to which it applied to the Competent Authority for a further extension of the exploration period to evaluate these commercial discoveries in accordance with its proposed work programme for further appraisal. As a result, the Competent Authority, pursuant to the seventh amendment to the PSA dated 17 November 2008, agreed to extend the exploration period until 26 May 2011 to allow Nostrum to fully appraise the newly declared discoveries.

The seventh amendment also clarified the Licence area determined the requirements of Nostrum under the extended exploration period, which included the drilling of 12 exploration wells and amended the clauses of the PSA pursuant to which Nostrum agreed to engage Kazakhstan goods and companies and give preference to Kazakhstan personnel. The Directors believe that Nostrum has fulfilled all of those contractual obligations. In addition, in the seventh amendment, Nostrum agreed to deliver at least 15% of its crude oil production to domestic buyers in Kazakhstan at domestic market prices, which are lower than those Nostrum can achieve in the export market.

The eighth amendment to the PSA dated 27 April 2010 formally incorporates the terms of the current production permit and the exploration permit as part of the PSA.

The ninth amendment to the PSA dated 12 August 2011 clarified Nostrum's obligations under the PSA related to social funds payments and expenses for the training of Kazakhstan personnel. Among other terms and conditions of the ninth amendment to the PSA, Nostrum received an increase in its Cost Oil recoverable social obligations under the PSA due to increased costs in relation to the relocation of the Rozhkovo village population in 2009 and the repair and reconstruction of the local state roads infrastructure.

The tenth amendment to the PSA dated 28 October 2013 contained, among other items, the extension of Nostrum's exploration period, other than for the Tournaisian horizons, to 26 May 2014. In April 2014, Nostrum submitted an application to the relevant authorities for a further extension of such exploration period beyond 26 May 2014. Nostrum believes that its prospects for obtaining such an extension are good, however it does not currently expect to obtain such extension from the authorities until after the current exploration period expires. The Directors believe that this will provide sufficient time for the Group to carry out its planned exploration programme before submitting the results to the State.

Exploration Permit

Nostrum was granted an extension of its exploration permit within the Chinarevskoye Field following the execution of the tenth supplementary agreement to the PSA on 28 October 2013. The tenth supplementary agreement extended the exploration period, other than for the Tournaisian horizons, to 26 May 2014. In April 2014, Nostrum submitted an application to the relevant authorities for a further extension of such exploration period beyond 26 May 2014. Nostrum believes that its prospects for obtaining such an extension are good, however it does not currently expect to obtain such extension from the authorities until after the current exploration period expires. Thereafter, Nostrum may relinquish the area covered by the exploration permit and/or request a production permit in respect of any new commercially viable reserves that are declared.

Development Plan

Following the appraisal and/or discovery of reserves, under the PSA Nostrum was required to submit a development plan for the particular reserves discovered to the SCFD. Following the appraisal and exploration of additional oil and gas condensate reserves at the end of May 2008, Nostrum received approval for the two Development Plans from the SCFD in March 2009, one regarding oil deposits (which relate to the Tournaisian and Mulinski reservoirs) and the other regarding gas condensate deposits (which relate to the Biski-Afoninski and Ardatovski reservoirs).

The Development Plan related to oil deposits required (i) the drilling of nine additional production and water injection wells and (ii) the start of water injection in 2009 to support reservoir pressure and to achieve final oil recovery of at least 32.2% from the Tournaisian reservoir. The Development Plan related to gas condensate deposits allowed Nostrum to begin commercial production of such deposits upon (i) the construction and commissioning of the gas treatment facility and (ii) the construction and commissioning of a 17 kilometre gas pipeline. All of these conditions have now been satisfied.

The following summarises the other principal terms of the PSA:

Royalty Payments

The rate of monthly royalty payments to be made by Nostrum to the State depends on the volume of hydrocarbons extracted, calculated according to the realised value for each class of hydrocarbon sales at its final destination less the cost of transportation to its final destination and any discounts incurred due to the quality of hydrocarbons produced, as compared to a benchmarked quality. See Part 2 "*Risk Factors—Risk Factors Relating to the Group's Business—The proportion of crude oil and gas production that must be shared with the State, as well as the Group's royalty payments to the State, may increase*".

	Royalty rate
Annual crude oil production levels (tonnes)	
From 0 to 100,000	3%
From 100,000 to 300,000	4%
From 300,000 to 600,000	5%
From 600,000 to 1,000,000	6%
Over 1,000,000	7%

	Royalty rate
Annual gas production levels (1,000m³)	
From 0 to 1,000,000	4%
From 1,000,000 to 2,000,000	4.5%
From 2,000,000 to 3,000,000	5%
From 3,000,000 to 4,000,000	6%
From 4,000,000 to 6,000,000	7%
Over 6,000,000	9%

State Share

Pursuant to the PSA, in addition to the royalty payments, the State receives a monthly share of Nostrum's hydrocarbon production. The share that the State receives is calculated, first, by notionally separating production into "**Cost Oil**" and "**Profit Oil**". Cost Oil denotes an amount of hydrocarbons produced in respect of which the market value is equal to Nostrum's monthly expenses that may be deducted pursuant to the PSA. Deductible expenses for the purposes of Cost Oil include all operating costs and the development and exploration costs of completed infrastructure and wells up to an annual maximum of 90% of the annual gross realised value of hydrocarbon production. Any unused expenses may be carried forward indefinitely in the calculation of Cost Oil. Profit Oil, being the difference between Cost Oil and the total amount of hydrocarbons produced each month, is shared between the State and Nostrum. Consequently, increases in Nostrum's monthly expenditures result in lower amounts of Profit Oil being transferred to the State (due to the higher notional value of Cost Oil).

The State's share of Profit Oil must be physically delivered to the State or, alternatively, the State can elect to receive an amount equal to the value of the Profit Oil on a monthly basis. To date, the State has always elected to receive a monetary payment. Any such amounts delivered or paid are based on actual monthly production volumes. The share to be allocated to the State is calculated based on annual levels of production of crude oil and gas as set out below.

	State's share
Annual Crude Oil Production levels (tonnes)	
From 0 to 2,000,000	10%
From 2,000,000 to 2,500,000	20%
From 2,500,000 to 3,000,000	30%
Over 3,000,000	40%

	State's share
Annual Gas Production levels (1,000m^3)	
From 0 to 2,000,000	10%
From 2,000,000 to 2,500,000	20%
From 2,500,000 to 3,000,000	30%
Over 3,000,000	40%

The State share of Profit Oil was 10% in 2011, 2012 and 2013.

If Nostrum pays cash in lieu of delivery of the State's share of Profit Oil, the price (in U.S. Dollars) is determined to be that which Nostrum actually received on the same date for a similar volume of hydrocarbons at connection to a trunk pipeline, on the basis of an arm's length transaction, less transportation costs from the trunk pipeline.

Upon expiration of the Licence and the PSA (which will occur between 2031-2033 depending on the geographical and geological area in question), Nostrum is obliged to transfer to the State all assets acquired, built or installed as per the work programme and the approved budget.

Delivery of crude oil

Pursuant to the PSA, the State has the priority right to purchase up to 50% of hydrocarbons produced by Nostrum calculated after the share of production with the State at prices not exceeding world market prices, as determined by the Kazakh Government. In addition, the State has the right under the PSA to request Nostrum to deliver the State's distributed oil and gas in-kind to destinations specified by the State. Also, the State has the right to requisition part or all of the hydrocarbons owned by Nostrum under the PSA in the event of war, natural disasters or other emergency situations. Moreover, the Kazakh Government can require oil producers in Kazakhstan to supply a portion of their crude oil production to domestic refineries to meet domestic energy requirements.

Pursuant to the seventh amendment of the PSA, Nostrum agreed to deliver not less than 15% of its monthly crude oil production to the domestic market. The seventh amendment of the PSA does not specify the price at which any such crude oil should be supplied.

Tax—General

Corporate Income Tax

In accordance with Kazakhstan's tax regulations, Nostrum makes monthly payments of corporate income tax at a fixed rate of 20% of Nostrum's taxable income from contract activity for each year of commercial production during the term of the PSA. Any taxable income from non-contract activity (such as income from hedging) is taxable at the corporate income tax rate applicable for the year the income is realised.

Discovery Payments

Under the PSA, Nostrum must declare each new discovery of a crude oil horizon that leads to commercial production and pay U.S.$500,000 to the State in respect of each of such discoveries. In 2008, Nostrum paid U.S.$3.0 million to the State in respect of six commercial discoveries which were declared in May 2008. There were no discovery payments due to the State in 2011 or 2012. For the commercial discovery declared for the Bashkirian horizon in October 2012 a commercial discovery bonus of U.S.$500,000 was paid in 2013.

Recovery Bonus

Nostrum must pay to the State a U.S.$1 million recovery bonus for each 10 million metric tonnes of cumulative recovery of crude oil and natural gas. Nostrum expects to pay the recovery bonus for the first time in 2016.

Reimbursement of Historic Expenses

Nostrum is required to reimburse the State for a total of U.S.$25.0 million for historic costs (its costs for appraisal activities undertaken prior to the grant of the Licence) in equal quarterly instalments during the production phase of the PSA starting from the production phase. Nostrum began making such payments on 1 January 2008. Nostrum repaid historic expenses in the amount of U.S.$1.0 million in 2011, U.S.$1.0 million in 2012 and U.S.$1.0 million in 2013.

Social Expenditures

Further, pursuant to the ninth amendment to the PSA, the Group is obliged to perform repair and reconstruction of state roads (including the construction of a 37 kilometre asphalt road accessing the field site), make an accrual of 1% of capital expenditures per annum for the purpose of educating Kazakhstan citizens and adhere to a spending schedule on education (which lasts to and including 2020).

Liquidation Fund

The PSA requires Nostrum to establish a liquidation fund in the amount of U.S.$12.0 million by making annual contributions to the fund of U.S.$100,000 per year during the exploration phase and U.S.$452,000 per year during the production phase. The liquidation fund will provide funds for the removal of Nostrum's property and equipment at the end of the PSA's term. Management sets aside the amounts required for the liquidation fund and believes that such provisions satisfy its obligations to make annual contributions to the fund.

In addition, Nostrum makes accruals for the abandonment of facilities. The amount of the obligation is the present value of the estimated expenditures expected to be required to settle the obligation adjusted for expected inflation and discounted using average long-term interest rates for emerging market debt adjusted for risks specific to the Kazakhstan market.

Procurement Contracts material to Nostrum's Business

Drilling Contracts

As at 31 December 2013, Nostrum had four major contracts for drilling services: two with Saipem, one with UNGG and one (supplying two drilling rigs) with Xi-Bu. The contracts provide for the relevant contractor to drill wells within the Licence area until a set number of wells have been drilled. The contracts can be renewed by the mutual agreement of the parties and the Directors expect that they will be able to renew these contracts on similar terms or find alternative providers of drilling rigs as required. The Directors believe that the terms of these contracts are sufficient for the Group's drilling programme. There are also two minor contracts with Kazburgaz and UNGG for well workover operations.

Third Gas Treatment Unit

Nostrum has appointed Ferrostaal Industrieanlagen GmbH and Rheinmetall International Engineering GmbH (a 50% subsidiary of Ferrostaal GmbH) as the project manager in charge of managing the engineering, procurement, construction and commissioning of the entire third gas treatment unit project on behalf of Nostrum's subsidiary Zhaikmunai LLP. The front end engineering design study, prepared by Lexington Group International (USA), has been the basis from which Ferrostaal Industrieanlagen GmbH's engineering team has developed the project starting in late 2012. As of the date of this Prospectus, Nostrum is in the final stages of procurement and in the initial stages of detailed engineering works. Nostrum has also agreed supply terms with its three suppliers for the supply of equipment totalling approximately U.S.$75 million and anticipates in the coming weeks that procurement terms will be agreed with suppliers for an additional U.S.$60 million of equipment. Based on the current timetable for the construction, Nostrum expects that the third gas treatment unit will be completed and commissioned by the middle of 2016. Management currently estimates that the total cost of this project will not exceed U.S.$500 million.

Transportation

Transportation of Crude Oil and Condensate

Transportation routes for the export of hydrocarbons by Nostrum and other oil and gas producers in Kazakhstan are important because of the country's land-locked position. In particular, Kazakhstan depends heavily on Russia's transportation infrastructure for export routes. Crude oil is exported from Kazakhstan through pipelines and railways across the Caspian Sea and through Russia to the Black Sea ports or by pipeline to China.

The principal transportation options for the export of the Group's crude oil and condensate are rail car and pipeline. Crude oil and condensate are pumped through the Group's 120 kilometre oil pipeline, completed in January 2009, from the Chinarevskoye Field to the nearby city of Rostoshi near Uralsk, where it is loaded at the Group's oil loading terminal onto rail cars. By transporting its production by rail, Nostrum does not encounter any dilution of the quality of its crude oil or condensate and is therefore able to obtain a higher price for its production in the export market. Also, as a result of the completion of the its oil pipeline, transportation of the Group's crude oil has become safer, less costly and more efficient.

In 2010, the Group entered into several agreements for the lease of 650 railway tank wagons for transportation of hydrocarbon products for a period of up to seven years for KZT 6,989 per day per one wagon. The lease agreements may be early terminated either upon mutual agreement of the parties or unilaterally by one of the parties in certain circumstances.

Due to the fact that the Group has been delivering larger cargoes than in 2012, the receivables balance during 2013 increased as compared to 2012. The Group continues to utilise its ability to achieve the best possible netback by selecting the transportation route and cargo size that delivers the highest possible return.

Alternatively, there is one pipeline operated by a third party—the KazTransOil pipeline—to which the Group's oil pipeline could be connected. However, there is currently no quality bank adjustment mechanism for exports carried by this trunk pipeline. In the absence of appropriate agreement as to the quality of the Group's crude oil, Nostrum could therefore receive a lower price for its production than the quality of its oil would otherwise demand. The Group does not currently use this pipeline to transport its crude oil and condensate.

Transportation of Dry Gas and LPG

The Group's gas production is transported by its 17 kilometre gas pipeline (commissioned in February 2011) linking the Chinarevskoye Field to the Orenburg-Novopskov gas pipeline. The gas pipeline has a maximum annual throughput of 5.0 billion cubic metres. As the gas is sold at the point of entry to the pipeline, the Group is not liable for any additional transportation tariffs.

In addition, the Group has engaged third-party contractors to transport its LPG products by truck to railway-loading terminals operated by third parties near Uralsk. LPG is then delivered by rail car to its ultimate purchaser.

Sales and Marketing

Crude Oil and Condensate

Pursuant to the PSA, Nostrum has agreed to deliver 15% of its crude oil production in the domestic market and sell the remaining crude oil to the export market.

Until 2010, the Group delivered most of its exported crude oil on the basis of FCA (free carrier) Uralsk, the price being based on the market price for Brent crude oil less a discount for rail fees, transportation costs, quality differentials and trader's fees incurred in order to deliver the crude oil from Uralsk to its ultimate destination at refineries in Finland and the Ukraine. Since 2011, the Group has sold its crude oil and condensates based on DAP (delivery at place) and FOB (free on board) terms. The benefit of selling on DAP and FOB terms is that the sales discount is significantly reduced, although this benefit is partially offset by an increase in transportation costs for the Group as it must pay for transportation costs from the terminal to the point of sale. The Group plans to continue selling on a DAP and FOB basis as management believes the Group will benefit from a net decrease in overall transportation costs.

Until 2010, the Group entered into crude oil contracts with one or more traders. The traders then contracted with the ultimate purchasers for the provision of the Group's crude oil products. The Group did not enter into contracts for crude oil products with its ultimate customers.

In 2011, 2012 and 2013, virtually all of Nostrum's oil products were sold directly to its ultimate customers. In 2011, all of Nostrum's condensate was sold directly to its ultimate customers. However, in 2012, most of Nostrum's condensate was sold through third party traders, with the remainder being sold to its ultimate customers. In 2013, approximately half of the condensate was sold through third party traders and approximately half was sold to Nostrum's ultimate customers.

Dry Gas and LPG

The Group's deliveries of dry gas are made to the Group's two significant gas purchasers at the Group's connection to the Orenberg-Novopskov gas pipeline. Prices for the Group's gas products are negotiated annually with the buyers pursuant to annual contracts at market rates on arm's length terms. The two purchasers of the Group's dry gas are well established gas companies within Kazakhstan and the commercial relationship between them and the Group has been stable since its inception.

In 2011, 2012 and 2013, virtually all of Nostrum's LPG products were sold directly to its ultimate customers. The Group's LPG is transported by truck and then by rail car.

Environmental Matters

The Directors are committed to complying with applicable local and international standards for environmental protection. Nostrum prepares and submits to authorities a yearly action plan in accordance with Kazakh environmental regulations. In addition, Nostrum has started to implement International Finance Corporation and World Bank Group (IFC/WBG) environmental standards for its operations and expects to achieve compliance with these standards in the next five to ten years.

The Group has engaged external consultants, AMEC Overseas (Cyprus) Limited ("**AMEC**"), to undertake an environmental, health and safety due diligence review. According to such review (completed in July 2013), Nostrum is generally in compliance with Kazakhstan and international environmental standards and regulations, which comprise of International Finance Corporation and World Bank Group (IFC/WBG) international requirements and standards.

Nostrum's environmental protection policies include the following key objectives: (i) cease gas flaring; (ii) remediate or recultivate areas impacted by petroleum hydrocarbons, particularly abandoned wells and mud pits; (iii) provide training to employees and contractors to understand its environmental policies and minimise environmental damage; (iv) monitor the impact of Nostrum's operations on the environment; (v) put in place emergency procedures to deal with the environmental impact of any spillage; and (vi) utilise associated production gas to produce low cost power as part of its gas treatment facility.

For details regarding Nostrum's compliance with applicable environment requirements see Part 8 "*Industry and Regulatory Overview—Regulation in Kazakhstan—Environmental Compliance*".

Employees, Health and Safety

Employees

The table below sets out the average number of people (full-time equivalents) employed by the Group over the periods indicated below:

	Year ended					
	2013	**2012**	**2011**	**2010**	**2009**	**2008**
Location						
Chinarevskoye Field	633	656	577	500	439	396
Uralsk	274	218	170	144	177	142
Total	**907**	**874**	**747**	**644**	**616**	**538**

The average number of people (full-time equivalents) employed by the Group has increased during 2013 due to growth throughout the operating company, following increases during 2012 due to the general ramp-up in production at the gas treatment facility. Nostrum has not experienced any work stoppages, strikes or similar actions in the past and considers its relations with its employees to be good.

The Directors believe that the Group has complied in all material respects with applicable health and safety standards within the Kazakh oil and gas industry. See Part 8 "*Industry and Regulatory Overview—Regulation in Kazakhstan—Health and Safety Compliance*".

Litigation

There are no governmental, legal or arbitration proceedings (including any such proceedings which are pending or threatened of which the Group is aware), during the period covering the 12 months prior to the date of this Prospectus, which may have or have had in the previous 12 months significant effects on the Group's financial position or profitability.

Insurance

The Directors believe that the types of coverage structure, limits and quality of the Group's insurance programme are comparable with other Kazakh oil companies of a similar size.

The Group insures some of its risks under the following mandatory insurance contracts:

(a) general third-party liability insurance;

(b) employer's liability insurance;

(c) environmental insurance; and

(d) civil liability as the owner of vehicles.

As at the date of this Prospectus, the Group maintains and is in compliance with all mandatory insurance requirements under Kazakh law. In addition, the Group maintains the following voluntary insurance contracts:

(a) voluntary cargo insurance;

(b) oil operations voluntary insurance contract;

(c) voluntary third party liability insurance;

(d) property voluntary insurance contract; and

(e) voluntary property insurance for the gas treatment facility.

The Company has also arranged directors' and officers' liability insurance through a third-party insurer.

The Group does not maintain business interruption, key-man, terrorism or sabotage insurance because the Group believes that the chance of any such event occurring is small. See Part 2 "*Risk Factors—Risk Factors Relating to the Group's Business—The Group's insurance coverage does not cover all risks and may not be adequate for covering losses arising from potential operational hazards and unforeseen interruptions*".

Competition

Since independence in 1991, major Western oil companies have dominated the oil and gas sector of Kazakhstan, with BG Group, Chevron, ENI, Exxon, Shell, Total, Mobil, LUKOIL and Texaco acquiring stakes in the world-scale TCO, North Caspian and Karachaganak projects. Investment from Asian oil and gas companies began in the late 1990s led by Indonesia's Central Asia Petroleum (which acquired a share in Mangistaumunaigas in 1997) and CNPC International (which acquired shares in Aktobemunaigas in 1997 and PetroKazakhstan in 2005). CNPC International has continued to invest heavily in the country and has been joined by, among others, Inpex, Sinopec and KNOC. LUKOIL and Rosneft have led the investment of Russian oil and gas companies in Kazakhstan with a focus on offshore Caspian Sea projects.

PART 8
INDUSTRY AND REGULATORY OVERVIEW

The information contained in this section is intended to give an overview of the upstream oil and gas industry in Kazakhstan and the Caspian region. This information has, unless otherwise stated, been extracted from documents, websites and other publications released by the President of Kazakhstan, the Statistics Agency of Kazakhstan, the Ministry of Finance of Kazakhstan, the Competent Authority and other public sources.

Some of the market and competitive position data has been obtained from US government publications and other third-party sources, including publicly available data from the World Bank, the Economist Intelligence Unit, the annual BP Statistical Review of World Energy for 2013, as well as from Kazakh press reports and publications, and edicts and resolutions of the Kazakh Government. In the case of statistical information, similar statistics may be obtainable from other sources, although the underlying assumptions and methodology, and consequently the resulting data, may vary from source to source.

Certain sources are only updated periodically. This means that certain data for current periods cannot be obtained and we cannot assure you that such data has not been revised or will not be subsequently amended.

Overview

The Caspian region includes those parts of the countries (including Russia and Iran) that are adjacent to the Caspian Sea. A part of Uzbekistan is also considered to be part of the Caspian region due to its proximity to the Caspian Sea. To date, the two significant crude oil producing countries in the Caspian region have been Kazakhstan and Azerbaijan. It is expected that these countries will continue to lead the region in crude oil production in the near future, driven by production growth from existing fields and the development of recently discovered fields. Turkmenistan and Uzbekistan are the predominant gas producers in the Caspian region but do not produce significant crude oil volumes relative to Kazakhstan and Azerbaijan. In addition, the areas of Russia and Iran near the Caspian Sea are not a source of substantial crude oil production for these countries. Russia, however, plays an important role in the region by providing a transportation corridor between the Caspian Sea and the Black Sea.

Investment in Kazakhstan's Oil and Gas Industry

Since 2000, Kazakhstan has experienced significant economic growth. Two of the main catalysts for this growth have been economic reform and foreign investment, much of which has been concentrated in the energy sector. Exports of crude oil have grown significantly since 2000 and most of the oil from Kazakhstan is currently delivered to international markets by pipelines through Russia to shipping points on the Black Sea. The opening of the Caspian Pipeline Consortium ("**CPC**") pipeline in 2001 substantially increased Kazakhstan's crude oil export capacity.

International investment in the Kazakh oil and gas sector has largely taken the form of joint ventures, including cooperation with the state-owned oil and gas company NC KazMunayGas JSC ("**NC KMG**"), as well as production sharing agreements and direct grants of exploration/production rights to subsoil users. Major projects in Kazakhstan include the Tengiz, Karachaganak and Kashagan fields. Tengizchevroil LLP ("**TCO**"), a joint venture between ChevronTexaco, ExxonMobil, Lukarco and NC KMG, is developing the Tengiz and Korolevskoye oil fields pursuant to a production licence granted in 1993. This production licence was initially granted for 10 years, but can be extended by TCO for up to a total of 40 years; it was extended by TCO in 2003. In April 2013, ChevronTexaco announced an intention to request an extension of the license up to 2070. Karachaganak Petroleum Operations ("**KPO**"), which is developing the Karachaganak field, operates under a 40-year final production sharing agreement entered into with the Kazakh Government in 1997. The Kashagan consortium, which is developing the Kashagan field, was also established in 1997 under a 40-year production sharing agreement with the Kazakh Government, covering oil structures in Kashagan, Kalamkas, Aktoty and Kairan.

In May 2003, President Nazarbayev approved a new Caspian Sea development programme (currently not in effect) through the year 2015, which created new offshore blocks (potential oil fields) that were auctioned by the Competent Authority between 2003 and 2010. NC KMG has a mandatory share of at least 50% in all projects related to the new offshore blocks.

In December 2004, certain amendments to the Old Subsoil Law were adopted. The amendments provided that the State has a pre-emptive right, in the case of a proposed transfer of a direct interest under both existing and new contracts for subsoil use, to purchase such interest on terms no worse than those agreed by the parties to the proposed transfer.

In August 2007, the Kazakh Government claimed that the Kashagan consortium had breached certain provisions of its licence and environmental regulations, and consequently suspended the consortium's activities. A settlement reached in January 2008 resulted in the terms of the production sharing agreement being revised in favour of NC KMG such that the share interest of NC KMG doubled. The settlement also required the other members of the consortium to pay U.S.$5 billion to NC KMG until the end of the concession in 2041. See Part 2 "*Risk Factors—Risk Factors Relating to Kazakhstan—The Group is exposed to the risk of adverse sovereign action by the Government*". Phase I of Kashagan's development, known as the Experimental Programme, is already in the construction phase with the first oil produced in September 2013. However, in the fourth quarter of 2013 the production in Kashagan was suspended for safety reasons. On 3 November 2007, additional amendments to the Old Subsoil Law became effective. These amendments provided the Competent Authority with the right to initiate reviews of subsurface use contract terms and to unilaterally terminate subsurface use contracts in respect of deposits of "strategic importance". See "*—Regulation in Kazakhstan—Regulation of mineral rights in Kazakhstan—Regulation of subsoil use rights*". The Old Subsoil Law has been replaced by the New Subsoil Law which was adopted on 24 June 2010. See "*—Regulation in Kazakhstan—Regulation of subsoil use rights in Kazakhstan—New Subsoil Law*".

Oil Supply and Demand

According to BP's Statistical Review of World Energy 2013, as at 31 December 2012, Kazakhstan ranked twelfth in the world by oil reserves and twentieth in the world by gas reserves. Kazakhstan is the second largest oil producer (after Russia) among the former Soviet Republics and has the Caspian region's largest recoverable oil reserves. Kazakhstan's proved oil and gas reserves were 3.9 billion tonnes (representing 1.8% of the world's proved oil reserves) and 1.3 trillion cubic metres (representing 0.7% of the world's proved gas reserves), respectively, as at 31 December 2012.

According to BP's Statistical Review of World Energy 2013, between 2001 and 2012, Kazakhstan's oil production grew at a compounded annual growth rate of approximately 7.5%. Kazakhstan produced approximately, 81.6 million tonnes of oil and gas condensate in 2010, 82.4 million tonnes in 2011, 81.3 million tonnes in 2012, and 81.8 million tonnes in 2013, an increase of 0.6% from 2012. The Kazakh Government has stated that it expects oil and gas production to increase to 150 million tonnes per year and 79.4 billion cubic metres per year in 2015. Most of this growth is expected to come from the Tengiz, Karachaganak and Kashagan fields.

According to BP's Statistical Review of World Energy 2013, the Asia Pacific region was the world's largest geographical region for oil consumption in 2012, accounting for approximately 33.6% of world consumption. The United States was the largest consumer of oil by country in 2012, accounting for 19.8% of world consumption of oil. Europe together with the former Soviet Republics represented the world's largest geographical region for the consumption of natural gas in 2012, accounting for 32.6% of world consumption. The United States was the largest consumer of natural gas by country, accounting for 21.9% of world consumption in 2012.

Kazakhstan has three major oil refineries supplying the northern region (at Pavlodar), the western region (at Atyrau) and the southern region (at Shymkent), with a planned total refining capacity of 21.0 million tonnes per year (approximately 427,000 bopd) by 2022. All three major refineries are either in the control or joint control of NC KMG. Crude oil is also processed at mini refineries (private small refineries).

In 2013, all three refineries together produced a combined average of approximately 14.3 million tonnes of crude oil products (approximately 5 million tonnes at Pavlodar, 4.4 million tonnes at Atyrau, 4.9 million tonnes at Shymkent).

The refinery at Pavlodar is supplied mainly by crude oil from western Siberia; the Atyrau refinery runs solely on domestic crude from the western region of Kazakhstan; and the Shymkent refinery generally uses oil from the southern region of Kazakhstan. The Atyrau refinery is undergoing modernisation to provide some additional capacity and to allow the refinery to meet current European fuel standards.

Gas Supply and Demand

Kazakhstan is a net exporter of gas. Increases in its own gas production are expected to come primarily from associated gas at the Tengiz, Karachaganak and Kashagan fields. Most of Kazakhstan's gas reserves are located in the west of the country near the Caspian Sea, with almost half of those reserves located in the Karachaganak field. Another important gas field, Amangeldy, is situated in the south of the country and is being developed by KazTransGas, a subsidiary of NC KMG.

Gas production in Kazakhstan has increased significantly since 2004 when the Parliament passed a law prohibiting the industrial production of oil and gas deposits without the utilization of natural and associated gas. As a result, gas production in 2000 reached 11.5 billion cubic metres, the highest level since independence in 1991. Gas production increased from 19.7 billion cubic metres in 2012 to 22.8 billion cubic metres in 2013, an increase of 16% 22.8.

According to the projections of the Competent Authority, Kazakhstan expects to increase its gas production to 79.4 billion cubic metres per year by 2015.

The following table sets forth gas consumption levels in Kazakhstan for the years indicated:

Gas Consumption

2008	2009	2010	2011	2012
		(billion cubic metres per year)		
8.1	7.8	8.2	9.2	9.5

Source: BP Statistical Review of World Energy 2013

Transportation

An important aspect of increasing hydrocarbon production in Kazakhstan has been the development of transportation infrastructure, as this in turn has raised Kazakhstan's export capacity.

Crude Oil

Historically, the lack of pipeline capacity providing access to international markets has impeded Kazakhstan's ability to exploit its oil reserves. In 2012, Kazakhstan had 20,238 kilometres of pipeline of which 7,920 were used for the transportation of oil. The three main pipelines are the Uzen-Atyrau-Samara ("**UAS**") pipeline, the CPC pipeline, and the Kazakhstan-China pipeline. Kazakhstan transported by pipelines approximately 214.1 million tonnes of product in 2011 and 213.2 million tonnes of product in 2012. Since Kazakhstan is landlocked, the pipelines have to travel through neighbouring countries to reach international markets.

The CPC pipeline, which has been operational since 2001, represents a major export route. It extends 1,510 kilometres, originating in the Tengiz field, running through Russia and terminating at the CPC marine terminal on the Black Sea near the Russian port of Novorossiysk. The CPC pipeline is the first major pipeline in Russian territory not wholly owned by the Russian pipeline operator Transneft. In 2011, the CPC shareholders launched an expansion project which targets to increase the pipeline's capacity to 67 million tones and is expected to be completed in three stages with the third stage completed by 2014. Approximately 34.2 million tonnes of crude oil, 30.6 million tonnes of crude oil and 32.7 million tonnes of crude oil were shipped through the CPC pipeline in 2011, 2012 and 2013, respectively.

The UAS pipeline transports oil from fields in the Atyrau and Mangistau regions to Russia. The pipeline system runs for approximately 1,500 kilometres, from Uzen in southwest Kazakhstan to Atyrau, before crossing into Russia and linking with Russia's Transneft system at Samara. In June 2002, Kazakhstan signed a 15 year oil transit agreement with Russia. Under this agreement, Kazakhstan will export at least 17.5 million tonnes of crude oil per year using the Russian pipeline system. The line was recently upgraded by the addition of pumping and heating stations and has a capacity of approximately 600,000 bopd. Before completion of the CPC pipeline, Kazakhstan exported almost all of its oil through this system.

The 1,767 kilometre Baku-Tbilisi-Ceyhan pipeline delivers crude oil from Baku in Azerbaijan to a new marine terminal in the Turkish port of Ceyhan on the Mediterranean Sea and is the first direct pipeline link between the Caspian Sea and the Mediterranean Sea. Construction of the pipeline was completed in May 2005 and it began operating in July 2006, costing approximately U.S.$4 billion. It has a capacity of 1 million bopd. The pipeline is largely dedicated to production from the Azeri-Chirag-Gunashli fields in the Azerbaijan sector of the Caspian Sea, however since October 2008, the Baku-Tbilisi-Ceyhan pipeline has been used to transport Kazakhstan crude oil shipped across the Caspian Sea to Baku by tanker. The volume of Kazakh oil transported via the Baku-Tbilisi-Ceyhan pipeline has been steadily increasing since October 2008 when Kazakhstan began to use the route. According to the State Statistical Committee of Azerbaijan, volume increased from 17,400 tonnes in October 2008 to 240,200 tonnes in February 2009. In 2009, the Baku-Tbilisi-Ceyhan pipeline transported 1.9 million tonnes of Kazakh crude oil, according to the State Statistical Committee of Azerbaijan. However, according to the State Oil Company of the Azerbaijan Republic, Kazakhstan stopped the transport of Kazakh oil via the Baku Tbilisi Ceyhan pipeline in January 2010. Based on recent statements, Kazakhstan resumed transportation of oil through the pipeline at the end of 2013 with an intention to transport up to 4.5 million tonnes of crude oil in 2014.

On 28 May 2008, Kazakhstan ratified the Treaty between Kazakhstan and the Azerbaijan Republic dated 16 June 2006 on the support and facilitation of petroleum transportation from Kazakhstan through the Caspian Sea and the territory of the Azerbaijan Republic to international markets via the Baku-Tbilisi-Ceyhan system. In order to facilitate exports of oil from the Kashagan oil field during the next decade, Kazakhstan is currently developing the Kazakhstan-Caspian Transportation System ("**KCTS**"), which includes the construction of a 515 mile, 600,000 bopd capacity onshore pipeline from Eskene in western Kazakhstan to Kuryk on the Caspian near Aqtau, where a new 760,000 bopd oil terminal is to be built. The system also includes the creation of a new fleet of tankers and new port facilities in Baku, Azerbaijan. On 14 November 2008, the State Oil Company of the Azerbaijan Republic and NC KMG signed an agreement on key principles of the KCTS. While still preliminary, it is the first practical move to create a system with defined conditions of supplies, tariffs and other matters, guiding the trans-Caspian transportation of oil. The implementation period, stages and system capacity of KCTS are expected to be linked to the second and third phases of Kashagan's development.

The Kazakhstan-China pipeline comprises two existing Soviet era pipeline sections and three major new pipeline sections with a total length of around 2,800 kilometres from Atyrau in western Kazakhstan to Alashankou on the Kazakhstan-China border. At the Chinese border the pipeline links in to the infrastructure in the Xinjiang Gansu province in North-West China. The pipeline has been built in several stages:

- The first section was the 449 kilometre Kenkiyak-Atyrau section which was completed in 2003. Oil is temporarily flowing westwards, allowing export of Aktobe region oil through the CPC and Atyrau-Samara pipelines. The plan is that this section will be reversed to allow oil production from the Caspian region to travel through the line and onwards to China.
- The 965 kilometre Atasu-Alashankou section began commercial operation in July 2006. The pipeline allows oil from Kazakhstan's south Turgai basin and Russia to be exported to China.
- The 794 kilometre Kenkiyak-Aralsk-Kumkol section was completed in July 2009 and began commercial operation in October 2009. It is sourced with oil from the Kenkiyak area fields (Aktobe region).

The overall capacity of the pipeline to China was 200,000 bopd, which increased to 240,000 bopd in 2012 and there are plans to expand this to 400,000 bopd by 2014. The capacity of the Kenkiyak-Atyrau section is lower, at 120,000 bopd, and there are plans to expand the capacity of this section to 180,000 bopd and then later to 240,000 bopd.

The timing of the reversal of the Kenkiyak-Atyrau section is uncertain, and the decision to reverse the line will be made by the Kazakh Government. It is likely that this will happen once there is sufficient throughput capacity for all production from fields in the Kenkiyak Area to be exported eastwards, which is expected to be in 2014.

Other pipeline routes from Kazakhstan are being considered, such as routes through the Caucasus region to Turkey and routes through Iran and Afghanistan.

Rail transportation was the primary export route for Kazakhstan crude production before the development of the UAS and CPC pipelines and it remains as an alternative transportation option.

Natural Gas

Out of the 20,230 kilometres of pipeline that Kazakhstan had in 2012, 12,318 kilometres were used for the transportation of gas (which is mostly transit gas from neighbouring countries).

Most of the gas pipelines in western Kazakhstan, with the exception of Makat-Atyrau-Astrakhan, are designed to provide gas to CAC. The pipeline has two branches that meet in the South-Western Kazakh city of Beyneu before crossing into Russia and connecting to the Russian pipeline system. The eastern branch of the pipeline originates in the south eastern gas field of Turkmenistan, while the western branch originates on the Caspian seacoast of Turkmenistan. The annual throughput capacity of CAC is 60.2 billion cubic metres.

In December 2010, Kazakhstan commenced the construction of the Beineu-Bozoi-Shymkent gas pipeline designed to transport gas from West Kazakhstan for use in the southern regions of Kazakhstan and export to China. The first phase of the project, comprising the Bozoi-Shymkent pipeline with a throughput capacity of 2.5 billion cubic metres per year, has been completed in 2013. The second phase of the project, comprising the Beineu-Bozoi pipeline, which will increase throughput capacity to 10 billion cubic metres per year, is expected to be completed by the end of 2015.

The Bukhara Urals gas pipeline originates in Uzbekistan and was initially built to supply gas from Uzbekistan to North-East Kazakhstan and Russia's southeast Urals region. Gas flows along the pipeline are variable and, at times, the pipeline transfers gas southwards from Russia. The annual throughput capacity of the Bukhara Urals gas pipeline is approximately 24.0 billion cubic metres.

Bukhara-Tashkent-Bishkek-Almaty is a transit gas pipeline that provides gas from Uzbekistan to Kazakhstan's main southern population centre. Between Shymkent and Almaty, the line crosses Kyrgyz territory to supply Bishkek, the Kyrgyz capital. The annual throughput capacity of the Bukhara-Tashkent-Bishkek-Almaty gas pipeline is 5.8 billion cubic metres.

Major Oil and Gas Projects in Kazakhstan

TCO

The TCO joint venture was created in 1993 with the aim of developing the Tengiz and Korolev fields. The participants in the joint venture are Chevron Overseas Company, ExxonMobil, NC KMG and LukArco.

The Tengiz field is located in the South-Eastern part of the Pre-Caspian Basin on the North-Eastern edge of the Caspian Sea. It was discovered in 1979 in the Atyrau region. The Tengiz field has estimated recoverable reserves of between 750 million tonnes (5.5 billion barrels) and 1,100 million tonnes (8.1 billion barrels) of oil. In 2004, 13.7 million tonnes (276,000 bopd) of oil were produced at the Tengiz field, as compared to 13.6 million tonnes (274,000 bopd) in 2005, and 20.0 million tonnes (403,000 bopd) in 2006. In late 2007, TCO was producing approximately 300,000 bopd of oil and 11.2 million cubic metres of gas per day. In 2008, TCO's production reportedly reached 17.3 million tonnes of crude oil. In October 2008, when the sour gas injection and second generation plant expansion were completed, daily production capacity was increased to 540,000 bopd. Production of oil for 2013 amounted to 27 million tonnes. The Future Growth Project is the next major expansion of oil production in Tengiz, aiming to increase oil production to approximately 38 million tonnes (720,000 bopd). The output of the Tengiz field is shipped through the CPC pipeline with CPC's planned capacity increase supporting Tengiz's expected production increase from the Future Growth Project. Shipments are also being shipped through the Baku-Tbilisi-Ceyhan pipeline, as well as via rail to Odessa, Feodosiya, Aktau, and then further to Batumi and Kulevi.

Karachaganak Project

The Karachaganak field is a large gas condensate field located in North-Western Kazakhstan, with an area of about 280 square kilometres. The field was discovered in 1979 and the consortium developing it are party to a 40-year production sharing agreement with the Kazakh Government. The field is operated by KPO and the consortium includes affiliates of ENI SpA, BG Group, Chevron, LUKOIL Overseas and NC KMG. BG Group, together with ENI are joint operators and each hold a 29.25% interest in the venture.

The Karachaganak field is Kazakhstan's main gas field. In 2013, it accounted for approximately 41.4% of Kazakhstan's gas production. The field holds an estimated 9 billion barrels of gas condensate and 48 trillion cubic feet of gas. In 2013, Karachaganak's total production was approximately 12.0 million tonnes of oil and condensate and 17 billion cubic metres of gas. According to KPO, the field holds reserves of around 2.4 billion barrels of gas concentrate and 16 trillion cubic feet of natural gas.

In previous years, almost all of Karachaganak's crude oil production was processed at Russian facilities associated with the Orenburg field located just across the border. In April 2003, a pipeline spur southward to Atyrau was completed that connects the Karachaganak field to Kazakhstan's primary export pipeline, the CPC pipeline. The new connection has enabled increased exports from Karachaganak, and has reduced the consortium members' dependence on Russian buyers.

In 2009, the Kazakh Government has made various allegations in respect of the operation of the Karachaganak Project by the KPO consortium, including criminal behaviour and tax evasion. In 2011, an agreement was reached that involved the transfer of a 10% stake in the KPO consortium to the Kazakh Government and the allocation of an additional 2 million tonnes per year capacity in the CPC pipeline. The transfer of the 10% stake was completed in June 2012.

North Caspian Project

The Kashagan field is located off the northern shore of the Caspian Sea, near the city of Atyrau. In 1997, a consortium of companies signed a 40-year production sharing agreement covering five structures, namely Kashagan, Kalamkas, Aktoty, Kairan and Kashagan SW. The structures consist of 11 offshore blocks and cover an area of 5,600 square kilometres. In June 2000, as a result of drilling and testing of wells in East Kashagan 1, workers found one of the largest oil and gas fields to be discovered in the last 30 years. The field is currently in development and its output is expected to be shipped through the CPC pipeline. The project is owned by the North Caspian Operating Company (NCOC) which is a consortium that includes ENI SpA, ExxonMobil Corporation, Shell, Total S.A., CNPC, INPEX Corporation and NC KMG. The consortium has been operating the project since 23 January 2009, but NCOC delegates to four agent companies (Agip KCO, Shell Development Kashagan B.V. (SDK), ExxonMobil Kazakhstan Inc., and NC KMG), which are responsible for managing the project. In August 2007, the licence granted to the consortium was suspended by the Kazakh Government for alleged breaches of Kazakh environmental regulations. A settlement reached in January 2008 resulted in the terms of the production sharing agreement being revised in favour of NC KMG such that the share interest of NC KMG doubled. The settlement also required the other members of the consortium to pay U.S.$5 billion to NC KMG until the end of the concession in 2041. The budget for the development of the Kashagan oilfield on Kazakhstan's Caspian Sea shelf in 2010 was reduced by U.S.$3 billion. See Part 2 "*Risk Factors—Risk Factors Related to Crude Oil and Gas Industry—The Group is obliged to comply with environmental regulations and cannot guarantee that it will be able to comply with these regulations in the future*".

In May 2012, the partners of NCOC and the PSA Authority of Kazakhstan, an entity representing Kazakhstan in NCOC PSA as an authority, reached an agreement on the amendment to the Kashagan development plan and budget that was necessary for the update of the development project's schedule and investment estimates. The NCOC partners also agreed to a commercial framework to contract a share of natural gas produced from Kashagan for domestic marketing. Phase I of Kashagan's development, known as the Experimental Programme, commenced production in September 2013, but was suspended due to an accident at the pipeline and is expected to re-commence in 2014.

In November 2012, ConocoPhillips announced its intended disposal of 8.4% interest in the project to a third party. In July 2013, the Kazakh Government decided to exercise its statutory pre-emptive right to acquire the interest disposed, while selling its 8.4% interest to CNPC. Both acquisitions have been completed by in 2013. On 1 August 2013, the NCOC partners announced that in July 2013 operational testing activities started at offshore production facilities. In September 2013, production commenced. However, it was suspended due to a leak in the pipeline which ran from the artificial D island to the Bolashak processing plant situated onshore. Production commenced soon after, but further leaks have once again suspended production.

Regulation in Kazakhstan

Regulation of the oil and gas sector can be divided into three broad areas:

- regulation in relation to subsoil use rights;
- regulation in relation to environmental, health and safety matters; and
- anti-monopoly regulation.

Regulation of subsoil use rights in Kazakhstan

General

In Kazakhstan, the subsoil and minerals contained therein are owned by the state in accordance with the Constitution of the Republic of Kazakhstan. The state shall ensure access to the subsoil on the terms, conditions and within the limits as provided for by the New Subsoil Law. Unless otherwise stipulated by Kazakhstan laws and subsoil use contracts, mineral raw materials shall be owned by the subsoil user under a right of ownership (or in the case of a state-owned enterprise, under a right of economic or day-to-day management). The Competent

Authority, on behalf of the State, grants exploration and production rights. Subsoil use rights are granted for a specific period but may be extended before the expiration of the applicable contract and licence (if applicable), subject to certain limitations and conditions. Subsoil use rights may be terminated by the Competent Authority if, among other things, subsoil users do not satisfy their contractual obligations, which may include periodic payment of royalties and taxes to the Kazakh Government and the satisfaction of mining, environmental, and health and safety requirements.

Prior to August 1999, subsoil use rights for hydrocarbons and mining sector operations were established by the grant of a licence and the execution of a subsoil use contract in a tax royalty or PSA model. In August 1999, in an attempt to simplify the procedure, the Kazakh Government abolished the licence regime for subsurface use rights granted after September 1999and, in December 2008, the PSA model was also abolished. Subsoil use rights are now established only by means of a subsoil use contract and no licence is required. Nevertheless, previously issued and unexpired licences and PSAs survived. Nostrum holds its subsoil use rights on the basis of the pre-August 1999 "licence and contract" regime. See Part 7 "*Information on the Group—Subsoil Licences and Permits*".

Regulation of subsoil use rights

There have been four main phases of subsoil use regulation in Kazakhstan:

- from Kazakhstan's independence in 1991 to August 1994;
- the licensing contractual regime from August 1994 to August 1999, which had two sub-phases: (i) August 1994 to January 1996, and (ii) January 1996 to August 1999;
- the contractual regime, which was effective from August 1999 through 7 July 2010 and was regulated by the Old Subsoil Law, as amended from time to time; and
- the present regulation of activities in the oil and gas sector by the New Subsoil Law, enacted in June 2010 and effective from 7 July 2010, and recently enacted Laws on Gas and Gas Supply (9 January 2012) and Trunk Pipeline (22 June 2012).

The Old Subsoil Law and the 1999 Amendments

The legal framework that formerly regulated Nostrum's subsoil activities under the PSA was established with the adoption of Kazakhstan Law No 2828 "On Subsoil and Subsoil Use" on 27 January 1996 (the "**Old Subsoil Law**"). In August 1999, the Old Subsoil Law was amended by Law No. 467 1 "Concerning the Introduction of Amendments and Additions to Several Legislative Acts on the Subsoil and Petroleum Operations in the Republic of Kazakhstan" (the "**1999 Amendments**"). The 1999 Amendments simplified the process of obtaining subsoil use rights, by allowing the Competent Authority to grant these rights based on a subsurface use contract only. Under the 1999 Amendments, the licence regime for subsurface use rights granted after September 1999 was abolished.

The 2004/2005 Amendments to the Old Subsoil Law

The Old Subsoil Law was further amended by the Law No. 2 III on "Introduction of Amendments and Additions to Certain Legal Acts on Subsoil Use and Petroleum Operations" dated 1 December 2004, and Law No. 79 3 on "Introduction of Amendments and Additions to Certain Legal Acts on Subsoil Use and Performance of Petroleum Operations in Kazakhstan" dated 14 October 2005 (the "**2004/2005 Amendments**"). The 2004/2005 Amendments provided to the State a pre-emptive right in connection with any transfer of subsoil use rights and/or shares or participation interests in subsoil users, and/or any transfer of the shares or participation interests in a legal entity which can, directly or indirectly, affect or determine decisions of a subsoil user, if the core business of such controlling entity is related to subsoil use in Kazakhstan (the "**State's Pre-Emptive Right**"). This gave the State a right of first refusal in respect of any such transfers on terms "no worse than those offered by other prospective purchasers".

The 2004/2005 Amendments also provided that transfers of subsoil use rights, including contribution of subsoil use rights to charter capital, transfer of subsoil use rights during bankruptcy proceedings and that pledge of subsoil use rights required the consent of the Competent Authority.

The 2007 Amendments to the Old Subsoil Law

In October 2007, Kazakhstan adopted new legislation amending the Old Subsoil Law (the "**2007 Amendments**"). The 2007 Amendments came into force on 3 November 2007. The 2007 Amendments introduced a concept of so called “strategic deposits”, the list of which was approved by the Kazakh Government on 13 August 2009 (and later superseded by a list approved by the Kazakh Government on 4 October 2011). The 2007 Amendments provided the Competent Authority with the right to initiate reviews of subsoil use contract terms and to require: (a) amendments and/or additions to subsoil use contracts in circumstances where the activities of the subsoil user in relation to so-called “strategic deposits” lead to material changes in the economic interests of the state which create a threat to national security; and (b) termination of subsoil use contracts if, *inter alia*, the parties fail to execute the respective amendments and/or additions to a subsoil use contract within six months from the date when an agreement was reached with the Competent Authority to restore the State’s economic interests.

Abolition of the PSA Law

Kazakhstan Law No. 68 III “On Production Sharing Agreements for Conducting Offshore Petroleum Operations”, dated 8 July 2005, (the “**PSA Law**”), which together with other subsoil legislation was the applicable law for production sharing agreements in Kazakhstan, was abolished by the introduction of the new Tax Code on 10 December 2008. The PSA Law ceased to have effect from 1 January 2009. The New Subsoil Law does not permit the State to enter into new production sharing agreements with contractors.

New Subsoil Law

The New Subsoil Law replaced two major laws governing relations of the State and subsoil users in the oil and gas sector; (i) the Old Subsoil Law and (ii) the Republic of Kazakhstan Law “On Oil” (No. 2350, dated 28 June 1995, as amended) (the latter replicating most of the provisions of the Old Subsoil Law). Adoption of the New Subsoil Law was aimed at, *inter alia*: (i) consolidation of existing overlapping laws and regulations related to subsoil and subsoil use, including those in the sphere of oil and gas; (ii) clarifying areas of uncertainty by adding more procedures (specifically relating to obtaining various consents/approvals/waivers from the Competent Authority); and (iii) eliminating stabilisation of subsoil use contracts.

Under the New Subsoil Law, the subsoil use rights may be permanent or temporary, alienable or inalienable, payable or free of charge. Most types of subsoil operations shall be carried out on the basis of temporary and payable subsoil use (except for production of commonly occurring minerals for the subsoil user’s own needs and production of underground water in volumes of up to 50 cubic meters in land plots held under the right of ownership or use, which shall be carried out under permanent and free of charge rights of subsoil use). Subsoil use rights shall be granted following a tender process or direct negotiations with the Competent Authority, with certain exceptions.

Subsoil use rights may be held by Kazakh and foreign individuals and legal entities. A subsoil user shall be guaranteed protection of its rights in accordance with Kazakhstan legislation. Any amendments and additions to legislation that worsen the results of a subsoil user’s business activities under subsoil use contracts shall not apply to subsoil use contracts that were concluded prior to such amendments and additions. Such guarantees shall not apply to changes in Kazakhstan legislation in the areas of national security, defence capabilities, environmental protection, health, taxation and customs regulation.

The following rights for the state were retained in the New Subsoil Law from the Old Subsoil Law:

- *Priority Right to Acquire Minerals*

  The State shall have a priority right over other parties to acquire a subsoil user’s minerals, at prices not exceeding those applied by the subsoil user that prevail on the date of the relevant transaction, minus transportation and selling costs.

- *Right to Requisition Minerals*

  In the event of martial law or a state of emergency, the Kazakh Government may requisition some or all of the minerals owned by a subsoil user. Requisition may be in any amount necessary to cover the needs of the State during the entire period of martial law or the state of emergency. Minerals may be requisitioned from any subsoil user regardless of the form of ownership. The State shall guarantee compensation for requisitioned minerals either by payment in kind, or by paying their monetary value to a foreign subsoil user in freely convertible currency and to a domestic subsoil user in the national currency at prices not exceeding those applied by subsoil users in transactions related to the relevant minerals that prevail on the date of requisition, minus transportation and selling costs.

- *The State's Pre-emptive Right*

  The New Subsoil Law differentiates between subsoil use rights and the objects related to the subsoil use rights (the "**Objects**"). Objects are participatory interests (shares, securities confirming title to shares and securities convertible into shares) in a legal entity holding the subsoil use right, as well as a legal entity which may directly and/or indirectly determine and/or influence decisions adopted by a subsoil user, if the principal activity of such entity is related to subsoil use in the Republic of Kazakhstan (the "**Controlling Legal Entity**"). The concept of the State's Pre-Emptive Right was transferred from the Old Subsoil Law to Article 12 of the New Subsoil Law in respect of both the subsoil use rights and the Objects. The State's Pre-Emptive Right applies retroactively to all existing contracts, as well as prospectively to future contracts, except for the contracts for underground water or commonly occurring minerals.

  With certain limited exemptions discussed in "*—The Consent for Transfers of Subsoil Use Rights and Objects*", the State's waiver of its pre-emptive rights would need to be obtained for any transfer of the subsoil use rights or the Objects.

  The State's Pre-Emptive Right is also applicable to any initial public offering of shares on an organised securities market, or other securities confirming title to shares, or securities convertible into shares, issued by a subsoil user legal entity or a Controlling Legal Entity, including any further public offerings of securities in such legal entities on an organised securities market. In addition, such public offerings require the permission of the Competent Authority, which may be granted in accordance with the New Subsoil Law provisions.

- *The Consent for Transfers of Subsoil Use Rights and Objects*

  The subsoil use right (or part thereof) and the Objects can only be transferred, including in cases of foreclosure (including a pledge), with the consent of the Competent Authority in accordance with the procedure established by Article 37 of the New Subsoil Law.

  A credit facility secured by a pledge of the subsoil use right shall only be used for the purposes of subsoil use, or for further treatment, if such a treatment is provided for the relevant subsoil use contract, and is carried out within the territory of Kazakhstan by the subsoil user itself or by a wholly-owned subsidiary.

  The initial public offering of shares on an organised securities market or other securities confirming title to shares or securities convertible into shares issued by a subsoil user legal entity or a Controlling Legal Entity, including the further placement of securities in such legal entities on an organised securities market, requires the permission of the Competent Authority. The Competent Authority's consent shall not, however, be required in the following instances:

  - transactions for alienation of shares or other securities confirming title to shares, or securities convertible into shares which are traded on an organised securities market and are issued by a subsoil user legal entity or a Controlling Legal Entity;
  - the transfer, in full or in part, of the subsoil use right and/or an Object:

    (a) to a subsidiary in which at least a 99% participatory interest (shareholding) is held directly or indirectly by the subsoil user, *provided that* such subsidiary is not registered in a jurisdiction with a preferential tax treatment (the so-called "black listed offshore jurisdictions"); and

    (b) between legal entities in each of which at least a 99% participatory interest (shareholding) is held directly or indirectly by one and the same person, provided that the acquirer of all or part of the subsoil use right and/or the Objects is not registered in a jurisdiction with a preferential tax treatment; or
  - the transfer of shares (participatory interests) in a subsoil user legal entity if, as the result of such a transfer, an entity acquires the right to directly or indirectly control less than 0.1% of the participatory interests (shareholdings) in the charter capital of the subsoil user or the Controlling Legal Entity.

  In these instances, the State's waiver of its pre-emptive rights shall not be required.

  Any transactions or other related actions effected without the required consent of the Competent Authority and waiver of the State's Pre-Emptive Right may be invalidated as of the date of their conclusion or undertaking.

- *Termination of Subsoil Use Contracts*

  According to Article 72.3 of the New Subsoil Law, the Competent Authority may prematurely terminate a subsoil use contract on a unilateral basis:

  (1) if the subsoil user fails to eliminate more than two violations of obligations under its subsoil use contract or project documents within the time set in the Competent Authority's notice; and

  (2) in the event of a transfer of a subsoil use right and/or of the Objects by the subsoil user without the Competent Authority's consent when such consent is required.

- *Treatment of Subsoil Use Contracts in Relation to Strategic Deposits*

  In October 2011, the Kazakh Government approved a list of over 300 hydrocarbon (including the Chinarevskoye oil, gas and condensate deposit), hard mineral and underground water deposits categorised as strategic. The New Subsoil Law does not establish the criteria for qualifying a deposit as 'strategic'. It is within the Kazakh Government's sole discretion to determine whether a deposit is strategic. Therefore there is no legal basis or mechanism or any action or step that can be taken under Kazakhstan law to obtain any assurance from the Kazakh Government or any other authority as to the likelihood of Nostrum's other deposits not being so designated in the future.

  Pursuant to the New Subsoil Law, the Competent Authority has the right to initiate amendments to any subsoil use contracts (including those pre-dating the enactment of the New Subsoil Law) in respect of a strategic deposit if particular actions of a subsoil user have a negative impact on Kazakhstan's economic interests thus threatening national security. The Law on National Security defines the term "threat to the national security" as any set of internal or external factors that obstructs the realisation of the national interests of Kazakhstan, with the term "national interests" being broadly defined as any lawful political, economic or social needs of Kazakhstan that enable the state to protect the rights of citizens, societal values and fundamentals of the Kazakh constitution. The main test for terminating a subsurface use contract, i.e. 'change of economic interests of Kazakhstan creating a threat to national security' is unclear and will be determined at the discretion of the relevant state authorities in each particular case.

  If the introduction of amendments proposed by the Competent Authority fails or is otherwise not agreed, the Competent Authority may unilaterally terminate the relevant subsoil use contract if the following conditions are met:

  (1) if within a period of up to two months after the receipt of the Competent Authority's notice of a required amendment and/or an addition to the relevant subsoil use contract, the subsoil user fails to give its consent in writing to the conduct of such negotiations or if it refuses to conduct them; or

  (2) if within a period of up to four months after the receipt of the subsoil user's consent to negotiate a required amendment and/or addition to the relevant contract, the subsoil user and the Competent Authority fail to reach an agreement on the amendment and/or addition to the contract; or

  (3) if within a period of up to six months after the date of achievement of a mutually agreed decision on restoration of economic interests of the state, the parties fail to sign the agreed amendments and/or additions to the contract,

  In addition, as an ultimate means of sanction, the Competent Authority (based on a decision of the Kazakh Government) has the right to unilaterally terminate a subsoil use contract in respect of a strategic deposit, if the Kazakh Government believes that there is a threat to national security, by giving two months' advance notice.

  Notwithstanding the breadth of these definitions, the national security threat test appears to be of a sufficiently high standard to ensure that the Kazakh Government should only use its unilateral termination right considerately and without abuse.

  From public discussions preceding the enactment of the New Subsoil Law, it was apparent that this provision, as well as certain other provisions of the New Subsoil Law, were meant to strengthen the Kazakh Government's legal options in confronting the group of largest subsoil users not willing to cooperate with the Kazakh Government's efforts to re-negotiate economic terms of underlying subsoil use contracts. Since the enactment of the New Subsoil Law, according to publicly available information, the Kazakh Government has never officially invoked this provision with respect to any of the strategic deposits. See Part 2 "*Risk Factors—Risk Factors Relating to the Oil and Gas Industry—The Group may be unable to comply with its obligations under the PSA and the Licence" and "Risk Factors Risks Relating to Kazakhstan—The Group is exposed to the risk of adverse sovereign action by the Government*".

- *Procurement Rules*

  In replication of the Old Subsoil Law, the New Subsoil Law generally requires subsoil users to comply with certain local content requirements, including the use of Kazakhstan suppliers and personnel. These general requirements should be detailed in subsoil use contracts. Further, the New Subsoil Law purports to extend certain provisions relating to specific Kazakh content requirements to subsoil use contracts executed prior to the enactment of the New Subsoil Law. See Part 2 "*Risk Factors—Risk Factors Relating to the Oil and Gas Industry—The Group may be unable to comply with its obligations under the PSA and the Licence*" and "*Risk Factors Risks Relating to Kazakhstan—The Group is exposed to the risk of adverse sovereign action by the Government*".

New Law on Trunk Pipeline

The Law on Trunk Pipeline No.20 V dated 22 June 2012 (the "**Trunk Pipeline Law**") provides a unified legislative basis for the construction, ownership, and operation of trunk pipelines and represents another step towards stiffening the State's control over strategic industries.

Pursuant to the Trunk Pipeline Law, the State will have a priority right to participate in any newly constructed trunk pipelines with an interest of no less than 51%. Further, the Trunk Pipeline Law provides that, for trunk pipelines where the State, national management holding company, or national company directly or indirectly owns 50% or more of the shares or participatory interests, operator services must be provided by the national operator, unless the Kazakh Government decides to authorise another legal entity (in which the State, a national management holding company, or a national company owns 50% or more of the shares or participatory interests) to provide such services in order to comply with international treaties.

The Trunk Pipeline Law (as well as the legislation regulating natural monopolies) provides for the equal right of shippers to access trunk pipeline services if there is free throughput capacity, subject to certain statutory limitations. If there is limited throughput pipeline capacity, oil and oil product transportation services must be rendered in the priority established by the Trunk Pipeline Law, where first priority is given to shippers supplying oil to domestic refineries. The Trunk Pipeline Law also provides for the possibility of swap operations (i.e., swap of products by one shipper for the products of another shipper) for the purposes of supplying oil to domestic refineries and gas to the domestic market and/or outside Kazakhstan, upon written consent of the pipeline owner (or any other person legally holding rights to the pipeline), the Competent Authority, and the relevant swapping entities.

New Law on Gas and Gas Supply

The Law on Gas and Gas Supply No.532 IV dated 9 January 2012 (the "**Gas Law**") consolidates and streamlines the various parts of legislation that previously regulated this area.

Pursuant to the Gas Law, state ownership of associated gas has been further elaborated. The State is the owner of associated gas produced in Kazakhstan (under all new contracts and old contracts that provide that the State is the owner of the associated gas) and transferred to the State by oil producers (under old contracts that provide that the subsoil user is the owner of the associated gas).

The Gas Law establishes the State's priority right to purchase (through a national operator, state-owned KazTransGas JSC) on terms no less favourable than those offered by a third party: (i) any facility within an integrated sales gas supply system (connecting pipeline, trunk pipelines, sales gas storage facilities and other facilities for production, transport, storage, sale and consumption of gas); (ii) a share in the right of common ownership over such facilities, and (iii) shares (participatory interest) in the owner of such facilities (i.e. any oil producer that owns gas processing facilities or connecting pipelines for sales of gas).

Further, the Gas Law provides for the State's priority right to buy (through the national operator) purified gas at a price approved by the Competent Authority and calculated pursuant to a formula provided in Kazakh Government decree. If the State waives its priority right, the seller may sell the gas to a third party.

The Competent Authority and other regulatory authorities

General

The State plays a role in four areas of subsoil management. First, the Kazakh Government is, *inter alia*, responsible for organising and managing state-owned reserves; outlining deposits available for a tender;

imposing restrictions on subsoil use for the purposes of national security, environmental security and the protection of life and health of the population; defining the procedures for the conclusion of contracts; approving model contracts; appointing the Competent Authority; regulating oil and gas export by imposing customs, protection, anti-dumping and compensation duties and quotes; establishing quotes for oil transportation by various transport methods; appointing IDC members to exercise the State's Pre-Emptive Right; and approving a number of normative legal acts in the sphere of oil and gas. Secondly, the state executes, implements and monitors subsoil use contracts through the Competent Authority (currently the Ministry of Oil and Gas), which has the power to execute and implement oil and gas contracts, and through a number of other state agencies. Thirdly, the State's Pre-Emptive Right is exercised through the national management holding company (JSC National Welfare Fund Samruk-Kazyna), the national oil and gas company (NC KMG) and authorised state agencies. Finally, local executive authorities have responsibility for, *inter alia*, granting land to subsoil users; supervising the protection of the land; and participating in negotiations with subsoil users for environmental and social protection.

The Ministry of Oil and Gas

According to resolutions of the Kazakh Government adopted in 2010, the Ministry of Oil and Gas is the Competent Authority and the Authorised Oil and Gas Agency. According to the New Subsoil Law and other effective legislation, the Ministry of Oil and Gas is responsible for, *inter alia*:

- implementing the state's policy in oil and gas, petrochemical and hydrocarbon transportation industries;
- representing the State's interests in production sharing agreements;
- organising tenders for grants of subsoil use rights for oil and gas exploration and production and preparing lists of blocks for tenders for consideration and approval by the Kazakh Government;
- executing and registering oil and gas contracts;
- approving working programmes and annual working programmes related to oil and gas contracts;
- monitoring compliance with the terms of oil and gas contracts;
- issuing permits for the transfer of subsoil use rights and registration of transactions involving pledges of subsoil use rights, as applicable to oil and gas projects;
- suspending and terminating subsoil use contracts in oil and gas in accordance with the procedures set forth in the New Subsoil Law;
- jointly, with the Anti-monopoly Agency, regulating activities of natural monopolies and relevant investment programmes;
- determining the amounts of oil and gas to be supplied by subsoil users to the domestic market;
- undertaking actions for equal access by subsoil users to the main pipelines;
- monitoring compliance of oil and gas subsoil users with requirements to purchase certain amounts of goods and services from local providers;
- licensing the activities related to engineering and exploitation of oil and gas facilities and engineering of trunk pipelines;
- approving gas utilisation programmes; and
- issuing permits for using money in the liquidation fund.

Other regulatory authorities

Other governmental ministries and authorities which regulate aspects of hydrocarbon extraction in Kazakhstan include:

- the Ministry of Environment and Water Resources (the "**MEWR**"), which is responsible for environmental protection and preservation of mineral resources;
- the Ministry of Industry and New Technologies (the "**MINT**"), which is the competent state body for subsoil users carrying out exploration and production activities in mining areas (except for the commonly occurring minerals):
- Committee for Technical Regulation and Metrology, which supervises compliance of oil and gas equipment with quality and safety standards in Kazakhstan; and

- Committee of Geology and Subsoil Use, which issues geological and mining allotments;
- the Ministry of Emergency Situations which, *inter alia*, supervises mining operations, and whose Committee on State Control of Emergency Situations and Industry Safety (the "**CSCES**") supervises health and safety matters, among other things;
- various governmental authorities responsible for the approval of construction projects and the use of water and land resources;
- the Consumer Rights Protection Agency, which is responsible for monitoring compliance with health standards;
- the Ministry of Labour and Social Protection of the Population, which is responsible for investigating labour disputes and complaints from individual employees and monitors compliance with subsoil users' obligations to give preference in hiring, (including employing a certain minimum percentage of), Kazakh nationals;
- regional and municipal regulatory authorities, which are responsible for registering properties, pledges and mortgages; and
- central and regional tax authorities.

Environmental permits

An environmental permit ("**EP**") is a special permit that grants a subsoil user a temporary right to emit or disburse emissions into the atmosphere and discharge waste substances into surface and underground waters. EPs contain the conditions governing the user's impact on the environment. The obligation to obtain an EP arises not only as a matter of law, but also under the PSA and the subsoil use contracts in respect of the Rostoshinskoye, Darinskoye and Yuzhno-Gremyachenskoye fields. Companies which have an impact on the environment (polluting, discharging waste, etc.) are required to obtain an EP. An EP is normally issued for up to five years, either by regional executive authorities or the MEWR. Fees for pollution of the environment are established by the Tax Code of Kazakhstan and may be increased (within certain limits) by local representative bodies (Maslikhat). The holding of an EP shall not exempt a subsoil user from liability to pay compensation for damage to the environment caused by its activities, or from any administrative or criminal liability.

The MEWR has granted Nostrum an EP, renewable on an annual basis, subject to Nostrum's compliance with its terms and conditions and applicable environmental laws. According to the EP, Nostrum is allowed to emit pollutants and store industrial and other wastes in the amounts not exceeding certain pre-set thresholds as set forth in the EP. For risks related to Nostrum's breach of terms and conditions of the EP, see Part 2 "*Risk Factors—Risk Factors Relating to the Oil and Gas Industry—The Group is obliged to comply with environmental regulations and cannot guarantee that it will be able to comply with these regulations in the future*".

Nostrum is generally in compliance with national and international regulations and standards associated with onshore oil and gas production (as confirmed by AMEC during its environmental, health and safety due diligence review in 2013). Only minor areas of non-compliance associated with hazardous waste storage were identified by AMEC, which do not require complex mitigation.

In February 2009, Kazakhstan ratified the Kyoto Protocol to the United Nations Framework Convention on Climate Change (the "**Kyoto Protocol**"). Ratification of the Kyoto Protocol, which was intended to limit or discourage emissions of greenhouse gases such as carbon dioxide, had an impact on environmental regulations in Kazakhstan. The effect of such ratification in other countries is still unclear, and accordingly, potential compliance costs associated with the Kyoto Protocol are unknown.

The Kazakhstan Environmental Code (dated 9 January 2007, as amended) (the "**Environmental Code**") sets out the framework of climate change control in Kazakhstan, which came into force on 1 January 2013. Starting from 1 January 2013, no person may carry on a specified activity (this includes energy activities) without quotas set out in the relevant greenhouse gas emissions permit to be issued annually by the Environmental Control Committee, although legal entities not emitting more than 20,000 tonnes of carbon dioxide in a year are exempted from this prohibition. Provisions have been made in relation to applications for a greenhouse gas emission permit, including the required information relating to the installation in respect of which the permit is sought, the programme for the reduction of emissions and the planned arrangements for the implementation of the programme, including the grounds on which an application may be refused.

Emissions quotas are allocated pursuant to a national allocation plan. For 2014 and 2015, national allocation plan was approved by the Resolution of the Government of the Republic of Kazakhstan No. 1536, dated 31 December 2013. According to Annex 2 to the national allocation plan, Nostrum may not emit more than 338 521.00 tonnes of CO2 or 338,521 emission units in 2014 and not more than 334 444.00 tonnes of CO2 or 333,444 emission units in 2015 (subject to obtaining a certificate for greenhouse gas emission).

Water permits

The Water Code dated 9 July 2003 No. 481 (the "**Water Code**") aims at implementing governmental policy in relation to the utilisation and protection of water resources. The Water Code sets out obligations for the use of water and discharge of certain materials into the water, on the basis of Water Use Permits (or "**WUPs**"). Nostrum was issued a WUP for exploration and production of industrial technical underground waters on 5 December 2008 and which is valid until 31 December 2014. See Part 2 "*Risk Factors—Risk Factors Relating to the Group's Business—The Group requires significant water supplies in order to conduct its business and failure to obtain such water may adversely affect its business*". WUPs can be withdrawn if the terms of special water use specified in the relevant WUP are breached. Such terms include monitoring the quality of underground water, submitting statistical reports and monitoring reports, complying with requirements relating to water protection during mining operations and regular checking of equipment. If any of Nostrum's circumstances relating to its water use change (for example, in relation to the drilling of new wells, the quality of underground water or limits on water extraction), Nostrum must agree such changes with the regional department of the Committee for Water Resources of the MEWR. The term of a WUP may be extended subject to compliance with requirements specified within the relevant WUP. Nostrum's current WUP fully suffices existing water requirements. On 10 January 2014 Nostrum applied for further WUPs for 2015-2016.

Enforcement

Article 116 of the Environmental Code specifies which state officials are responsible for monitoring environmental compliance and enforcing environmental requirements. These officials include the Chief State Ecological Inspector, the Deputy State Ecological Inspector and other regional officials who have the authority to supervise environmental compliance and initiate judicial proceedings.

Article 117 of the Environmental Code authorises state officials, in their enforcement of environmental protection measures, to, *inter alia*:

- inspect facilities and take measurements and/or samples for analysis;
- request and receive documentation, results of analysis and other materials;
- initiate procedures relating to the (i) recall of licences; (ii) termination of contracts for the use and taking of natural resources; and (iii) suspension and annulment of environmental and other permits in the event of violation of the terms of such permits;
- issue orders for individuals and legal entities to eliminate violations of Kazakh environmental laws;
- file court claims with respect to violations of Kazakh laws; and
- file with the competent body, offers on suspension or termination of a subsoil use contract in certain circumstances.

Statute of limitations on proceedings

The time limit for bringing civil proceedings for breach of environmental requirements is governed by the general limitation period provisions under Kazakh law, in particular, under Article 178 of the Civil Code which provides for a three-year limitation period. This limitation does not apply to regulatory procedures, criminal or administrative prosecutions in connection with breaches of environmental requirements, since administrative and criminal laws establish their own limitation periods.

Health and safety compliance

Nostrum's business is affected by various laws and normative acts of the Republic of Kazakhstan relating to safety and health matters and regulated by various state bodies, including Committee for State Sanitary and Epidemiological Supervision of the Ministry of Public Health. Such laws and normative acts include the Sanitary Rules "Sanitary and Epidemiological Requirements to the Facilities of Oil Producing Industry" approved by the

Government Resolution No. 167 dated 25 January 2012 and other normative acts setting requirements for the industry safety in oil and gas industry. Oil and gas operations carried out by Nostrum within Kazakhstan are also regulated by the CSCES with respect to industry specific health and safety requirements. As part of the health and safety assessment dated 31 July 2013, AMEC confirmed that Nostrum generally complied with health and safety standards applicable to the Kazakhstan oil and gas industry. The health and safety assessment of Nostrum conducted by AMEC found no significant issues.

Nostrum's operations are subject to legislation, regulations and other requirements relating to health and safety applicable to oil and gas companies operating in Kazakhstan, which are regulated by state authorities, including the Ministry of Labour and Social Protection of the Population. The PSA and the subsoil use contracts in respect of the Rostoshinskoye, Darinskoye and Yuzhno-Gremyachenskoye fields additionally require that Nostrum's operations be carried out in conformity with applicable health and safety requirements. As required by Kazakhstan regulations, Nostrum receives a health and safety certification once every three years.

Insurance

Kazakhstan law establishes several types of mandatory insurance to be obtained by any entity conducting certain types of activities. As at the date of this Prospectus, Nostrum is in compliance with all mandatory insurances required by Kazakh law.

The following types of mandatory insurance are applicable to the oil and gas industry under Kazakh law:

Insurance of the Employees against Accidents at Work

According to the Kazakhstan Law "On Mandatory Insurance of an Employee against Accidents when Carrying Out Employee's Labour Duties" (No. 30-III ZRK, dated 7 February 2005, as amended), all employers are obliged to insure employees against accidents when carrying out their employment duties.

Insurance of the Civil Liability of Transport Vehicle Owners

According to the Kazakhstan Law "On Mandatory Insurance of the Civil Liability of Transport Vehicle Owners" (No. N 446-II, dated 1 July 2003, as amended), civil liability of owners of cars, trucks, buses, microbuses, and transport vehicles, motor transport and trailers (semi-trailers) are subject to mandatory insurance requirements, and any use of such vehicles without insurance is prohibited.

Environmental Insurance

Pursuant to the Kazakhstan Law "On Mandatory Environmental Insurance" (No. 93-III ZRK, dated 13 December 2005, as amended), any entity carrying out environmentally hazardous activities should insure against the risks associated with such respective activities. Environmental insurance should cover damages to life, health and property of third parties and the environment caused as a result of an environmentally hazardous activity (except for payments for moral damage, loss of profit and payment of penalty interest).

According to Article 7 of the List of Environmentally Hazardous and Other Activities, approved by the Governmental Resolution "On Approval of the List of Environmentally Hazardous and Other Activities" (No. 543, dated 27 June 2007), oil and gas commercial production; oil, oil products and chemicals storage; and operating oil and gas main pipelines are classified as environmentally hazardous types of activities.

Insurance of Civil Liability of Danger Units Owners

According to the Kazakhstan Law "On Industrial Security of the Hazardous Manufacturing Units" (dated 3 April 2002, No. 314-II) and the Kazakhstan Law "On Mandatory Insurance of Civil Liability of Owners of Units the Activity of which is Associated with Danger of Damage to Third Parties" (No. 580-II, dated 7 July 2004, as amended), companies must insure against risks associated with their hazardous manufacturing units, defined as a unit that produces, uses, processes, generates, stores, transports or destroys at least one of the following substances: flammable substances, explosives, fuels, oxidising agents, toxic agents, highly toxic substances and other hazardous substances.

For additional information, please see Part 6 "*Information on the Group—Insurance*".

Licencing of Subsoil Services, Storage and Pipeline Transportation

In July 2007, the new Kazakhstan Law "On Licencing" came into force (the "**Licencing Law**"). According to the Licencing Law, operations concerning production of oil and gas and operation of oil and gas main pipeline are licenced activities. Subsoil services (such as the drilling of oil and gas wells and other related services) are also subject to licencing.

A licence is not transferable from an existing facility to another. It is granted for an unlimited period of time by the Competent Authority after submission of the required documentation confirming that the facility fulfils all applicable requirements and payment of a fee.

A licence can be suspended or terminated in case a licensee fails to comply with qualification requirements, including but not limited to, a lack of qualified personnel or proper equipment.

If a legal entity conducts activities without the relevant licence, as required by the Licencing Law, such entity and its managers are subject to administrative and criminal liability.

Nostrum is not required to obtain most operational licences to conduct exploration and production works, as it engages third parties which already possess the relevant licences including the licenses for performing drilling operations in the Chinarevskoye Field.

However, Nostrum does hold licences for the following types of activities:

- operating main gas, oil and oil products pipelines (State licence no. 000102 09, dated 7 March 2012); and
- assembling and repair of oil and gas fields, generating power, explosion proof electrical equipment, lifting constructions, boilers with working pressure above 0.7 kg/square centimetres and heating medium temperature above 115°, and vessels and pipelines working under pressure exceeding 0.7 kg/square centimetres (State licence no. 002596).

Oil and Gas Export Duties

The export duty for crude oil exports was effectively replaced with a rent tax under the 2009 Tax Code, but in 2010, the Kazakh Government re-introduced an export duty for crude oil exports.

On 15 October 2005, the Kazakh Government adopted Resolution (No. 1036), which approved a list of certain oil products on which an export customs duty was levied (the "**ED Resolution**"). Initially, one of the purposes of the ED Resolution was to stimulate development of internal refinery/processing industries. By amendments to the ED Resolution, dated 8 April 2008, "crude oil" was added to the list of oil products covered by the ED Resolution.

As of 12 March 2014, the rate of export customs duty for crude oil is U.S.$80 per tonne. The ED Resolution provides that the export duties for crude oil shall not apply to (i) export by subsoil users of crude oil produced under their production sharing agreements, if such agreements had been signed with the Kazakh Government or the Competent Authority before 1 January 2009, and such agreement had undergone a mandatory tax appraisal and contains a specific exemption from paying export customs duties for crude oil; and (ii) export by subsoil users of crude oil produced under their subsoil use contracts, which are not production sharing agreements and which provide for an exemption from paying export customs duties for crude oil, except for crude oil that is exported by subsoil users paying royalties. In addition to these exemptions, a specific export duty applies if the importing countries are party to the Free Trade Zone Treaty of 18 October 2011 between CIS countries (e.g. Ukraine) except as may be otherwise provided in the treaty.

Notwithstanding this, the authorities currently seek to impose export customs duty in all cases pursuant to the ED Resolution. Nostrum has written to the Ministry of Finance and the Competent Authority to state that Nostrum is not subject to such export duty and to protest against the application of such duty to it. However, to date, the Ministry of Finance continues to seek to compel Nostrum to pay such export duty. Nostrum therefore currently pays such export duty under protest. See "*Risk Factors—Risk Factors Relating to the Group's Business—The Group is subject to an uncertain tax environment that may lead to disputes with regulatory authorities*".

Anti-monopoly regulation

The Anti-monopoly Agency is responsible for the supervision of competition matters, including those relating to the oil and gas industry. It regulates the competitive behaviour of legal entities that are not natural monopolies and supervises legal entities that hold dominant positions in a particular commodity market. The Anti-monopoly Agency also maintains a register of legal entities having a dominant or monopolistic position in the market.

In accordance with the Kazakhstan Competition law (dated 25 December 2008) (the "**Competition Law**"), a company is deemed to occupy a dominant position if its market share is equal to or exceeds a threshold of 35%. In addition, if not more than three entities in a relevant market hold an aggregate market share of 50% or more, or if not more than four entities in a relevant market hold an aggregate market share of 70% or more, each is deemed to hold a dominant market position, provided that, if an entity holds a market share not exceeding 15% of the relevant market, such entity shall not be deemed to hold a dominant market position.

Market participants that intend to engage or have engaged in an economic concentration must obtain approval from the Anti-monopoly Agency or properly notify it of the engagement, depending on the type of concentration.

According to the Competition Law, an economic concentration is:

(1) reorganisation of a market participant through a merger or consolidation;

(2) acquisition by a person (or a group of persons) of voting shares (or participation interests in charter capital or participatory shares) in a market participant where such person (or group of persons) gains the right to dispose of more than 25% of such shares (or participation interests in charter capital or participatory shares) if prior to such acquisition such person (or group of persons) did not possess shares (or participation interests or participatory shares) in such market participant or possessed 25% or less of the voting shares (or participation interests in charter capital or participatory shares) in the charter capital of such market participant;

(3) acquisition by a market participant (or a group of persons) of fixed production assets and/or intangible assets of another market participant into ownership, possession and use, including in payment (transfer) of charter capital if the book value of the property constituting the subject of the transaction (inter-related transactions) exceeds 10% of the book value of the fixed production assets and intangible assets of the market participant alienating or transferring the property;

(4) acquisition by a market participant (including on the basis of a trust management agreement, joint operation agreement or agency agreement) of rights which allow such market participant to issue binding instructions to the other market participant for the conduct of its business activities or to perform the functions of its executive body; or

(5) participation of the same individuals in the executive bodies, boards of directors, supervisory boards or other management bodies of two or more market participants, provided that such individuals determine the terms of business activities conducted by such market participants.

Either of the above transactions effected within one group of entities is not considered to be an economic concentration and as such does not require approval from or notification to the Anti-monopoly Agency.

Approval by the Anti-monopoly Agency (for transaction(s) numbered (1) to (3) immediately above) or the notification to the Anti-monopoly Agency (for transactions numbered (4) and (5)) is required when the aggregate book value of assets of the reorganised market participants (or group of persons) or the acquirer (or group of persons) and the market participant whose voting shares (or participation interests in charter capital or participatory shares) are acquired, or their aggregate sales of goods in the most recent financial year exceed ten million-times the monthly calculation index in effect in the year of filing an application for approval (notification) (which is currently approximately U.S.$100 million), or if one of the parties to the transaction is a market participant occupying a dominant or monopoly position on the relevant goods market.

In general, it is the responsibility of the purchaser, which acquires shares (participation interests, stocks), fixed production assets, intangible assets or respective rights, to obtain prior approval from the Anti-monopoly Agency.

A company which engages in an economic concentration without the applicable approval of or notification to the Anti-monopoly Agency in violation of the Competition Law may be subject to administrative fines and penalties.

State registration, re-registration of a market participant, rights to real estate and economic concentration conducted in violation of the requirements of the Competition Law discussed above may be invalidated and cancelled by a court on the basis of an action brought by the Anti-monopoly Agency.

PART 9
DIRECTORS, MANAGEMENT AND CORPORATE GOVERNANCE

1. Directors

As at the date of this Prospectus, the members of the Board and their positions are:

Name	Position
Frank Monstrey	Executive Chairman
Kai-Uwe Kessel	Chief Executive Officer
Jan-Ru Muller	Chief Financial Officer
Eike von der Linden	Senior Independent Non-Executive Director
Atul Gupta	Independent Non-Executive Director
Sir Christopher Codrington, Bt.	Independent Non-Executive Director
Mark Martin	Independent Non-Executive Director
Piet Everaert	Non-Executive Director
Pankaj Jain	Non-Executive Director

Frank Monstrey (Executive Chairman)

Mr. Monstrey was appointed as a director of the General Partner on 16 November 2007, as a Director on 3 October 2013 and has served as chairman of the partners participating in Nostrum since September 2004. Since 1991, Mr Monstrey has been Chief Executive Officer of Probel, a private equity and asset management firm based in Belgium specialising in long term capital management in emerging markets. Mr Monstrey holds a graduate degree in Business Economics from the University of Louvain (KUL).

Kai-Uwe Kessel (Chief Executive Officer)

Mr. Kessel was appointed as a director of the General Partner on 16 November 2007, as a Director on 3 October 2013 and has served as chief executive of the partners participating in Nostrum since November 2004. Since 2005, Mr Kessel has been Managing Director of Probel. From 2002 to 2005, Mr Kessel was director of Gaz de France's North African E&P division. From 1992 to 2001, Mr Kessel was Managing Director of Erdgas Erdol GmbH, an oil and gas company owned by Gaz de France, and a member and chairman of the board of KazGermunai. Mr Kessel is a graduate of the Gubkin Russian State University of Oil and Gas.

Jan-Ru Muller (Chief Financial Officer)

Mr. Muller was appointed as Chief Financial Officer of Nostrum on 16 November 2007 and as a Director on 3 October 2013. Mr Muller has served in various capacities at Probel since 2000. He oversaw Nostrum's adoption of IFRS and the implementation of SAP. Mr Muller has been the managing director of Axio systems, an information technology company he founded in 1990. From 1988 to 1990 he worked with Andersen Consulting. He holds a BEng degree from Utrecht Municipal Institute of Technology and an MBA degree from the University of Louvain (KUL).

Eike von der Linden (Senior Independent Non-Executive Director)

Mr. von der Linden was appointed as a director of the General Partner on 16 November 2007 and as a Director on 19 May 2014. He has been the Managing Director of Linden Advisory and Consulting Services since 1988. Since 1985, Mr. von der Linden has acted as an independent adviser to financial institutions for equity investments, mezzanine and debt funding (project finance) in the field of natural resources. Mr von der Linden holds a PhD in mining economics from the Technical University of Clausthal.

Atul Gupta (Independent Non-Executive Director)

Mr. Gupta was appointed as a director of the General Partner on 30 November 2009 and as a Director on 19 May 2014. Mr. Gupta has worked for 25 years in the international upstream oil and gas business with Charterhouse Petroleum, Petrofina, Monument and Burren Energy. Mr. Gupta joined Burren in 1999 as Chief Operating Officer and served as its Chief Executive Officer from 2006 until the company was sold to ENI in 2008. Mr. Gupta has a degree in chemical engineering from Cambridge University and studied petroleum engineering at the Heriot Watt University, Edinburgh.

Sir Christopher Codrington, Bt. (Independent Non-Executive Director)

Sir Christopher was appointed as a Director on 19 May 2014. Sir Christopher has 28 years of executive board and senior management experience in the oil and gas, hospitality and other industries and has spent eight years living in Houston, Texas developing prospects in various oil and gas fields for COG, Inc, Texas General Resources, Inc, TexBrit Corporation, Inc and Whitehall Energy Limited. Sir Christopher has a diploma in advanced farm management from the Royal Agricultural College.

Mark Martin (Independent Non-Executive Director)

Mr. Martin was appointed as a Director on 19 May 2014. Mr. Martin has over 20 years of investment banking experience with Barclays, Baring Securities and ING, where he was the global head of equity capital markets from 2003 to 2011. Between 2011 and 2014, he served as the CEO of Exillon Energy PLC. Mr. Martin graduated from Cambridge University with a degree in social and political sciences.

Piet Everaert (Non-Executive Director)

Mr. Everaert was appointed as a director of the General Partner on 16 November 2007 and as a Director on 19 May 2014. He has been a lawyer at the Brussels Bar since 1986 and has served as a partner of the VWEW Advocaten law firm since 1993. He is active in the field of Belgian business law. Mr. Everaert graduated from the University of Leuven (KUL) in 1984 and obtained the Diploma of Advanced European Legal Studies at the College of Europe (Bruges-Belgium) in 1985. Mr. Everaert is Claremont's nominee on the Board pursuant to the terms of the Claremont Relationship Agreement.

Pankaj Jain (Non-Executive Director)

Mr. Jain was appointed as a director of the General Partner on 26 November 2012 and as a Director on 19 May 2014. Since 2012, Mr. Jain has been CEO of KSS Global and has over 20 years of experience in engineering, procurement and construction projects in India, Kazakhstan, the Middle East and the Far East. Mr. Jain is a graduate from the Regional Engineering College, Trichy, India (B.E. Hons in Civil Engineering (Major: oil and gas infrastructure)). Mr. Jain is KSS Global's nominee on the Board pursuant to the terms of the KSS Global Relationship Agreement.

2. Senior Management

As at the date of this Prospectus, in addition to the Board, the members of the senior management and their positions are:

Name	Position
Thomas Hartnett	Group General Counsel
Jan Laga	Deputy CEO
Thomas Richardson	Head of Corporate Finance

Thomas Hartnett

Mr. Hartnett was appointed as Group General Counsel of Nostrum on 5 September 2008. Mr. Hartnett was previously a partner in the international law firm White & Case LLP, where he focused on cross-border corporate and mergers and acquisitions transactions and worked in the firm's New York, Istanbul, London, Brussels and Bangkok offices over a 16 year period. Mr Hartnett also served as Senior Corporate Counsel for Intercontinental Hotels Group from 1996 to 1998. Mr Hartnett holds a BA in Comparative and Developmental Politics from the University of Pennsylvania and a JD from the New York University School of Law, and is a member of the New York Bar.

Jan Laga

Mr. Laga was appointed as deputy CEO of Nostrum on 1 January 2010. Mr. Laga has over 20 years of experience in industrial group management, including positions with Picanol, Berry Group, Ackermans & van Haaren and Koramic. Mr. Laga holds a Master's Degree in Electro-Mechanical Engineering (University of Leuven (KUL) and an MBA from Insead.

Thomas Richardson

Mr. Richardson graduated from Bristol University with a BSc in Economics and Politics. Mr. Richardson has seven years of experience in banking covering the emerging markets and has been involved in raising over U.S.$5 billion for emerging markets companies in the capital markets. He also has two years of experience in consultancy work across the emerging markets, being involved in over $1.25 billion of financings.

3. Corporate Governance

The Directors support high standards of corporate governance. Except as set out below, as at the date of the Prospectus and upon Admission, the Company will comply with the provisions of the Corporate Governance Code. The Board comprises an executive chairman, two further Executive Directors and six Non-Executive Directors. The Company regards all of the Non-Executive Directors to be independent within the meaning of "independent" as defined in the Corporate Governance Code, other than Piet Everaert and Pankaj Jain. Piet Everaert and Pankaj Jain are not deemed to be independent as a result of representing Claremont (a Dutch limited partnership indirectly controlled and beneficially owned by Frank Monstrey, the chairman of the Company, and his spouse) and KSS Global, respectively, who are expected to hold approximately 27.2% and 26.6% of the Ordinary Shares of the Company on Admission.

The Board plans to meet on at least six occasions during the course of the year to review trading performance and budgets, funding, to set and monitor strategy, examine acquisition opportunities and report to shareholders. The Board has a formal schedule of matters specifically reserved to it for decisions. The roles of Chairman and Chief Executive Officer are separate and the responsibilities of Chairman and Chief Executive Officer are independently defined. It is the Chairman's responsibility to provide leadership of the Board and set the overall objectives and strategic direction of the Company as well as to ensure that the Board is provided with accurate, timely and clear information in relation to the Group and its business. The Chief Executive Officer will have day-to-day executive responsibility for the running of the Company's businesses. The Chairman and Chief Executive Officer will share responsibility for the representation of the Company to third parties.

The Corporate Governance Code recommends that the Board should appoint one of its Independent Non-Executive Directors to be the Senior Independent Director. The senior independent director should be available to shareholders if they have concerns that contact through the normal channels of Chairman, Chief Executive Officer or Chief Financial Officer has failed to resolve or where such contact is inappropriate. Eike von der Linden is the Board's senior independent director and will continue in this role following Admission.

The Board has appointed an Audit Committee, a Remuneration Committee and a Nomination Committee. The members of these committees are appointed principally from among the independent directors and all appointments to these committees shall be for a period of one year. The terms of reference of the committees have been drawn up in accordance with the provisions of the Corporate Governance Code. A summary of the terms of reference of these committees is set out below.

Each committee and each Director has the authority to seek independent professional advice where necessary to discharge their respective duties, in each case at the Company's expense. In addition, each Director and committee has access to the advice of the Company Secretary, Thomas Hartnett.

The Company has adopted a share dealing code of securities dealings in relation to the Ordinary Shares which is based on, and is no less exacting than, the Model Code as published in the Listing Rules. The code will apply to the Directors, senior management and other relevant employees of the Group.

The Company has implemented internal procedures and measures designed to ensure compliance by it and other members of the Group with the Bribery Act.

Areas of Non-Compliance

Executive chairman

The Corporate Governance Code requires that a company's chairman should be independent upon appointment. The Directors consider that Mr. Monstrey does not meet the independence criteria set out in the Corporate Governance Code, in part given his executive position in the Company. Companies owned and controlled by Mr. Monstrey acquired the Group's assets outright in 2004 and Mr. Monstrey has been the leading driver behind the successful development of the business since that date, including the listing of

Nostrum Oil & Gas LP on the London Stock Exchange. As such, the Directors consider that his continued involvement as an Executive Director is important for the future of the business, given his experience and expertise in the development of the Group's oil and gas assets in Kazakhstan.

The roles of the Chairman and the Chief Executive Officer are separately held and there are clear written guidelines to support the division of responsibility between them. The Chairman will be responsible for leadership of the Board and setting the overall objectives and strategic direction of the Company. The Chief Executive Officer will have day-to-day executive responsibility for the running of the Company's businesses. The Chairman and Chief Executive Officer will share responsibility for the representation of the Company to third parties.

Eike von der Linden, as the Senior Independent Director, will undertake the senior non-executive role and make himself available to shareholders as required.

Number of independent directors

In addition, the Corporate Governance Code requires that at least half of a company's board of directors, excluding the chairman, comprise Non-Executive Directors determined by the board to be independent. The Board, excluding the Executive Chairman, will have four Independent Non-Executive Directors and therefore will satisfy this requirement under the Corporate Governance Code. However, given the Chairman fulfils an executive role, five of the nine directors will not be considered independent for the purposes of the Corporate Governance Code.

As noted above, KSS Global, whilst not considered independent for the Corporate Governance Code purposes, is independent of the other shareholders in the Company. KSS Global has no alignment with any other major shareholder and hence KSS Global's nominee to the Board is considered to be independent in character and judgement with no relationships which directly affect his judgement. For example, there is no cross-ownership, cross-directorships or familial relationship with other major shareholders; KSS Global does not pursue business interests with any other shareholders; and, any commercial interaction between KSS Global and the Group has been on an arm's length basis. On this basis, Pankaj Jain, as KSS Global's nominee on the Board, is considered independent of the other Directors on the Board.

No single group is therefore able to exercise majority influence over the Board as a whole.

In order to provide additional protections to the Company in respect of these areas of non-compliance with the Corporate Governance Code, the Company has entered into relationship agreements with each of Claremont and KSS Global (see paragraphs 2 and 3 of Part 10 "*Principal Shareholders and Related Party Transactions*" and Part 2 "*Risk Factors—Risks Relating to the Group's Business—Certain major shareholders in the Company may be able to exercise substantial influence over the Company and the Group*"). Pursuant to these relationship agreements, each of Claremont and KSS Global have independently undertaken that they shall, for so long as they (and any person acting jointly by agreement with such entity whether formal or otherwise, which shall be deemed to include any affiliate of such person) are entitled to exercise, or to control the exercise of, 10% or more of the rights to vote at the Company's general meetings (amongst other undertakings):

- allow the Company and its affiliates at all times to carry on its business independently of Claremont and its affiliates or KSS Global (as applicable);
- not influence the day-to-day running of the Company at an operational level or hold or acquire a material shareholding in one or more significant subsidiaries of the Company;
- exercise its voting rights in such a manner as to procure (to the extent possible):
  - at least half of the Board comprises independent directors (excluding the chairman of the Board);
  - the Audit and Remuneration Committees shall comprise entirely independent directors; and
  - the Nomination Committee and any other committee of the Board to which significant powers, authorities or discretions are delegated shall at all times consist of a majority of independent directors; and
- In addition, under the Claremont Relationship Agreement, Claremont undertakes to allow the business and affairs of the Company and Group to be operated in the best interests of the Shareholders as a whole, to allow the Company to be managed in accordance with the Corporate Governance Code to the extent and on such terms as may be determined by the Board, to comply with the Disclosure and Transparency Rules in respect of its interests in the Ordinary Shares and to comply with any further amendments or supplements to the Corporate Governance Code.

Audit Committee

The Audit Committee comprises Eike von der Linden, Atul Gupta and Sir Christopher Codrington, Bt.. It is the opinion of the Directors that Mr. von der Linden has recent and relevant financial experience to chair the Audit Committee.

The Audit Committee plans to meet at least four times a year at appropriate times in the reporting and audit cycle of the Company and more frequently if required.

The purpose of the Audit Committee is to assist the Board in fulfilling its responsibilities of oversight and supervision of, among other things:

- the integrity of the financial statements of the Company including annual and interim reports, financial returns to regulators and announcements of a price sensitive nature;
- the adequacy of the Company's internal controls and accountancy standards; assessing consistency and clarity of disclosure as well as the operating and financial review and corporate governance statement; and
- the relationship with the Company's external auditor including appointment, remuneration, terms of engagement, assessing independence and objectivity and ultimately reviewing the findings and assessing the standard and effectiveness of the external audit.

The Audit Committee considers annually how the Group's internal audit requirements shall be satisfied and makes recommendations to the Board accordingly as well as on any area it deems needs improvement or action.

Remuneration Committee

The Remuneration Committee comprises Eike von der Linden (chairman), Piet Everaert, Mark Martin and Sir Christopher Codrington, Bt.. The Remuneration Committee is responsible for:

- making recommendations to the Board on the Company's overall framework for remuneration and its cost and in consultation with the Chairman and Chief Executive Officer determining remuneration packages of each Executive Director;
- reviewing the scale and structure of Executive Directors' remuneration and the terms of their service or employment contracts, including share based schemes, other employee incentive schemes adopted by the Company from time to time and pension contributions. Executive Directors of the Company are not permitted to participate in discussions or decisions of the Committee regarding their own remuneration; and
- ensuring that payments made on termination are fair to the individual and the Company.

The remuneration of the Non-Executive Directors is determined by the Chairman and the other Executive Directors outside the framework of the Remuneration Committee.

Nomination Committee

The Nomination Committee comprises of Eike von der Linden (chairman), Sir Christopher Codrington, Bt. and Frank Monstrey. The terms of reference of this committee require that a majority of its members comprise Independent Non-Executive Directors and that the chairman is either the Senior Independent Non-Executive Director or another Independent Non-Executive Director.

The Nomination Committee plans to meet at least twice a year and more frequently if required and has responsibility for making recommendations to the Board regarding the composition of the Board, its committees and corporate governance issues. The nominations committee is also responsible for periodically reviewing the Board's structure, determining succession plans for the Chairman and Chief Executive, and providing advice to the Board on the retirement and appointment of additional and/or replacement Directors.

4. The City Code

The City Code is issued and administered by the Takeover Panel. The Company is subject to the City Code and therefore its shareholders are entitled to the protection afforded by the City Code.

Mandatory bids

Under the City Code, if an acquisition of interests in the Company's shares were to result in the aggregate interests of an acquirer and persons acting in concert with it in the Company's shares representing 30% or more of the voting rights in the Company, the acquirer and, depending upon the circumstances, persons acting in concert with it, would be required (except with the consent of the Takeover Panel) to make a cash offer for the outstanding shares. A similar obligation to make such a mandatory offer would also arise on the acquisition of an interest in shares by a person holding (together with persons acting in concert with it) an interest in shares carrying between 30% and 50% of the voting rights in the Company if the effect of such acquisition were to increase that person's percentage of the voting rights.

Squeeze-out

Under the Companies Act, if a "takeover offer" (as defined in section 974 of the Companies Act) is made for the Company's shares and the offeror were to acquire, or unconditionally contract to acquire, not less than 90% in value of the shares to which the offer relates (the "**Takeover Offer Shares**") and not less than 90% of the voting rights attached to the Takeover Offer Shares, within three months of the last day on which its offer can be accepted, it could acquire compulsorily the remaining 10%. It would do so by sending a notice to outstanding shareholders telling them that it will acquire compulsorily their Takeover Offer Shares and then, six weeks later, it would execute a transfer of the outstanding Takeover Offer Shares in its favour and pay the consideration to the Company, which would hold the consideration on trust for outstanding shareholders. The consideration offered to the shareholders whose Takeover Offer Shares are acquired compulsorily under the Companies Act must, in general, be the same as the consideration that was available under the takeover offer.

Sell-out

The Companies Act also gives minority shareholders a right to be bought out in certain circumstances by an offeror who has made a takeover offer. If a takeover offer related to all the shares and at any time before the end of the period within which the offer could be accepted the offeror held or had agreed to acquire not less than 90% of the shares to which the offer relates, any holder of shares to which the offer related who had not accepted the offer could by a written communication to the offeror require it to acquire those shares. The offeror is required to give any shareholder notice of his right to be bought out within one month of that right arising. The offeror may impose a time limit on the rights of the minority shareholders to be bought out, but that period cannot end less than three months after the end of the acceptance period. If a shareholder exercises his or her rights, the offeror is bound to acquire those shares on the terms of the offer or on such other terms as may be agreed.

PART 10
PRINCIPAL SHAREHOLDERS AND RELATED PARTY TRANSACTIONS

1. Principal Shareholders

As at the date of this Prospectus, and as expected to exist on Admission, and in addition to the interests of certain Directors, as set out in paragraph 8 of Part 17 "*Additional Information*", the Company is aware of the following persons who, directly or indirectly, had or are expected to have at Admission a notifiable interest in 3% or more of the Company's issued Ordinary Shares:

	As at the date of this Prospectus		Admission[1]	
Name	**Number of Shares**	**% of issued Ordinary Shares**	**Number of Shares**	**% of issued Ordinary Shares**
Claremont Holdings C.V.[2]	—	—	51,190,476	27.2
KazStroyService Global B.V.[3]	—	—	50,000,000	26.6
Dehus Dolmen Nominees Limited[4]	—	—	28,906,483	15.3
M&G Investment Management Limited	—	—	17,640,800	9.4
J.P. Morgan Asset Management (Korea) Company, Ltd.	—	—	8,013,400	4.3
Templeton Asset Management (Singapore) Limited	—	—	7,000,000	3.7
Nostrum Oil & Gas LP[5]	49,999	50.0	—	—
Thomas Hartnett[6]	50,001	50.0	—	—

Notes:

(1) Assuming (i) no new GDRs are issued prior to the date of Admission and (ii) there are no transfers of GDRs by the holders listed above prior to the date of Admission.

(2) Claremont Holdings C.V. is indirectly controlled and beneficially owned by Frank Monstrey, the chairman of the Company, and his spouse.

(3) KazStroyService Global B.V. is indirectly controlled by Timur Kulibayev, Arvind Tiku, Lakshmi Mittal and Goldman Sachs. The Company notes that Timur Kulibayev, Arvind Tiku and Lakshmi Mittal are business associates.

(4) Baring Vostok Investments PCC Limited, which is managed by an affiliate of Dehus Dolmen Nominees Limited, holds 152,885 GDRs. Dehus Dolmen Nominees Limited does not however have any interest in those GDRs.

(5) Nostrum Oil & Gas LP is the subscriber for one of the two ordinary shares issued upon incorporation of the Company. This subscriber share will, upon Admission, be repurchased by the Company.

(6) Thomas Hartnett (the company secretary of the Company) holds 50,001 Ordinary Shares for the purposes of the structuring of the Scheme. These Ordinary Shares will be acquired by Nostrum Oil & Gas LP in connection with the Scheme at their subscription value.

None of the Shareholders detailed above have voting rights which differ in any way from those of the Company's other shareholders. So far as the Company is aware, save as set out in the table above no person owns 3% or more of the issued share capital of the Company.

As far as the Company is aware, as at 16 May 2014 (being the last practicable date prior to the publication of this Prospectus) there are no arrangements the operation of which may at a later date result in a change of control of the Company.

The Company is not aware of any person who either as at the date of this Prospectus or immediately following Admission exercises, or could exercise, directly or indirectly, control over the Company.

Claremont and KSS Global will each be a substantial shareholder of, a "person exercising significant influence" over, and a "related party" to, the Company for the purposes of the Listing Rules.

2. Relationship Agreement with Claremont

On Admission, Claremont, a company indirectly controlled by Frank Monstrey, the chairman of the Company, and his spouse, and its affiliates are expected to own approximately 27.2% of the issued share capital of the Company.

On 19 May 2014, the Company entered into a relationship agreement with Claremont (the "**Claremont Relationship Agreement**") which will, conditional upon Admission, regulate (in part) the degree of control that Claremont and its affiliates may exercise over the management of the Company. The principal purposes of the Claremont Relationship Agreement are to ensure that the Company is capable at all times of carrying on its business independently of Claremont and its affiliates and all of the Company's transactions and relationships with Claremont and its affiliates are at arm's length and on normal commercial terms.

The Claremont Relationship Agreement will continue until the earlier of (i) the Ordinary Shares ceasing to be admitted to the Official List of the FCA and to trading on the London Stock Exchange or (ii) Claremont (together with any of its affiliates) ceasing to be entitled to exercise, or to control the exercise of, 10% or more of the rights to vote at the Company's general meetings.

Under the Claremont Relationship Agreement, Claremont undertakes that:

(a) it will, and will procure its affiliates to, allow the business and affairs of the Company and the Group to be operated in the best interests of the Shareholders as a whole;

(b) it will, and will procure its affiliates will, allow the Company and its affiliates at all times to carry on its business independently of Claremont and its affiliates;

(c) it will not, and will procure its affiliates will not, act in any way which shall prejudice the ability of the Company and its affiliates to carry on its business independently of Claremont or its affiliates;

(d) it will, and will procure its affiliates to, allow the Company to be managed in accordance with the Corporate Governance Code to the extent and on such terms as may be determined by the Board and to comply with any further amendments or supplements to the Corporate Governance Code as may be adopted by the Board, and it acknowledges its obligations under, and agrees to comply with, and will procure its affilates comply with, the Disclosure and Transparency Rules in respect of its interests in the Ordinary Shares;

(e) it will not, and will procure its affiliates will not, take any action (or omit to take any action) to prejudice the Company's status as a listed company or its suitability for listing under the Listing Rules after Admission has occurred or the Company's ongoing compliance with the Listing Rules and the Disclosure and Transparency Rules or have the effect of preventing the Company from complying with its obligations under the Listing Rules, provided that this shall not prevent Claremont (or any other person) from:

    (i) accepting a takeover offer for the Company made in accordance with the City Code (a "**Takeover Offer**") in relation to their respective interests in the Company or, where such Takeover Offer is made by way of a scheme of arrangement under Part 26 of the Companies Act (a "**CA2006 Scheme**"), voting in favour of such CA2006 Scheme at the court and related shareholder meetings or otherwise agreeing to sell their Ordinary Shares in connection with a Takeover Offer; or

    (ii) making a Takeover Offer by way of a general offer for all the outstanding Ordinary Shares or by way of a CA2006 Scheme and de-listing the Company after such Takeover Offer has become wholly unconditional or, in the case of a CA2006 Scheme, after it has become effective;

(f) it will not, and will procure that its affiliates will not, influence the day-to-day running of the Company at an operational level or hold or acquire a material shareholding in one or more significant subsidiaries of the Company; and

(g) it will exercise its voting rights in such a manner as to procure (to the extent possible):

    (i) at least half of the Board comprises independent directors (excluding the chairman of the Board);

    (ii) the Audit Committee shall comprise entirely independent directors and the Remuneration Committee shall comprise not less than three independent directors; and

    (iii) the Nomination Committee and any other committee of the Board to which significant powers, authorities or discretions are delegated shall at all times consist of a majority of independent directors.

Both Claremont and the Company undertake that they shall (and shall procure that the relevant members of their respective affiliates shall) with effect from the date of the Claremont Relationship Agreement conduct any transactions and relationships (whether contractual or otherwise, including any subsequent amendment thereof or variation thereto, including the implementation or enforcement thereof) between Claremont or any of its affiliates, on the one hand, and of the Company or any of its affiliates, on the other, on arm's length terms and on a normal commercial basis.

The Company undertakes that it shall treat all holders of the same class of Ordinary Shares that are in the same position equally in respect of the rights attaching to such shares, save that the Company has agreed that Claremont shall have the right (i) to nominate two directors to the Board for so long as Claremont is a significant shareholder and (ii) to nominate one director to the Board so long as Claremont (and its affiliates) own 10% or more of the issued Ordinary Shares (such persons being a "**Claremont Director**"). For these purposes, a "significant shareholder" is any person (or persons acting jointly by agreement whether formal or otherwise, which shall be deemed to include any affiliate of such person) who is entitled to exercise, or to control the exercise of, 20% or more of the rights to vote at the Company's general meetings.

Nothing in the Claremont Relationship Agreement shall prevent any of the Claremont Directors from performing any duty or exercising any discretion in such manner as such Claremont Director sees fit in his capacity as a director of the Company or any of its affiliates.

The Directors believe that the terms of the Claremont Relationship Agreement will enable the Company to carry on its business independently from Claremont and its affiliates, and ensure that (subject to other existing contractual arrangements with Claremont as at the date of Admission) all transactions and relationships between the Company and Claremont and its affiliates are, and will be, at arm's length and on a normal commercial basis, such that Claremont is not able to abuse its position as a major shareholder of the Company.

3. Relationship Agreement with KSS Global

On Admission, KSS Global is expected to own approximately 26.6% of the issued share capital of the Company.

On 19 May 2014, the Company entered into a relationship agreement with KSS Global (the "**KSS Global Relationship Agreement**") which will, conditional upon Admission, regulate (in part) the degree of control that KSS Global and its affiliates may exercise over the management of the Company. The principal purposes of the KSS Global Relationship Agreement are to ensure that the Company is capable at all times of carrying on its business independently of KSS Global and its affiliates and all of the Company's transactions and relationships with KSS Global and its affiliates are at arm's length and on normal commercial terms.

The KSS Global Relationship Agreement will continue until the earlier of (i) the Ordinary Shares ceasing to be admitted to the Official List of the FCA and to trading on the London Stock Exchange or (ii) KSS Global (together with any of its affiliates) ceasing to be entitled to exercise, or to control the exercise of, 10% or more of the rights to vote at the Company's general meetings.

Under the KSS Global Relationship Agreement, KSS Global undertakes that:

(a) it will, and will procure its affiliates will, allow the Company and its affiliates at all times to carry on its business independently of KSS Global and its affiliates;

(b) it will not, and will procure its affiliates will not, act in any way which shall prejudice the ability of the Company and its affiliates to carry on its business independently of KSS Global or its affiliates;

(c) it will comply with, and will procure its affilates comply with, the Disclosure and Transparency Rules in respect of its interests in the Ordinary Shares;

(d) it will not, and will procure its affiliates will not, take any action (or omit to take any action) to prejudice the Company's status as a listed company or its suitability for listing under the Listing Rules after Admission has occurred or the Company's ongoing compliance with the Listing Rules and the Disclosure and Transparency Rules or have the effect of preventing the Company from complying with its obligations under the Listing Rules, provided that this shall not prevent KSS Global (or any other person) from:

    (i) accepting a Takeover Offer for the Company in relation to their respective interests in the Company or, where such Takeover Offer is made by way of a CA2006 Scheme, voting in favour of such CA2006 Scheme at the court and related shareholder meetings or otherwise agreeing to sell their Ordinary Shares in connection with a Takeover Offer; or

    (ii) making a Takeover Offer by way of a general offer for all the outstanding Ordinary Shares or by way of a CA2006 Scheme and de-listing the Company after such Takeover Offer has become wholly unconditional or, in the case of a CA2006 Scheme, after it has become effective;

(e) it will not, and will procure that its affiliates will not, influence the day-to-day running of the Company at an operational level or hold or acquire a material shareholding in one or more significant subsidiaries of the Company; and

(f) it will exercise its voting rights in such a manner as to procure (to the extent possible):

(i) at least half of the Board comprises independent directors (excluding the chairman of the Board);

(ii) the Audit Committee shall comprise entirely independent directors and the Remuneration Committee shall comprise not less than three independent directors; and

(iii) the Nomination Committee and any other committee of the Board to which significant powers, authorities or discretions are delegated shall at all times consist of a majority of independent directors.

Both KSS Global and the Company undertake that they shall (and shall procure that the relevant members of their respective affiliates shall) with effect from the date of the KSS Global Relationship Agreement conduct any transactions and relationships (whether contractual or otherwise, including any subsequent amendment thereof or variation thereto, including the implementation or enforcement thereof) between KSS Global or any of its affiliates, on the one hand, and of the Company or any of its affiliates, on the other, on arm's length terms and on a normal commercial basis.

The Company undertakes that it shall treat all holders of the same class of Ordinary Shares that are in the same position equally in respect of the rights attaching to such shares, save that the Company has agreed that KSS Global shall have the right to nominate one director to the Board so long as KSS Global (and its affiliates) own 10% or more of the issued Ordinary Shares (such person being a "**KSS Global Director**").

Nothing in the KSS Global Relationship Agreement shall prevent the KSS Global Director from performing any duty or exercising any discretion in such manner as the KSS Global Director sees fit in his capacity as a director of the Company or any of its affiliates.

The Directors believe that the terms of the KSS Global Relationship Agreement will enable the Company to carry on its business independently from KSS Global and its affiliates, and ensure that (subject to other existing contractual arrangements with KSS Global as at the date of Admission) all transactions and relationships between the Company and KSS Global and its affiliates are, and will be, at arm's length and on a normal commercial basis, such that KSS Global is not able to abuse its position as a major shareholder of the Company.

4. Related party transactions

The following is a description of the material transactions with related parties to which the Company or its subsidiaries are a party. The Company believes that it has executed all of its transactions with related parties on terms no less favourable to the Group than those it could have obtained from unaffiliated third parties.

Save as disclosed below and paragraph 28 of Part 14 "*Historical Financial Information*", there were no related party transactions entered into during the period covered by the historical financial information in this Prospectus and up to the date of this Prospectus.

4.1 *Reorganisation in connection with the Scheme*

4.1.1 Paragraph 2.5 of Part 17 "*Additional Information*" sets out details on the incorporation of the Company, which was formed by Nostrum Oil & Gas LP and NOGGL (the general partner of Nostrum Oil & Gas LP which is indirectly owned and controlled by Frank Monstrey, the chairman of the Company). As noted in paragraph 2.5 of Part 17 "*Additional Information*", it is intended that following Admission the Subscriber Shares held by Nostrum Oil & Gas LP and NOGGL will be acquired by the Company for nil consideration and cancelled. It is expected that the Redeemable Shares held by NOGGL will be redeemed following Admission.

4.1.2 In connection with the Scheme, the Company entered into the Scheme Implementation Agreement with the Partnership, the General Partner and VTB. A summary of the terms of the Scheme Implementation Agreement is set out in paragraph 12.4(a) of Part 17 "*Additional Information*". The General Partner is indirectly owned and controlled by Frank Monstrey and his spouse.

4.1.3 In connection with the Scheme, the Partnership and the Company have received irrevocable undertakings to vote in favour of the amendment of the Limited Partnership Agreement and the Scheme (the "**Irrevocable Undertakings**") from (i) Claremont and its affiliates in respect of, in aggregate, 51,190,476 Existing Securities, (ii) KSS Global in respect of 50,000,000 Existing Securities and (iii) Dehus Dolman Nominees Limited and its affiliates in respect of 28,906,483 Existing Securities, representing in aggregate 69.13% of the existing Common Units as at the date of this Prospectus. A summary of these Irrevocable Undertakings is set out in paragraph 19 of Part 17 "*Additional Information*".

4.2 *Related Party Transactions with Directors*

4.2.1 Appointment of Directors

Paragraph 9 of Part 17 "*Additional Information*" contains details of the services agreements and letters of appointment with the Directors.

4.2.2 Technical Assistance Agreements

Certain senior managers provide their services to Nostrum pursuant to a service agreement dated 27 March 2007 between Probel Capital Management N.V. ("**Probel**") and Nostrum (the "**Probel Services Agreement**"). Prior to its acquisition on 30 December 2013 by Co-op, Probel was controlled by Mr. Monstrey, the chairman of the Company. Under the Probel Services Agreement, Nostrum pays a fee to Probel calculated by multiplying the relevant executive's or manager's number of working days per month by the executive's or manager's daily rate as stipulated in the Probel Services Agreement. The aggregate compensation paid by Nostrum to Probel under the Probel Services Agreement was U.S.$17.5 million, U.S.$13.6 million and U.S.$10.3 million for the years ended 31 December 2013, 2012 and 2011, respectively.

On 28 February 2009, Nostrum entered into a service agreement (the "**Prolag Services Agreement**") with Prolag BVBA ("**Prolag**"), a subsidiary of Probel, pursuant to which Prolag has agreed to provide certain commercial, marketing and other services to Nostrum, including, but not limited to, consultations on Nostrum's sales strategy and effective marketing policy, structuring its pricing policy and providing regular consultations and assistance on financial matters such as budgeting, credit policy and finance control. Fees are agreed per project on an ad hoc basis, or otherwise an agreed fee is paid, calculated for the specified period of the services with reference to an agreed schedule set out in the agreement. The aggregate compensation paid by Nostrum to Prolag under the Prolag Services Agreement was U.S.$1.3 million, U.S.$2.2 million and U.S.$1.9 million for the years ended 31 December 2013, 2012 and 2011, respectively.

For more information regarding Mr. Monstrey's, Mr. Kessel's and Mr. Muller's service arrangements and compensation, see paragraph 9 of Part 17 "Additional Information".

Certain other personnel provide their services to the Group pursuant to a service agreement dated 1 January 2009 between Amersham Oil LLP ("**Amersham**") and Nostrum (the "**Personnel Agreement**"). Amersham is indirectly controlled by Mr Monstrey. Under the Personnel Agreement, Nostrum pays a monthly fee to Amersham in return for Amersham's provision of personnel and consultancy services for management and related activities. The fee is determined each month the Personnel Agreement remains in force. The aggregate compensation paid by Nostrum to Amersham under the Personnel Agreement was U.S.$1.5 million, U.S.$1.4 million and U.S.$1.4 million for the years ended 31 December 2013, 2012 and 2011, respectively.

On 30 December 2013, ELATA Burgerlijke Maatschap, Petra Noé, Frank Monstrey and Co-op entered into a purchase agreement pursuant to which Co-op acquired the entire issued share capital of Probel (the "**Probel Acquisition Agreement**") for a consideration of €21.07 million. Prior to completion of the sale of these shares under the Probel Acquisition Agreement the sellers had carved out all non-Nostrum related activities, liabilities and obligations of Probel. The Probel Acquisition Agreement provides that Co-op may rescind the purchase of such shares in the event that the Scheme is not approved. In addition, it is envisaged that Prolag (formerly a subsidiary of Probel), will also become part of the Group pursuant to a purchase agreement on terms substantially identical to those of the Probel Acquisition Agreement, but for no additional consideration, as all services previously provided by Prolag to the Group were internalised within Probel prior to the signing of the Probel Acquisition Agreement.

On 19 May 2014, SEPOL AG and Co-op entered into a purchase agreement for the acquisition by Co-op of the entire issued share capital of Amersham (the "**Amersham Acquisition Agreement**") for a consideration of €1.69 million. Completion of the sale of these shares under the Amersham Acquisition Agreement is conditional upon clearance being obtained from the competition authorities in the Republic of Kazakhstan (which is expected to occur in the third quarter of 2014). The Amersham Acquisition Agreement provides that Co-op may rescind the purchase of such shares in the event that the Scheme is not approved.

4.3 ***Other***

In addition to the above, the Group has entered into a number of related party transactions for amounts and terms which are immaterial to the Group both individually and in the aggregate. See Note 28 to the financial information set out in Part 14 "*Historical Financial Information*".

Thomas Hartnett, the company secretary of the Company, holds 50,001 Ordinary Shares as at the date of this Prospectus for the purposes of the structuring of the Scheme. These Ordinary Shares will be acquired by the Partnership at their subscription value in connection with the Scheme before the Company acquires any indirect interest in Zhaikmunai LLP.

On 13 February 2014, Probel and Cervus Business Services BVBA entered into an agreement for the provision to Probel by Cervus Business Services BVBA of, *inter alia*, office units and IT-infrastructure at the business center Brand Whitlock 42-44, Brussels, Belgium for an annual fee of EUR 1,016,000.

PART 11
SELECTED FINANCIAL INFORMATION

The following sets out summary consolidated audited financial information for the Group as at and for each of the three years ended 31 December 2013, 2012 and 2011 prepared in accordance with IFRS. The information has been extracted without material adjustment from the financial information in Part 14 "*Historical Financial Information*" of this Prospectus.

The summary should be read in conjunction with the information referred to above and in Part 12 "*Operating and Financial Review*". Investors are advised to read the whole of this Prospectus and not rely on the information summarised in this Part 11 "*Selected Financial Information*".

Summary Audited Consolidated Income Statement

	Year ended 31 December		
	2013	2012	2011
	(U.S.$ thousands)		
Revenue			
Revenue from export sales	765,029	630,412	284,548
Revenue from domestic sales	129,985	106,653	16,289
Total	**895,014**	**737,065**	**300,837**
Costs of sales	(286,222)	(238,224)	(70,805)
Gross profit	**608,792**	**498,841**	**230,032**
General and administrative expenses	(60,449)	(64,882)	(39,462)
Selling and transportation expenses	(121,674)	(103,604)	(35,395)
Loss on derivative financial instruments	—	—	—
Finance costs	(43,615)	(46,785)	(1,660)
Foreign exchange (loss)/gain, net	(636)	776	(389)
Interest income	764	698	336
Other expenses	(25,593)	(6,612)	(7,855)
Other income	4,426	3,940	3,365
Profit before income tax	362,015	**282,372**	**148,972**
Income tax expense	(142,496)	(120,363)	(67,348)
Profit for the period	**219,519**	**162,009**	**81,624**
Total comprehensive profit for the period	**219,519**	**162,009**	**81,624**

Summary Audited Consolidated Balance Sheet

	As at 31 December		
	2013	2012	2011
	(U.S.$ thousands)		
Non-Current Assets	1,425,977	1,251,595	1,126,897
Current Assets	334,798	351,067	179,283
Total Assets	**1,760,775**	**1,602,662**	**1,306,180**
Partnership capital and Reserves	832,451	695,104	585,231
Non-Current Liabilities	793,600	781,860	599,680
Current Liabilities	134,724	125,698	121,269
Total Equity and Liabilities	**1,760,775**	**1,602,662**	**1,306,180**

PART 12
OPERATING AND FINANCIAL REVIEW

The following discussion and analysis should be read together with the financial information in this Prospectus, including the notes thereto and the basis of preparation thereof. Prospective investors should read the whole of this Prospectus and not rely on the summarised data. The Group's consolidated financial information has been prepared in accordance with IFRS as adopted by the European Union.

Some of the information in the discussion and analysis set forth below and elsewhere in this Prospectus includes forward-looking statements that involve risks and uncertainties. See Part 5 "Presentation of Information—Cautionary Note Regarding Forward-Looking Statements" and Part 2 "Risk Factors" for a discussion of important factors that could cause actual results to differ materially from the results described in the forward-looking statements contained in this Prospectus.

This operating and financial review includes information on the Group extracted from the Group's audited financial information in respect of the years ended 31 December 2013, 2012 and 2011 prepared in accordance with IFRS as adopted by the European Union, as set out in Part 14 "*Historical Financial Information*" of this Prospectus.

Overview

Nostrum is the indirect holding entity of Zhaikmunai LLP, an independent oil and gas enterprise engaged in the exploration and production of oil and gas products in North-Western Kazakhstan. Nostrum's primary field and Licence area is the Chinarevskoye Field located in the northern part of the oil-rich Pre-Caspian Basin. In addition, in May 2013, the Group completed the acquisition of the subsoil use licences for three development fields, Rostoshinskoye, Darinskoye and Yuzhno-Gremyachenskoye, located in the Pre-Caspian basin to the North-West of Uralsk, approximately 50-105 kilometres from the Chinarevskoye Field.

Prior to 2011, all of Nostrum's revenues were generated by its crude oil sales. However, starting in late 2011 when the gas treatment facility came into full production, the Group began producing and selling stabilised condensate, dry gas and LPG in addition to crude oil. The gas treatment facility has enabled Nostrum to increase its daily production of oil and gas products from an average daily production of approximately 9,700 boepd (primarily crude oil) during the first half of 2011 to an average daily production of 46,370 boepd (comprised of crude oil, stabilised condensate, dry gas and LPG) during the six months ended 30 June 2013 and 45,414 boepd during the nine months ended 30 September 2013.

The primary factors affecting the Group's results of operations are: (i) the prices received by Nostrum for its products, (ii) the quantities of Nostrum's production for a given period, (iii) the costs Nostrum incurs to produce and transport its products, (iv) finance costs incurred by the Group under its borrowings and (v) amounts payable pursuant to the PSA (see "*—Primary Factors Affecting Results of Operations*").

The following table sets forth the Group's revenues from the sale of its oil and gas products, cost of sales, gross profit, profit before income tax and net income/(loss) for the years ended 31 December 2013, 2012 and 2011:

	Years ended 31 December		
	2013	2012	2011
	(U.S.$ thousands)		
Revenue	895,014	737,065	300,837
Cost of sales	(286,222)	(238,224)	(70,805)
Gross profit	608,792	498,841	230,032
Profit before income tax	362,015	282,372	148,972
Net income/(loss)	219,519	162,009	81,624

Primary Factors Affecting Results of Operations

The primary factors affecting the Group's results of operations during the periods under review are the following:

Pricing

The pricing for all of the Group's crude oil, condensate and LPG is, directly or indirectly, related to the price of Brent crude oil and the pricing of the Group's dry gas is related to domestic Kazakh prices for gas. During the periods under review, the price of Brent crude oil experienced significant fluctuations. According to Bloomberg, the spot price of Brent crude oil prices reached approximately U.S.$96.99 per barrel as at 31 December 2011, U.S.$102.32 per barrel as at December 2012 and U.S.$109.02 per barrel as at 31 December 2013. Prices have varied between a low of approximately U.S.$103.99 per barrel and a high of approximately U.S.$110.01 per barrel in the first three months of 2014. See Part 2 "*Risk Factors—Risk Factors Relating to the Oil and Gas Industry—Any volatility and future decreases in commodity prices could materially adversely affect the Group's business, prospects, financial condition and results of operations*".

	Years ended 31 December		
	2013	**2012**	**2011**
Average Brent crude oil price (U.S.$/bbl)	103.17	101.34	102.08

The Group has a hedging policy whereby it hedges against adverse oil price movements during times of considerable non scalable capital expenditure. Based on the contracts Zhaikmunai LLP has entered into with various equipment suppliers for the third gas treatment unit and the fact that further contracts will be entered into in the next several months, Nostrum is closely monitoring the hedging market and may in the near future enter into a hedge to cover a portion or all of its non-scalable capital expenditure linked to the construction of the third gas treatment unit (see "*—Current Trading and Prospects*"). During the 2010 and 2011 financial years, the Group had hedging arrangements in place while it was completing and commissioning the first phase of the gas treatment facility. For the financial year ended 31 December 2010, the Group suffered a hedging loss of U.S.$470,000, resulting in a liability of U.S.$372,000 as at year end. As of 31 December 2011, all hedging contracts were terminated and no new contracts have been entered into since.

Until 2010, the Group's products were sold and delivered from Uralsk to Nostrum's customers on a FCA (free carrier) shipment basis. However, in order to avoid incurring higher transportation costs and to introduce higher profitability into the Group's pricing, in 2010, Nostrum started selling its products on the basis of DAP (delivered at place) and FOB (free on board) terms. This means that Nostrum incurs most of the transportation costs relating to shipment. However, it also provides the Group with access to a larger number of purchasers, resulting in greater competition for its products and therefore higher profitability.

The Group generates revenue from the sale of four principal products: crude oil, condensate, dry gas and LPG.

- *Crude oil*

  Pursuant to the PSA, the Group is required to deliver 15% of its crude oil production sourced from wells in production in the domestic Kazakhstan market at government-regulated prices. The remainder of the Group's crude oil is free to be exported; currently the Group exports all of this remaining crude oil to various destinations including Ukraine, Finland and the Black Sea ports.

- *Condensate*

  The Group exports 100% of its condensate.

- *Dry gas*

  The Group sells 100% of its dry gas not used in production domestically in Kazakhstan to two customers for prices that are broadly in line with domestic gas prices and are payable in Tenge.

- *LPG*

  Currently the Group sells approximately 10-15% of its LPG production domestically in Kazakhstan and the remainder is exported to various destinations.

Production

The Group's results of operations are also directly affected by production because, except for a portion of the dry gas that is utilised in the operations of the gas treatment facility, all production by Nostrum is sold. The table below sets forth Nostrum's production for the years ended 31 December 2013, 2012 and 2011.

	Years ended 31 December		
	2013	2012	2011
Total production (boe)	**16,854,970**	**13,520,040**	**4,802,561**
Average production (boepd)	46,178	36,940	13,158
Increase in production from previous period (boepd)	9,238	23,782	5,406
Increase in production from previous period (%)	25.0	180.7	69.7

Nostrum's production growth in 2011, 2012 and 2013 was primarily driven by the output from its newly installed gas treatment facility.

The gas treatment facility, which has contributed to a significant increase in production in 2012 and 2013, operated at or near its design capacity by the end of 2012 following a maintenance shutdown of the gas treatment facility in October 2012. In addition, the Group intend to drill 11 new wells (five new exploration/appraisal wells and six new production/water injection wells) in order to maintain production above the 45,000 boepd target and is also planning the development of a third gas treatment unit for the gas treatment facility, both of which they believe will significantly increase production in the future. See "*—Liquidity and Capital Resources—Capital Expenditures*".

Cost of sales

The Group's oil and gas prices are based on a mix of fixed and quotation pricing, and therefore Nostrum's ability to control costs is critical to its profitability. Nostrum's cost of sales comprise various costs including depreciation of oil and gas properties, repair, maintenance and other services, royalties, payroll and related taxes, materials and supplies, management fees, other transportation services, government profit share, environmental levies, and well workover costs.

Depreciation and amortisation costs, during the periods under review, have represented as a percentage of total cost of sales 41.6%, 42.6% and 27.5% for the years ended 31 December 2013, 2012 and 2011, respectively. Such costs fluctuate according to the level of Nostrum's proved developed reserves, the volume of oil and gas it produces and the net book value of its oil and gas properties (see "*—Summary of Critical Accounting Policies*" below for an explanation of this accounting policy).

Repair, maintenance and other services are related to the repair and maintenance of the Group's infrastructure, including the gas treatment facility but does not include ongoing repair and maintenance of production and exploration wells. These costs, during the periods under review, have represented as a percentage of total cost of sales, 18.3%, 23.3% and 23.5% for the years ended 31 December 2013, 2012 and 2011, respectively. The increases in 2011, 2012 and 2013 were primarily driven by the ramp up of operations of the gas treatment facility, which came online in the second half of 2011.

Well workover costs are related to ongoing repair and maintenance of production and exploration wells. These costs, during the periods under review, have represented as a percentage of total cost of sales 1.0%, 3.2% and 5.6% for the years ended 31 December 2013, 2012 and 2011, respectively.

The increase in management fees and payroll costs resulted from an increase in the number of personnel contracted and/or employed by Nostrum as well as through increases in salaries. Costs for repairs and maintenance and material and supplies increased principally due to the gas treatment facility's operations.

Finance costs

Finance costs in the years ended 31 December 2013, 2012 and 2011 consisted of interest expenses and fees and expenses in relation to the 2015 Bonds issued by Zhaikmunai Finance B.V. in October 2010 and the 2019 Bonds issued by Zhaikmunai International B.V. in November 2012; unwinding of discount on amounts due to the Kazakh Government; and unwinding of discount on abandonment and site restoration liability.

Interest expense in the years ended 31 December 2013 and 2012 consisted of interest on the 2015 Bonds and the 2019 Bonds. Interest expense in the year ended 31 December 2011 consisted solely of interest on the 2015 Bonds. Capitalised borrowing costs (including a portion of the interest expense and amortisation of the arrangement fees) amounted to U.S.$14.6 million in 2013, U.S.$26.1 million in 2012 and U.S.$51.6 million in 2011. Non-capitalised interest amounted to U.S.$41.7 million in 2013, U.S.$45 million in 2012 and nil in 2011.

Royalties, Government Share and Taxes payable pursuant to the PSA

Nostrum operates and produces pursuant to the PSA. The PSA has, during the periods under review, and will continue to have both a positive and negative effect on Nostrum's results of operations as a result of (i) the tax regime applicable to Nostrum under the PSA (discussed below) (ii) increasing royalty expenses payable to the State, (iii) the share of profit oil and the share of gas that Nostrum pays to the State and (iv) recovery bonus payable to the State.

Under the PSA, the Kazakh tax regime that was in place in 1997 applies to the Group for the entire term of the PSA and the Licence (as to VAT and social tax, the regime that was in place as of 1 July 2001 applies). As of 1 January 2009, the new Tax Code became effective and introduced a new tax regime and taxes applicable to subsoil users (including oil mineral extraction tax and historical cost). However, the Tax Code did not supersede the previous tax regime applicable to PSAs entered into before 1 January 2009, which continue to be effective under Articles 308 and 308-1of the Tax Code. Despite the stabilisation clauses (providing for general and tax stability) provided for by the PSA, in 2008, in 2010 and again in 2013, Nostrum was required to pay new crude oil export duties introduced by the Kazakh Government. Despite Nostrum's efforts to show that the new export duties were not applicable to it, the State authorities did not accept this position and Nostrum was required to pay the export duties. During January 2009, the Kazakh Government revised and established the rate of the export duties at U.S.$ nil per tonne of crude oil, but reimposed a U.S.$20 per tonne duty in August 2010, which was increased to U.S.$40 per tonne in January 2011 and then to U.S.$60 per tonne in April 2013.

For the purposes of corporate income tax from 1 January 2007, the Group considers its revenue from oil and gas sales related to the Tournaisian horizon as taxable revenue and its expenses related to the Tournaisian horizon as deductible expenses, except those expenses which are not deductible in accordance with the tax legislation of Kazakhstan. Assets related to the Tournaisian reservoir that were acquired during the exploration phase are then depreciated for tax purposes at a maximum rate of 25.0% per annum. Assets related to the Tournaisian reservoir that were acquired after the commencement of the production phase are subject to the depreciation rate in accordance with the 1997 Kazakh tax regime, which is between 5% and 25% depending on the nature of the asset. Under the PSA, the exploration phase for the remainder of the Chinarevskoye Field expired in May 2011 and a further extension has been applied for. Assets related to the other horizons will depreciate in the same manner as those described above for the Tournaisian reservoir.

Under the PSA, Nostrum is obliged to pay to the State royalties on the volumes of crude oil and gas produced, with the royalty rate increasing as the volume of hydrocarbons produced increases. In addition, Nostrum is required to deliver a share of its monthly production to the State (or make a payment in lieu of such delivery). The share to be delivered to the State also increases as annual production levels increase. Pursuant to the PSA, the Group is currently able to effectively deduct a significant proportion of production (known as Cost Oil) from the sharing arrangement that it would otherwise have to share with the Kazakh Government. Cost Oil reflects the deductible capital and operating expenditures incurred by the Group in relation to its operations. During the periods under review, royalties and government profit share represented, as a percentage of total cost of sales, 13.8% and 10.7%, respectively, for the year ended 31 December 2013, 14.4% and 3.3%, respectively, for the year ended 31 December 2012 and 12.3% and 2.6%, respectively, for the year ended 31 December 2011.

Factors Affecting Comparability

Gas Treatment Facility

In the past several years the Group has been investing significantly in the construction and development of the gas treatment facility, which was in test production from May 2011 and came online into full production in November 2011. The Group started recording revenue and costs of sales from sales of products from the gas treatment unit in the Group's income statement in November 2011 when the gas treatment facility moved from construction in progress to working asset. Prior to November 2011, revenue and costs of sales of the gas treatment facility were recorded against construction in progress. See Note 18 to the audited consolidated financial statements for the year ended 31 December 2012. Prior to the construction of the gas treatment facility the Group's revenue resulted solely from the sale of crude oil. Commencing in November 2011, the Group began selling condensate, dry gas and LPG in addition to crude oil. This materially impacted the Group's results in 2012, making it difficult to compare this period to earlier periods.

Summary of Critical Accounting Policies

The Group's significant accounting policies are more fully described in note 1 of the Financial Statements.

However, certain of the Group's accounting policies are particularly important to the presentation of the Group's results of operations and require the application of significant judgment by its management.

In applying these policies, the Group's management uses its judgment to determine the appropriate assumption to be used in the determination of certain estimates used in the preparation of the Group's results of operations. These estimates are based on the Group's previous experience, the terms of existing contracts, information available from external sources and other factors, as appropriate.

The Group's management believes that, among others, the following accounting policies that involve management judgments and estimates are the most critical to understanding and evaluating its reported financial results.

Estimations and Assumptions

Oil and gas reserves

Oil and gas reserves are a material factor in Nostrum Oil & Gas LP's computation of depreciation, depletion and amortisation (the "**DD&A**"). Nostrum Oil & Gas LP estimates its reserves of oil and gas in accordance with the definitions and disclosure guidelines contained in the SPE-PRMS. In estimating its reserves under SPE-PRMS methodology, Nostrum Oil & Gas LP uses long-term planning prices which are also used by management to make investment decisions about the development of a field. Using planning prices for estimating proved reserves removes the impact of the volatility inherent in using year-end spot prices. Management believes that long-term planning price assumptions are more consistent with the long-term nature of the Group's business and provide the most appropriate basis for estimating oil and gas reserves. All reserve estimates involve some degree of uncertainty. The uncertainty depends mainly on the amount of reliable geological and engineering data available at the time of the estimate and the interpretation of this data.

The relative degree of uncertainty can be conveyed by placing reserves into one of two principal classifications, either proved or unproved. Proved reserves are more certain to be recovered than unproved reserves and may be further sub-classified as developed and undeveloped to denote progressively increasing uncertainty in their recoverability. Estimates are reviewed and revised annually. Revisions occur due to the evaluation or re-evaluation of already available geological, reservoir or production data, availability of new data, or changes to underlying price assumptions. Reserve estimates may also be revised due to improved recovery projects, changes in production capacity or changes in development strategy. Proved developed reserves are used to calculate the unit of production rates for DD&A.

Property, Plant and Equipment

Exploration expenditure

Geological and geophysical exploration costs are charged against income as incurred. Costs directly associated with exploration wells are capitalised within property, plant and equipment (construction work-in-progress) until the drilling of the well is complete and the results have been evaluated. These costs include employee remuneration and materials and fuel used, rig costs and payments made to contractors and asset retirement obligation fees. If hydrocarbons are not found, the exploration expenditure is written off as a dry hole. If hydrocarbons are found and, subject to further appraisal activity, which may include the drilling of further wells (exploration or exploratory-type stratigraphic test wells), are likely to be capable of commercial development, the costs continue to be carried as an asset. All such carried costs are subject to technical, commercial and management review at least once a year to confirm the continued intent to develop or otherwise extract value from the discovery. When this is no longer the case, the costs are written off.

Oil and gas properties

Expenditure on the construction, installation or completion of infrastructure facilities such as treatment facilities, pipelines and the drilling of development wells, is capitalised within property, plant and equipment as oil and gas properties. The initial cost of an asset comprises its purchase price or construction cost, any costs directly attributable to bringing the asset into operation and the initial estimate of decommissioning obligation, if any. The purchase price or construction cost is the aggregate amount paid and the fair value of any other consideration given to acquire the asset. Property, plant and equipment are stated at cost less accumulated depreciation, depletion and impairment.

All capitalised costs of oil and gas properties are amortised using the unit-of-production method based on estimated proved developed reserves of the field, except the Group depreciates its oil pipeline and oil loading terminal on a straight line basis over the life of the license. In the case of assets that have a useful life shorter than the lifetime of the field the straight line method is applied.

Oil and gas reserves

Proved oil and gas reserves are estimated quantities of commercially viable hydrocarbons which existing geological, geophysical and engineering data show to be recoverable in future years from known reservoirs. The Group uses the reserve estimates provided by an independent appraiser to assess the oil and gas reserves of its oil and gas fields. These reserve quantities are used for calculating the unit of production depreciation rate as it reflects the expected pattern of consumption of future economic benefits by the Group.

Provisions

Provision for decommissioning is recognised in full, on a discounted cash flow basis, when the Group has an obligation to dismantle and remove a facility or an item of plant and to restore the site on which it is located, and when a reasonable estimate of that provision can be made. The amount of the obligation is the present value of the estimated expenditures expected to be required to settle the obligation, adjusted for expected inflation and discounted using average long-term interest rates for emerging market debt adjusted for risks specific to the Kazakhstan market. The unwinding of the discount related to the obligation is recorded in finance costs. A corresponding tangible fixed asset of an amount equivalent to the provision is also created. This asset is subsequently depreciated as part of the capital costs of the oil and gas properties on a unit of production basis.

Changes in the measurement of an existing decommissioning liability that result from changes in the estimated timing or amount of the outflow of resources embodying economic benefits required to settle the obligation, or changes to the discount rate:

(a) are added to, or deducted from, the cost of the related asset in the current period. If deducted from the cost of the asset the amount deducted shall not exceed its carrying amount. If a decrease in the provision exceeds the carrying amount of the asset, the excess is recognised immediately in the income statement; and

(b) if the adjustment results in an addition to the cost of an asset, the Group considers whether this is an indication that the new carrying amount of the asset may not be fully recoverable. If it is such an indication, the Group tests the asset for impairment by estimating its recoverable amount, and accounts for any impairment loss in accordance with IAS 36.

Borrowing Costs

The Group capitalises borrowing costs on qualifying assets. Assets qualifying for borrowing costs capitalisation include all assets under construction, *provided that* significant work has been in progress during the reporting period. Qualifying assets mostly include wells and other field infrastructure under construction. Capitalised borrowing costs are calculated by applying the capitalisation rate to the expenditures on qualifying assets. The capitalisation rate is the weighted average of the effective interest rate of the borrowing costs applicable to the Group's borrowings that are outstanding during the period.

Derivative Financial Instruments and Hedging

The Group has a hedging policy whereby it hedges against adverse oil price movements during times of considerable non scalable capital expenditure. Based on the contracts Zhaikmunai LLP has entered into with various equipment suppliers for the third gas treatment unit and the fact that further contracts will be entered into in the next several months the Group is closely monitoring the hedging market and may in the near future enter into a hedge to cover a portion or all of its non-scalable capital expenditure linked to the construction of the third gas treatment unit (see "—*Current Trading and Prospects*"). Such derivative financial instruments are initially recognised at fair value on the date on which a derivative contract is entered into and are subsequently re-measured at fair value. Derivatives are carried as assets when the fair value is positive and as liabilities when the fair value is negative.

Any gains or losses arising from changes in fair value on derivatives during the year that do not qualify for hedge accounting are taken directly to profit or loss.

The fair value of financial instruments contracts is determined by reference to market values for similar instruments.

Results of Operations

Comparison of the years ended 31 December 2013 and 2012

The table below sets forth the line items of the Group's consolidated statement of comprehensive income for the years ended 31 December 2013 and 2012 in U.S. Dollars and as a percentage of revenue.

	Year ended 31 December 2013	% of revenue	Year ended 31 December 2012	% of revenue
	(U.S.$ thousands)		*(U.S.$ thousands)*	
Revenue	895,014	100.0	737,065	100.0
Cost of sales	(286,222)	32.0	(238,224)	32.3
Gross Profit	**608,792**	**68.0**	**498,841**	**67.7**
General and administrative expenses	(60,449)	6.8	(64,882)	8.8
Selling and transportation expenses	(121,674)	13.6	(103,604)	14.1
Finance costs	(43,615)	4.9	(46,785)	6.3
Foreign exchange gain/(loss), net	(636)	0.1	776	0.1
Interest income	764	0.1	698	0.1
Other income/(expenses)	(21,167)	2.4	(2,672)	0.4
Profit before income tax	**362,015**	**40.4**	**282,372**	**38.3**
Income tax expense	(142,496)	16.0	(120,363)	16.3
Profit/(loss) for the period	**219,519**	**24.5**	**162,009**	**22.0**

Revenue increased by U.S.$157.9 million, or 21.4%, to U.S.$895.0 million in the year ended 31 December 2013 from U.S.$737.1 million in the year ended 31 December 2012 primarily due to the increase in output from the gas treatment facility.

For the year ended 31 December 2013, revenue from sales to the Group's top two customers amounted to U.S.$203.0 million and U.S.$173.4 million, respectively. For the year ended 31 December 2012, revenue from sales to the Group's top three customers amounted to U.S.$200.6 million, U.S.$54.0 million and U.S.$118.8 million, respectively.

The following table shows the Group's revenue, sales volumes and the commodity price of Brent crude oil for the years ended 31 December 2013 and 2012:

	Years ended 31 December	
	2013	2012
Oil and gas condensate (U.S.$ thousands)	709,107	587,371
Gas products (U.S.$ thousands)	185,907	149,694
Total revenue (U.S.$ thousands)	**895,014**	**737,065**
Sales volumes (boe)	16,854,970	13,629,245
Average Brent crude oil price on which Nostrum based its sales (U.S.$/bbl)	108.4	107.43

The following table shows the Group's revenue breakdown by export/domestic sales for the years ended 31 December 2013 and 2012:

	Years ended 31 December	
	2013	**2012**
	(U.S.$ thousands)	
Revenue from export sales	765,029	630,412
Revenue from domestic sales	129,985	106,653
Total revenue	**895,014**	**737,065**

The significant increase in domestic sales in the year ended 31 December 2013 compared to the year ended 31 December 2012 was primarily due to the commencement of dry gas production and sales, 100% of which was sold in the domestic Kazakhstan market.

Cost of sales increased by U.S.$48 million, or 20.2%, to U.S.$286.2 million in the year ended 31 December 2013 from U.S.$238.2 million in the year ended 31 December 2012 primarily due to an increase in production, depreciation, depletion and amortisation, royalties, government profit share, materials and supply expenses and changes in stock, partially offset by a decrease in payroll and related taxes, well workover costs and repair and maintenance expenses. The increase of 20% in cost of sales is in line with the increase in revenue in 2013 of 21% compared to 2012. On a boe basis, cost of sales decreased marginally by U.S.$0.5 or 2.86%, to U.S.$16.98 in the year ended 31 December 2013 from U.S.$17.48 in the year ended 31 December 2012, and cost of sales net of depreciation per boe decreased by U.S.$0.12, or 1.12% to U.S.$9.92 in the year ended 31 December 2013 from U.S.$10.04 in the year ended 31 December 2012.

Depreciation, depletion and amortisation increased by 17.4% or U.S.$17.6 million in the year ended 31 December 2013 to U.S.$119.0 million from U.S.$101.4 million in the year ended 31 December 2012,. The increase is due to an increase of production without a similar increase in proved developed reserves during the period. The depletion rate for oil and gas working assets was 12.1% and 11.96% in 2013 and 2012, respectively.

Materials and supply expenses, taken together with repair, maintenance and other services and well workover costs decreased by 1% to U.S.$67.4 million in 2013 from U.S.$68.4 million in 2012. The increase of 132.1% in materials and supplies from U.S.$5.3 in 2012 to U.S.$12.3 million in 2013 is the result of repair and maintenance works in 2013 being focusses on the facilities, specifically the Gas Treatment Facility, and less so on wells.

Payroll and related taxes decreased by 6.5% to U.S.$17.2 million in the year ended 31 December 2013 compared to U.S.$ 18.4 million in the year ended 31 December 2012.

Royalty costs are calculated on the basis of production and market prices for the different products. Royalties increased by U.S.$5.2 million, or 15.2%, to U.S.$39.4 million in 2013 from U.S.$ 34.2 million in 2012, whereas production was up 25% to an average production of 46,178 boepd in 2013 up from 36,940 bopd in 2012. The average brent price for the year was down 0.6% to U.S.$108.41 per bbl from U.S.$109.03 per bbl in 2012.

Costs for government profit share increased by U.S.$22.8 million, or 288.6%, to U.S.$30.7 million in 2013 from U.S.$7.9 million in 2012, primarily due to the fact that the cost oil balance which had been carried forward from previous years was depleted in August 2013, causing the Government share to substantially rise in the second half of 2013.

General and administrative expenses decreased by U.S.$4.5 million, or 6.9%, to U.S.$60.4 million in the year ended 31 December 2013 from U.S.$64.9 million in the year ended 31 December 2012 due primarily to a decrease in social programme expenditures of U.S.$21.5 million in the year ended 31 December 2013 from U.S.$21.8 million in the year 31 December 2012. This decrease was related to the completion in 2012 of construction of a 37 kilometer asphalt road accessing the field site with no similar expense incurred in 2013. The decrease in social costs was primarily offset by increased management fees and professional services.

Selling and transportation expenses increased by U.S.$18.1 million, or 17.5%, to U.S.$121.7 million in the year ended 31 December 2013 from U.S.$ 103.6 million in the year ended 31 December 2012. This was primarily driven by an increase of U.S.$15.4 million in loading and storage costs to U.S.$37.0 million in the year ended 31 December 2013 from U.S.$21.6 million in the year ended 31 December 2012. This increase was primarily driven by the rise in output of LPG and condensate volumes.

Finance costs decreased by U.S.$3.2 million, or 6.8%, to U.S.$43.6 million in the year ended 31 December 2013 from U.S.$ 46.8 million in the year ended 31 December 2012. The decrease in costs was primarily driven by the raising of a new bond in November 2012, with a significantly lower interest rate, with which the first bond was repaid.

Other expenses increased to U.S.$25.6 million in the year ended 31 December 2013 from U.S.$6.6 million in the year ended 31 December 2012. The increase in other expenses was due to the increase in export duties paid by the Group. The export duties represent custom duties for export of crude oil and customs fees for its services such as processing of declarations, temporary warehousing etc. The Kazakhstan custom authorities, based on their interpretation of CIS free-trade legislation, have imposed custom duties on oil exports from Kazakhstan to Ukraine starting from December 2012.

Profit before income tax increased by U.S.$79.6 million, or 28.2%, to U.S.$362.0 million in the year ended 31 December 2013 compared to a profit of U.S.$ 282.4 million in the year ended 31 December 2012. The higher level of profit was driven primarily by increased revenue due to the increase in output from the gas treatment facility.

Income tax expense increased by U.S.$22.1 million, or 18.4%, to U.S.$142.5 million in the year ended 31 December 2013 from U.S.$ 120.4 million in the year ended 31 December 2012 primarily due to the increase in Group's profit before income tax.

Net income increased by U.S.$57.5 million, or 35.5%, to U.S.$219.5 million in the year ended 31 December 2012 from U.S.$ 162.0 million in the year ended 31 December 2012. This higher profitability was driven principally by increased revenue from increased production of hydrocarbons.

Comparison of the years ended 31 December 2012 and 2011

The table below sets forth the line items of the Group's consolidated statement of comprehensive income for the years ended 31 December 2012 and 2011 in U.S. Dollars and as a percentage of revenue.

	Year ended 31 December 2012	% of revenue	Year ended 31 December 2011	% of revenue
	(U.S.$ thousands)		*(U.S.$ thousands)*	
Revenue	737,065	100.0	300,837	100.0
Cost of sales	(238,224)	32.3	(70,805)	23.5
Gross Profit	**498,841**	**67.7**	**230,032**	**76.5**
General and administrative expenses	(64,882)	8.8	(39,462)	13.1
Selling and transportation expenses	(103,604)	14.1	(35,395)	11.8
Finance costs	(46,785)	6.3	(1,660)	0.6
Foreign exchange gain/(loss), net	776	0.1	(389)	0.1
Interest income	698	0.1	336	0.1
Other income/(expenses)	(2,672)	0.4	(4,490)	1.5
Profit before income tax	**282,372**	**38.3**	**148,972**	**49.5**
Income tax expense	(120,363)	16.3	(67,348)	22.4
Profit/(loss) for the period	**162,009**	**22.0**	**81,624**	**27.1**

Revenue increased by U.S.$436.3 million, or 145.0%, to U.S.$737.1 million in the year ended 31 December 2012 from U.S.$300.8 million in the year ended 31 December 2011 primarily due to the additional revenue generated by the increased production primarily from the gas treatment facility.

The following table shows the Group's revenue, sales volumes and the commodity price of Brent crude oil for the years ended 31 December 2012 and 2011:

	Years ended 31 December	
	2012	2011
	(U.S.$ thousands)	
Sales volumes (boe)	13,629,245	3,397,815
Average Brent crude oil price on which Nostrum based its sales (U.S.$/bbl)	107.43	106.87
Total Revenue	**737,065**	**300,837**

The following table shows the Group's revenue breakdown by product for the years ended 31 December 2012 and 2011:

	Years ended 31 December	
	2012	2011
	(U.S.$ thousands)	
Revenue:		
Oil and gas condensate	587,371	289,947
Gas and liquefied petroleum gas	149,694	10,890
Total Revenue	**737,065**	**300,837**

The following table shows the Group's revenue breakdown by export/domestic sales for the years ended 31 December 2012 and 2011:

	Years ended 31 December	
	2012	2011
	(U.S.$ thousands)	
Revenue:		
Revenue from export sales	630,412	284,548
Revenue from domestic sales	106,653	16,289
Total Revenue	**737,065**	**300,837**

The significant increase in domestic sales in the year ended 31 December 2012 compared to the same period in 2011 was primarily due to the commencement of dry gas production and sales, 100% of which is sold in the domestic Kazakhstan market.

Cost of sales increased by U.S.$167.4 million, or 236.4%, to U.S.$238.2 million in the year ended 31 December 2012 from U.S.$70.8 million in the year ended 31 December 2011 primarily due to an increase in production, depreciation, repair and maintenance, payroll expenses and materials and supplies driven by commencement of operations at the gas treatment facility. On a boe basis, cost of sales decreased by U.S.$3.36 or 16.1%, to U.S.$17.48 in the year ended 31 December 2012 from U.S.$20.83 in the year ended 31 December 2011, and cost of sales net of depreciation per boe decreased by U.S.$5.07, or 33.6% to U.S.$10.04 in the year ended 31 December 2012 from U.S.$15.11 in the year ended 31 December 2011.

Depreciation and amortisation increased by 422.7% or U.S.$82 million in the year ended 31 December 2012 to U.S.$101.4 million, primarily resulting from the gas treatment facility and associated wells coming into production.

Materials and supply expenses increased by 6% to U.S.$5.3 million while repair and maintenance expenses increased by 234.3% to U.S.$55.5 million, mainly due to the increased operations and production related to the gas treatment facility.

Payroll and related taxes increased by 100% to U.S.$18.4 million in the year ended 31 December 2012 compared to U.S.$9.2 million in the year ended 31 December 2011 primarily due to an increase in the number of employees required to operate the gas treatment facility and increase in salary rates.

Royalty costs increased by U.S.$25.5 million, or 293.1%, to U.S.$34.2 million in 2012 from U.S.$8.7 million in 2011, primarily due to increased revenue resulting from increased production.

Costs for government profit share increased by U.S.$6.1 million, or 338.9%, to U.S.$7.9 million in 2012 from U.S.$1.8 million in 2011, primarily due to increased revenue resulting from increased production.

General and administrative expenses increased by U.S.$25.4 million, or 64.3%, to U.S.$64.9 million in the year ended 31 December 2012 from U.S.$39.5 million in the year ended 31 December 2011 due primarily to an increase in social programme expenditures of U.S.$20.7 million in the year ended 31 December 2012 from U.S.$1.1 million in the year ended 31 December 2011. This increase was related to the cost of construction of a 37-kilometre asphalt road accessing the field site, which the Group agreed to construct as part of the ninth amendment to the PSA. The costs associated with the construction of this road are significantly higher than the

Group's usual costs relating to social programmes under the PSA. Other expenses contributing to the increase in general and administrative expenses include an increase in management fees, an increase in payroll and related taxes and an increase in training expenses.

Selling and transportation expenses increased by U.S.$68.2 million, or 192.7%, to U.S.$103.6 million in the year ended 31 December 2012 from U.S.$35.4 million in the year ended 31 December 2011, primarily driven by an increase of U.S.$44.3 million for transportation costs to U.S.$74.0 million in the year ended 31 December 2012 from U.S.$29.7 million in the year ended 31 December 2011. Additionally, the company's loading and storage costs increased to U.S.$21.6 million in the year ended 31 December 2012 from U.S.$1.4 million in the year ended 31 December 2011. These cost increases were driven by the overall increase in production and specifically the rise in output of LPG and condensate volumes, which products require more specialised transportation and therefore higher costs.

Finance costs increased by U.S.$45.1 million, or 2,652.9%, to U.S.$46.8 million in the year ended 31 December 2012 from U.S.$1.7 million in the year ended 31 December 2011. The increase in costs was primarily driven by the coming into operation of the gas treatment facility, which resulted in decreased capitalisation of interest costs in the period.

Profit before income tax increased by U.S.$133.4 million, or 90%, to U.S.$282.4 million in the year ended 31 December 2012 compared to a profit of U.S.$149.0 million in the year ended 31 December 2011. The higher level of profit was driven primarily by increased revenue due to the inclusion of output from the gas treatment facility.

Income tax expense increased by U.S.$53.1 million, or 78.9%, to U.S.$120.4 million in the year ended 31 December 2012 from U.S.$67.3 million in the year ended 31 December 2011 primarily due to the Group's increased gross profit.

Net income increased by U.S.$80.4 million, or 98.5%, to U.S.$162.0 million in the year ended 31 December 2012 from U.S.$81.6 million in the year ended 31 December 2011. This higher profitability was driven by increased revenue from increased production.

Liquidity and Capital Resources

General

During the periods under review, Nostrum's principal sources of funds were cash from operations and amounts raised under the 2015 Bonds and the 2019 Bonds. Its liquidity requirements primarily relate to meeting ongoing debt service obligations (under the 2015 Bonds and the 2019 Bonds) and to funding capital expenditures and working capital requirements.

Cash Flows

The following table sets forth the Group's consolidated cash flow statement data for the years ended 31 December 2013, 2012 and 2011.

	Year ended 31 December		
	2013	**2012**	**2011**
	(U.S.$ thousands)		
Net cash flow from operating activities	357,253	291,825	132,859
Net cash used in investing activities	(237,522)	(269,674)[1]	(104,317)
Net cash (used in)/ provided by financing activities	(132,350)	50,390	(47,350)
Cash and cash equivalents at the end of period	184,914	197,730	125,393

(1) Net cash used in investing activities includes U.S.$50 million of bank deposits that are not included in cash and cash equivalents at the end of 2012 due to the long-term nature of the deposits.

Net cash flows from operating activities

Net cash flows from operating activities were U.S.$ 357.3 million for the year ended 31 December 2013 as compared to U.S.$291.8 million for the year ended 31 December 2012 and were primarily attributable to:

- profit before income tax for the period of U.S.$362.0 million, adjusted by a non-cash charge for depreciation, depletion and amortisation of U.S.$120.4 million, and finance costs of U.S.$43.6 million;

- a U.S.$15.1 million increase in working capital primarily attributable to (i) an increase in receivables of U.S.$12.6 million, (ii) an increase in prepayments and other current assets of U.S.$6.2 million and (iii) an increase of other current liabilities of U.S.$8.7 million; and
- income tax paid of U.S.$155.5 million.

Net cash flows from operating activities were U.S.$291.8 million for the year ended 31 December 2012 and were primarily attributable to:

- profit before income tax for the period of U.S.$ 282.4 million, adjusted by a non-cash charge for depreciation, depletion and amortisation of U.S.$102.6 million, and finance costs of U.S.$46.8 million;
- a U.S.$42.5 million increase in working capital primarily attributable to (i) an increase in receivables of U.S.$41.4 million, (ii) a decrease in payables of U.S.$2.7 million, (iii) an increase in inventories of U.S.$10.4 million and (iv) an increase in other current liabilities of U.S.$25.3 million mostly attributable to the tax treatment of the diversified production of the first and second gas treatment units; and
- income tax paid of U.S.$94.2 million.

Net cash flows from operating activities were U.S.$132.9 million for the year ended 31 December 2011 and were primarily attributable to:

- a profit before income tax for the period of U.S.$149.0 million, adjusted by a non-cash charge for depreciation, depletion and amortisation of U.S.$19.8 million;
- a U.S.$25.8 million increase in working capital primarily attributable to (i) an increase in pre-payments of U.S.$6.5 million, (ii) an increase in trade receivables of U.S.$11.0 million, (iii) an increase in inventories of U.S.$8.9 million, (iv) a decrease in advances received of U.S.$8.5 million and (v) partially offset by an increase in accounts payable of U.S.$10.5 million; and
- income tax paid of U.S.$13.2 million.

Net cash used in investing activities

The substantial portion of cash used in investing activities is related to the drilling programme and the construction of gas treatment units one, two and three. During the period from 1 January 2010 through 31 December 2013, cash used in the drilling programme represented between 43% and 70% of total cash flow from investment activities. During the period from 1 January 2011 through 31 December 2013, cash used in the construction of gas treatment units one, two and three represented between 1% and 40% of total cash flow from investment activities. Together, drilling and the construction of the gas treatment units represented between 44% and 92% of cash used for investment in property, plant and equipment.

Net cash used in investing activities was U.S.$239 million for the year ended 31 December 2013 due primarily to the drilling of new wells (U.S.$141.4 million), costs associated with the third gas treatment unit and Rostoshinskoye, Darinskoye and Yuzhno-Gremyachenskoye fields and the placement of U.S.$30.0 million of cash deposits, partially offset by the redemption of U.S.$25 million of term bank deposits.

Net cash used in investing activities was U.S.$269.7 million for the year ended 31 December 2012 due primarily to the drilling of new wells (U.S.$116.2 million), investments in the gas treatment facility (U.S.$38.6 million), U.S.$50 million short term bank deposits and costs associated with the first two units of the gas treatment facility and Rostoshinskoye, Darinskoye and Yuzhno-Gremyachenskoye fields.

Net cash used in investing activities was U.S.$103.7 million for the year ended 31 December 2011 primarily due to investments in the gas treatment facility (U.S.$23.5 million) and the drilling of new wells (U.S.$72.4 million).

Net cash (used in)/provided by financing activities

Net cash used in financing activities was U.S.$132.4 million for the year ended 31 December 2013, primarily attributable to the payment of U.S.$63.2 million in distributions and the interest paid on the Group's 2015 Bonds and 2019 Bonds.

Net cash provided by financing activities was U.S.$50.4 million for the year ended 31 December 2012, primarily attributable to the receipt of proceeds of the 2019 Bonds partially offset by the partial repurchase of the 2015 Bonds at a premium and the payment of U.S.$59.5 million in distributions.

Net cash used in financing activities was U.S.$47.4 million for the year ended 31 December 2011, primarily attributable to the interest paid on the Group's 2015 Bonds.

Indebtedness

The following is a summary of certain provisions of the Group's indebtedness.

2019 Bonds

On 13 November 2012, Zhaikmunai International B.V. (the "**2019 Initial Issuer**") issued U.S.$560,000,000 bonds (the "**2019 Bonds**").

On 24 April 2013, Zhaikmunai LLP (the "**2019 Issuer**") replaced the 2019 Initial Issuer of the 2019 Bonds, whereupon it assumed all of the obligations of the 2019 Initial Issuer under the 2015 Bonds. The 2019 Bonds bear interest at the rate of 7.125% per annum. Interest on the 2019 Bonds is payable on 14 May and 13 November of each year, beginning on 14 May 2013. Prior to 13 November 2016, the 2019 Issuer may, at its option, on any one or more occasions redeem up to 35% of the aggregate principal amount of the 2019 Bonds with the net cash proceeds of one or more equity offerings at a redemption price of 107.125% of the principal amount thereof, plus accrued and unpaid interest, if any, to the redemption date (subject to the right of holders of record on the relevant record date to receive interest due on the relevant interest payment date); provided that (1) at least 65% of the original principal amount of the 2019 Bonds (including Additional Notes as defined in the indenture relating to the 2019 Bonds) remains outstanding after each such redemption; and (2) the redemption occurs within 90 days after the closing of the related equity offering.

In addition, the 2019 Bonds may be redeemed, in whole or in part, at any time prior to 13 November 2016 at the option of the 2019 Issuer upon not less than 30 nor more than 60 days' prior notice mailed by first-class mail to each holder of 2019 Bonds at its registered address, at a redemption price equal to 100% of the principal amount of the 2019 Bonds redeemed plus the Applicable Premium (as defined below) as of, and accrued and unpaid interest to, the applicable redemption date (subject to the right of holders of record on the relevant record date to receive interest due on the relevant interest payment date). Applicable Premium means, with respect to any 2019 Bond on any applicable redemption date, the greater of: (1) 1.0% of the principal amount of such 2019 Bond; and (2) the excess, if any, of: (a) the present value at such redemption date of (i) the redemption price of such 2019 Bond at 13 November 2016 plus (ii) all required interest payments (excluding accrued and unpaid interest to such redemption date) due on such 2019 Bond through 13 November 2016 computed using a discount rate equal to the United States treasury rate as of such redemption date plus 50 basis points; over (b) the principal amount of such 2019 Bond.

The 2019 Bonds are jointly and severally guaranteed (the "**2019 Guarantees**") on a senior basis by Nostrum Oil & Gas LP and all of its subsidiaries other than the 2019 Issuer (the "**2019 Guarantors**"). The 2019 Bonds are the 2019 Issuer's and the 2019 Guarantors' senior obligations and rank equally with all of the 2019 Issuer's and the 2019 Guarantors' other senior indebtedness. The 2019 Bonds and the 2019 Guarantees do not have the benefit of any security. For further details of the 2019 Bonds, please see paragraph 12.3 of Part 17 "*Additional Information*".

New 2019 Bonds

On 14 February 2014, Nostrum Oil & Gas Finance B.V. (the "**New 2019 Initial Issuer**") issued U.S.$400,000,000 bonds (the "**New 2019 Bonds**").

On 6 May 2014, Zhaikmunai LLP (the "**New 2019 Issuer**") replaced the New 2019 Initial Issuer, whereupon it assumed all of the obligations of the New 2019 Initial Issuer under the New 2019 Bonds. The New 2019 Bonds bear interest at the rate of 6.375% per annum. Interest on the New 2019 Bonds is payable on 14 February and 14 August of each year, beginning on 14 August 2014. Prior to 14 February 2017, the New 2019 Issuer may, at its option, on any one or more occasions redeem up to 35% of the aggregate principal amount of the New 2019 Bonds with the net cash proceeds of one or more equity offerings at a redemption price of 106.375% of the principal amount thereof, plus accrued and unpaid interest, if any, to the redemption date (subject to the right of holders of record on the relevant record date to receive interest due on the relevant interest payment date); provided that (1) at least 65% of the original principal amount of the New 2019 Bonds (including Additional Notes as defined in the indenture relating to the New 2019 Bonds) remains outstanding after each such redemption; and (2) the redemption occurs within 90 days after the closing of the related equity offering.

In addition, the New 2019 Bonds may be redeemed, in whole or in part, at any time prior to 14 February 2017 at the option of the New 2019 Issuer upon not less than 30 nor more than 60 days' prior notice mailed by first-class mail to each holder of New 2019 Bonds at its registered address, at a redemption price equal to 100% of the principal amount of the New 2019 Bonds redeemed plus the Applicable Premium (as defined below) as of, and accrued and unpaid interest to, the applicable redemption date (subject to the right of holders of record on the relevant record date to receive interest due on the relevant interest payment date). Applicable Premium means, with respect to any New 2019 Bond on any applicable redemption date, the greater of: (1) 1.0% of the principal amount of such New 2019 Bond; and (2) the excess, if any, of: (a) the present value at such redemption date of (i) the redemption price of such New 2019 Bond at 14 February 2017 plus (ii) all required interest payments (excluding accrued and unpaid interest to such redemption date) due on such New 2019 Bond through 14 February 2017 computed using a discount rate equal to the United States treasury rate as of such redemption date plus 50 basis points; over (b) the principal amount of such New 2019 Bond.

The New 2019 Bonds are jointly and severally guaranteed (the "**New 2019 Guarantees**") on a senior basis by Nostrum Oil & Gas LP and all of its subsidiaries other than the New 2019 Issuer (the "**New 2019 Guarantors**"). The New 2019 Bonds are the New 2019 Issuer's and the New 2019 Guarantors' senior obligations and rank equally with all of the New 2019 Issuer's and the New 2019 Guarantors' other senior indebtedness. The New 2019 Bonds and the New 2019 Guarantees do not have the benefit of any security. For further details of the New 2019 Bonds, please see paragraph 12.3 of Part 17 "*Additional Information*".

Commitments

Liquidity risk is the risk that the Group will encounter difficulty in raising funds to meet commitments associated with its financial liabilities. Liquidity requirements are monitored on a regular basis and management seeks to ensure that sufficient funds are available to meet any commitments as they arise. The treasury policy requires the Group to maintain a minimum level of cash of U.S.$100 million. The table below summarises the maturity profile of the Group's financial liabilities at 31 December 2013 based on contractual undiscounted payments:

	Year ended 31 December 2013					
	On demand	Less than 3 months	3-12 months	1-5 years	More than 5 years	Total
			(U.S.$ thousands)			
Borrowings	—	—	43,613	259,902	594,691	898,206
Trade payables	58,518	—	—	—	—	58,518
Other current liabilities	22,524	—	—	—	—	22,524
Due to Government of Kazakhstan	—	258	773	4,124	12,371	17,526
Total	**81,042**	**258**	**44,386**	**264,026**	**607,062**	**996,774**

For more information on the Group's commitments regarding the Chinarevskoye, Rostoshinskoye, Darinskoye and Yuzhno-Gremyachenskoye field, see "*Business—Subsoil Licences and Permits*". For the year ended 31 December 2013, the Group had additions of explorations and evaluation assets as disclosed in Note 4 of Part 14 "*Historical Financial Information*" of this Prospectus.

Contingent Liabilities

For a description of the Group's contingent liabilities, please see Note 30 of Part 14 "*Historical Financial Information*" of the Prospectus.

Capital Expenditures

In the years ended 31 December 2013, 2012 and 2011, Nostrum's cash used in capital expenditures for purchase of property, plant and equipment (excluding VAT) was approximately U.S.$201.4 million, U.S.$210.3 million and U.S.$104.7 million, respectively, reflecting primarily drilling costs and infrastructure and development costs for the crude oil pipeline, the gas pipeline, the oil treatment unit and the gas treatment facility. This represented 22.0%, 28.5% and 34.6% of revenue, respectively. The Group has implemented a capital expenditure programme in which Nostrum has budgeted a cost per well of approximately U.S.$10 million for oil wells and approximately U.S.$14.0 million for gas condensate wells. Nostrum has also budgeted for capital expenditures of approximately U.S.$500 million for the construction of the third unit of the gas treatment facility (U.S.$29.7 million of which had already been incurred as at 31 December 2013).

In addition, Nostrum has budgeted for capital expenditures of approximately U.S.$1.5 billion to develop its reserves over the next five years (with approximately U.S.$550 million allocated to infrastructure and the remainder to drilling related capital expenditures).

Drilling Expenditures

Drilling expenditures amounted to U.S.$141.4 million for the year ended 31 December 2013, compared to U.S.$116.2 million in 2012.

Gas Treatment Facility

Following the successful implementation of the first phase of the gas treatment facility, Nostrum is expected to build a third unit for the gas treatment facility (phase two of the gas treatment facility development plan). This will depend on a number of factors such as the ability of Nostrum to convert probable reserves into proved reserves, the oil price environment and the cash flow being generated from the first phase of the gas treatment facility. Management currently estimates that the construction of the third gas treatment unit will cost approximately U.S.$500 million (U.S.$29.7 million of which had already been incurred as at 31 December 2013).

See Part 2 "*Risk Factors—Risk Factors Relating to the Group's Business—The Group's future hydrocarbon production profile is based principally on its gas treatment facility and to a lesser extent its oil treatment unit operating at full or near full capacity. If these facilities were not operating at full or near full capacity, the Group may not be able to meet its strategic production objectives.*" and "*—Operations—Gas Treatment Facility*".

Nostrum has a hedging policy whereby it hedges against adverse oil price during times of considerable non scalable capital expenditure. Based on the contracts Zhaikmunai LLP has entered in to with various equipment suppliers for third gas treatment unit and the fact that further contracts will be entered into over the coming months Nostrum is closely monitoring the hedging market and may in the near future enter in to a hedge to cover a portion or all of its non-scalable capital expenditure linked to the construction of the third gas treatment unit (see "*—Current Trading and Prospects*").

In relation to the construction of the third gas treatment unit, certain key milestones have been achieved by the Group. Nostrum has appointed FIA and Rheinmetall International Engineering GmbH (a 50% subsidiary of Ferrostaal GmbH) as the project manager in charge of managing the engineering, procurement, construction and commissioning of the entire third gas treatment unit project on behalf of Nostrum's subsidiary Zhaikmunai LLP. The FEED study, prepared by Lexington Group International (USA), has been the basis from which FIA's engineering team has developed the project starting in late 2012. As of the date of this Prospectus, Nostrum is in the final stages of procurement and in the initial stages of detailed engineering works. Nostrum has also agreed supply terms with its three suppliers for the supply of equipment totalling approximately U.S.$75 million and anticipates that in the coming weeks procurement terms will be agreed with suppliers for an additional U.S.$60 million of equipment. Nostrum expects that all procurement contracts for major equipment will be signed during the first half of 2014. Based on the current timetable for the construction, the Nostrum expects that the third gas treatment unit will be completed and commissioned by the middle of 2016. Management currently estimates that the total cost of this project will not exceed U.S.$500 million.

Oil Treatment Units

Currently Nostrum operates a first crude oil treatment unit, which was built and commissioned at the beginning of 2006. The Group expects to complete a second oil treatment unit by the end of 2015 in order to double its oil treatment capacity. Total capital expenditure for the oil treatment unit is expected to be approximately U.S.$40-50 million.

Acquisition of Oil and Gas Development Fields

In the third quarter of 2012, the Group signed purchase agreements for the acquisition of three new licenses in fields near the Chinarevskoye Field for a total purchase price of U.S.$17 million.

On 24 May 2013, the Group notified the Competent Authority of the completion of the acquisition of three development fields, Rostoshinskoye, Darinskoye and Yuzhno--Gremyachenskoye, located in the Pre-Caspian basin to the North-West of Uralsk, approximately 50 to 105 kilometres from the Chinarevskoye Field. Nostrum has estimated that it will cost approximately U.S.$85 million to conduct the necessary appraisal activities for the development of these fields, which has begun in 2013 initially through 3D seismic acquisition. See "*Business—Subsoil License and Permits*". On 9 August 2013, the Rostoshinskoye oilfield appraisal period was extended to 8 February 2015.

Disclosure about Market Risk

The Group is exposed to a variety of market risks with respect to the market price of crude oil and condensate, foreign currency exchange rates, interest rates and the creditworthiness of the counterparties with whom Nostrum expects payments under normal commercial conditions.

Commodity price risk

Commodity price risk is the risk that the Group's current or future earnings will be adversely impacted by changes in the market price of crude oil. and other hydrocarbons commodities. Commodity price risk is extremely significant to the Group's results of operations given that all sales of the Group's products are based on the commodity price in the relevant market. Commodity prices are influenced by factors such as OPEC actions, political events and supply and demand fundamentals. The Group's hedging policy is that, upon entering into longer term non scalable capital expenditure commitments, it will hedge up to a maximum of 70% of its liquids production. The instrument the Group employed in the past is a zero-cost-capped-collar. Such contract fixes the floor price at a certain predetermined level while limiting the upside risk. Although the Group enters into hedging contracts, these only partially protect the Group against decreases in commodity prices from their current levels. The Group intends to keep the same hedging policy going forward.

Foreign currency exchange rate risk

The Group is exposed to foreign currency risk associated with transactions entered into, and assets and liabilities denominated, in currencies other than the functional currency of its operating entities, being the U.S. dollar since 1 January 2009. This exposure is primarily associated with transactions, contracts and borrowings denominated in Tenge. Most of the Group's cash inflows as well as its accounts receivable are denominated in U.S. Dollars, and most of the Group's expenses are primarily denominated in U.S. Dollars, with approximately 40% to 45% denominated in Tenge. Thus, Tenge appreciation would adversely impact results. There is no significant forward market for the Tenge and the Group does not use other foreign exchange or forward contracts to manage this exposure.

With respect to foreign exchange, the Group incurred a loss of U.S.$636 thousand for the year ended 31 December 2013, a gain of U.S.$776 thousand in the year ended 31 December 2012 and a loss of U.S.$389 thousand in the year ended 31 December 2011. The Group does not hedge against this risk. As at the date of this Prospectus, all of the Group's financing is in U.S. Dollars and in the future the Group's capital expenditures are expected to be primarily denominated in U.S. Dollars.

The Group does not hedge its exposure to foreign exchange rate risk. Foreign exchange rate risk is limited, as the vast majority of its income is denominated in U.S. Dollars and expenditures are largely indirectly linked to U.S. Dollars as well. Even if procurement contracts are legally required to be stated in Tenge, most material contracts have clauses that stipulate a certain exchange rate of the Tenge to the U.S. Dollar.

Interest rate risk

The Group's interest rate risk principally relates to interest receivable and payable on its cash deposits and borrowings. During the periods under review, the Group's existing borrowings have borne interest at a fixed rate under the 2015 Bonds, the 2019 Bonds and the New 2019 Bonds.

The Group does not hedge interest rate risk nor does it swap a fixed interest rate for a variable interest rate or vice versa. The 2015 Bonds, 2019 Bonds and New 2019 Bonds bear interest at a fixed coupon.

The interest on the 2019 Bonds is 7.125% and the interest on the New 2019 Bonds is 6.375%.

Credit risk

Nostrum sells all of its crude oil pursuant to contracts with one or more oil trader(s) who purchase(s) its production.

Nostrum's policy is to mitigate the payment risk on its off takers by requiring all purchases to be prepaid or secured by a letter of credit from an international bank.

Current Trading and Recent Developments

On 23 January 2014, the contract for exploration and production of hydrocarbons from Darinskoye field was amended so as to require Zhaikmunai LLP to:

- spend at least U.S.$200,000 for education of personnel engaged to work under the contract during the exploration stage;
- spend U.S.$225,000 to finance social infrastructure of the region;
- invest at least U.S.$20,355,000 for exploration of the field during the exploration period;
- create a liquidation fund (special deposit account with local bank) equal to U.S.$208,000.

On 23 January 2014, the contract for exploration and production of hydrocarbons from Yuzhno-Gremyachenskoye field was amended so as to require Zhaikmunai LLP to:

- spend at least U.S.$338,000 for education of personnel engaged to work under the contract during the exploration stage;
- spend U.S.$225,000 to finance social infrastructure of the region;
- invest at least U.S.$33,600,000 for exploration of the field during the exploration period; and
- create a liquidation fund (special deposit account with local bank) equal to U.S.$244,000.

The remaining contingent consideration (KZT 312,168,910 for Darinskoye and KZT 487,375,905 for Yuzhno-Gremyachenskoye) was paid to the sellers in January 2014.

On 11 February 2014 the Tenge was devalued against the U.S. Dollar and other major currencies. The exchange rates before and after devaluation were 155 Tenge/U.S. Dollar and 185 Tenge/U.S. Dollar respectively.

On 14 February 2014, Nostrum Oil & Gas Finance B.V., a subsidiary of Zhaikmunai Netherlands B.V. (established on 15 January 2014), issued the New 2019 Bonds. The New 2019 Bonds are jointly and severally guaranteed on a senior basis by Nostrum Oil & Gas LP and all of its subsidiaries other than Nostrum Oil & Gas Finance B.V. On 28 February 2014, Zhaikmunai LLP entered into a deed of sale and transfer with Zhaikmunai Netherlands B.V. for the acquisition of the share capital of Nostrum Oil & Gas Finance B.V.

On 3 March 2014, in accordance with its hedging policy, Zhaikmunai LLP entered, at nil upfront cost, into a new hedging contract covering oil sales of 7,500 bopd, or a total of 5,482,500 boe running through 29 February 2016. The counterparty to the hedging agreement was Citibank. Based on the hedging contract Zhaikmunai LLP bought a put at U.S.$85/bbl, which protected it against any fall in the price of oil below U.S.$85/bbl. As part of this contract Zhaikmunai LLP, also sold a call at U.S.$111.5/bbl and bought a call at U.S.$117.5/bbl which further allowed Zhaikmunai LLP to benefit from oil prices up to U.S.$111.5/bbl and above U.S.$117.5/bbl.

For the three months ended 31 March 2014, the Group had total estimated Revenue of above U.S.$226 million as compared to U.S.$229 million for the three months ended 31 March 2013. For the three months ended 31 March 2014, the Group estimated EBITDA of above U.S.$150 million as compared to U.S.$153 million for the three months ended 31 March 2013. As at 31 March 2014, the Group estimates cash (cash and cash equivalents, restricted cash, short-term and non-current deposits) to be approximately U.S.$642 million as compared to U.S.$287 million at 31 March 2013. The Group estimates its net debt to be approximately U.S.$415 million and net debt to EBITDA ratio of 365.

The table below sets out Nostrum's production for the three months ended 31 March 2014 and 2013:

	Total Average Production (boepd) for the first three months of	
	2014	**2013**
Products		
Crude Oil & Stabilised Condensate	20,143	19,705
LPG (Liquid Petroleum Gas)	4,943	3,651
Dry Gas	23,264	22,917
Total	48,350	46,273

PART 13
CAPITALISATION AND INDEBTEDNESS

The information in the table set out below should be read together with Part 12 "*Operating and Financial Review*" and has been extracted from the financial information set out in Part 14 "*Historical Financial Information*".

	As of 31 December 2013
	(U.S.$ thousands)
Total current debt	
Guaranteed	7,263
Secured	—
Unguaranteed/unsecured	—
	7,263
Total non-current debt (excluding current portion of long-term debt)	
Guaranteed	621,160
Secured	—
Unguaranteed/unsecured	—
	621,160

	As of 31 December 2013
	(U.S.$ thousands)
Shareholders' equity	
Partnership capital	350,123
Additional paid-in capital	8,126
Other reserves	3,299
	361,548
Total	**989,971**

On 14 February 2014, the Group issued the New 2019 Bonds in a principal amount of U.S.$400 million and on 14 April 2014 the Group redeemed the outstanding U.S.$92.5 million in principal amount of the 2015 Bonds. Apart from these facts, there have been no material changes to the Group's capitalisation since 31 December 2013.

The following table sets out the Group's unaudited net financial indebtedness as of 28 February 2014 and has been extracted without material adjustment from the unaudited accounting records of the Group.

	As of 28 February 2014
	(U.S.$ thousands, unaudited)
Cash	573,622
Cash equivalents	—
Trading securities	—
Total liquidity	573,622
Current financial receivable	
Current bank debt	—
Current portion of non-current debt	15,496
Other current financial debt	—
Total current financial debt	15,496
Net current financial indebtedness	(558,126)
Non-current bank loans	—
Bonds issued	1,015,815
Other non-current loans	—
Non-current financial indebtedness	1,015,815
Net financial indebtedness	457,689

The Group has no indirect and contingent indebtedness.

PART 14
HISTORICAL FINANCIAL INFORMATION

Section A: Accountant's Report on the Historical Financial Information of the Group

The Directors
Nostrum Oil & Gas plc
4th Floor
53-54 Grosvenor Street
London, W1K 3HU
United Kingdom

20 May 2014

Dear Sirs

We report on the financial information of Nostrum Oil & Gas LP and its subsidiaries (the "**Group**") set out in Section B of this Part 14 "*Historical Financial Information*" for the years ended 31 December 2011, 2012 and 2013 (the "**Historical Financial Information**"). The Historical Financial Information has been prepared for inclusion in the Prospectus dated 20 May 2014 of Nostrum Oil & Gas plc on the basis of the accounting policies set out in note 1 to the Historical Financial Information. This report is required by item 20.1 of Annex I of the Prospectus Directive Regulation and is given for the purpose of complying with that item and for no other purpose.

Save for any responsibility arising under Prospectus Rule 5.5.3R (2)(f) to any person as and to the extent there provided, to the fullest extent permitted by law we do not assume any responsibility and will not accept any liability to any other person for any loss suffered by any such other person as a result of, arising out of, or in connection with this report or our statement, required by and given solely for the purposes of complying with item 23.1 of Annex I to Commission Regulation (EC) 809/2004, consenting to its inclusion in the Prospectus.

Responsibilities

The Directors of Nostrum Oil & Gas plc are responsible for preparing the financial information in accordance with International Financial Reporting Standards as adopted by the European Union.

It is our responsibility to form an opinion on the financial information and to report our opinion to you.

Basis of opinion

We conducted our work in accordance with Standards for Investment Reporting issued by the Auditing Practices Board in the United Kingdom. Our work included an assessment of evidence relevant to the amounts and disclosures in the Historical Financial Information. It also included an assessment of significant estimates and judgments made by those responsible for the preparation of the Historical Financial Information and whether the accounting policies are appropriate to the entity's circumstances, consistently applied and adequately disclosed.

We planned and performed our work so as to obtain all the information and explanations which we considered necessary in order to provide us with sufficient evidence to give reasonable assurance that the Historical Financial Information is free from material misstatement whether caused by fraud or other irregularity or error.

Our work has not been carried out in accordance with auditing or other standards and practices generally accepted in other jurisdictions and accordingly should not be relied upon as if it had been carried out in accordance with those standards and practices.

Opinion

In our opinion, the Historical Financial Information gives, for the purposes of the prospectus dated 20 May 2014, a true and fair view of the state of affairs of the Group as at the dates stated and of its profits, cash flows and changes in equity for the periods then ended in accordance with International Financial Reporting Standards as adopted by the European Union.

Declaration

For the purposes of Prospectus Rule 5.5.3R (2)(f) we are responsible for this report as part of the prospectus and declare that we have taken all reasonable care to ensure that the information contained in this report is, to the best of our knowledge, in accordance with the facts and contains no omission likely to affect its import. This declaration is included in the prospectus in compliance with item 1.2 of Annex I of Commission Regulation (EC) 809/2004.

Yours faithfully

Ernst & Young Advisory LLP (Kazakhstan)

Section B: Operating Group IFRS Financial Information

Consolidated Statement of Comprehensive Income

	Notes	2011	2012	2013
			(U.S.$ thousands)	
Revenue	4	300,837	737,065	895,014
Cost of sales	5	(70,805)	(238,224)	(286,222)
Gross profit		**230,032**	**498,841**	**608,792**
General and administrative expenses	6	(36,462)	(64,882)	(60,449)
Selling and transportation expenses	7	(35,395)	(103,604)	(121,674)
Loss on derivative financial instrument		—	—	—
Finance costs	8	(1,660)	(46,785)	(43,615)
Foreign exchange gain/(loss), net		(389)	776	(636)
Interest income		336	698	764
Other expense	9	(7,855)	(6,612)	(25,593)
Other income		3,365	3,940	4,426
Profit before income tax		148,972	282,372	**362,015**
Income tax expense	10	(67,348)	(120,363)	(142,496)
Profit for the period		81,624	162,009	**219,519**
Total comprehensive income for the period		**81,624**	**162,009**	**219,519**
			(U.S.$ per Common Unit)	
Basic and diluted earnings per share	20	0.44	0.87	1.18

Consolidated Statement of Financial Position

	Notes	As at 31 December 2011	As at 31 December 2012	As at 31 December 2013
			(U.S.$ thousands)	
Assets				
Non-current assets:				
Exploration and evaluation assets	12	—	—	20,434
Goodwill	11	—	—	30,386
Property, plant and equipment	13, 14	1,120,453	1,222,665	1,330,903
Non-current investments	19	—	—	30,000
Advances for non-current assets	15	3,368	25,278	10,037
		1,126,897	**1,251,595**	**1,425,977**
Current assets:				
Inventories	16	14,518	24,964	22,085
Trade receivables	17	12,640	54,004	66,565
Prepayments and other current assets	18	23,279	24,369	31,192
Income tax prepayment		3,453	—	5,042
Restricted cash		—	—	
Short-term investments	19	—	50,000	25,000
Cash and cash equivalents	20	125,393	197,730	184,914
		179,283	**351,067**	**334,798**
Total assets		**1,306,180**	**1,602,662**	**1,760,775**
Equity and Liabilities				
Partnership capital and reserves:				
Partnership capital	21	368,203	371,147	350,123
Additional paid-in capital		1,677	6,095	8,126
Retained earnings and translation reserve	21	215,351	317,862	474,202
		585,231	**695,104**	**832,451**
Non-current liabilities:				
Long-term borrowings	22	438,082	615,742	621,160
Abandonment and site restoration liabilities	23	8,713	11,064	13,874
Due to Government of Kazakhstan	24	6,211	6,122	6,021
Deferred tax liability		146,674	148,932	152,545
		599,680	**781,860**	**793,600**
Current liabilities:				
Trade payables	25	81,914	58,390	58,518
Current portion of long term borrowings	22	9,450	7,152	7,263
Employee share option plan	28	11,734	9,788	12,016
Income tax payable		—	11,762	1,232
Current portion of Due to Government of Kazakhstan	24	1,031	1,031	1,031
Other current liabilities	26	17,140	37,575	54,664
		121,269	**125,698**	**134,724**
Total equity and liabilities		**1,306,180**	**1,602,662**	**1,760,775**

Consolidated Statement of Changes in Equity

	Notes	Partnership capital	Treasury capital	Additional paid-in capital	Retained earnings and reserves	Total
				(U.S.$ thousands)		
As at 1 January 2011		**366,942**	**—**	**—**	**133,727**	**500,669**
Net income for the period		—	—	—	81,624	81,624
Total comprehensive income for the period		**—**	**—**	**—**	**81,624**	**81,624**
Issuance of treasury capital (GDRs)	21	7,048	(7,048)	—	—	—
Transaction costs		—	—	(238)	—	(238)
Sale of treasury capital	28	—	1,261	1,915	—	3,176
As at 31 December 2011		**373,990**	**(5,787)**	**1,677**	**215,351**	**585,231**
As at 1 January 2012		**373,990**	**(5,787)**	**1,677**	**215,351**	**585,231**
Net income for the period		—	—	—	162,009	162,009
Total comprehensive income for the period		**—**	**—**	**—**	**162,009**	**162,009**
Issuance of treasury capital (GDRs)		6,884	(6,884)	—	—	—
Sale of treasury capital	28	—	2,944	4,418	—	7,362
Distributions	21	—	—	—	(59,498)	(59,498)
As at 31 December 2012		**380,874**	**(9,727)**	**6,095**	**317,862**	**695,104**
As at 1 January 2013		**380,874**	**(9,727)**	**6,095**	**317,862**	**695,104**
Net income for the period		—	—	—	219,519	219,519
Total comprehensive income for the period		—	—	—	**219,519**	**219,519**
Buyback of GDRs		—	(22,165)	—	—	(22,165)
Sale of treasury capital	28	—	1,141	2,031	—	3,172
Distributions	21	—	—	—	(63,179)	(63,179)
As at 31 December 2013		**380,874**	**(30,751)**	**8,126**	**474,202**	**832,451**

Consolidated Statement of Cash Flows

	Notes	2011	2012	2013
			(U.S.$ thousands)	
Cash flow from operating activities:				
Profit before income tax		**148,972**	**282,372**	**362,015**
Adjustments for:				
Depreciation, depletion and amortization	5, 6	19,843	102,632	120,370
Employee share option plan		3,545	2,470	4,430
Finance costs		1,660	46,785	43,615
Interest income		(336)	(698)	(764)
Loss on derivative financial instruments		—	—	—
Reversal of tax provision		(728)	—	—
Foreign exchange gain on investing and financing activities		202	(745)	245
Loss on disposal of property, plant and equipment		—	79	84
Operating profit before working capital changes		**173,794**	**432,895**	**529,995**
Changes in working capital:				
Change in inventories		(8,879)	(10,446)	2,879
Change in trade receivables		(11,004)	(41,364)	(12,561)
Change in prepayments and other current assets		(6,519)	(9,190)	(6,225)
Change in trade payables		10,497	(2,673)	(6,768)
Change in advances received		(8,539)	(3,094)	(23)
Change in due to Government of Kazakhstan		(1,033)	(1,030)	(1,031)
Change in other current liabilities		(333)	25,316	8,659
Cash generated from operations		**147,984**	**390,414**	**514,925**
Income tax paid		(13,210)	(94,173)	(155,470)
Payments under Employee share option plan		(1,915)	(4,416)	(2,202)
Net cash flows from operating activities		**132,859**	**291,825**	**357,253**
Cash flow from investing activities:				
Interest received		336	698	764
Placement of short-term bank deposits		—	(50,000)	—
Redemption of short-term bank deposits		—	—	25,000
Purchases of property, plant and equipment		(104,653)	(210,283)	(201,358)
Purchase of licenses		—	(10,089)	(5,045)
Placement of non-current bank deposits		—	—	(30,000)
Acquisition of Probel, net of cash acquired		—	—	(26,883)
Net cash used in investing activities		**(104,317)**	**(269,674)**	**(237,522)**
Cash flow from financing activities:				
Finance costs paid		(50,583)	(53,735)	(49,613)
Issue of notes		—	560,000	—
Repurchase of GDRs		—	—	—
Fees paid on arrangement of notes and borrowings		—	(7,259)	—
Repayment of borrowings		—	(357,495)	—
Premium paid for early repayment of notes		—	(38,409)	—
Transfer from/(to) restricted cash		667	(576)	(565)
Treasury shares (purchases)/sold		2,938	7,362	(18,993)
Distributions paid		—	(59,498)	(63,179)
Realized gain on derivative financial instrument		(372)	—	—
Net cash provided/(used in) by financing activities		**(47,350)**	**50,390**	**(132,350)**
Effects of exchange rate changes on cash and cash equivalents		—	(204)	(197)
Net increase/(decrease) in cash and cash equivalents		**(18,808)**	**72,337**	**(12,816)**
Cash and cash equivalents at the beginning of the year		144,201	125,393	197,730
Cash and cash equivalents at the end of the year		**125,393**	**197,730**	**184,914**

Notes Forming Part of the Financial Information

1. Accounting Policies

(a) ***Reporting entity***

Nostrum Oil & Gas LP is a Limited Partnership formed on 29 August 2007 pursuant to the Partnership Act 1909 of the Isle of Man. Nostrum Oil & Gas LP is registered in the Isle of Man with registered number 295P.

The registered address of Nostrum Oil & Gas LP is: 7th Floor, Harbour Court, Lord Street, Douglas, Isle of Man, IM1 4LN.

The Consolidated Financial Information includes the results of the operations of Nostrum Oil & Gas LP ("**Partnership**") and its wholly owned subsidiaries Zhaikmunai Netherlands B.V. (formerly Frans Van Der Schoot B.V.), Zhaikmunai Finance B.V., Zhaikmunai International B.V., Claydon Industrial Limited ("**Claydon**"), Jubilata Investments Limited ("**Jubilata**"), Zhaikmunai LLP, Condensate-Holding LLP ("**Condensate**"), Nostrum Oil & Gas Coöperatief U.A., Probel Capital Management N.V. and Probel Capital Management UK Ltd. Nostrum Oil & Gas LP and its subsidiaries are hereinafter referred to as "the Group". The Group's operations comprise of a single operating segment and are primarily conducted through its oil and gas producing entity Zhaikmunai LLP located in Kazakhstan. The General Partner of Nostrum Oil & Gas LP is Nostrum Oil & Gas Group Limited, which is responsible for the management of the Group (Note 21). The Partnership does not have an ultimate controlling party.

Zhaikmunai LLP carries out its activities in accordance with the Contract for Additional Exploration, Production and Production-Sharing of Crude Hydrocarbons in the Chinarevskoye oil and gas condensate field (the "**Contract**") dated 31 October 1997 between the State Committee of Investments of the Republic of Kazakhstan and Zhaikmunai LLP in accordance with the license MG No. 253D for the exploration and production of hydrocarbons in Chinarevskoye oil and gas condensate field.

On 17 August 2012 Zhaikmunai LLP signed Asset Purchase Agreements to acquire 100% of the subsoil use rights related to three oil and gas fields—Rostoshinskoye, Darinskoye and Yuzhno-Gremyachinskoye—all located in the Western Kazakhstan region. On 1 March 2013 Zhaikmunai LLP has acquired the subsoil use rights related to these three oil and gas fields in Kazakhstan following the signing of the respective supplementary agreements related thereto by the Ministry of Oil and Gas of the Republic of Kazakhstan ("**MOG**").

On 30 December 2013 Nostrum Oil & Gas Coöperatief U.A. signed a purchase agreement to acquire 100% of Probel Capital Management N.V., located in Brussels, Belgium.

Licence terms

The term of the Chinarevskoye subsoil use rights originally included a 5-year exploration period and a 25-year production period. The exploration period was initially extended for additional 4 years and then for further 2 years according to the supplements to the Contract dated 12 January 2004 and 23 June 2005, respectively. In accordance with the supplement dated 5 June 2008, Tournaisian North reservoir entered into production period as at 1 January 2007. Following additional commercial discoveries during 2008, the exploration period under the Chinarevskoye subsoil use rights, other than for the Tournaisian horizons, was extended for an additional 3-year period, which expired on 26 May 2011. A further extension to 26 May 2014 was made under the supplement dated 28 October 2013. The extensions to the exploration periods have not changed the Chinarevskoye subsoil use rights term, which expires in 2031.

The contract for exploration and production of hydrocarbons from Rostoshinskoye field dated 8 February 2008 originally included a 3-year exploration period and a 12-year production period. On 27 April 2009 the exploration period was extended so as to have a total duration of 6 years. In January 2012 the MOG made the decision to extend the exploration period until 8 February 2015 and the corresponding supplementary agreement between MOG and Zhaikmunai LLP was signed on 9 August 2013.

The contract for exploration and production of hydrocarbons from Darjinskoye field dated 28 July 2006 originally included a 6-year exploration period and a 19-year production period. On 21 October 2008 the exploration period was extended for 6 months so as to expire on 28 January 2013. On 27 April 2009 the exploration period was extended until 28 January 2015. Upon receipt of the ownership rights Zhaikmunai LLP started the process of application for further extension of the exploration period.

The contract for exploration and production of hydrocarbons from Yuzhno-Gremyachinskoye field dated 28 July 2006 originally included a 5-year exploration period and a 20-year production period. On 27 April 2009 the exploration period was extended until 28 July 2012. On 8 July 2011 the exploration period was further extended until 28 July 2014. Upon receipt of the ownership rights the Zhaikmunai LLP started the process of application for further extension of the exploration period.

Royalty payments

Zhaikmunai LLP is required to make monthly royalty payments throughout the entire production period, at the rates specified in the Contract. Royalty rates depend on recovery levels and the phase of production and can vary from 3% to 7% of produced crude oil and from 4% to 9% of produced natural gas. Royalty is accounted on gross basis.

Government "profit share"

Zhaikmunai LLP makes payments to the Government of its "profit share" as determined in the Contract. The "profit share" depends on hydrocarbon production levels and varies from 10% to 40% of production after deducting royalties and reimbursable expenditures. Reimbursable expenditures include operating expenses, costs of additional exploration and development costs. Government "profit share" is expensed as incurred and paid in cash. Government profit share is accounted on gross basis.

Seasonality of operations

The Group's operating expenses are subject to seasonal fluctuations, with higher expenses for various maintenance and other oil field services usually incurred in the warmer months.

(b) ***Basis of preparation***

The Consolidated Financial Information has been prepared in accordance with International Financial Reporting Standards ("**IFRS**") as issued by International Accounting Standards Board ("**IASB**"), as adopted by the European Union.

The preparation of consolidated financial statements in conformity with IFRS requires the use of certain critical accounting estimates. It also requires from management to exercise its judgment in the process of applying the Group's accounting policies. The areas involving a higher degree of judgment or complexity, or areas where assumptions and estimates are significant to the consolidated financial statements are disclosed in Note 2.

The accounting policies adopted have been applied consistently to all periods presented.

(c) ***Statement of compliance***

The consolidated financial information of the Group has been prepared in accordance with International Financial Reporting Standards ("**IFRS**") as issued by International Accounting Standards Board ("**IASB**"), as adopted by the European Union. The Group's financial statements are also consistent with IFRS as issued by IASB.

(d) ***Basis of measurement***

The Consolidated Financial Information has been prepared under the historical cost convention except for certain financial assets and liabilities that have been measured at fair value.

(e) ***Presentation and functional currencies***

The Consolidated Financial Information is presented in United States dollars. Each entity in the Group determines its own functional currency and items included in the financial statements of each entity are measured using that functional currency.

The Consolidated Financial Information is rounded to the nearest thousand unless stated otherwise.

(f) ***Basis of consolidation***

The consolidated financial information includes the financial information of the Partnership and all of its subsidiaries as at 31 December 2011, 2012 and 2013 and for the years then ended. Subsidiaries are fully consolidated from the date on which control is transferred to the Group, and cease to be consolidated from the date at which control is transferred out of the Group. Control is achieved when the Group is exposed, or has rights, to variable returns from its involvement with the investee and has the ability to affect those returns through its power over the investee. Specifically, the Group controls an investee if and only if the Group has:

- Power over the investee (i.e. existing rights that give it the current ability to direct the relevant activities of the investee);
- Exposure, or rights, to variable returns from its involvement with the investee; and
- The ability to use its power over the investee to affect its returns.

The Group re-assesses whether or not it controls an investee if facts and circumstances indicate that there are changes to one or more of the three elements of control. Consolidation of a subsidiary begins when the Group obtains control over the subsidiary and ceases when the Group loses control of the subsidiary. Assets, liabilities, income and expenses of a subsidiary acquired or disposed of during the year are included in the statement of comprehensive income from the date the Group gains control until the date the Group ceases to control the subsidiary.

Profit or loss and each component of other comprehensive income (OCI) are attributed to the equity holders of the parent of the Group and to the non-controlling interests, even if this results in the non-controlling interests having a deficit balance. When necessary, adjustments are made to the financial statements of subsidiaries to bring their accounting policies into line with the Group's accounting policies. All intra-group assets and liabilities, equity, income, expenses and cash flows relating to transactions between members of the Group are eliminated in full on consolidation.

(g) ***Foreign currency translation***

Each entity in the Group determines its own functional currency and items included in the consolidated financial statements of each entity are measured using that functional currency. The functional currency of the Partnership and each of its subsidiaries is the United States dollar (the "**US dollar**" or "**US$**"), except for Condensate, the functional currency of which is Kazakhstani Tenge (the "**Tenge**").

Transactions and balances denominated in foreign currencies

Transactions in foreign currencies are initially recorded by the Group at their respective functional currency rates prevailing at the date of the transaction. Monetary assets and liabilities denominated in foreign currencies are retranslated at the functional currency spot rate of exchange ruling at the reporting date. All differences are taken to the profit or loss. Non-monetary items that are measured in terms of historical cost in a foreign currency are translated using the exchange rates as at the dates of the initial transactions. Non-monetary items measured at fair value in a foreign currency are translated using the exchange rates at the date when the fair value is determined.

(h) ***Business combinations and goodwill***

Business combinations are accounted for using the acquisition method. The cost of an acquisition is measured as the aggregate of the consideration transferred, measured at acquisition date fair value and the amount of any non-controlling interest ("**NCI**") in the acquiree. For each business combination, the Group elects whether to measure NCI in the acquiree at fair value or at the proportionate share of the acquiree's identifiable net assets. Acquisition related costs are expensed as incurred and included in administrative expenses.

When the Group acquires a business, it assesses the assets and liabilities assumed for appropriate classification and designation in accordance with the contractual terms, economic circumstances and pertinent conditions as at the acquisition date.

Any contingent consideration to be transferred by the acquirer will be recognised at fair value at the acquisition date. Contingent consideration classified as an asset or liability that is a financial instrument and within the scope of IAS 39 Financial Instruments: Recognition and Measurement is measured at fair value, with changes in fair value recognised either in the statement of profit or loss or as a change to other comprehensive income. If the contingent consideration is not within the scope of IAS 39, it is measured in accordance with the appropriate IFRS. Contingent consideration that is classified as equity is not re-measured, and subsequent settlement is accounted for within equity.

Goodwill is initially measured at cost, being the excess of the aggregate of the consideration transferred and the amount recognised for NCI over the fair value of the identifiable net assets acquired and liabilities assumed. After initial recognition, goodwill is measured at cost less any accumulated impairment losses. For the purpose of impairment testing, goodwill acquired in a business combination is, from the acquisition date, allocated to each of the Group's CGUs that are expected to benefit from the combination, irrespective of whether other assets or liabilities of the acquiree are assigned to those units.

Where goodwill forms part of a Cash Generating Unit ("**CGU**") and part of the operation in that unit is disposed of, the goodwill associated with the disposed operation is included in the carrying amount of the operation when determining the gain or loss on disposal. Goodwill disposed of in these circumstances is measured based on the relative values of the disposed operation and the portion of the CGU retained.

(i) ***Exploration expenditure***

Geological and geophysical exploration costs are charged to profit or loss as incurred. Costs directly associated with exploration wells are capitalized within exploration and evaluation assets until the drilling of the well is complete and the results have been evaluated. These costs include employee remuneration and materials and fuel used, rig costs and payments made to contractors and asset retirement obligation fees. If hydrocarbons are found and, subject to further appraisal activity (e.g., the drilling of additional wells), it is probable that they can be commercially developed, the costs continue to be carried as an asset while sufficient/continued progress is made in assessing the commerciality of the hydrocarbons.

All such carried costs are subject to technical, commercial and management review at least once a year to confirm the continued intent to develop or otherwise extract value from the discovery. When this is no longer the case, the costs are written off. The exploration expenditure expensed to profit or loss during 2013 amounted to US$ 3,810 thousand (2012: Nil).

Subsoil use rights acquisition costs are initially capitalised in exploration and evaluation assets. Subsoil use rights acquisition costs are reviewed at each reporting date to confirm that there is no indication that the carrying amount exceeds the recoverable amount. This review includes confirming that exploration drilling is still under way or firmly planned, or that it has been determined, or work is under way to determine that the discovery is economically viable based on a range of technical and commercial considerations and sufficient progress is being made on establishing development plans and timing. If no future activity is planned or the subsoil use rights have been relinquished or has expired, the carrying value of the subsoil use rights acquisition costs is written off through profit or loss. Upon recognition of proved reserves and internal approval for development, the relevant expenditure is transferred to oil and gas properties.

(j) ***Oil and gas properties***

Expenditure on the construction, installation or completion of infrastructure facilities such as treatment facilities, pipelines and the drilling of development wells, is capitalized within property, plant and equipment as oil and gas properties. The initial cost of an asset comprises its purchase price or construction cost, any costs directly attributable to bringing the asset into operation and the initial estimate of decommissioning obligation, if any. The purchase price or construction cost is the aggregate amount paid and the fair value of any other consideration given to acquire the asset. When a development project moves into the production stage, the capitalisation of certain construction/ development costs ceases and costs are either regarded as part of the cost of inventory or expensed, except for costs which qualify for capitalisation relating to oil and gas property asset additions, improvements or new developments.

Property, plant and equipment are stated at cost less accumulated depreciation, depletion and impairment.

All capitalized costs of oil and gas properties, except construction work-in-progress, are amortized using the unit-of-production method based on estimated proved developed reserves of the field, except the Group depreciates its oil pipeline and oil loading terminal on a straight line basis over the life of the subsoil use rights. In the case of assets that have a useful life shorter than the lifetime of the field the straight line method is applied.

Proved oil and gas reserves are estimated quantities of commercially viable hydrocarbons which existing geological, geophysical and engineering data show to be recoverable in future years from known reservoirs.

The Group uses the reserve estimates provided by an independent appraiser on an annual basis to assess the oil and gas reserves of its oil and gas fields. These reserve quantities are used for calculating the unit of production depreciation rate as it reflects the expected pattern of consumption of future economic benefits by the Group.

(k) ***Impairment of non-financial assets***

The Group assesses assets or groups of assets for impairment whenever events or changes in circumstances indicate that the carrying value of an asset may not be recoverable. Individual assets are grouped for impairment assessment purposes at the lowest level at which there are identifiable cash inflows that are largely independent of the cash flows of other groups of assets. If any such indication of impairment exists or when annual impairment testing for an asset group is required, the Group makes an estimate of its recoverable amount. An asset group's recoverable amount is the higher of its fair value less costs of disposal and its value in use. Where the carrying amount of an asset group exceeds its recoverable amount, the asset group is considered impaired and is written down to its recoverable amount. In assessing value in use, the estimated future cash flows are adjusted for the risks specific to the asset group and are discounted to their present value using a pre-tax discount rate that reflects current market assessments of the time value of money.

In determining fair value less costs of disposal, recent market transactions are taken into account. If no such transactions can be identified, an appropriate valuation model is used. These calculations are corroborated by valuation multiples, quoted share prices for publicly traded companies or other available fair value indicators.

An assessment is made at each reporting date as to whether there is any indication that previously recognized impairment losses may no longer exist or may have decreased. If such indication exists, the recoverable amount is estimated. A previously recognized impairment loss is reversed only if there has been a change in the estimates used to determine the asset's recoverable amount since the last impairment loss was recognized. If that is the case, the carrying amount of the asset is increased to its recoverable amount. That increased amount cannot exceed the carrying amount that would have been determined, net of depreciation, had no impairment loss been recognized for the asset in prior years. Such reversal is recognized in the profit or loss.

Impairment losses of continuing operations, including impairment of inventories, are recognised in profit or loss in those expense categories consistent with the function of the impaired asset.

After such a reversal, the depreciation charge is adjusted in future periods to allocate the asset's revised carrying amount, less any residual value, on a systematic basis over its remaining useful life.

(l) ***Other properties***

All other property, plant and equipment are stated at historical cost less accumulated depreciation and impairment. Historical cost includes expenditures that are directly attributable to the acquisition of the items. Subsequent costs are included in the asset's carrying amount or recognized as a separate asset, as appropriate, only when it is probable that future economic benefits associated with the item will flow to the Group and the cost of the item can be measured reliably. All other repairs and maintenance are charged to the profit or loss during the year in which they are incurred.

Depreciation is calculated on a straight-line basis over the estimated useful lives of the assets as follows:

	Years
Buildings and constructions	7-15
Vehicles	8
Machinery and equipment	3-13
Other	3-10

(m) ***Borrowing costs***

The Group capitalizes borrowing costs on qualifying assets. Assets qualifying for borrowing costs capitalization include all assets under construction that are not being depreciated, depleted, or amortized, provided that work is in progress at that time. Qualifying assets mostly include wells and other operations field infrastructure under construction. Capitalized borrowing costs are calculated by applying the capitalization rate to the expenditures on qualifying assets. The capitalization rate is the weighted average of the borrowing costs applicable to the Group's borrowings that are outstanding during the period.

All other borrowing costs are recognised in profit or loss in the period in which they are incurred. Even though exploration and evaluation assets can be qualifying assets, they generally do not meet the 'probable economic benefits' test and also are rarely debt funded. Any related borrowing costs incurred during this phase are therefore generally recognised in profit or loss in the period in which they are incurred.

(n) ***Cash and short-term deposits***

Cash and cash equivalents in the statement of financial position comprise cash at banks and at hand and short term deposits with an original maturity of three months or less, but exclude any restricted cash which is not available for use by the Group and therefore is not considered highly liquid—for example, cash set aside to cover decommissioning obligations.

For the purpose of the consolidated statement of cash flows, cash and cash equivalents consist of cash and cash equivalents, as defined above, net of outstanding bank overdrafts.

(o) ***Inventories***

Inventories are stated at the lower of cost or net realizable value ("**NRV**"). Cost of oil, gas condensate and liquefied petroleum gas ("**LPG**") is determined on the weighted-average method based on the production cost including the relevant expenses on depreciation, depletion and impairment and overhead costs based on production volume. Net realizable value is the estimated selling price in the ordinary course of business, less selling expenses.

(p) ***Provisions***

Provisions are recognized when the Group has a present obligation (legal or constructive) as a result of a past event, it is probable that an outflow of resources embodying economic benefits will be required to settle the obligation and a reliable estimate of the amount of the obligation can be made.

Abandonment and site restoration (decommissioning)

Provision for decommissioning is recognized in full, on a discounted cash flow basis, when the Group has an obligation to dismantle and remove a facility or an item of plant and to restore the site on which it is located, and when a reasonable estimate of that provision can be made. The amount of the obligation is the present value of the estimated expenditures expected to be required to settle the obligation adjusted for expected inflation and discounted using average long-term interest rates for emerging market debt adjusted for risks specific to the Kazakhstan market. The unwinding of the discount related to the obligation is recorded in finance costs. A corresponding amount equivalent to the provision is also recognized as part of the cost of the related oil and gas properties. This asset is subsequently depreciated as part of the capital costs of the oil and gas properties on a unit-of-production basis.

Changes in the measurement of an existing decommissioning liability that result from changes in the estimated timing or amount of the outflow of resources embodying economic benefits required to settle the obligation, or changes to the discount rate:

(a) are added to, or deducted from, the cost of the related asset in the current period. If deducted from the cost of the asset the amount deducted shall not exceed its carrying amount. If a decrease in the provision exceeds the carrying amount of the asset, the excess is recognized immediately in the profit or loss; and

(b) if the adjustment results in an addition to the cost of an asset, the Group considers whether this is an indication that the new carrying amount of the asset may not be fully recoverable. If it is such an indication, the Group tests the asset for impairment by estimating its recoverable amount, and accounts for any impairment loss in accordance with IAS 36.

(q) ***Financial assets***

Initial recognition and measurement

Financial assets within the scope of IAS 39 are classified as financial assets at fair value through profit or loss, loans and receivables, held-to-maturity investments, available-for-sale financial assets, or as derivatives designated as hedging instruments in an effective hedge, as appropriate. The Group determines the classification of its financial assets at initial recognition.

All financial assets are recognised initially at fair value plus, in the case of investments not at fair value through profit or loss, directly attributable transaction costs.

Purchases or sales of financial assets that require delivery of assets within a time frame established by regulation or convention in the marketplace (regular way trades) are recognised on the trade date, i.e., the date that the Group commits to purchase or sell the asset.

The Group's financial assets include cash and short-term deposits, trade and other receivables.

Loans and receivables

Loans and receivables are non-derivative financial assets with fixed or determinable payments that are not quoted in an active market. After initial measurement, such financial assets are subsequently measured at amortised cost using the effective interest rate method (EIR), less impairment. Amortised cost is calculated by taking into account any discount or premium on acquisition and fee or costs that are an integral part of the EIR.

The EIR amortisation is included in finance income in the statement of comprehensive income. The losses arising from impairment are recognised in the statement of comprehensive income in finance costs.

Accounts receivable

Accounts receivables are recognized and carried at original invoice amount less an allowance for any uncollectible amounts. An estimate for uncollectible amounts is made when collection of the full amount is no longer probable. These estimates are reviewed periodically, and as adjustments become necessary, they are reported as expense (credit) in the period in which they become known.

Derecognition

A financial asset (or, where applicable a part of a financial asset or part of a group of similar financial assets) is derecognized when:

- The rights to receive cash flows from the asset have expired
- The Group has transferred its rights to receive cash flows from the asset or has assumed an obligation to pay the received cash flows in full without material delay to a third party under a 'pass-through' arrangement; and either (a) the Group has transferred substantially all the risks and rewards of the asset, or (b) the Group has neither transferred nor retained substantially all the risks and rewards of the asset, but has transferred control of the asset.

When the Group has transferred its rights to receive cash flows from an asset or has entered into a pass-through arrangement, and has neither transferred nor retained substantially all the risks and rewards of the asset nor transferred control of the asset, the asset is recognized to the extent of the Group's continuing involvement in the asset.

In that case, the Group also recognizes an associated liability. The transferred asset and the associated liability are measured on a basis that reflects the rights and obligations that the Group has retained.

Continuing involvement that takes the form of a guarantee over the transferred asset is measured at the lower of the original carrying amount of the asset and the maximum amount of consideration that the Group could be required to repay.

Impairment of financial assets

The Group assesses at each reporting date whether there is any objective evidence that a financial asset or a group of financial assets is impaired. A financial asset or a group of financial assets is deemed to be impaired if, and only if, there is objective evidence of impairment as a result of one or more events that has occurred after the initial recognition of the asset (an incurred 'loss event') and that loss event has an impact on the estimated future cash flows of the financial asset or the group of financial assets that can be reliably estimated. Evidence of impairment may include indications that the debtors or a group of debtors is experiencing significant financial difficulty, default or delinquency in interest or principal payments, the probability that they will enter bankruptcy or other financial reorganization and where observable data indicate that there is a measurable decrease in the estimated future cash flows, such as changes in arrears or economic conditions that correlate with defaults.

Financial assets carried at amortized cost

For financial assets carried at amortized cost the Group first assesses individually whether objective evidence of impairment exists individually for financial assets that are individually significant, or collectively for financial assets that are not individually significant. If the Group determines that no objective evidence of impairment exists for an individually assessed financial asset, whether significant or not, it includes the asset in a group of financial assets with similar credit risk characteristics and collectively assesses them for impairment. Assets that are individually assessed for impairment and for which an impairment loss is, or continues to be, recognized are not included in a collective assessment of impairment.

If there is objective evidence that an impairment loss has incurred, the amount of the loss is measured as the difference between the asset's carrying amount and the present value of estimated future cash flows (excluding future expected credit losses that have not yet been incurred). The present value of the estimated future cash flows is discounted at the financial assets original effective interest rate. If a loan has a variable interest rate, the discount rate for measuring any impairment loss is the current effective interest rate.

The carrying amount of the asset is reduced through the use of an allowance account and the amount of the loss is recognized in the profit or loss. Interest income continues to be accrued on the reduced carrying amount and is accrued using the rate of interest used to discount the future cash flows for the purpose of measuring the impairment loss. The interest income is recorded as part of finance income in the profit or loss. Loans together with the associated allowance are written off when there is no realistic prospect of future recovery and all collateral has been realized or has been transferred to the Group. If, in a subsequent year, the amount of the estimated impairment loss increases or decreases because of an event occurring after the impairment was recognized, the previously recognized impairment loss is increased or reduced by adjusting the allowance account. If a future write-off is later recovered, the recovery is credited to finance costs in the profit or loss.

(r) ***Financial liabilities***

Initial recognition and measurement

Financial liabilities within the scope of IAS 39 are classified as financial liabilities at fair value through profit or loss, loans and borrowings, or as derivatives designated as hedging instruments in an effective hedge, as appropriate. The Group determines the classification of its financial liabilities at initial recognition. All financial liabilities are recognized initially at fair value and in the case of loans and borrowings, net of directly attributable transaction costs.

The Group's financial liabilities include trade and other payables and borrowings.

Subsequent measurement

After initial recognition, interest bearing borrowings are subsequently measured at amortized cost using the effective interest rate method (EIR). Gains and losses are recognized in the profit or loss when the liabilities are derecognized as well as through the EIR amortization process.

Amortized cost is calculated by taking into account any discount or premium on acquisition and fee or costs that are an integral part of the EIR. The EIR amortization is included in finance cost in the profit or loss.

Derecognition

A financial liability is derecognized when the obligation under the liability is discharged or cancelled or expires. When an existing financial liability is replaced by another from the same lender on substantially different terms, or the terms of an existing liability are substantially modified, such an exchange or modification is treated as a derecognition of the original liability and the recognition of a new liability, and the difference in the respective carrying amounts is recognized in the profit or loss.

Offsetting of financial instruments

Financial assets and financial liabilities are offset and the net amount reported in the statement of financial position if, and only if, there is a currently enforceable legal right to offset the recognized amounts and there is an intention to settle on a net basis, or to realize the assets and settle the liabilities simultaneously.

Fair value of financial instruments

The fair value of financial instruments that are traded in active markets at each reporting date is determined by reference to quoted market prices or dealer price quotations (bid price for long positions and ask price for short positions), without any deduction for transaction costs.

For financial instruments not traded in an active market, the fair value is determined using appropriate valuation techniques. Such techniques may include using recent arm's length market transactions; reference to the current fair value of another instrument that is substantially the same; discounted cash flow analysis or other valuation models.

An analysis of fair values of financial instruments and further details as to how they are measured are provided in Note 31.

(s) ***Derivative financial instruments and hedging***

The Group uses a hedging contract for oil export sales to cover part of its risks associated with oil price fluctuations. Such derivative financial instruments are initially recognized at fair value on the date on which a derivative contract is entered into and are subsequently remeasured at fair value. Derivatives are carried as assets when the fair value is positive and as liabilities when the fair value is negative.

Any gains or losses arising from changes in fair value of derivatives during the year that do not qualify for hedge accounting are taken directly to profit or loss.

The fair value of financial instruments contracts is determined by reference to market values for similar instruments. As at 31 December 2013, 2012 and 2011 the Group had no open hedging contracts.

(t) ***Taxation***

Current income tax

Current income tax assets and liabilities for the current and prior periods are measured at the amount expected to be recovered from or paid to the taxation authorities. The tax rates and tax laws used to compute the amount are those that are enacted or substantively enacted at the reporting date in the countries where the Group operates and generates taxable income.

Current income tax relating to items recognised directly in other comprehensive income or equity is recognised in other comprehensive income or equity and not in profit or loss. Management periodically evaluates position taken in the tax returns with respect to situations where applicable tax regulations are subject to interpretation and establishes provisions where appropriate.

Deferred tax

Deferred tax assets and liabilities are calculated in respect of temporary differences using the liability method. Deferred income taxes are provided for all temporary differences arising between the tax bases of assets and liabilities and their carrying values for financial reporting purposes, except where the deferred income tax arises from the initial recognition of goodwill or of an asset or liability in a transaction that is not a business combination and, at the time of the transaction, affects neither the accounting profit nor taxable profit or loss.

A deferred tax asset is recorded only to the extent that it is probable that taxable profit will be available against which the deductible temporary differences can be utilized. Deferred tax assets and liabilities are measured at tax rates that are expected to apply to the period when the asset is realized or the liability is settled, based on tax rates that have been enacted or substantively enacted at the reporting date.

Deferred income tax is provided on temporary differences arising on investments in subsidiaries and associates, except where the timing of the reversal of the temporary difference can be controlled and it is probable that the temporary difference will not reverse in the foreseeable future.

(u) ***Revenue recognition***

The Group sells crude oil, gas condensate and LPG under agreements priced by reference to Platt's and/or Argus' index quotations and adjusted for freight, insurance and quality differentials where applicable. The Group sells gas under agreements at fixed prices.

Revenue from the sale of crude oil, gas condensate, gas and LPG is recognized when delivery has taken place and risks and rewards of ownership have passed to the customer.

Revenue is recognized when it is probable that the economic benefits associated with the transaction will flow to the Group and the amount of revenue can be reliably measured.

(v) ***Treasury shares***

Own equity instruments that are reacquired (treasury shares) are recognised at cost and deducted from equity. No gain or loss is recognised in profit or loss on the purchase, sale, issue or cancellation of the Group's own equity instruments. Any difference between the carrying amount and the consideration, if reissued, is recognised in additional paid-in capital. Voting rights related to treasury shares are nullified for the Group and no distributions are accepted in relation to them. Share options exercised during the reporting period are satisfied with treasury shares.

(w) ***Share-based payments***

The Group measures the cost of cash-settled transactions with employees by reference to the fair value of the equity instruments at the date at which they are granted. Estimating fair value for share-based payment transactions requires determination of the most appropriate valuation model, which is dependent on the terms and conditions of the grant. This estimate also requires determination of the most appropriate inputs to the valuation model including the expected life of the share option, volatility and distribution yield and making assumptions about them. The assumptions and models used for estimating fair value for share-based payment transactions are disclosed in Note 28.

2. Critical Accounting Estimates, Assumptions and Judgements

The key assumptions concerning the future, and other key sources of estimation uncertainty at the statement of financial position date, that have a significant risk of causing a material change to the carrying amounts of assets and liabilities are discussed below:

(a) ***Oil and gas reserves***

Oil and gas reserves are a material factor in the Group's computation of depreciation, depletion and amortization (the "**DD&A**"). The Group estimates its reserves of oil and gas in accordance with the methodology of the Society of Petroleum Engineers (the "**SPE**"). In estimating its reserves under SPE methodology, the Group uses long-term planning prices which are also used by management to make investment decisions about development of a field. Using planning prices for estimating proved reserves removes the impact of the volatility inherent in using year-end spot prices. Management believes that long-term planning price assumptions are more consistent with the long-term nature of the upstream business and provide the most appropriate basis for estimating oil and gas reserves. All reserve estimates involve some degree of uncertainty. The uncertainty depends mainly on the amount of reliable geological and engineering data available at the time of the estimate and the interpretation of this data.

The relative degree of uncertainty can be conveyed by placing reserves into one of two principal classifications, either proved or unproved. Proved reserves are more certain to be recovered than unproved reserves and may be further sub-classified as developed and undeveloped to denote progressively increasing uncertainty in their recoverability. Estimates are reviewed and revised annually. Revisions occur due to the evaluation or re-evaluation of already available geological, reservoir or production data; availability of new data; or changes to underlying price assumptions. Reserve estimates may also be revised due to improved recovery projects, changes in production capacity or changes in development strategy. Proved developed reserves are used to calculate the unit of production rates for DD&A.

(b) ***Fair value of financial instruments***

Where the fair value of financial assets and financial liabilities recorded in the statement of financial position cannot be derived from active markets, they are determined using valuation techniques including the discounted cash flows model. The inputs to these models are taken from observable markets where possible, but where this is not feasible, a degree of judgment is required in establishing fair values. The judgments include considerations of inputs such as liquidity risk, credit risk and volatility. Changes in assumptions about these factors could affect the reported fair value of financial instruments.

(c) ***Abandonment and site restoration liabilities***

The Group estimates future dismantlement and site restoration costs for oil and gas properties with reference to the estimates provided from either internal or external engineers after taking into consideration the anticipated method of dismantlement and the extent of site restoration required in accordance with current legislation and industry practice. The amount of the provision is the present value of the estimated expenditures expected to be required to settle the obligation adjusted for expected inflation and discounted at applicable rate. The Group reviews site restoration provisions at each date of financial position and adjusts it to reflect the current best estimate in accordance with IFRIC 1 Changes in Existing Decommissioning, Restoration and Similar Liabilities. Estimating the future closure costs involves significant estimates and judgments by management. Significant judgments in making such estimates include estimate of discount rate and timing of cash flow. The management made its estimate based on the assumption that cash flow will take place at the expected end of the subsoil use rights.

Management of the Group believes that the interest rates on its debt financing shall provide best estimates of applicable discount rate, which approximates a pre-tax rate that reflects current market assessments of the time value of money and the risks specific to abandonment and site restoration liabilities. The discount rate shall be applied to the nominal amounts the managements expect to spend on site restoration in the future. The Group estimates future well abandonment cost using current year prices and the average long-term inflation rate.

The long term inflation and discount rates used to determine the balance sheet obligation at 31 December 2013, 2012 and 2011 were 7% and 10%, respectively. Movements in the provision for decommissioning liability are disclosed in Note 23.

(d) ***Taxation***

Uncertainties exist with respect to the interpretation of complex tax regulations, changes in tax laws, and the amount and timing of future taxable income. Given the wide range of international business relationships and the long-term nature and complexity of existing contractual agreements, differences arising between the actual results and the assumptions made, or future changes to such assumptions, could necessitate future adjustments to tax bases of income and expense already recorded. The Group establishes provisions, based on reasonable estimates, for possible consequences of audits by the tax authorities of the respective counties in which it operates. The amount of such provisions is based on various factors, such as experience of previous tax audits and differing interpretations of tax regulations by the Group and the responsible tax authority. Such differences in interpretation may arise for a wide variety of issues depending on the conditions prevailing in the respective domicile of the Group companies.

(e) ***Business combination***

The price adjustment based on accounts of acquiree at 30 December 2013 is based on the actual accounts of acquiree at 31 December 2013 and did not involve exercise of significant judgement. Since the assets and liabilities acquired in a business combination are represented by cash and cash equivalents, advances received, trade payables and income tax liability, management assessed that their fair value approximate their carrying amounts largely due to the short-term maturities of these instruments.

Historically, certain senior managers of the Group have provided their services to the Group pursuant to a service agreement between Probel and the Group. Respectively, a business combination effectively represented settlement of a pre-existing relationship. No gains or losses were recognized in the income statement as a result of this settlement, since the management assessed that the services are provided on market terms. The goodwill arising on acquisition represents the savings of the Group on management fees.

3. Changes in Accounting Policies and Disclosures

New Standards, Interpretations and Amendments thereof, Adopted by the Group

The accounting policies adopted in 2013 are consistent with those of the previous financial year, except for the following new standards and amendments to IFRS adopted as of 1 January 2013, and which did not have an impact on the Group's financial position and financial performance, except for certain additional disclosures made in accordance with the new requirements.

- *IFRS 7 Financial Instruments: Disclosures—Offsetting Financial Assets and Financial Liabilities—Amendments to IFRS 7;*
- *IFRS 10 Consolidated Financial Statements and IAS 27 Separate Financial Statements;*
- *IFRS 11 Joint Arrangements and IAS 28 Investments in Associates and Joint Ventures;*
- *IFRS 12 Disclosure of Interests in Other Entities;*
- *IFRS 13 Fair Value Measurement;*
- *IAS 19 Employee Benefits (Revised 2011).*

Improvements to IFRSs—2009-2011 Cycle:

- *IFRS 1—Repeat application of IFRS 1;*
- *IFRS 1—Borrowing costs;*
- *IAS 1—Clarification of the requirement for comparative information;*
- *IAS 16—Classification of servicing equipment;*
- *IAS 32—Tax effects of distributions to holders of equity instruments;*
- *IAS 34—Interim financial reporting and segment information for total assets and liabilities.*

Standards issued but not yet effective

The standards and interpretations that are issued, but not yet effective, up to the date of issuance of the Group's consolidated financial statements are disclosed below. The Group intends to adopt these standards, if applicable, when they become effective and does not expect that they will have a material financial impact in future financial statements.

- *IFRS 9—Financial Instruments (effective from 1 January 2015)*
- *Amendments to IFRS 10, IFRS 12 and IAS 27—Investment Entities (effective from 1 January 2014)*
- *Amendments to IAS 32—Offsetting Financial Assets and Financial Liabilities (effective from 1 January 2014)*
- *IFRIC 21—Levies (effective from 1 January 2014)*
- *Amendment to IAS 39—Novation of Derivatives and Continuation of Hedge Accounting (effective from 1 January 2014)*
- *Amendments to IAS 36 Impairment of Assets—Recoverable Amount Disclosures for Non-Financial Assets*

4. Revenue

	2011	2012	2013
	(U.S.$ thousands)		
Oil and gas condensate	289,947	587,371	709,107
Gas and LPG	10,890	149,694	185,907
Total	300,837	737,065	895,014

During the year ended 31 December 2013 the revenue from sales to two major customers amounted to US$ 202,945 thousand and US$ 173,440 thousand (2012: three major customers—US$ 250,933 thousand, US$ 222,150 thousand and US$ 53,994 thousand, respectively; 2011: one major customer—US$ 227,043 thousand).

5. Cost of Sales

	2011	2012	2013
	(U.S.$ thousands)		
Depreciation, depletion and amortization	19,448	101,374	118,957
Repair, maintenance and other services	16,637	55,470	52,361
Royalties	8,684	34,195	39,356
Payroll and related taxes	9,233	18,409	17,240
Government profit share	1,825	7,899	30,747
Well workover costs	4,000	7,639	2,794
Other transportation services	2,737	5,350	4,306
Materials and supplies	4,952	5,332	12,262
Management fees	1,789	1,880	3,558
Environmental levies	817	1,614	1,029
Change in stock	(1,592)	(3,298)	2,490
Other	2,275	2,360	1,122
Total	**70,805**	**238,224**	**286,222**

For the purpose of the profit sharing under the Contract, the Group is entitled to reimbursement of operating, exploration and development costs, which are included in the approved work programs. The costs not reimbursed during the year may be carried forward for reimbursement in subsequent years. During the year ended 31 December 2013 the reimbursable costs carried forward from prior periods were fully reimbursed resulting in relatively higher amount of government profit share expense.

6. General and Administrative Expenses

	2011	2012	2013
	(U.S.$ thousands)		
Social program	1,064	21,818	300
Management fees	9,949	13,497	16,006
Payroll and related taxes	4,295	4,966	7,576
Training	3,215	4,118	2,736
Professional services	5,973	4,012	9,072
Business travel	4,114	2,739	4,089
Employee share option plan	3,545	2,470	4,430
Insurance fees	743	1,403	2,050
Depreciation and amortization	395	1,258	1,413
Bank charges	625	1,069	1,100
Other taxes	3,318	4,320	4,839
Communication	718	824	1,010
Sponsorship	525	721	2,919
Materials and supplies	624	602	664
Lease payments	352	406	585
Provision for tax claims	(728)	—	—
Other	735	659	1,660
Total	**39,462**	**64,882**	**60,449**

7. Selling and Transportation Expense

	2011	2012	2013
	(U.S.$ thousands)		
Transportation costs	29,655	73,973	72,229
Loading and storage costs	1,441	21,622	36,991
Payroll and related taxes	1,413	2,330	2,486
Materials and supplies	—	1,204	2,360
Consulting expenses	—	—	2,958
Management fees	1,071	1,882	701
Other	1,815	2,593	3,949
Total	**35,395**	**103,604**	**121,674**

8. Finance Costs

	2011	2012	2013
	(U.S.$ thousands)		
Interest expense on borrowings	—	44,996	41,651
Unwinding of discount on Due to Government	954	941	930
Unwinding of discount on Abandonment and Site Restoration Liability	706	848	1,034
Total	**1,660**	**46,785**	**43,615**

9. Other Expenses

	2011	2012	2013
	(U.S.$ thousands)		
Export customs duty	—	—	12,268
Loss on the lease of railway wagons	6,279	—	—
Compensation	—	4,797	6,387
Fines and penalties	—	—	5,352
Other	1,576	1,815	1,586
Total	**7,855**	**6,612**	**25,593**

The export customs duty is represented by the customs duties for export of crude oil and customs fees for its services such as processing of declarations, temporary warehousing, etc. Based on their interpretation of CIS free-trade legislation the Kazakhstan customs authorities have imposed customs duties on oil exports from Kazakhstan to Ukraine starting from December 2012.

During the year ended 31 December 2011, the Group incurred losses in the amount of US$ 6,279 thousand on the lease of railway wagons. Although the Group has been leasing these wagons since 30 June 2010 for the purposes of transportation of GTU production, the wagons were not extensively utilised until October 2011.

10. Income Tax Expenses

The income tax expense consisted of the following:

	2011	2012	2013
	(U.S.$ thousands)		
Current income tax expenses:	19,834	118,105	138,883
Adjustment in respect of current income tax of prior periods:	1,663	—	—
Deferred income tax expense/(benefit)	45,851	2,258	3,613
Income tax expense reported in the consolidated income statement	**67,348**	**120,363**	**142,496**

The Group has profits assessable for income taxes only in the Republic of Kazakhstan. A reconciliation between tax expense and the product of accounting profit multiplied by the tax rate applicable to the Chinarevskoye subsoil use rights is as follows:

	2011	2012	2013
		(U.S.$ thousands)	
Profit before income tax	148,972	282,372	362,015
Statutory tax rate	30%	30%	30%
Expected tax provision	44,692	84,712	108,605
Non-deductible interest expense on borrowings	22,385	26,579	19,084
Change of the tax base	704	2,312	2,836
Non-deductible other tax expenses	—	5,243	2,037
Non-deductible technological losses	203	763	1,850
Non-deductible cost of gas	351	1,226	1,711
Foreign exchange (gain)/loss	30	491	1,624
Non-deductible social expenditures	—	1,589	890
Non-assessable income	(4,755)	(4,223)	—
Non-deductible training expenditures	697	552	—
Adjustment in respect of current income tax of prior periods	1,663	—	—
Other	1,378	1,119	3,859
Income tax expense charged to the consolidated income statement	**67,348**	**120,363**	**142,496**

Deferred tax balances are calculated by applying the tax rate applicable to the Chinarevskoye subsoil use rights to the temporary differences between the tax amounts and the amounts reported in the consolidated financial statements are comprised of the following:

	As at 31 December 2011	As at 31 December 2012	As at 31 December 2013
		(U.S.$ thousands)	
Deferred tax asset:			
Derivative financial instrument	—	—	—
Accounts payable and provisions	2,289	2,690	2,811
Deferred tax liability:			
Property, plant and equipment	(148,963)	(151,622)	(155,356)
Net deferred tax liability	**(146,674)**	**(148,932)**	**(152,545)**

The movements in the deferred tax liability were as follows:

	2011	2012	2013
		(U.S.$ thousands)	
Deferred tax liability as at 1 January	(100,823)	(146,674)	(148,932)
Expense / (benefit) to the Income Statement	(45,851)	(2,258)	(3,613)
Deferred tax liability as at 31 December	**(146,674)**	**(148,932)**	**(152,545)**

11. Business Combinations

On 30 December 2013 the Group has acquired 100% of the share capital of Probel Capital Management N.V. ("**Probel**"), a company providing management and consulting services to the Group, from Group's related parties, in exchange for a cash consideration consisting of initial purchase price of US$ 28,836 thousand subject to a price adjustment based on accounts of Probel at 30 December 2013. The amount of the price adjustment has not yet been agreed or paid as at the date of the authorization of the financial statements for issue, but it is estimated that the amount will not exceed US$ 4,598 thousand. Respective liability for this amount has been recognized within other current liabilities (Note 26) as at 31 December 2013, part of which was offset against receivables of Probel from previous owners.

Historically, certain senior managers have provided their services to the Group pursuant to a service agreement between Probel and the Group. The Probel acquisition was completed in connection with a proposed alternative listing of the Group's listed entity, so as to comply with certain exchange requirements that listed companies be managed by persons employed by entities within the listed company's group. The goodwill arising on acquisition represents the savings of the Group on management fees.

The provisional fair values of the identifiable assets and liabilities of Probel as at the date of acquisition were:

	Fair value recognized on acquisition
Assets	
Property, plant and equipment	32
Prepayments and other current assets	3,243
Cash and cash equivalents	1,953
	5,228
Liabilities	
Trade payables	(1,021)
Income tax payable	(1,159)
	(2,180)
Total identifiable net assets at fair value	3,048
Goodwill arising on acquisition	30,386
Purchase consideration	33,434

12. Exploration and Evaluation Assets

	2011	2012	2013
		(U.S.$ thousands)	
Net carrying amount as at 1 January	—	—	—
Additions	—	—	20,434
Carrying amount as at 31 December	**—**	**—**	**20,434**

During the year ended 31 December 2013 the Group had additions of exploration and evaluation assets of US$ 20,434 thousand (2012: US$ nil). The additions are mainly represented by the consideration related to acquisition of subsoil use rights of three oil and gas fields—Rostoshinskoye, Darjinskoye and Yuzhno-Gremyachinskoye in the amount of US$ 15,835 thousand, including capitalized contingent consideration under acquisition agreement of Darjinskoye and Yuzhno-Gremyachinskoye oil and gas fields in the amount of US$ 5,300 thousand respective liabilities for which were recognized as other current liabilities (Note 26). The contingent consideration is the difference between the total contractual amount and the prepayments made and represents maximum amount payable by the Group upon signing of the addendums to the contracts of these fields for further extension of exploration periods.

Also additions to exploration and evaluation assets include expenditures on geological and geophysical studies in the amount of US$ 4,599 thousand.

The exploration expenditure expensed to profit or loss during 2013 amounted to US$ 3,810 thousand (2012: Nil; 2011: nil).

13. Oil and Gas Properties

The category "Oil and Gas properties" represents mainly wells, oil and gas treatment facilities, oil transportation and other related assets. The movement of oil and gas properties for the years ended 31 December 2013 and 2012 was as follows:

	Working assets	Construction in progress	Total oil and gas properties
Balance at 31 December 2010, net of accumulated depreciation	**456,005**	**490,424**	**946,429**
Additions	6,280	178,672	184,952
Transfers	464,860	(464,860)	—
Depreciation charge	(23,967)	—	(23,967)
Balance at 31 December 2011, net of accumulated depreciation	**903,178**	**204,236**	**1,107,414**
Cost at 31 December 2011	1,010,746	204,236	1,214,982
Accumulated depreciation	(107,568)	—	(107,568)
Balance at 31 December 2011, net of accumulated depreciation	**903,178**	**204,236**	**1,107,414**
Balance at 31 December 2011, net of accumulated depreciation	**903,178**	**204,236**	**1,107,414**
Additions	5,816	178,082	183,898
Transfers	192,872	(192,872)	—
Disposal	(61)	—	(61)
Disposals depreciation	6	—	6
Depreciation charge	(99,209)	—	(99,209)
Balance at 31 December 2012, net of accumulated depreciation	**1,002,602**	**189,446**	**1,192,048**
Cost at 31 December 2012	1,209,373	189,446	1,398,819
Accumulated depreciation	(206,771)	—	(206,771)
Balance at 31 December 2012, net of accumulated depreciation	**1,002,602**	**189,446**	**1,192,048**
Balance at 31 December 2012, net of accumulated depreciation	**1,002,602**	**189,446**	**1,192,048**
Additions	5,108	210,076	215,184
Transfers	197,271	(197,271)	—
Depreciation charge	(115,159)	—	(115,159)
Balance at 31 December 2013, net of accumulated depreciation	**1,089,822**	**202,251**	**1,292,073**
Cost at 31 December 2013	1,411,752	202,251	1,614,003
Accumulated depreciation	(321,930)	—	(321,930)
Balance at 31 December 2013, net of accumulated depreciation	**1,089,822**	**202,251**	**1,292,073**

The category "Oil and Gas properties" represents mainly wells, oil and gas treatment facilities, oil transportation and other related assets. The subcategory "Construction in progress" is represented by the employee remuneration, materials and fuel used, rig costs, payments made to contractors, and asset retirement obligation fees directly associated with development of wells until the drilling of the well is complete and results have been evaluated.

The depletion rate for oil and gas working assets was as follows:

	2011	2012	2013
		(U.S.$ thousands)	
Depletion rate	4.8%	11.96%	12.14%

The Group engaged independent petroleum engineers to perform a reserves evaluation as at 31 August 2013. Starting from 1 October 2013 the depletion has been calculated using the unit of production method based on these reserves estimates.

The Group's incurred borrowing costs including amortization of arrangement fee capitalization rate and capitalized borrowing costs were as follows:

	2011	2012	2013
		(U.S.$ thousands)	
Borrowing costs including amortization of arrangement fee	54,647	71,076	56,260
Capitalization rate	11.73%	15.84%	8.95%
Capitalized borrowing costs	51,590	26,080	14,609

14. Property, Plant and Equipment

	Buildings	Machinery and equipment	Vehicles	Others	Construction in Progress	Total non oil gas properties
			(U.S.$ thousands)			
Balance at 31 December 2010, net of accumulated depreciation	**2,614**	**3,325**	**1,504**	**1,638**	**401**	**9,482**
Additions	2,714	789	40	1,360	1,370	6,273
Transfers	765	—	—	—	(765)	—
Disposal	(178)	(100)	(334)	(291)	—	(903)
Depreciation charge	(482)	(1,097)	(204)	(297)	—	(2,080)
Disposal depreciation	55	2	100	110	—	267
Balance at 31 December 2011, net of accumulated depreciation	**5,488**	**2,919**	**1,106**	**2,520**	**1,006**	**13,039**
Historical at 31 December 2011	7,594	5,813	2,625	4,017	1,006	21,055
Accumulated depreciation	(2,106)	(2,894)	(1,519)	(1,497)	—	(8,016)
Balance at 31 December 2011, net of accumulated depreciation	**5,488**	**2,919**	**1,106**	**2,520**	**1,006**	**13,039**
Balance at 31 December 2011, net of accumulated depreciation	**5,488**	**2,919**	**1,106**	**2,520**	**1,006**	**13,039**
Additions	609	4,062	378	2,026	13,950	21,025
Transfers	358	1,245	—	11	(1,614)	—
Disposal	—	(143)	—	(201)	—	(344)
Disposals depreciation	—	140	—	180	—	320
Depreciation charge	(848)	(1,727)	(314)	(534)	—	(3,423)
Balance at 31 December 2012, net of accumulated depreciation	**5,607**	**6,496**	**1,170**	**4,002**	**13,342**	**30,617**
Historical at 31 December 2012	8,561	10,977	3,003	5,853	13,342	41,736
Accumulated depreciation	(2,954)	(4,481)	(1,833)	(1,851)	—	(11,119)
Balance at 31 December 2012, net of accumulated depreciation	**5,607**	**6,496**	**1,170**	**4,002**	**13,342**	**30,617**
Balance at 31 December 2012, net of accumulated depreciation	**5,607**	**6,496**	**1,170**	**4,002**	**13,342**	**30,617**
Additions	562	2,515	560	1,217	8,654	13,508
Transfers	21,799	—	—	150	(21,949)	—
Disposal	(35)	(102)	(50)	(44)	—	(231)
Disposals depreciation	16	52	49	30	—	147
Depreciation charge	(1,653)	(2,483)	(334)	(741)	—	(5,211)
Balance at 31 December 2013, net of accumulated depreciation	**26,296**	**6,478**	**1,395**	**4,614**	**47**	**38,830**
Historical at 31 December 2013	30,887	13,285	3,513	7,166	47	54,898
Accumulated depreciation	(4,591)	(6,807)	(2,118)	(2,552)	—	(16,068)
Balance at 31 December 2013, net of accumulated depreciation	**26,296**	**6,478**	**1,395**	**4,614**	**47**	**38,830**

15. Advances for non-current assets

	As at 31 December 2011	As at 31 December 2012	As at 31 December 2013
		(U.S.$ thousands)	
Advances for pipes and construction materials	485	9,126	6,241
Advances for construction services	2,883	6,063	3,796
Advances for purchase of licenses	—	10,089	—
Total	**3,368**	**25,278**	**10,037**

16. Inventories

	As at 31 December 2011	As at 31 December 2012	As at 31 December 2013
		(U.S.$ thousands)	
Materials and supplies	9,979	17,127	16,738
Gas condensate	2,161	4,633	2,986
Crude oil	2,081	2,750	1,754
LPG	297	454	607
Total	**14,518**	**24,964**	**22,085**

Inventories are carried at cost for all reporting dates stated in the table above.

17. Trade Receivables

	As at 31 December 2011	As at 31 December 2012	As at 31 December 2013
		(U.S.$ thousands)	
Trade receivables	12,640	54,004	66,565
Total	**12,640**	**54,004**	**66,565**

Trade receivables are not interest bearing and are denominated in US dollars as at all reporting dates stated in the table above.

The ageing analysis of trade receivables is as follows:

	Total	Neither past due nor impaired	Past due but not impaired				
			<30 days	30-60 days	60-90 days	90-120 days	>120 days
			(U.S.$ thousands)				
31 December 2013	**66,565**	**66,561**	**—**	**—**	**—**	**—**	**4**
31 December 2012	54,004	54,000	—	—	—	—	4
31 December 2011	12,640	12,640	—	—	—	—	—

See Note 31 on credit risk of trade receivables, which explains how the Group manages and measures credit quality of trade receivables that are neither past due nor impaired.

18. Prepayments and Other Current Assets

	As at 31 December 2011	As at 31 December 2012	As at 31 December 2013
		(U.S.$ thousands)	
VAT receivable	12,036	9,173	17,192
Advances paid	9,356	12,613	7,817
Customs duties prepaid	290	1,609	2,736
Other	1,597	974	3,447
Total	**23,279**	**24,369**	**31,192**

Advances paid consist primarily of prepayments made to service providers.

19. Short-Term and Non-Current Investments

Current investments as at 31 December 2013 were represented by an interest bearing short-term deposit placed on 30 September 2013 for a six-month period. Current investments as at 31 December 2012 were represented by an interest bearing short-term deposit placed on 16 November 2012 for a six-month period.

Non-current investments were represented by an interest bearing deposit placed on 30 September 2013 for a period of more than one year and an interest bearing deposit placed on 4 March 2013 for a two-year period.

20. Cash and Cash Equivalents and Restricted Cash

	As at 31 December 2011	As at 31 December 2012	As at 31 December 2013
		(U.S.$ thousands)	
Current accounts in US dollars	123,112	84,615	150,931
Current accounts in Tenge	692	10,595	5,485
Cash accounts in other currencies	1,589	2,520	3,492
Petty cash	—	—	6
Bank deposits with maturity less than three month	—	100,000	25,000
Total	**125,393**	**197,730**	**184,914**

The Group has restricted cash accounts as liquidation fund deposits in the amount of US$ 4,217 thousand with Kazkommertsbank JSC in Kazakhstan (2012: US$ 3,652 thousand; 2011: US$ 3,076 thousand), which are kept as required by the subsoil use rights for abandonment and site restoration provision of the Group.

Bank deposits with maturity of less than three months as at 31 December 2013, represent an interest bearing short-term deposit placed on 30 December 2013.

21. Partnership Capital

The ownership interests in the Partnership consist of (a) Common Units, which represent a fractional entitlement in respect of all of the limited partner interests in the Partnership and (b) the interest of the General Partner. At any general meeting every holder of Common Units shall have one vote for each Common Unit of which he or she is the holder. Under the Partnership Agreement, distributions to limited partners will be made either as determined by the General Partner in its sole discretion or following the approval of a majority of limited partners provided such amount does not exceed the amount recommended by the General Partner. Any distributions to the Partnership's limited partners will be made on a pro rata basis according to their respective partnership interests in the Partnership and will be paid only to the recorded holders of Common Units.

On 28 June 2013 the limited partners of the Partnership duly passed all proposed resolutions at the Annual General Meeting ("**AGM**") of limited partners. Such resolutions included approval by the limited partners at the AGM of the distribution to the Partnership's limited partners of US$ 0.34 per Common Unit to holders of Partnership's Common Unit. The distribution (in the amount of US$ 63,179 thousand, since the ESOP Trustee referenced below declined the distribution) was paid on 26 July 2013 to Common Unit holders on the register of partners and interests at the close of business on 19 July 2013.

In September 2012, the Board of Directors of the General Partner approved the payment of the Partnership's inaugural distribution of US$ 0.32 per Common Unit to the holders of the Partnership's Common Units, representing a cash distribution of US$ 60,219 thousand (equal to approximately 20% of retained earnings at 30 June 2012). The distribution (in the amount of US$ 59,498 thousand, since the ESOP Trustee referenced below declined the distribution) was paid on 2 October 2012 to Common Unit holders on the register of partners and interests at the close of business on 1 October 2012.

The following tables summarise the number of Common Units authorised and fully paid and do not have par value, all but 10 of which are represented by GDRs:

	In circulation	Treasury capital	Total
		(number of Common Units)	
As at 31 December 2010	185,000,000	—	**185,000,000**
Issued for ESOP	—	1,761,882	**1,761,882**
Share options exercised	315,341	(315,341)	—
As at 31 December 2011	**185,315,341**	**1,446,541**	**186,761,882**
Issued for ESOP	—	1,421,076	**1,421,076**
Share options exercised	735,894	(735,894)	—
As at 31 December 2012	**186,051,235**	**2,131,723**	**188,182,958**
Share options exercised	285,375	(285,375)	—
Buyback of GDRs	(1,814,348)	1,814,348	—
As at 31 December 2013	184,522,262	3,660,696	**188,182,958**

1,421,076 and 1,761,882 new Common Units (represented by GDRs) were issued in 2012 and 2011, respectively, to support Group's obligations to employees under the Employee Share Option Plan (ESOP). The issued GDRs are held by Ogier Employee Benefit Trustee Limited (the "**Trustee**"), which upon request from employees to exercise options, sells GDRs on the market and settles respective obligations under the ESOP. This trust constitutes a special purpose entity under IFRS and therefore, these newly issued GDRs are recorded as treasury capital of the Partnership. During the year ended 31 December 2013 no new Common Units were issued but and 284,375 share options were exercised by employees (2012: 735,894 GDRs; 2011: 315,341 GDRs). The aggregate number of GDRs in respect of which share options may be outstanding under the ESOP must not exceed 5,000,000. There are no common units held by Partnership's subsidiaries, except for the treasury shares held to support the ESOP.

As at 31 December 2013 there are no Common Units held by Partnership's subsidiaries or affiliates, except for the treasury shares held to support the ESOP (2012: nil; 2011: nil).

Additional paid-in capital includes excess of the sale price of treasury shares at the transaction date over their original cost, deducted by transaction costs incurred for issuance of treasury shares.

Retained earnings and reserves include foreign currency translation reserve accumulated before 2009, when the functional currency of the Group entities was Tenge. No significant foreign currency translation differences arise from Condensate.

Earnings per share (EPS)

Basic EPS amounts are calculated by dividing the profit for the period by the weighted average number of Common Units outstanding during the period.

The basic and diluted earnings per share are the same as there are no instruments that have a dilutive effect on earnings.

	Year ended 31 December 2011	**Year ended 31 December 2012**	**Year ended 31 December 2013**
Net profit attributable to Common Unit holders (U.S.$ thousands)	81,624	162,009	219,519
Weighted average number of Common Units	185,157,661	185,683,278	185,286,739
Basic and diluted earnings per Common Unit (US$)	0.44	0.87	1.18

There have been no other transactions involving ordinary shares or potential ordinary shares between the reporting date and the date of authorisation of these financial statements.

22. Borrowings

	As at 31 December 2011	**As at 31 December 2012**	**As at 31 December 2013**
		(U.S.$ thousands)	
Notes issued in 2010 and maturing in 2015	447,532	92,469	92,122
Notes issued in 2012 and maturing in 2019	—	530,425	536,301
	447,532	622,894	628,423
Less: amounts due within 12 months	(9,450)	(7,152)	(7,263)
Total	**438,082**	**615,742**	**621,160**

2010 Notes

On 19 October 2010 Zhaikmunai Finance B.V. (the "**2010 Initial Issuer**") issued US$ 450,000 thousand notes (the "**2010 Notes**").

On 28 February 2011 Zhaikmunai LLP (the "**2010 Issuer**") replaced the 2010 Initial Issuer of the 2010 Notes, whereupon it assumed all of the obligations of the 2010 Initial Issuer under the 2010 Notes.

The 2010 Notes bear interest at the rate of 10.50% per year. Interest on the 2010 Notes is payable on April 19 and October 19 of each year, beginning on 19 April 2011. Prior to 19 October 2013, the 2010 Issuer could, at its option, on any one or more occasions redeem up to 35% of the aggregate principal amount of the 2010 Notes with the net cash proceeds of one or more equity offerings at a redemption price of 110.50% of the principal amount thereof, plus accrued and unpaid interest, if any, to the redemption date (subject to the right of holders of record on the relevant record date to receive interest due on the relevant interest payment date); provided that (1) at least 65% of the original principal amount of the 2010 Notes (including Additional Notes as defined in the indenture relating to the 2010 Notes) remains outstanding after each such redemption; and (2) the redemption occurs within 90 days after the closing of the related equity offering.

In addition, the 2010 Notes could have been redeemed, in whole or in part, at any time prior to 19 October 2013 at the option of the 2010 Issuer upon not less than 30 nor more than 60 days' prior notice mailed by first-class mail to each holder of 2010 Notes at its registered address, at a redemption price equal to 100% of the principal amount of the 2010 Notes redeemed plus the Applicable Premium (as defined below) as of, and accrued and unpaid interest to, the applicable redemption date (subject to the right of holders of record on the relevant record date to receive interest due on the relevant interest payment date). Applicable Premium means, with respect to any 2010 Note on any applicable redemption date, the greater of: (1) 1.0% of the principal amount of such 2010 Note; and (2) the excess, if any, of: (a) the present value at such redemption date of (i) the redemption price of such 2010 Note at 19 October 2013 plus (ii) all required interest payments (excluding accrued and unpaid interest to such redemption date) due on such 2010 Note through 19 October 2013 computed using a discount rate equal to the United States treasury rate as of such redemption date plus 50 basis points; over (b) the principal amount of such 2010 Note.

The 2010 Notes are jointly and severally guaranteed (the "**2010 Guarantees**") on a senior basis by Nostrum Oil & Gas LP and all of its subsidiaries other than the 2010 Issuer (the "**2010 Guarantors**"). The 2010 Notes are the 2010 Issuer's and the 2010 Guarantors' senior obligations and rank equally with all of the 2010 Issuer's and the 2010 Guarantors' other senior indebtedness. The 2010 Notes and the 2010 Guarantees have the benefit of first-priority pledges over the shares of Zhaikmunai Finance B.V. and Zhaikmunai Netherlands B.V.

On 19 October 2012, Zhaikmunai International B.V. commenced a cash tender offer (the "**Tender Offer**") to purchase any and all of the 2010 Notes. US$ 347,604 thousand aggregate principal amount of the 2010 Notes had been tendered into the Tender Offer, representing approximately 77% of the outstanding 2010 Notes, by the time the Tender Offer for 2010 Notes expired on 19 November 2012. The holders of US$ 200,732 thousand 2010 Notes that accepted the Tender Offer have subscribed to the 2012 Notes of the same amount. Also premium was paid to the holders of 2010 Notes for early repayment of notes in the amount of US$ 38,509 thousand.

2012 Notes

On 13 November 2012, Zhaikmunai International B.V. (the "**2012 Initial Issuer**") issued US$ 560,000 thousand notes (the "**2012 Notes**").

On 24 April 2013 Zhaikmunai LLP (the "**2012 Issuer**") replaced the 2012 Initial Issuer of the 2012 Notes, whereupon it assumed all of the obligations of the 2012 Initial Issuer under the 2012 Notes. The 2012 Notes bear interest at the rate of 7.125% per year. Interest on the 2012 Notes is payable on May 14 and November 13 of each year, beginning on May 14 2013. Prior to 13 November 2016, the 2012 Issuer may, at its option, on any one or more occasions redeem up to 35% of the aggregate principal amount of the 2012 Notes with the net cash proceeds of one or more equity offerings at a redemption price of 107.125% of the principal amount thereof, plus accrued and unpaid interest, if any, to the redemption date (subject to the right of holders of record on the relevant record date to receive interest due on the relevant interest payment date); provided that (1) at least 65% of the original principal amount of the 2012 Notes (including Additional Notes as defined in the indenture relating to the 2012 Notes) remains outstanding after each such redemption; and (2) the redemption occurs within 90 days after the closing of the related equity offering.

In addition, the 2012 Notes may be redeemed, in whole or in part, at any time prior to 13 November 2016 at the option of the 2012 Issuer upon not less than 30 nor more than 60 days' prior notice mailed by first-class mail to each holder of 2012 Notes at its registered address, at a redemption price equal to 100% of the principal amount of the 2012 Notes redeemed plus the Applicable Premium (as defined below) as of, and accrued and unpaid interest to, the applicable redemption date (subject to the right of holders of record on the relevant record date to receive interest due on the relevant interest payment date). Applicable Premium means, with respect to any 2012 Note on any applicable redemption date, the greater of: (1) 1.0% of the principal amount of such 2012 Note; and (2) the excess, if any, of: (a) the present value at such redemption date of (i) the redemption price of such 2012 Note at 13 November 2016 plus (ii) all required interest payments (excluding accrued and unpaid interest to such redemption date) due on such 2012 Note through 13 November 2016 computed using a discount rate equal to the United States treasury rate as of such redemption date plus 50 basis points; over (b) the principal amount of such 2012 Note.

The 2012 Notes are jointly and severally guaranteed (the "**2012 Guarantees**") on a senior basis by Nostrum Oil & Gas LP and all of its subsidiaries other than the 2012 Issuer (the "**2012 Guarantors**"). The 2012 Notes are the 2012 Issuer's and the 2012 Guarantors' senior obligations and rank equally with all of the 2012 Issuer's and the 2012 Guarantors' other senior indebtedness. The 2012 Notes and the 2012 Guarantees do not have the benefit of first-priority pledges over the shares of Zhaikmunai Finance B.V. and Zhaikmunai Netherlands B.V.

23. Abandonment and site restoration liabilities

	2011	2012	2013
		(U.S.$ thousands)	
Abandonment and site restoration liability as at 1 January	4,543	8,713	11,064
Unwinding of discount	706	847	1,034
Additional provision	952	1,743	2,500
Change in estimates	2,512	(239)	(724)
Abandonment and site restoration liability as at 31 December	**8,713**	**11,064**	**13,874**

Abandonment and site restoration liabilities represents the present value of decommissioning costs relating to oil and gas properties, which are expected to be incurred up to 2033 which is when the producing oil and gas properties are expected to cease operations.

The long-term inflation and discount rates used to determine the abandonment and site restoration liabilities at 31 December 2013 were 7% and 10%, respectively (2012: 7% and 10%, 2011: 7% and 10%).

24. Due to Government of Kazakhstan

	2011	2012	2013
		(U.S.$ thousands)	
Due to Government of Kazakhstan as at 1 January	7,321	7,242	7,153
Unwinding of discount	954	942	930
Paid during the period	(1,033)	(1,031)	(1,031)
	7,242	7,153	7,052
Less: current portion of due to Government of Kazakhstan	(1,031)	(1,031)	(1,031)
Due to Government of Kazakhstan as at 31 December	**6,211**	**6,122**	**6,021**

The amount due to Government of the Republic of Kazakhstan has been recorded to reflect the present value of a liability in relation to the expenditures made by the Government in the time period prior to signing the Contract that were related to exploration of the Contract territory and the construction of surface facilities in fields discovered therein and that are reimbursable by the Group to the Government during the production period. The total amount of liability due to Government as stipulated by the Contract is US$ 25,000 thousand.

Repayment of this liability commenced in 2008 with the first payment of US$ 1,030 thousand in March 2008 and with further payments by equal quarterly instalments of US$ 258 thousand until 26 May 2031. The liability was discounted at 13%.

25. Trade Payables

	As at 31 December 2011	As at 31 December 2012	As at 31 December 2013
		(U.S.$ thousands)	
Tenge denominated trade payables	79,424	48,622	42,950
US dollar denominated trade payables	1,367	6,659	12,719
Trade payables denominated in other currencies	1,123	3,109	2,849
Total	**81,914**	**58,390**	**58,518**

Accounts payable to KazStroyService JSC for construction of the gas treatment unit amounted to US$ 37,016 thousand as of 31 December 2011 (2013: nil; 2012: nil). Other payables for PPE and purchase of other non-current assets amounted to US$ 17,411 thousand as of 31 December 2011 (2013: US$ 32,245 thousand; 2012: US$ 26,580 thousand).

In 2012 the trade payables to KazStroyService JSC had been fully repaid.

26. Other Current Liabilities

	As at 31 December 2011	As at 31 December 2012	As at 31 December 2013
		(U.S.$ thousands)	
Taxes payable, other than corporate income tax	3,459	24,650	32,110
Training obligations *(Note 30)*	7,398	9,256	8,986
Contingent consideration	—	—	5,300
Due to employees	973	1,180	3,227
Accrual for additional payment for acquisition of Probel	—	—	1,953
Advances received	3,154	60	37
Other	2,156	2,429	3,051
Total	**17,140**	**37,575**	**54,664**

27. Derivate Financial Instrument

Pursuant to the terms of the BNP Paribas facility in 2008 the Group entered, at nil cost, into a hedging contract covering oil export sales commencing March 2008 through till December 2013 which was sold on 30 March 2009. On the same day the Group entered into a new hedging contract at a cost of US$ 7,700 thousand covering oil export sales of 967,058 bbl and 596,766 bbl in 2009 and 2010, respectively. The floor price for Brent crude oil under this hedging contract was fixed at a price of US$ 50 per bbl. The contract expired on 30 June 2010.

On 4 March 2010, the Group entered, at nil cost, into a hedging contract covering oil export sales of 4,000 bbls/day from March 2010 through December 2010. The counterparties ("**Hedging Providers**") to the hedging agreement were BNP Paribas, Natixis and Raiffeisen Zentralbank Österreich AG. Based on the new hedging contract the floor price for Brent crude oil was fixed at a price of US$ 60 per bbl. The ceiling price was set at a range from US$ 89.25 per bbl to US$ 100 per bbl such that the Group received all sales proceeds in excess of $ 100 per bbl.

On 19 October 2010, after prepayment in full of the BNP Paribas Facility all the rights, liabilities, duties and obligations of the Group under and in respect of each of the hedging agreements were transferred by novation to Citibank, N.A. ("**Citibank**"). The contract was settled in January 2011.

On 29 March 2011, in accordance with its hedging policy, the Group entered, at nil upfront cost, into a new hedging contract covering oil sales of 2,000 bbls/day, or a total of 556,000 bbls running through 31 December 2011. The counterparty to the hedging agreement was Citibank. Based on the hedging contract the Group bought a put at $85/bbl, which protected it against any fall in the price of oil below $85/bbl. As part of this contract it also sold a call at $125/bbl and bought a call at $134/bbl which further allowed the Group to benefit from oil prices up to $125/bbl and above $134/bbl.

Gains and losses on the hedge contract, which do not qualify for hedge accounting, are taken directly to profit or loss.

	2011	2012	2013
		(U.S.$ thousands)	
Hedging contract fair value at 1 January	(372)	—	—
Realized hedging gain	372	—	—
Hedging loss	—	—	—
Hedging contract at fair value at 31 December	**—**	**—**	**—**

As at 31 December 2013, 2012 and 2011 the Group had no open hedging contracts.

28. Employee Share Option Plan

Employees (including senior executives and executive directors) of members of the Group receive remuneration in the form of equity-based payment transactions, whereby employees render services as consideration for share appreciation rights, which can only be settled in cash ("**cash-settled transactions**").

The cost of cash-settled equity-based employee compensation is measured initially at fair value at the grant date using a trinomial lattice valuation model. This fair value is expensed over the period until vesting with the recognition of a corresponding liability. The liability is remeasured at each reporting date up to and including the settlement date with changes in fair value recognised in the statement of comprehensive income.

The equity-based payment plan is described below.

During 2008-2013, 3,192,958 equity appreciation rights (SARs) were granted to senior employees and executive directors of members of the Group, which can only be settled in cash. These generally vest over a five year period from the date of grant, so that one fifth of granted SARs vests on each of the five anniversaries from the date of grant. The contractual life of the SARs is ten years. The fair value of the SARs is measured at the grant date using a trinomial lattice valuation option pricing model taking into account the terms and conditions upon which the instruments were granted. SARs are exercisable at any time after vesting till the end of the contractual life and give its holder a right to a difference between the market value of the Group's GDRs at the date of exercise and a stated base value. The services received and a liability to pay for those services are recognised over the expected vesting period.

Until the liability is settled it is remeasured at each reporting date with changes in fair value recognised in profit or loss as part of the employee benefit expenses arising from cash-settled share-based payment transactions.

The carrying value of the liability relating to 2,912,348 of SARs at 31 December 2013 is US$ 12,016 thousand (2012: 2,131,723 SARs with carrying value of US$ 9,788 thousand; 2011: 2,867,617 SARs with carrying value of US$ 11,734 thousand). 728,487 SARs were fully vested during the year ended 31 December 2013 (2012: 426,345 SARs; 2011: 474,455; SARs).

The following table illustrates the number ("**No.**") and exercise prices ("**EP**") of, and movements in, SARs during the year:

	2011		2012		2013	
	No.	EP, US Dollar	No.	EP, US Dollar	No.	EP, US Dollar
Outstanding at the beginning of the period (with EP of US$ 4)	2,982,958	4	2,667,617	4	1,931,723	4
Outstanding at the beginning of the period (with EP of US$ 10)	—	—	200,000	10	200,000	10
Total outstanding at 1 January	2,982,958		2,867,617	—	2,131,723	
Granted	200,000	10	—	—	1,115,000	10
Exercised	(315,341)	4	(735,894)	4	(285,375)	4
Lapsed	—	—	—	—	(49,000)	10
Total outstanding at 31 December	2,867,617		2,131,723		2,912,348	
Exercisable as at 31 December	1,476,711		1,311,170		1,808,348	

The weighted average fair value of SARs granted during the year ended 31 December 2013 amounted to US$ 6.22 per SAR and the weighted average price at the date of exercise for SARs exercised during the year amounted to US$ 8.22 per SAR (2012: US$ 5.96 per SAR; 2011: US$ 5.95 per SAR). The Hull-White trinomial lattice valuation model was used to value the share options. The following table lists the inputs to the model used for the plan:

	2011	2012	2013
GDR price at the reporting date	9.7	10.7	13.0
Distribution yield (%)	—	1.5	3.0
Expected volatility (%)	86	86	85
Risk-free interest rate (%)	3.2	2.0	2.0
Expected life (years)	3.5	3.5	10.0
Option turnover (%)	10	10	10
Price trigger (US Dollars)	2	2	2

The expected life of the options is based on historical data and is not necessarily indicative of exercise patterns that may occur. The expected volatility reflects the assumption that the historical volatility is indicative of future trends, which may also not necessarily be the actual outcome. Option turnover rate represents the rate of employees expected to leave the Group during the vesting period, which is based on historical data and may not necessarily be the actual outcome. The model considers that when share price reaches the level of exercise price multiplied by the price trigger the employees are expected to exercise their options.

29. Related Party Transactions

For the purpose of these consolidated financial statements transactions with related parties mainly comprise arm's length transactions between the members of the Group and the participants and/or their subsidiaries or associated companies.

Accounts payable to and borrowings from related parties represented by entities indirectly controlled by a shareholder with significant influence over the Group consisted of the following:

	As at 31 December 2011	As at 31 December 2012	As at 31 December 2013
		(U.S.$ thousands)	
Parent			
Trade receivables			
Probel Capital Management B.V.	—	—	—
Trade payables			
Prolag BVBA	—	—	—
Probel Capital Management B.V.	48	—	—
Subsidiaries			
Trade payables			
Amersham Oil LLP	39	48	52
Prolag BVBA	18	298	240
Probel Capital Management B.V.	194	288	—

The Group had the following transactions with related parties represented by entities indirectly controlled by shareholder with significant influence over the Group:

	2011	2012	2013
		(U.S.$ thousands)	
Parent			
Management fees and consulting services			
Probel Capital Management B.V.	6,082	9,600	12,443
Subsidiaries			
Management fees and consulting services			
Probel Capital Management B.V.	3,475	4,049	5,064
Prolag BVBA	1,892	2,195	1,253
Amersham Oil	1,360	1,415	1,506

Management fees are payable in accordance with the Technical Assistance Agreements signed between the members of the Group and Amersham Oil LLP, Prolag B.V.B.A. and Probel Capital Management N.V. related to the rendering of geological, geophysical, drilling, technical and other consultancy services. The amount related to Probel Capital Management N.V. in 2013 are related to the transactions prior to its acquisition at 30 December 2013 (Note 11).

Remuneration (represented by short-term employee benefits) of key management personnel amounted to US$ 634 thousand for the year ended 31 December 2013 (2012: US$ 624 thousand, 2011: US$ 484 thousand). Other key management personnel were employed and paid by Amersham Oil LLP and Probel Capital Management N.V. and whose remuneration forms part of the management fees and consulting services above.

Payments to key management personnel under ESOP amounted to US$ 2,202 thousand for the year ended 31 December 2013 (2012: US$ 4,416 thousand, 2011: US$ 1,915 thousand) (Note 27).

30. Contingent Liabilities, Commitments, and Operating Risks

Taxation

Kazakhstan's tax legislation and regulations are subject to ongoing changes and varying interpretations. Instances of inconsistent opinions between local, regional and national tax authorities are not unusual. The current regime of penalties and interest related to reported and discovered violations of Kazakhstan's tax laws are severe. Penalties are generally 50% of the taxes additionally assessed and interest is assessed at the refinancing rate established by the National Bank of Kazakhstan multiplied by 2.5. As a result, penalties and interest can amount to multiples of any assessed taxes. Fiscal periods remain open to review by tax authorities for five calendar years preceding the year of review. Under certain circumstances reviews may cover longer periods. Because of the uncertainties associated with Kazakhstan's tax system, the ultimate amount of taxes, penalties and interest, if any, may be in excess of the amount expensed to date and accrued at 31 December 2013. As at 31 December 2013 management believes that its interpretation of the relevant legislation is appropriate and that it is probable that the Group's tax position will be sustained.

In 2010, a comprehensive tax audit was performed on the Group's tax accounts for 2006, 2007 and 2008 which resulted in tax claims being made. Management believed that those claims contradicted the terms of the Contract and the relevant tax codes. The Group appealed to the court to resolve these claims. A provision of US$ 728 thousand was made in Group's consolidated financial statements for the year ended 31 December 2010 in respect to the claims where the likelihood of the Group being required to pay additional tax, fines and penalties was probable.

By the Court decision as of 7 April 2011 the tax claims were cancelled in full. The Tax authorities appealed the Court's decision. The Group therefore continued to provide for the US$ 728 thousand as the risk of loss remained substantially unchanged. On 28 July 2011 by unanimous resolution of the court of cassation of West Kazakhstan oblast the Court decision dated 7 April 2011 was affirmed. The Group therefore reversed the US$ 728 thousand provision.

Abandonment and site restoration (decommissioning)

As Kazakh laws and regulations concerning site restoration and cleanup evolve, the Group may incur future costs, the amount of which is currently indeterminable. Such costs, when known, will be provided for as new information, legislation and estimates evolve.

Environmental obligations

The Group may also be subject to loss contingencies relating to regional environmental claims that may arise from the past operations of the related fields in which it operates. As Kazakh laws and regulations evolve concerning environmental assessments and site restoration, the Group may incur future costs, the amount of which is currently indeterminable due to such factors as the ultimate determination of responsible parties associated with these costs and the Government's assessment of respective parties' ability to pay for the costs related to environmental reclamation. However, depending on any unfavourable claims or penalties assessed by the Kazakh regulatory agencies, it is possible that the Group's future results of operations or cash flow could be materially affected in a particular period.

Capital commitments

As at 31 December 2013 the Group had contractual capital commitments in the amount of US$ 26,842 thousand (2012: US$ 23,088 thousand; 2011: US$ 17,880 thousand) mainly in respect to the Group's oil field development activities.

Operating lease

During 2010-2013 Zhaikmunai LLP entered into several agreements on lease of 650 railway tank wagons for transportation of hydrocarbon products for a period of up to 7 years for KZT 6,989 (equivalent of US$ 47) per day per one wagon. The lease agreements may be early terminated either upon mutual agreement of the parties, or unilaterally by one of the parties if the other party does not fulfil its obligations under the contract.

The total of future minimum lease payments under non-cancellable operating leases were represented as follows:

	31 December 2011	31 December 2012	31 December 2013
		(U.S.$ thousands)	
no later than 1 year	10,394	12,586	12,501
later than 1 year and not later than five years	13,880	17,112	23,846
later than five years	1,444	—	—

Payments for lease of railway tank wagons for the year ended 31 December 2013 amounted to US$ 12,628 thousand (2012: US$ 10,705 thousand; 2011: US$ 2,065 thousand).

Social and education commitments

As required by the Contract (as amended by, inter alia, Supplement #9), Zhaikmunai LLP is obliged to:

(i) spend US$ 300 thousand per annum to finance social infrastructure;

(ii) perform repair and reconstruction of state automobile roads for the amount of US$ 12,000 thousand in 2012;

(iii) make an accrual of one percent per annum of the financial obligations for the Chinarevskoye field for the purposes of educating Kazakh citizens; and

(iv) adhere to a spending schedule on education which lasts until (and including) 2020.

The contracts for exploration and production of hydrocarbons from Rostoshinskoye, Darjinskoye and Yuzhno-Gremyachinskoye fields require fulfillment of several social and other obligations. However, these obligations were amended in the year ended 31 December 2013 (in the case of Rostoshinskoye) or were (as at 31 December 2013) in the process of being amended (in the case of Darjinskoye and Yuzhno-Gremyachinskoye).

The current contract for exploration and production of hydrocarbons from Rostoshinskoye field (as amended on 9 August 2013) requires the subsurface user to:

(i) spend at least US$ 206 thousand of investments for education of personnel engaged to work under the contract during the exploration stage;

(ii) spend US$ 600 thousand to finance social infrastructure of the region during the exploration stage;

(iii) invest at least US$ 20,750 thousand for exploration of the field during the exploration period; and

(iv) create a liquidation fund (special deposit account with local bank) equal to US$ 206 thousand.

The contract for exploration and production of hydrocarbons from Darjinskoye field (as at 31 December 2013) required the subsurface user to:

(i) spend at least US$ 200 thousand for education of personnel engaged to work under the contract during the exploration stage;

(ii) spend US$ 18,850 thousand to finance social infrastructure of the region (including US $1,000 thousand for funding of development of Astana city in case of commercial discovery);

(iii) invest at least US$ 20,000 thousand for exploration of the field during the exploration period;

(iv) reimburse historical costs of US$ 6,499 thousand to the Government, including US$ 195 thousand for the right to use geological information; and

(v) create a liquidation fund (special deposit account with local bank) equal to 1% of the capital expenditures during the exploration stage and 0.1% of the operational costs during the production stage.

The current contract for exploration and production of hydrocarbons from Yuzhno-Gremyachinskoye field (as at 31 December 2013) required the subsurface user to:

(i) spend at least 1% of investments for education of personnel engaged to work under the contract during the exploration stage;

(ii) spend US$ 18,950 thousand to finance social infrastructure of the region (including US$ 1,000 thousand for funding of development of Astana city in case of commercial discovery);

(iii) invest at least US$ 23,050 thousand for exploration of the field during the exploration period;

(iv) reimburse historical costs of US$ 3,194 thousand to the Government, including US$ 96 thousand for right to use geological information; and

(v) create a liquidation fund (special deposit account with local bank) equal to 1% of capital expenditures during the exploration stage and 0.1% of operational costs during the production stage.

Domestic oil sales

In accordance with Supplement #7 to the Contract, Zhaikmunai LLP is required to sell at least 15% of produced oil on the domestic market on a monthly basis for which prices are materially lower than export prices.

31. Financial Risk Management Objectives and Policies

The Group's principal financial liabilities comprise borrowings, payables to Government of Kazakhstan, trade payables and other current liabilities. The main purpose of these financial liabilities is to finance the development of the Chinarevskoye oil and gas condensate field and its operations, as well as exploration of the three new oil and gas fields—Rostoshinskoye, Darjinskoye and Yuzhno-Gremyachinskoye. The Group's financial assets consist of trade and other receivables, non-current investments, current investments and cash and cash equivalents.

The main risks arising from the Group's financial instruments are interest rate risk, foreign exchange risk, liquidity risk and credit risk. The Group's management reviews and agrees policies for managing each of these risks, which are summarised below.

Interest rate risk

The Group was not exposed to interest rate risk in years from 2010 till 2013 as the Group had no floating-rate borrowings as the reporting dates for those years. The Group's policy is to manage its interest cost using a mix of fixed and variable rate debt. The Group's policy is to keep between 70% and 100% of its borrowings at fixed rates of interest.

Foreign currency risk

As a significant portion of the Group's operation is Tenge denominated, the Group's statement of financial position can be affected significantly by movements in the US dollar / Tenge exchange rates. Mainly Tenge denominated assets are represented by trade receivables related to domestic sales and cash balances on Tenge denominated accounts, while the liabilities consists of the trade payables to suppliers and contractors registered in Kazakhstan. The Group mitigates the effect of its structural currency exposure by borrowing in US dollars and denominating sales in US dollars.

The following table demonstrates the sensitivity to a reasonably possible change in the US dollars exchange rate, with all other variables held constant, of the Group's profit before tax (due to changes in the fair value of monetary assets and liabilities).

	Increase / decrease in US$ rate	Increase / (decrease) in profit before tax
	(U.S.$ thousands)	
2011	10.72%	(2,341)
	-10.72%	2,341
2012	1.57%	(235)
	-1.57%	235
2013	30.00%	(3,294)
	10.00%	(1,098)

Significant change in the assumptions of increase/decrease in US$ rate in 2013 as compared to 2012 is explained by the devaluation of Tenge against the US Dollar and other major currencies in 2014 (Note 32).

The Group's foreign currency denominated monetary assets and liabilities were as follows:

At 31 December 2011	KZT	Russian roubles	Euro	Other	Total
			(U.S.$ thousands)		
Cash and cash equivalents	692	—	—	1,589	2,281
Trade receivables	12,634	—	—	—	12,634
Trade payables	(79,424)	(253)	(397)	(473)	(80,547)
Other current liabilities	(8,371)	—	—	—	(8,371)
	(74,469)	(253)	(397)	1,116	(74,003)

At 31 December 2012	KZT	Russian roubles	Euro	Other	Total
			(U.S.$ thousands)		
Cash and cash equivalents	10,595	—	2,520	2	13,117
Trade receivables	10,573	—	—	—	10,573
Trade payables	(48,622)	(10)	(2,251)	(848)	(51,731)
Other current liabilities	(10,436)	—	—	—	(10,436)
	(37,890)	(10)	269	(846)	(38,477)

At 31 December 2013	KZT	Russian roubles	Euro	Other	Total
			(U.S.$ thousands)		
Cash and cash equivalents	5,491	—	3,492	—	8,983
Trade receivables	27,619	—	1	—	27,620
Trade payables	(42,950)	(372)	(2,472)	(5)	(45,799)
Other current liabilities	(257)	—	(7,173)	—	(7,430)
	(10,097)	(372)	(6,152)	(5)	(16,626)

Liquidity risk

Liquidity risk is the risk that the Group will encounter difficulty in raising funds to meet commitments associated with its financial liabilities. Liquidity risk may result from an inability to sell a financial asset quickly at close to its fair value.

The Group monitors its risk to a shortage of funds using a liquidity planning tool. The tool allows selecting severe stress test scenarios. To ensure an adequate level of liquidity a minimum cash balance has been defined as a cushion of liquid assets. The Group's objective is to maintain a balance between continuity of funding and flexibility through the use of notes, loans, hedges, export financing and financial leases.

The Group's policy is that, while it has an investment program on-going: (a) not more than 25% of borrowings should mature in the next twelve-month period and (b) a minimum balance of US$ 50 million is retained on the balance sheet post repayment or refinancing of any debt due in the next twelve-month period.

The Group's total outstanding debt consists of two notes: US$ 92.5 million issued in 2010 and maturing in 2015 and US$ 560 million issued in 2012 and maturing in 2019. The Group assessed the concentration of risk with respect to refinancing its debt and concluded it to be low.

Access to sources of funding is sufficiently available and if there would be debt maturing within twelve months it could be rolled over with existing lenders.

The table below summarizes the maturity profile of the Group's financial liabilities based on contractual undiscounted payments:

31 December 2011	On demand	Less than 3 months	3-12 months	1-5 years	More than 5 years	Total
Borrowings	—	13,271	53,375	663,063	—	729,709
Trade payables	81,914	—	—	—	—	81,914
Other current liabilities	8,371	—	—	—	—	8,371
Due to Government of Kazakhstan	—	258	773	4,124	14,689	19,844
	90,285	**13,529**	**54,148**	**667,187**	**14,689**	**839,838**

31 December 2012	On demand	Less than 3 months	3-12 months	1-5 years	More than 5 years	Total
Borrowings	—	—	49,613	264,451	639,800	953,864
Trade payables	58,390	—	—	—	—	58,390
Other current liabilities	10,437	—	—	—	—	10,437
Due to Government of Kazakhstan	—	258	773	4,124	13,402	18,557
	68,827	**258**	**50,386**	**268,575**	**653,202**	**1,041,248**

31 December 2013	On demand	Less than 3 months	3-12 months	1-5 years	More than 5 years	Total
Borrowings	—	—	43,613	259,902	594,691	898,206
Trade payables	58,518	—	—	—	—	58,518
Other current liabilities	22,524	—	—	—	—	22,524
Due to Government of Kazakhstan	—	258	773	4,124	12,371	17,526
	81,042	**258**	**44,386**	**264,026**	**607,062**	**996,774**

Credit risk

Financial instruments, which potentially subject the Group to credit risk, consist primarily of accounts receivable and cash in banks. The maximum exposure to credit risk is represented by the carrying amount of each financial asset. The Group considers that its maximum exposure is reflected by the amount of trade accounts receivable and cash and cash equivalents.

The Group places its Tenge denominated cash with SB Sberbank JSC, which has a credit rating of Ba2 (stable) from Moody's rating agency and its US Dollar denominated cash with BNP Paribas with a credit rating of A2 (stable) and ING with a credit rating of A2 (negative) from Moody's rating agency at 31 December 2013. The Group does not guarantee obligations of other parties.

The Group sells its products and makes advance payments only to recognized, creditworthy third parties. In addition, receivable balances are monitored on an ongoing basis with the result that the Group's exposure to bad debts and recoverability of prepayments made is not significant and thus risk of credit default is low.

Customer credit risk is managed by each business unit subject to the Group's established policy, procedures and control relating to customer credit risk management. Credit quality of a customer is assessed based on an extensive credit rating scorecard. Outstanding customer receivables are regularly monitored.

An impairment analysis is performed at each reporting date on an individual basis for major clients. The maximum exposure to credit risk at the reporting date is the carrying value of each class of financial assets. The Group does not hold collateral as security. The Group evaluates the concentration of risk with respect to trade receivables as low, as its customers are located in several jurisdictions and industries and operate in largely independent markets.

Commodity Price Risk

The Group is exposed to the effect of fluctuations in price of crude oil, which is quoted in US Dollar on the international markets. The Group prepares annual budgets and periodic forecasts including sensitivity analyses in respect of various levels of crude oil prices in the future.

Other than the hedge arrangements described in Notes 27 and 32 the Group does not hedge its exposure to the risk of fluctuations in the price of crude oil.

Fair values of financial instruments

Set out below, is a comparison by class of the carrying amounts and fair value of the Group's financial instruments, other than those with carrying amounts reasonably approximating their fair values:

	Carrying amount			Fair Value		
	As at 31 December 2011	As at 31 December 2012	As at 31 December 2013	As at 31 December 2011	As at 31 December 2012	As at 31 December 2013
	(U.S.$ thousands)					
Financial liabilities						
Interest bearing borrowings	447,532	622,894	628,423	445,950	692,828	686,795
Total	**447,532**	**622,894**	**628,423**	**445,950**	**692,828**	**686,795**

The management assessed that cash and cash equivalents, short-term deposits, trade receivables, trade payables and other current liabilities approximate their carrying amounts largely due to the short-term maturities of these instruments. The contingent consideration liability under acquisition agreement of Darjinskoye and Yuzhno-Gremyachenskoye oil and gas fields (Note 12) was recognized at fair value, which was assessed to be equal to its nominal amount due to its short-term nature and respectively categorized as level 3 within the fair value hierarchy. There were no gains or losses arising in 2013 from fair value measurement of this contingent consideration liability.

The fair value of the financial assets and liabilities represents the amount at which the instrument could be exchanged in a current transaction between willing parties, other than in a forced or liquidation sale. Fair value of the quoted notes is based on price quotations at the reporting date and respectively categorised as Level 1 within the fair value hierarchy.

Capital management

For the purpose of the Group's capital management, capital includes issued capital, additional paid-in capital and all other equity reserves attributable to the equity holders of the parent. The primary objective of the Group's capital management is to maximise the shareholder value.

In order to achieve this overall objective, the Group's capital management, amongst other things, aims to ensure that it meets financial covenants attached to the notes that define capital structure requirements. Breaches in meeting the financial covenants would permit the borrowers to immediately call borrowings. There have been no breaches in the financial covenants of the notes in the current period, nor the prior period.

The Group manages its capital structure and makes adjustments in light of changes in economic conditions and the requirements of the financial covenants. To maintain or adjust the capital structure, the Group may adjust the distribution payment to participants, return capital to participants or increase partnership capital. The Group monitors capital using a gearing ratio, which is net debt divided by total capital plus net debt. The Group's policy is to keep the gearing ratio between 20% and 40%. The Group includes within net debt, interest bearing loans and borrowings, less cash, short-term deposits and long-term deposits, excluding discontinued operations.

	As at 31 December 2011	As at 31 December 2012	As at 31 December 2013
		(U.S.$ thousands)	
Interest bearing borrowings	447,532	622,894	628,423
Less: cash and cash equivalents and deposits	(128,469)	(251,382)	(244,131)
Net debt	**319,063**	**371,512**	**384,292**
Equity	585,231	695,104	832,451
Total capital	**585,231**	**695,104**	**832,451**
Capital and net debt	**904,294**	**1,066,616**	**1,216,743**
Gearing ratio	35%	35%	32%

No changes were made in the objectives, policies or processes for managing capital during the years ended 31 December 2013, 2012 and 2011.

32. Events after the Reporting Period

On 23 January 2014, the contract for exploration and production of hydrocarbons from Darjinskoye field was amended so as to require Zhaikmunai LLP to:

(i) spend at least US$ 200 thousand for education of personnel engaged to work under the contract during the exploration stage;

(ii) spend US$ 225 thousand to finance social infrastructure of the region;

(iii) invest at least US$ 20,355 thousand for exploration of the field during the exploration period;

(iv) create a liquidation fund (special deposit account with local bank) equal to US$ 208 thousand.

On 23 January 2014, the contract for exploration and production of hydrocarbons from Yuzhno-Gremyachenskoye field was amended so as to require Zhaikmuna LLP to:

(i) spend at least US$ 200 thousand for education of personnel engaged to work under the contract during the exploration stage;

(ii) spend US$ 1,050 thousand to finance social infrastructure of the region;

(iii) invest at least US$ 19,850 thousand for exploration of the field during the exploration period;

(iv) reimburse historical costs of US$ 96 thousand; and

(v) create a liquidation fund (special deposit account with local bank) equal to US$ 244 thousand.

The remaining contingent consideration of US$ 5,300 thousand (Note 12) (312,168,910 Tenge for Darjinskoye and 487,375,905 Tenge for Yuzhno-Gremyachenskoye) was paid to the sellers in January 2014.

On 11 February 2014 the Tenge was devalued against the US Dollar and other major currencies. The exchange rates before and after devaluation were 155 Tenge/US Dollar and 185 Tenge/US Dollar respectively.

On 14 February 2014, Nostrum Oil & Gas Finance B.V., a subsidiary of Zhaikmunai Netherlands B.V. (established on 15 January 2014), issued USD 400 million notes at a coupon of 6.325% maturing 2019. The Notes are jointly and severally guaranteed on a senior basis by Nostrum Oil & Gas LP and all of its subsidiaries other than Nostrum Oil & Gas Finance B.V. On 28 February 2014, Zhaikmunai LLP entered into a deed of sale and transfer with Zhaikmunai Netherlands B.V. for the acquisition of the share capital of Nostrum Oil & Gas Finance B.V..

On 3 March 2014, in accordance with its hedging policy, Zhaikmunai LLP entered, at nil upfront cost, into a new hedging contract covering oil sales of 7,500 bbls/day, or a total of 5,482,500 bbls running through 29 February 2016. The counterparty to the hedging agreement was Citibank. Based on the hedging contract Zhaikmunai LLP bought a put at $85/bbl, which protected it against any fall in the price of oil below $85/bbl. As part of this contract Zhaikmunai LLP also sold a call at $111.5/bbl and bought a call at $117.5/bbl which further allowed Zhaikmunai LLP to benefit from oil prices up to $111.5/bbl and above $117.5/bbl.

PART 15
COMPETENT PERSON'S REPORT

December 16, 2013

The Directors
Nostrum Oil & Gas plc
4th Floor
53-54 Grosvenor Street
London, W1K 3HU
United Kingdom

Nostrum Oil & Gas LP
Acting by its General Partner, Nostrum Oil & Gas Group Limited
7th F, Anglo International House
Lord Street, Douglas
Isle of Mann IM14LN

Attn: Mr. Kai Uwe Kessel
Chief Executive Officer

Deutsche Bank AG, London Branch
Winchester House
1 Great Winchester Street
London, EC2N 2DB
United Kingdom

Gentlemen:

At the request of Nostrum Oil & Gas plc (the "**Issuer**") and Nostrum Oil & Gas LP, Ryder Scott Company, L.P (Ryder Scott) has prepared a Competent Person's Report ("**CPR**") which contains an estimate of the proven, probable, and possible hydrocarbon reserves, future production and income of the proven and probable hydrocarbon reserves derived through certain Production Sharing Agreements ("**PSA**") for four license areas between the Republic of Kazakhstan and Zhaikmunai LLP (Zhaikmunai) as of August 31, 2013. This CPR is required for the purposes of a prospectus that is being prepared in relation to the proposed admission of the shares of the Issuer ("**the Admission**") to the Official List of the United Kingdom Listing Authority ("**UKLA**") and in the prospectus relating to such Admission. The reserves and contingent resources volumes included herein were estimated based on the definitions and disclosure guidelines contained in the Society of Petroleum Engineers (SPE), World Petroleum Council (WPC), American Association of Petroleum Geologists (AAPG), and Society of Petroleum Evaluation Engineers (SPEE) Petroleum Resources Management System (SPE-PRMS) based on unescalated price and cost parameters (SPE-PRMS constant case). The income data were estimated using future price and cost parameters as noted herein and held constant throughout the life of the properties (SPE-PRMS constant case). The results of our third party study, completed on December 16, 2013, are presented herein.

The properties evaluated by Ryder Scott represent 100 percent of the total net proved, probable and possible liquid hydrocarbon reserves and 100 percent of the total net proved, probable and possible gas reserves of Zhaikmunai as of August 31, 2013. This estimate also represents 100 percent of the total liquid hydrocarbon contingent resource volumes and 100 percent of the total gas contingent resource volumes of Zhaikmunai as of August 31, 2013.

Zhaikmunai holds an interest in certain oil and gas properties in the Chinarevskoye field located in the Republic of Kazakhstan. Zhaikmunai entered into both a License and Production Sharing Agreement ("**PSA**") with the Republic of Kazakhstan in May 1997 and in October 1997, respectively. The PSA sets out the parameters for the exploration and development of the field and the fees, basis for production sharing, and the taxes payable to the Republic of Kazakhstan.

Zhaikmunai holds an interest in certain oil and gas properties recently acquired licenses, the Rostoshinskoye, Yuzhno-Gremyachinskoye and Darinskoye fields, located in the Republic of Kazakhstan. The combined field areas are known as the Trident Project (Trident). Zhaikmunai entered into both a License and Production Sharing

Agreement ("**PSA**") with the Republic of Kazakhstan in March 2013. The PSA sets out the parameters for the exploration and development of the field and the fees, basis for production sharing, and the taxes payable to the Republic of Kazakhstan.

The income data were estimated using Nostrum Oil & Gas LP's corporate price policy. As a result of both economic and political forces, there is significant uncertainty regarding the forecasting of future hydrocarbon prices. The recoverable reserves and the income attributable thereto have a direct relationship to the hydrocarbon prices actually received; therefore, volumes of reserves actually recovered and amounts of income actually received may differ significantly from the estimated quantities presented in this report. The results of this study are summarized below:

Zhaikmunai LLP
Estimated Future Reserves and Income Derived
Through the Terms of the Production Sharing Agreements
Between the Republic of Kazakhstan and Zhaikmunai LLP
Chinarevskoye and Trident Fields
As of August 31, 2013

	Proved			
	Developed			
	Producing	Non-Producing	Undeveloped	Total Proved
Net Remaining Reserves				
Oil/Condensate—Barrels	38,016,000	3,514,000	29,215,000	70,746,000
Plant Products—Barrels	13,840,000	1,653,000	10,786,000	26,278,000
Gas—MMCF	234,000	20,000	173,000	428,000
Income Data ($ millions)				
Future Gross Revenue	$ 4,424,000	$ 427,000	$ 3,393,000	$ 8,243,000
Deductions	1,676,000	169,000	1,354,000	3,200,000
Future Net Income (FNI)	$ 2,748,000	$ 258,000	$ 2,039,000	$ 5,044,000
Discounted FNI @ 10%	$ 1,570,000	$ 153,000	$ 985,000	$ 2,707,000

Zhaikmunai LLP
Estimated Future Reserves and Income Derived
Through the Terms of the Production Sharing Agreements
Between the Republic of Kazakhstan and Zhaikmunai LLP
Chinarevskoye and Trident Fields
As of August 31, 2013

	Probable		
	Non-Producing	Undeveloped	Total Probable
Net Remaining Reserves			
Oil/Condensate—Barrels	16,877,000	87,303,000	104,180,000
Plant Products—Barrels	6,558,000	31,952,000	38,510,000
Gas—MMCF	96,000	1,000,000	1,097,000
Income Data ($ millions)			
Future Gross Revenue	$ 1,945,000	$11,208,000	$ 13,153,000
Deductions	800,000	4,754,000	5,554,000
Future Net Income (FNI)	$ 1,145,000	$ 6,454,000	$ 7,599,000
Discounted FNI @ 10%	$ 365,000	$ 2,714,000	$ 3,079,000

Zhaikmunai LLP
Estimated Future Reserves and Income Derived
Through the Terms of the Production Sharing Agreements
Between the Republic of Kazakhstan and Zhaikmunai LLP
Chinarevskoye and Trident Fields
As of August 31, 2013

	Proved + Probable			
	Developed			
	Producing	Non-Producing	Undeveloped	Total Proved + Probable
Net Remaining Reserves				
Oil/Condensate—Barrels	38,016,000	20,392,000	116,518,000	174,926,000
Plant Products—Barrels	13,840,000	8,210,000	42,738,000	64,788,000
Gas—MMCF	234,000	117,000	1,173,000	1,524,000
Income Data ($ millions)				
Future Gross Revenue	$ 4,424,000	$ 2,371,000	$ 14,601,000	$ 21,396,000
Deductions	1,676,000	969,000	6,108,000	8,754,000
Future Net Income (FNI)	$ 2,748,000	$ 1,402,000	$ 8,493,000	$ 12,643,000
Discounted FNI @ 10%	$ 1,570,000	$ 517,000	$ 3,700,000	$ 5,786,000

Liquid hydrocarbons are expressed in standard 42 gallon barrels. All gas volumes are reported on an "as sold" basis expressed in millions of cubic feet (MMCF) at the official temperature and pressure bases of the areas in which the gas reserves are located. The net remaining reserves and contingent resource volumes are also shown in this report on an equivalent unit basis wherein natural gas is converted to oil equivalent using a factor of 6,000 cubic feet of natural gas per one barrel of oil equivalent. MMBOE means million barrels of oil equivalent. In this report, the revenues, deductions, and income data are expressed as thousands of U.S. dollars (M$).

The future gross revenue is after the deduction of royalties due to the Republic of Kazakhstan under the Production Sharing Agreement. The deductions comprise the normal direct costs of operating the wells, recompletion costs, drilling and completion costs, gas processing plant, other infrastructure costs, production bonus payments and abandonment costs. The future net income is before the deduction of income taxes by the Republic of Kazakhstan and general administrative overhead, and has not been adjusted for outstanding loans that may exist nor does it include any adjustment for cash on hand or undistributed income.

Liquid hydrocarbon reserves account for approximately 88 percent of the total future gross revenue from proved reserves and gas reserves account for the remaining 12 percent of total future gross revenue from the proved reserves reported herein. Liquid hydrocarbon reserves account for approximately 81 percent of the total future gross revenue from probable reserves and gas reserves account for the remaining 19 percent of total future gross revenue from the probable reserves reported herein.

The discounted future net income shown above was calculated using a discount rate of 10 percent per annum compounded monthly. Future net income was discounted at four other discount rates which were also compounded monthly. These results are shown in summary form as follows:

	Discounted Future Net Income (M$) As of August 31, 2013		
	Total Proved	Total Probable	Total Proved + Probable
Discount Rate Percent			
12	$2,441,000	$2,604,000	$5,045,000
15	$2,112,000	$2,037,000	$4,150,000
20	$1,702,000	$1,369,000	$3,071,000
25	$1,408,000	$ 926,000	$2,335,000

The results shown above are presented for your information and should not be construed as our estimate of fair market value.

CHINAREVSKOYE FIELD
Estimated Future Reserves and Income Derived
Through the Terms of the Production Sharing Agreements
Between the Republic of Kazakhstan and Zhaikmunai LLP
Chinarevskoye and Trident Fields
As of August 31, 2013

	Proved			
	Developed			
	Producing	Non-Producing	Undeveloped	Total Proved
Net Remaining Reserves				
Oil/Condensate—Barrels	38,016,000	3,514,000	29,215,000	70,746,000
Plant Products—Barrels	13,840,000	1,653,000	10,786,000	26,278,000
Gas—MMCF	234,000	20,000	173,000	428,000
Income Data ($ millions)				
Future Gross Revenue	$ 4,424,000	$ 427,000	$ 3,393,000	$ 8,243,000
Deductions	1,676,000	169,000	1,354,000	3,200,000
Future Net Income (FNI)	$ 2,747,000	$ 257,000	$ 2,039,000	$ 5,044,000
Discounted FNI @ 10%	$ 1,570,000	$ 152,000	$ 985,000	$ 2,707,000

CHINAREVSKOYE FIELD
Estimated Future Reserves and Income Derived
Through the Terms of the Production Sharing Agreements
Between the Republic of Kazakhstan and Zhaikmunai LLP
Chinarevskoye and Trident Fields
As of August 31, 2013

	Probable		
	Non-Producing	Undeveloped	Total Probable
Net Remaining Reserves			
Oil/Condensate—Barrels	14,653,000	85,696,000	100,348,000
Plant Products—Barrels	6,085,000	31,781,000	37,865,000
Gas—MMCF	81,000	517,000	598,000
Income Data ($ millions)			
Future Gross Revenue	$ 1,724,000	$ 9,933,000	$ 11,657,000
Deductions	665,000	3,726,000	4,392,000
Future Net Income (FNI)	$ 1,059,000	$ 6,207,000	$ 7,266,000
Discounted FNI @ 10%	$ 344,000	$ 2,691,000	$ 3,034,000

CHINAREVSKOYE FIELD
Estimated Future Reserves and Income Derived
Through the Terms of the Production Sharing Agreements
Between the Republic of Kazakhstan and Zhaikmunai LLP
Chinarevskoye and Trident Fields
As of August 31, 2013

	Proved + Probable			
	Developed			
	Producing	Non-Producing	Undeveloped	Total Proved + Probable
Net Remaining Reserves				
Oil/Condensate—Barrels	38,016,000	18,167,000	114,911,000	171,095,000
Plant Products—Barrels	13,840,002	7,737,000	42,567,000	64,144,000
Gas—MMCF	234,000	101,000	690,000	1,025,000
Income Data ($ millions)				
Future Gross Revenue	$ 4,424,000	$ 2,151,000	$ 13,326,000	$ 19,901,000
Deductions	1,676,000	834,000	5,081,000	7,591,000
Future Net Income (FNI)	$ 2,747,000	$ 1,316,000	$ 8,246,000	$ 12,310,000
Discounted FNI @ 10%	$ 1,570,000	$ 496,000	$ 3,676,000	$ 5,741,000

The following tables present the gross remaining reserves of the Chinarevskoye field before the terms of the production sharing agreement terms as of August 31, 2013 through the end of the license term.

CHINAREVSKOYE FIELD
Estimated Future Reserves
As of August 31, 2013

	Proved			
	Developed			
	Producing	Non-Producing	Undeveloped	Total Proved
Oil/Condensate—Barrels	42,529,000	3,958,000	33,014,000	79,501,000
Plant Products—Barrels	15,485,000	1,851,000	12,195,000	29,530,000
Gas—MMCF (after shrink)	262,000	23,000	196,000	481,000

CHINAREVSKOYE FIELD
Estimated Future Reserves
As of August 31, 2013

	Probable			
	Developed			
	Producing	Non-Producing	Undeveloped	Total Probable
Oil/Condensate—Barrels	0	16,480,000	97,266,000	113,746,000
Plant Products—Barrels	0	6,857,000	36,049,000	42,906,000
Gas—MMCF (after shrink)	0	91,000	586,000	677,000

CHINAREVSKOYE FIELD
Estimated Future Reserves
As of August 31, 2013

	Proved + Probable			
	Developed			
	Producing	Non-Producing	Undeveloped	Total Proved + Probable
Oil/Condensate—Barrels	42,529,000	20,438,000	130,280,000	193,247,000
Plant Products—Barrels	15,485,000	8,708,000	48,244,000	72,437,000
Gas—MMCF (after shrink)	262,000	114,000	782,000	1,157,000

Price Sensitivity Cases for Chinarevskoye Field

The sensitivity of the future net income and future net income discounted at 10 percent to variations of the base price forecast was evaluated and are summarized in the following tables. The base forecast for oil was $85.00 per barrel and held constant for life. The oil price for each sensitivity case is shown in parenthesis.

CHINAREVSKOYE FIELD
Proved
As of August 31, 2013

Price Variance	Future Net Income ($ millions)	Future Net Income (M$) Discounted @10%
+20% ($102.00)	$6,627,000	$3,609,000
+10% ($ 93.50)	$5,836,000	$3,158,000
-10% ($ 76.50)	$4,250,000	$2,255,000
-20% ($ 68.00)	$3,454,000	$1,801,000

CHINAREVSKOYE FIELD
Proved
As of August 31, 2013

Price Variance	Future Net Income ($ millions)	Future Net Income ($ millions) Discounted @10%
+20% ($102.00)	$9,508,000	$4,052,000
+10% ($ 93.50)	$8,388,000	$3,544,000
-10% ($ 76.50)	$6,142,000	$2,524,000
-20% ($ 68.00)	$5,015,000	$2,012,000

CHINAREVSKOYE FIELD
Proved
As of August 31, 2013

Price Variance	Future Net Income (($ millions)	Future Net Income (($ millions) Discounted @10%
+20% ($102.00)	$16,135,000	$7,661,000
+10% ($ 93.50)	$14,225,000	$6,702,000
-10% ($ 76.50)	$10,392,000	$4,779,000
-20% ($ 68.00)	$ 8,469,000	$3,813,000

TRIDENT FIELDS
Estimated Future Reserves and Income Derived
Through the Terms of the Production Sharing Agreements
Between the Republic of Kazakhstan and Zhaikmunai LLP
Chinarevskoye and Trident Fields
As of August 31, 2013

	Probable		
	Non-Producing	Undeveloped	Total Probable
Net Remaining Reserves			
Oil/Condensate—Barrels	2,225,000	1,607,000	3,832,000
Plant Products—Barrels	473,000	172,000	644,000
Gas—MMCF	16,000	483,000	499,000
Income Data ($ millions)			
Future Gross Revenue	$ 221,000	$1,275,000	$1,496,000
Deductions	135,000	1,028,000	1,162,000
Future Net Income (FNI)	$ 86,000	$ 247,000	$ 333,000
Discounted FNI @ 10%	$ 21,000	$ 24,000	$ 45,000

Price Sensitivity Cases for Trident Fields

The sensitivity of the future net income and future net income discounted at 10 percent to variations of the base price forecast was evaluated and are summarized in the following table. The base forecast for oil was $85.00 per barrel and held constant for life. The oil price for each sensitivity case is shown in parenthesis.

CHINAREVSKOYE FIELD
Proved
As of August 31, 2013

Price Variance	Future Net Income (M$)	Future Net Income (M$) Discounted @10%
+20% ($102.00)	$461,000	$ 94,000
+10% ($ 93.50)	$399,000	$ 70,000
-10% ($ 76.50)	$258,000	$ 15,000
-20% ($ 68.00)	$182,000	($11,000)

Reserves and Resources Included in This Report

The proved, probable and possible reserves and contingent resources included herein conform to the definitions of reserves and contingent resources sponsored and approved by the Society of Petroleum Engineers (SPE), the World Petroleum Council (WPC), the American Association of Petroleum Geologists (AAPG) and the Society of Petroleum Evaluation Engineers (SPEE) as set forth in the 2007 SPE/WpC/AApG/SPEE Petroleum Resources Management System (SPE-PRMS). An abridged version of the SPE/WPC/AAPG/SPEE reserves and contingent resources terms and definitions used herein are included as attachments to this report and entitled "Petroleum Reserves Definitions" and "Petroleum Resource Classification and Definitions."

The various reserve and contingent resources development and production status categories are defined in the attachment to this report entitled "Petroleum Reserves and Resources Status Definitions and Guidelines." The developed proved and probable non-producing reserves included herein consist of the shut-in and behind pipe categories.

No attempt was made to quantify or otherwise account for any accumulated gas production imbalances that may exist. The gas volumes presented herein do not include volumes of gas consumed in operations as reserves.

Reserves and Resources Classification

Recoverable petroleum resources may be classified according to the SPE-PRMS into one of three principal resource classifications: prospective resources, contingent resources, or reserves. The distinction between prospective and contingent resources depends on whether or not there exist one or more wells and other data indicating the potential for moveable hydrocarbons (e.g. the discovery status). Discovered petroleum resources may be classified as either contingent resources or as reserves depending on the chance that if a project is implemented it will reach commercial producing status (e.g. chance of commerciality). The distinction between various "classifications" of resources and reserves relates to their discovery status and increasing chance of commerciality. Commerciality is not solely determined based on the economic status of a project which refers to the situation where the income from an operation exceeds the expenses involved in, or attributable to, that operation. Conditions addressed in the determination of commerciality also include technological, economic, legal, environmental, social, and governmental factors. While economic factors are generally related to costs and product prices, the underlying influences include, but are not limited to, market conditions, transportation and processing infrastructure, fiscal terms and taxes.

Certain estimated recoverable volumes have been classified as contingent resources in this report due to one or more contingencies. These contingencies are related to geologic uncertainty, adequate seismic to interpret the reservoir area, drilling to determine reservoir properties, production tests of sufficient time to determine commerciality and reserve potential.

Reserves and Resources Uncertainty

All reserve and resource estimates involve an assessment of the uncertainty relating the likelihood that the actual remaining quantities recovered will be greater or less than the estimated quantities determined as of the date the estimate is made. The uncertainty depends chiefly on the amount of reliable geologic and engineering data available at the time of the estimate and the interpretation of these data. Estimates will generally be revised only as additional geologic or engineering data becomes available or as economic conditions change.

Reserves are "those quantities of petroleum anticipated to be commercially recoverable by application of development projects to known accumulations from a given date forward under defined conditions." The relative degree of uncertainty may be conveyed by placing reserves into one of two principal classifications, either proved or unproved.

Proved oil and gas reserves are "those quantities of petroleum which, by analysis of geoscience and engineering data, can be estimated with reasonable certainty to be commercially recoverable, from a given date forward, from known reservoirs and under defined economic conditions, operating methods, and government regulations."

Unproved reserves are less certain to be recovered than proved reserves and may be further sub-classified as probable and possible reserves to denote progressively increasing uncertainty in their recoverability. Probable reserves are "those additional reserves which analysis of geoscience and engineering data indicate are less likely to be recovered than proved reserves but more certain to be recovered than possible reserves." For probable reserves, it is "equally likely that actual remaining quantities recovered will be greater than or less than the sum of the estimated proved plus probable reserves" (cumulative 2P volumes). Possible reserves are "those additional reserves which analysis of geoscience and engineering data indicate are less likely to be recovered than probable reserves." For possible reserves, the "total quantities ultimately recovered from the project have a low probability to exceed the sum of the proved plus probable plus possible reserves" (cumulative 3P volumes).

The reserves included herein were estimated using deterministic methods and presented as incremental quantities. Under the deterministic incremental approach, discrete quantities of reserves are estimated and assigned separately as proved, probable or possible based on their individual level of uncertainty.

Contingent resources are "those quantities of petroleum estimated, as of a given date, to be potentially recoverable from known accumulations by application of development projects, but which are not currently considered to be commercially recoverable due to one or more contingencies." The contingent resources included herein were estimated using deterministic methods and presented as incremental quantities.

The reserves volumes and income quantities attributable to the different reserve classifications that are included herein have not been adjusted to reflect these varying degrees of risk associated with them and thus are not comparable. Petroleum quantities classified as reserves or contingent resources should not be aggregated with each other without due consideration of the significant differences in the criteria associated with their classification. In particular, there may be a significant risk that accumulations containing contingent resources will not achieve commercial production. Moreover, estimates of reserves and resources may increase or decrease as a result of future operations, effects of regulation by governmental agencies or geopolitical risks. As a result, the estimates of oil and gas reserves and resources have an intrinsic uncertainty. The reserves and contingent resources included in this report are therefore estimates only and should not be construed as being exact quantities. They may or may not be actually recovered, and if recovered, the revenues therefrom and the actual costs related thereto could be more or less than the estimated amounts.

Reserves and Resources Derived Through Certain Production Sharing Contracts

The reserves reported herein are limited to the period prior to expiration of current contracts providing the legal right to produce or a revenue interest in such production unless there is a reasonable expectation that an extension, a renewal or a new contract will be granted. The contingent resources reported herein may be subject to a contract providing the legal right to produce or a revenue interest in such production which is subject to negotiations. Recoverable hydrocarbon volumes are classified as contingent resources when such negotiations have yet to establish that there is a reasonable expectation that a new contract or contract renewal will be granted. A reasonable expectation is noted as representing a high degree of confidence that an extension, a renewal or new contract will be granted.

Furthermore, properties in the different countries may be subjected to significantly varying contractual fiscal terms that affect the net revenue to Zhaikmunai for the production of these volumes. The prices and economic return received for these net volumes can vary significantly based on the terms of these contracts. Therefore, when applicable, Ryder Scott reviewed the fiscal terms of such existing or proposed contracts and discussed with Zhaikmunai the net economic benefit attributed to such operations for the determination of the net hydrocarbon volumes and income thereof. Ryder Scott has not conducted an exhaustive audit or verification of such contractual information. Neither our review of such contractual information or our acceptance of Zhaikmunai's representations regarding such contractual information should be construed as a legal opinion on this matter.

Possible Effects of Regulation

Ryder Scott did not evaluate country and geopolitical risks in the country where Zhaikmunai operates or has interests. Zhaikmunai's operations may be subject to various levels of governmental controls and regulations. These controls and regulations may include matters relating to land tenure and leasing, the legal rights to produce hydrocarbons including the granting, extension or termination of production sharing contracts, the fiscal terms or various production sharing contracts, drilling and production practices, environmental protection, marketing and pricing policies, royalties, various taxes and levies including income tax, and foreign trade and investment and are subject to change from time to time. Such changes in governmental regulations and policies may cause volumes of reserves and contingent resources actually recovered and amounts of income actually received to differ significantly from the estimated quantities.

The estimates of reserves and contingent resources presented herein were based upon a detailed study of the properties in which Zhaikmunai owns an interest; however, we have not made any field examination of the properties. No consideration was given in this report to potential environmental liabilities that may exist nor were any costs included for potential liability to restore and clean up damages, if any, caused by past operating practices.

Methodology Employed for Estimates of Reserves and Resources

The estimation of reserve and resource quantities involves two distinct determinations. The first determination results in the estimation of the quantities of recoverable oil and gas and the second determination results in the estimation of the uncertainty associated with those estimated quantities. The process of estimating the quantities of recoverable oil and gas reserves and resources relies on the use of certain generally accepted analytical procedures. These analytical procedures fall into three broad categories or methods: (1) performance-based methods, (2) volumetric-based methods and (3) analogy. These methods may be used singularly or in combination by the reserve evaluator in the process of estimating the quantities of reserves and/or resources. Reserve evaluators must select the method or combination of methods which in their professional judgment is most appropriate given the nature and amount of reliable geoscience and engineering data available at the time of the estimate, the established or anticipated performance characteristics of the reservoir being evaluated, and the stage of development or producing maturity of the property.

In many cases, the analysis of the available geoscience and engineering data and the subsequent interpretation of this data may indicate a range of possible outcomes in an estimate, irrespective of the method selected by the evaluator. When a range in the quantity of recoverable hydrocarbons is identified, the evaluator must determine the uncertainty associated with the incremental quantities of those recoverable hydrocarbons. If the quantities are estimated using the deterministic incremental approach, the uncertainty for each discrete incremental quantity is addressed by the reserve or resource category assigned by the evaluator. Therefore, it is the categorization of incremental recoverable quantities that addresses the inherent uncertainty in the estimated quantities reported.

Estimates of reserve and resource quantities and their associated categories or classifications may be revised in the future as additional geoscience or engineering data become available. Furthermore, estimates of the recoverable quantities and their associated categories or classifications may also be revised due to other factors such as changes in economic conditions, results of future operations, effects of regulation by governmental agencies or geopolitical or economic risks as previously noted herein.

The reserves and contingent resources for the properties included herein were estimated by performance methods, the volumetric method, analogy, or a combination of methods. In general, reserves attributable to producing wells and/or reservoirs were estimated by performance methods or a combination of methods. These performance methods include, but may not be limited to, decline curve analysis, material balance and/or reservoir simulation which utilized extrapolations of historical production and pressure data available through August 2013 in those cases where such data were considered to be definitive. The data used in this analysis were furnished to Ryder Scott by Zhaikmunai and were considered sufficient for the purpose thereof. In certain cases, producing reserves were estimated by the volumetric method, analogy, or a combination of methods. These methods were used where there were inadequate historical performance data to establish a definitive trend and where the use of production performance data as a basis for the estimates was considered to be inappropriate.

Reserves and contingent resources attributable to non-producing and undeveloped reserves included herein were estimated by the volumetric method, analogy, or a combination of methods. The volumetric analysis utilized pertinent well and seismic data furnished to Ryder Scott by Zhaikmunai. The data utilized from the analogues as well as well and seismic data incorporated into our volumetric analysis were considered sufficient for the purpose thereof.

Assumptions and Data Considered for Estimates of Reserves and Resources

To estimate recoverable oil and gas reserves and resources and related future net cash flows, we consider many factors and assumptions including, but not limited to, the use of reservoir parameters derived from geological, geophysical and engineering data which cannot be measured directly, economic criteria based on the cost and price assumptions as noted herein, and forecasts of future production rates. Under the SPE-PRMS Section 2.2.2 and Table 3, proved reserves must be demonstrated to be commercially recoverable under defined economic conditions, operating methods and governmental regulations from a given date forward. We have applied the same criteria for economic producibility to the probable and possible reserves included in this report.

Zhaikmunai has informed us that they have furnished us all of the material accounts, records, geological and engineering data, and reports and other data required for this investigation. In preparing our forecasts of future production and income, we have relied upon data furnished by Zhaikmunai with respect to property interests owned or derived, production and well tests from examined wells, normal direct costs of operating the wells or leases, other costs such as transportation and/or processing fees, ad valorem and production taxes, recompletion and development costs, abandonment costs after salvage, product prices, geological structural and isochore maps, well logs, core analyses, and pressure measurements. Ryder Scott reviewed such factual data for its reasonableness; however, we have not conducted an independent verification of the data supplied by Zhaikmunai.

In summary, we consider the assumptions, data, methods and analytical procedures used in this report appropriate for the purpose hereof, and we have used all such methods and procedures that we consider necessary and appropriate to prepare the estimates of reserves and contingent resources herein.

Future Production Rates

For wells currently on production, our forecasts of future production rates are based on historical performance data. If no production decline trend has been established, future production rates were held constant, or adjusted for the effects of curtailment where appropriate, until a decline in ability to produce was anticipated. An estimated rate of decline was then applied to depletion of the reserves. If a decline trend has been established, this trend was used as the basis for estimating future production rates.

Test data and other related information were used to estimate the anticipated initial production rates for those wells or locations that are not currently producing. For reserves not yet on production, sales were estimated to commence at an anticipated date furnished by Zhaikmunai. Wells or locations that are not currently producing may start producing earlier or later than anticipated in our estimates due to unforeseen factors causing a change in the timing to initiate production. Such factors may include delays due to weather, the availability of rigs, the sequence of drilling, completing and/or recompleting wells and/or constraints set by regulatory bodies.

The future production rates from wells currently on production or wells or locations that are not currently producing may be more or less than estimated because of changes including, but not limited to, reservoir performance, operating conditions related to surface facilities, compression and artificial lift, pipeline capacity and/or operating conditions, producing market demand and/or allowables or other constraints set by regulatory bodies.

Hydrocarbon Prices

The August 31, 2013 initial prices of $2.407 per Mcf for gas, $60.65 per barrel for natural gas liquids (NGLs), and $85.00 per barrel for condensate and oil were specified by Zhaikmunai. These prices were held constant for the life of each property, unless prices were defined by contractual arrangements.

Product prices which were actually used for each property reflect adjustments for gravity, quality, local conditions, gathering and transportation fees and/or distance from market, referred to herein as "differentials." The differentials used in the preparation of this report were furnished to us by Zhaikmunai.

The effects of derivative instruments designated as price hedges of oil and gas quantities are not reflected in Zhaikmunai's individual property evaluations.

While it may reasonably be anticipated that the future prices received for the sale of production and the operating costs and other costs relating to such production may also increase or decrease from existing levels, such changes were omitted from consideration in making this evaluation.

Costs

Operating costs for the leases and wells in this report were furnished by Zhaikmunai and are based on the operating expense reports of Zhaikmunai and include only those costs directly applicable to the leases or wells. The operating costs include a portion of general and administrative costs allocated directly to the leases and wells. Operating costs were on both a fixed and variable basis and in our opinion represent the expected increased costs as production increased. They also include salary costs and adjustments to salary costs based on the number employees as well as a yearly salary increase until 2017.

Transportation costs of $14.97/bbl for oil/condensate and $18.53/bbl LPG ("plant products" or "LPG") were supplied by Zhaikmunai.

No deduction was made for loan repayments, interest expenses, or exploration and development prepayments that were not charged directly to the leases or wells.

Development costs were furnished to us by Zhaikmunai and are based on authorizations for expenditure for the proposed work or actual costs for similar projects. The costs for infrastructure were based on current estimates and/or the actual costs of similar projects. Development costs include costs associated with well drilling and completion, gas and oil pipeline construction, other infrastructure costs, costs for oil treatment facilities, gas processing plant, LPG terminal, LPG trucks for transportation, costs for camp construction, water injection and power generation, as well as facility and well abandonment costs. The development cost also includes commissioning, management costs, insurances and contingencies. The estimated net cost of abandonment after salvage was included for properties where abandonment costs net of salvage were significant. The estimates of the net abandonment costs furnished by Zhaikmunai were accepted without independent verification.

Because of the direct relationship between volumes of undeveloped reserves and resources and development plans, we include in the undeveloped category only reserves and resources assigned to undeveloped locations that we have been assured will definitely be drilled and reserves and resources assigned to the undeveloped portions of secondary or tertiary projects which we have been assured will definitely be developed. Zhaikmunai has assured us of their intent and ability to proceed with the development activities included in this report, and that they are not aware of any legal, regulatory or political obstacles that would significantly alter their plans.

Current costs used by Zhaikmunai were held constant throughout the life of the properties.

Chinarevskoye License Description

Summary

Zhaikmunai holds an interest in certain oil and gas properties in the Chinarevskoye field located in the Republic of Kazakhstan. Zhaikmunai entered into both a License and Production Sharing Agreement ("PSA") with the Republic of Kazakhstan in May 1997 and in October 1997, respectively.

The PSA sets out the parameters for the exploration and development of the field and the fees, basis for production sharing, and the taxes payable to the Republic of Kazakhstan.

Chinarevskoye is a multi-formation field, divided into three areas - North (also called Northeast or Central), South and West. There are several hydrocarbon accumulations in different strata in the pre-salt section. The presence of seven prospective reservoir intervals in the pre-salt Permian, Carboniferous and Devonian reservoirs had already been proven by well P9, a wildcat well drilled in 1989. Based on the results of this well and of a 2-D seismic survey, exploration well 4 was drilled in 1991 which discovered a gas-condensate accumulation in the Middle Devonian Afoninski horizon at a depth of 5,150m. Well 10, drilled in 1992, in the northeastern area confirmed the existence of a gas-condensate accumulation in the Afoninski horizon and tested gas-condensate in the underlying Biski horizon and an oil accumulation in the Lower Carboniferous Tournaisian horizon. The Tournaisian accumulation was also the first reservoir to begin commercial production on January 1, 2007 following a three year appraisal and a five and a half year test production period. The mining license for the Tournaisian North accumulation is valid until December 31, 2031. The appraisal drilling program in the Tournaisian North area showed the existence of four independent reservoir horizons in this Carboniferous formation. The uppermost T1gas horizon is a gas condensate accumulation, whereas the underlying three horizons T1oil, T2 and T3 horizons are oil accumulations. Current production from the Tournaisian North is approximately 9,900 barrels oil equivalent per day.

The commercial production of the Biski-Afoninski Northeast reservoir started in May 2011. Currently, the production from 7 production wells amounts to 30,658 barrels oil equivalent per day.

In the north area commercial accumulations were also found in the Middle Devonian Givetian reservoir horizons. The uppermost Mullinski horizon was successfully tested by wells 22, 30 and 54. During a 2-month production test in 2007, well 30 flowed between 25 and 45 m3/d volatile oil. The gas oil ratio was 300-500 m3/m3. During 2007, a production test was also carried out on well 54. The well had a stable production rate of about 80 m3 of volatile oil per day from a 12.2 m clastic reservoir at a depth of 4,865 m.

The underlying Ardatovski carbonate horizon was successfully tested by wells 28 and 54. The production test of well 28 showed a stable rate of about 230 m3/d of gas condensate. The lower Givetian Vorobyovski horizon was tested by an open-hole test in 2008. The well flowed a very light gas condensate from a 16m clastic reservoir at 4,960m. The estimated gas rate was to 200,000-300,000 m3/d with a gas-condensate ratio of 1,500 m3/m3. The reservoir is in commercial production since May 2011. Currently, three wells are producing from this reservoir—wells 28, 115, 213. The daily production amounts to 6,955 barrels of oil equivalent per day.

In the southern area the Ardatovski horizon was successfully tested in 2008 by well 32. The well was in test production in 2009-2010. The cumulative production amounted to 98,829 barrels of oil equivalent.

In 2008, the first open-hole tests were conducted on wells 51 and 52 in the Middle Carboniferous Bashkirian carbonate formation. Well 51 had a water free oil rate of about 150 m3/d from the test interval 3,645-3,686 m. Well 701, drilled in 2013, found the Bashkirian horizon oil bearing and is under preparation for production testing.

Appraisal well 45 tested in 2012 the Bashkirian horizon in the western area. During production test a stable flow of 120 m3 per day of oil was produced through a 7 mm choke at 60 bars wellhead pressure. The test production project for the well was approved and the well is currently being prepared for test production.

In the west area of the Chinarevskoye block, well 33 successfully tested the Afoninski and Biski reservoirs in the spring of 2008. Appraisal well 33 in the western part of the Chinarevskoye field test- flowed 28,000 m3 of natural gas and 35 m3 of condensate per day from the Middle Devonian Biski- Afoninski carbonate formations. This test confirmed and extended the Western Biski-Afoninski discovery. The discovery well 4 tested 86,000 m3 of natural gas and 33 m3 of condensate per day from a correlative zone of the Biski formation in 1991. Well 33 tested the upper 22 m of Afoninski and 25 m of Biski pay on a 7-mm choke from perforations between 5,067-5,210 m as shown from production logging. The formation required acid treatment prior to flow testing. PLT shows no water inflow and indicated that most of the flow came from the Biski. Appraisal well 45 found the Biski- Afoninski hydrocarbon bearing and a stable flow was obtained during an 8 hour test. Due to technical problems with the well completion the reservoir was damaged and tests could not be repeated because of reservoir damage which occurred during a work over.

Well 33 also successfully tested oil and gas condensate in the Tournaisian T1, T2 and T3 horizons in the western block. The well was implemented in 2011 in the Field Development plan.

In the southern area of the Chinarevskoye field, the Tournaisian T1 horizon was proven to be gas-condensate bearing by wells 23, 31, 401, 404 and 406. A step-out well, 410 didn’t find productive reservoir. Well 402 is currently under investigation. Commercial production from Tournaisian South reservoir started in 2011. Current production is about 1,900 barrels of oil equivalent per day.

Well 31 also successfully tested the Upper Devonian Famennian horizon at 4,520 m. The well flowed 14.1 m3/day of gas condensate and 25,500 m3/d of gas from 6 m net pay carbonate reservoir at a depth of 4,520 m. An acid treatment was required prior to flow testing.

The Permian Filipovski, Artinski and Asselski horizons have been successfully tested by a Modular Formation Dynamics Tester (MDT[1]) in well 29 and open-hole tests in wells P9, 20, 27, 31 and 33. In well 20, the Permian tested oil and gas from a 30 m interval at 2,686 m. There are high expectations of upside potential from the Lower Permian formation since log data showed similar hydrocarbon saturations for the other wells to those shown in well 20. The first casing test of the Permian Filipovski horizon was conducted in well 31 in August 2008. The same interval had been previously tested successfully by an openhole test in June 2007. However, the acid treatment job was not successful and only a weak gas flow to surface was obtained. The first production test was carried out in January 2013 where a stable flow of 35.2 m3/day of gas condensate and 16,878 m3/d of gas was obtained from appraisal well 725. The well is being prepared for test production.

[1] MDT—this is a Modular Formation Dynamics Tester for pressure measurement and high-quality fluid sampling.

As a result of the exploration programs carried out between 1997 and 2008, Zhaikmunai declared six commercial discoveries to the MEMR (Ministry of Energy and Mineral Resources) of the RoK (Republic of Kazakhstan) in May 2008 and one discovery in 2013 based on results of appraisal well 45.

These discoveries are:

- Biski-Afoninski West gas condensate,
- Tournaisian West oil-gas condensate,
- Mullinski oil-gas condensate,
- Ardatovski gas condensate,
- Mullinski South oil-gas condensate,
- Famennian gas condensate.
- Bashkirian oil

Based on the license terms, contract bonus payments for all discoveries were made and appraisal programs for each discovery were submitted to the Ministry within one month from the date of declaration. As requested by the MEMR, the six appraisal programs were later combined to a single appraisal program. This appraisal program was approved by the Ministry on August 12, 2008. Zhaikmunai was awarded a new exploration license ("*geologicheski otvod*") and the corresponding changes were included into the Production Sharing Agreement (PSA) as supplementary #7, effective November 17, 2008. The appraisal period for the new commercial discoveries ends on May 26, 2014.

According to the license terms, the exploration period for the Chinarevskoye license ended on May 26, 2008. Therefore the final reserves report for the Chinarevskoye field, prepared by NIPIneftegaz institute was submitted to the Kazakh Authorities on May 23, 2008. This report provided reserve estimates for Kazakh categories C1 and C2 for the

- Tournaisian North oil accumulations
- Givetian Mullinski North and West oil accumulations
- Tournaisian North T1gas gas condensate accumulation
- Tournaisian South T1 gas condensate accumulation
- Givetian Ardatovski North and West gas condensate accumulations
- Biski Afoninski North and West gas condensate accumulations
- Famennian South gas condensate accumulation

This report was approved by the State Committee of Reserves (GKZ) on October 2, 2008. A new reserves report was prepared in 2013 and is currently in the approval process with Kazakh Authorities.

The first field development plan was approved in 2009 by the Kazakh Authorities. It included the construction of a gas treatment facility with a capacity of 1.7 billion cubic meters of raw gas per year with possibility of extracting LPG from the raw gas; a water injection project for the Tournaisian Northeast reservoir and the connection to the gas pipeline Orenburg-Western Europe.

Location and License Commitments

Zhaikmunai LLP is a 100% privately owned company. It is the owner and operator of the Chinarevskoye field.

The Chinarevskoye field is located in northwestern Kazakhstan on the border of the Republic of Kazakhstan (the Republic) and the Russian Federation as shown in Figure 1.

Figure 1: Regional Location Map

Zhaikmunai LLP was established in March 1997 for the supplementary exploration, production and sale of crude hydrocarbons from the Chinarevskoye field. The Chinarevskoye oil and gas condensate field is part of the Chinarevskoye license block, which is located in the northern part of the Pre-Caspian basin on the territory of the Republic of Kazakhstan. From an administrative viewpoint it is located in the region of West Kazakhstan (Batyk Kazakhstan) near the border between Kazakhstan and the Russian Federation. The West Kazakhstan administrative center Uralsk (Oral) is about 80 km southwest of the Chinarevskoye field. The nearest villages are Rozhkovo, Chesnokovo, Chebotariovo, Balbanov and Chinarev.

Surface features are hilled plain, with abundant ravines, hollows and brooks. The flora is typical for dry steppe—feather grass, wormwood, etc. There are no woods, but the field is in the vicinity of the Ural river. The average temperature ranges -14.2°C to -14.4°C in January and +22°C to +23°C in July, where the lowest is -42°C in winter, and the highest is +40°C in summer. Annual precipitation ranges between 300 and 350 mm. The maximum freezing depth of soil is 1.5 m. Wnter road conditions last from early November until early April and the snow can be firm for as long as 130 days. Wnd speed is 5 to 9 m/s in February and 3 to 6 m/s in August-September. Regular changes of wind direction occur in spring, mainly northwards.

The existing nearby infrastructure is favorable for an efficient development program for the Chinarevskoye field. As shown on the infrastructure map in Figure 2, the Orenburg gas pipeline crosses the license area, the Atyrau-Samara oil pipeline is located 100 kilometers to the west, a railway is located 55 kilometers to the south and a large oil and gas refinery has been constructed 75 kilometers to the southeast at the Karachaganak field to process unstable natural gas liquids.

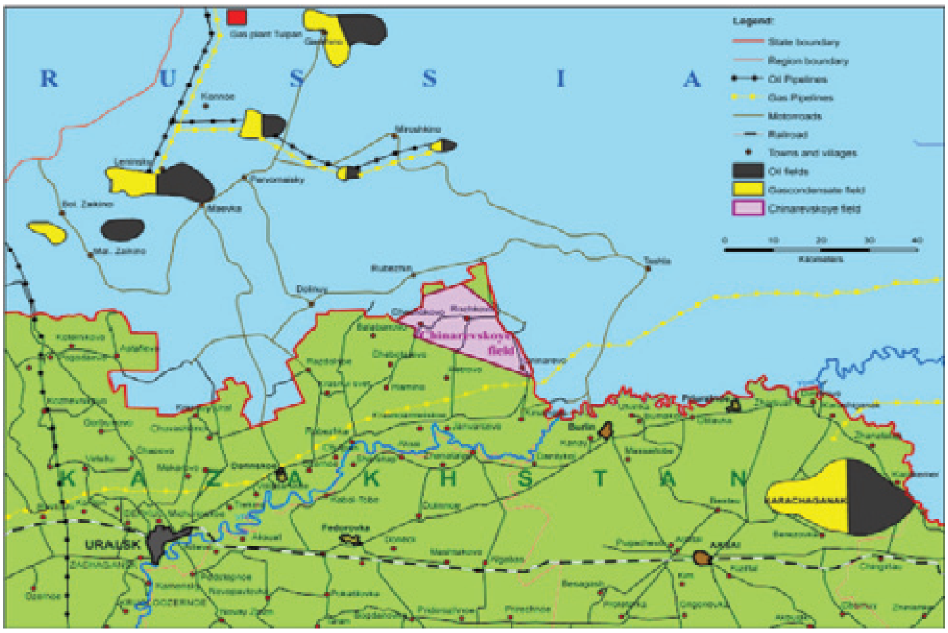


Figure 2: Local Infrastructure Map

The license granting the right to use the subsurface in the Republic of Kazakhstan for the exploration and production of hydrocarbons in the Chinarevskoye oil and gas condensate field was issued to Zhaikmunai Limited Liability Partnership (LLP) in May 26, 1997 and is based on the license Series MG #253-D(oil) by the Government of the Republic of Kazakhstan.

The license encompasses the following blocks:

- XII-12-D (partial), E (partial, F (partial)
- XIII-12-A (partial), B (partial), C (partial), F (partial) and
- XIII-13-A (partial)

The duration of the original license was for a period of 30 years. The first five years of exploration is followed by a 25 years production period.

The contract is a combined License and Production Sharing Agreement with the Kazakh government. It includes a Minimum Work Program and a Minimum Capital Investment requirement.

The original Minimum Work Program was to drill four exploration wells during the first exploration stage and nine exploration wells during the second exploration phase.

The second exploration phase started in November 2001 and was extended twice. It ended on May 26, 2008. During this second phase and its extension periods a total of nine additional wells had to be drilled to fulfill the minimum work requirements with a total Capital investment of $100.5 MM US (for the second phase including the two extension phases). Out of these nine wells, two were required to be drilled to the Givetian formation and four new exploration wells and three future production wells drilled to the Tournaisian formation. In addition, production tests of the Permian reservoirs had to be performed in four wells (as additional target of exploration or future production wells).

The overall commitments for the minimum work program of both exploration phases amounted to $125.5 MM US.

As of May 25, 2008, the four commitment wells for the first exploration phase had been drilled (wells 10, 12, 13, 24) and all 9 commitment wells of the second phase had been finalized (wells 20, 22, 23, 28, 29, 50, 53, 56 and 30), six of which (20, 22, 23, 28, 29 and 30) reached the Givetian formation. In addition to the commitment wells the following appraisal and production wells were drilled before the end of the exploration license period: production well 54 and appraisal wells 27, 31, 32 and 33.

As a result of this exploration period six commercial discoveries were made and declared to the Kazakh Authorities. An appraisal program was prepared for these discoveries by Kazakh Institute NIPIneftegaz and approved by the Kazakh Authorities in 2008. The appraisal phase for these discoveries ended on May 26, 2011 and was extended until May 26, 2014 according to License contract supplementary #10. The prolongation of the appraisal phase was based on a new appraisal program which had been approved in October 2012 by the Kazakh Authorities. It foresees the drilling of 4 independent and 8 dependent appraisal wells and includes the appraisal of the Bashkirian and Permian reservoirs. The commitments for the prolongation of the appraisal period until May 26, 2014 include the drilling of 4 independent exploration wells and 8 dependent wells. The drilling of the dependent wells is based on the exploration success of the independent wells. The overall investment amounts to $29.2 million US for the independent phase and $109.7 million US for the dependent appraisal phase.

As of August 31, 2013 two of the appraisal wells (701 and 725) were finalized. They confirmed hydrocarbon bearing of the Bashkirian and Permian reservoirs. One appraisal well (well 724) was under drilling and well 40 was under preparation for drilling.

A summary of the existing subsurface contracts is given below:

Chinarevskoye—Existing Contracts

In addition to the PSA, Zhaikmunai performs its current operations under two main permits with the Government:

- **The Exploration Permit** ("*Geologicheski otvod*") and
- **The Production Permit** ("*Gorny otvod*") for the northern, western and southern area for the Tournaisian, Mullinski, Ardatovski, Biski, Afoninski, Famennian and Bashkirian reservoirs

The original Exploration permit expired on May 26, 2008. Currently, Zhaikmunai is carrying out the appraisal of discoveries based on a State approved program. As stated above the current appraisal phase 2008 ends on May 26, 2014.

The first Production Permit for the Tournaisian North was awarded in 2006. The commercial production of this reservoir started on January 1, 2007 and ends on December 31, 2031. After approval of the reserves for the Biski/Afoninski, Tournaisian, Mullinski, Ardatovski and Famennian accumulations a new mining license was issued in December 2008.

The main original commitments under the original exploration contract were as follows:

- Acquisition of a 3-D seismic survey
- Drilling of 11 exploration wells of which three can be future production wells under the Test Production project for the North area of the Tournaisian reservoir (which was in place until end of year 2006)
- Drilling of water disposal well R1
- Construction of the first stage of an Oil Treatment unit
- Construction of an oil pipeline from the field to Uralsk

Subsequent to the extension of the second exploration phase until May 26, 2008 the following commitments had been added:

- Drilling of two additional exploration wells to the Givetian formation
- Four tests of the Permian formation

All commitments were fulfilled before the end of the exploration phase:

- 3-D seismic survey was acquired and processed and was re-processed and re-interpreted by PGS-RES in 2006-2007

- 13 of the 13 committed exploration and early production wells were drilled
- Re-entry on well 10, deviation of wells 12 and 13 in North area
- Drilling of new wells 22, 24, 20, 28, 29, 30 in the North area
- Well 23 was drilled in the Southern area
- Early production wells 50, 53, and 56 in the North area
- Oil treatment unit was built and commissioned in July, 2006
- Disposal well R1 was drilled and tested
- All open hole tests in the Permian formation were performed in appraisal and production wells
- Commissioning of oil pipeline by end of year 2008
- In total 11 wells were drilled down to the Givetian formation or deeper (20, 22, 23, 27, 28, 29, 30, 31, 32, 33, 54).

The main original commitments under the production permit for the Tournaisian Northeast were as follows:

- Drilling of 32 additional production and water injection wells
- Full gas utilization of associated gas
- Water injection to support reservoir pressure and to achieve a final oil recovery of at least 32.8%

The initial approved development plan for the Tournaisian North oil accumulation was revised in 2007.

Separate development plans for the oil and the gas reservoirs were prepared by NIPINeftegaz and approved by the Authorities in 2008. Based on this, a new production permit became effective in 2009. It included the development of the following oil and gas condensate accumulations:

- Tournaisian North oil accumulation, Tournaisian North gas condensate accumulation
- Tournaisian South gas condensate accumulation, Tournaisian South oil accumulation,
- Tournaisian West oil accumulation, Tournaisian West gas condensate accumulation
- Ardatovski North and West gas condensate accumulation
- Mullinski North, West and South oil accumulations
- Biski/Afoninski North gas condensate accumulation
- Famennian South gas condensate accumulation

The development plans require full gas utilization for associated and non-associated gas, water injection into the Tournaisian North oil reservoirs and the drilling of horizontal wells in the Mullinski and the Biski/Afoninski reservoirs.

A gas plant with an annual capacity of 1.7 billion cubic meters of raw gas was built during 2008-2010 and commercial gas, condensate and LPG production started in 2011. It is planned to build an additional gas plant to reach a total treatment capacity of 4.2 billion cubic meters per year. The planned start operations date of this plant is July 1, 2016.

The Tournaisian North water injection project was launched in 2008. Currently, 3 wells are injecting water (wells 53, 121, 50). Three new injection wells are going to be drilled and one production shall be converted into an injection well.

For the Mullinski reservoir it is planned to drill a technical horizontal appraisal well in 2014-2015 to find an appropriate drilling and completion technology for the terrigenous type of reservoir.

Currently, both development plans are under revision ("*avtorski nadsor*"). It is expected that the revised development plans for both the oil and the gas condensate reservoirs will be approved during 2014.

Geology

Geological History

The Chinarevskoye field is located on the Northern margin of the Pre-Caspian Basin. The Pre-Caspian Basin covers an area of approximately 550,000 km2 and represents a huge, deeply subsided portion of the Russian Platform. The basin is entirely bounded by deep-seated regional faults upon which most of the basin's Paleozoic and Mesozoic subsidence has taken place. The entire southern part of the basin lies along a Hercynian-aged suture zone. The Chinarevskoye field area experienced a similar tectonic history of basement-related block faulting throughout the Paleozoic period. A ring of uplifts fringing the basin margin were positive features for much of the geological history as depicted in the pre-salt high map in Figure 3. The Chinarevskoye field discovery lies within this uplift zone.

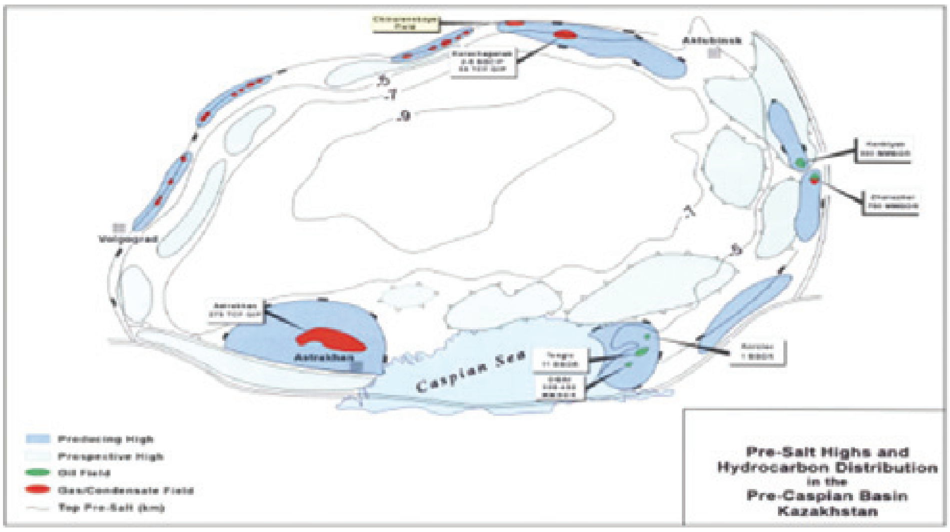


Figure 3: Pre-Salt Highs and Hydrocarbon Distribution in the Pre-Caspian Basin[2]

These uplift features are believed to be long-lived structural highs. During the Paleozoic Age, sedimentation on these highs was dominated by shelf carbonates with reef development on the margins. The deeper inter-block areas predominantly received shales and deepwater carbonates. Much of the structural setting of the Carboniferous and Devonian intervals is therefore represented by broad, gentle structures with minor or no identifiable faulting. By the Middle Permian Age, the basin became partially closed, and restricted marine influx allowed for the accumulation of a thick Kungurian evaporite section (see Figure 4).

The Frasnian unconformity represents the main event in the pre-salt section. Below this unconformity the prevalent trapping mechanism is tectonic (tilted fault blocks). Above the unconformity, the traps are mainly of a lithological type.

Two main intervals of Devonian and Carboniferous source rock generated hydrocarbons mainly during and after the accumulation of the Kungurian evaporites. These evaporites present a regional seal which divides the pre-salt hydrocarbon system from the post-salt.

All hydrocarbon bearing reservoirs in the Chinarevskoye area belong to different strata of the pre-salt section. This also applies to all adjacent fields (see Figure 3). Most of these fields also have two or more independent reservoir horizons. Therefore, only the pre-salt section is analyzed in more detail.

[2] From NSA report 2003: Estimate of reserves and future revenues to the Zhaikmunai LLP interest in certain oil and gas properties located in Chinarevskoye field Republic of Kazakhstan as of September 30, 2003; Netherland, Sewell & Associates, Inc (NSA)

Stratigraphy

The lithological and Stratigraphic sections of the Chinarevskoye field are represented by crystalline basement rocks and sedimentary formations (see Figure 4). The seismic markers are shown in Figure 5.

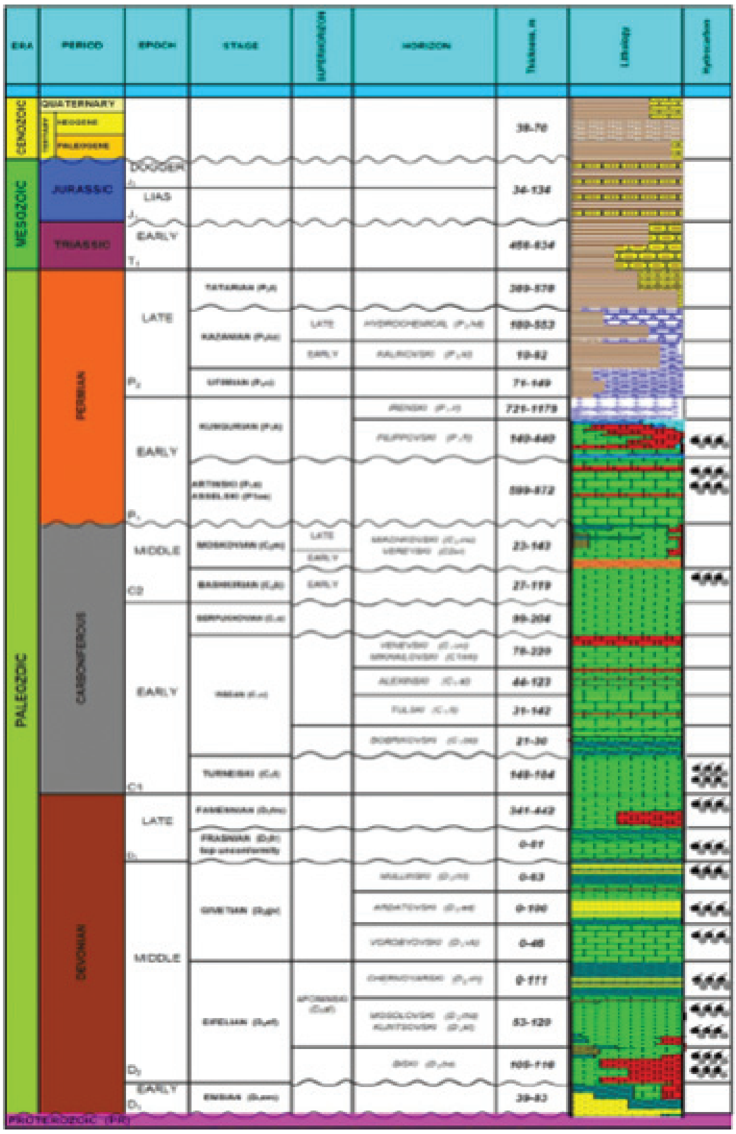


Figure 4: Stratigraphic Column

Crystalline Basement

The basement of the Chinarevskoye uplift was identified by 4 wells: 20, P-9, 10, and 4. The age of the basement rocks is Proterozoic and they are represented by fallow-pink, large-grained granites. The top of the basement is associated with the “F” reflector.

Chinarevskoye Field
Seismic markers
Devonian and Carboniferous section

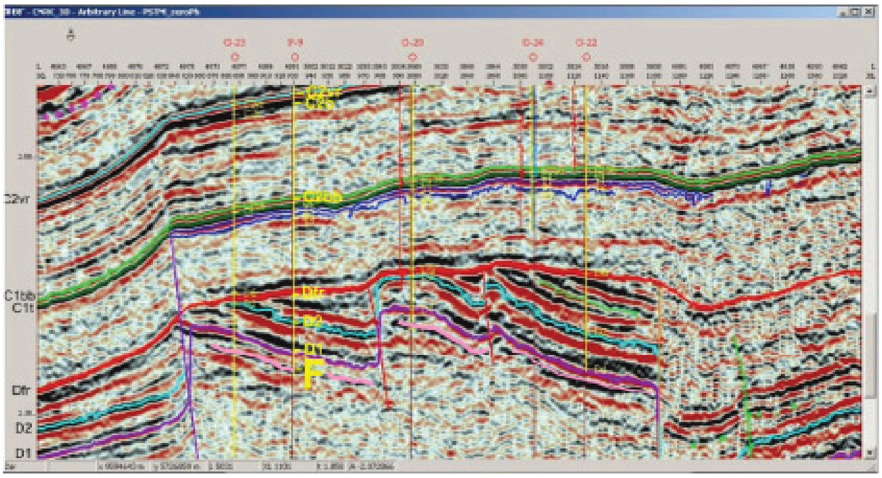


Figure 5: Chinarevskoye Field Seismic Markers of Devonian/Carboniferous Section

Devonian System

Devonian system sediments in the area are represented by lower, middle and upper sections.

The lower section is represented by unequal inter-bedding of gravel-sandstones, greenish-grey sandstones and dark-cherry argillites. The thickness of the Lower Devonian sediment is between 39 m and. The top of the Lower Devonian sediments and the base of the Middle Devonian Biski sediments are associated with the “DI” reflector.

The middle section is represented by Eifelian and Givetian stages. The Eifelian stage is represented by the Biski and Afoninski horizons.

The Biski horizon is characterized by inter-bedding of dolomitized, bio-homogeneous limestones with biomorphic, detrital, dolomitized limestones and dark-brown, biomorphic, detrital dolomites unequally saturated with bituminous substance. In well 4, there are bioherm limestone differences. The thickness of Biski sediments varies from 105 m to 116 m. The top of the Biski sediments is associated with the D2bs reflector.

The Afoninski horizon is, lithologically, mainly represented by carbonate rocks. The upper part of this horizon is represented by the inter-bedding of clayey bituminous limestones with marls and argillites. The color of the rocks is dark, highly bituminous, and thinly layered with fauna. The Afoninski horizon composed of subgroups Chernoyarski and Klintsovski-Mosolovski. Therefore the thickness of the Afoninski sediments vary in thickness through the subdivisions Chernoyarski and Klintsovski- Mosolovski between 0 m to 111 m and from 53 m to 120 m, respectively. The top of the Afoninski sediments is associated with the D2af (D2) reflector.

The Givetian stage is lithologically represented by argillites with limey areas. Argillites are thin- plated and dense. The Givetian consist of Mullinski, Ardatovski and Vorobyovski subdivisions. The thickness of the Muliinski sediments is between 0 m and 63 m, Ardatovski is between 0 m to 100 m and Vorobyovski is between 0 m to 46 m. The top of the Givetian stage is associated with the “D3” (Dfr) reflector.

The Upper section is represented by the Famennian stage sediments. Sediments of the Frasnian stage are absent within the limits of the oil accumulation due to pre-Famennian erosion.

In Givetian sediments the Famennian stage occurs with some erosion. Lithologically it is represented by grey, dark-grey, biomorphic detrital, dolomitic, slightly bituminous limestone. The thickness of Famennian sediments is between 341 m and 442 m.

Carboniferous System

Sediments of the Carboniferous stage lie conformably on Devonian rocks and are represented by two sections: Lower and Middle. Sediments of the upper section are absent from the Pre-Asselian erosion.

The Lower section is represented by the Tournaisian, Visean and Serpukhovski stages.

The Tournaisian section is represented by Lower and Upper substages, composed of grey, dark-grey, and over-crystallized limestones, with dolomitic and clayey areas. The lithological boundary between substages passes within the limestones and is characterized by a change from clayey plated accumulations into massive detrital accumulations. In the Chinarevskoye area, a core was taken from the P-9 well where the Tournaisian is represented by light-grey, dense, massive limestones with single organic remnants. In the Lower part there is a slight smell of hydrogen sulfide. The thickness of Tournaisian sediments varies between 148 m and 184 m.

The Visean stage is represented by carbonate sediments, grey, dark-grey, thin, granular, dense sediments and terrigenous sediments - from dark argillites to black ones of the Bobrikovski horizon. They serve along with dense clayey limestones of the Upper part of the Tournaisian stage as a seal for the Tournaisian oil accumulation. The thickness of the horizon amounts to 25-30 m. The top of the Bobrikovski horizon is associated with the "C1bb" reflector. The thickness of Visean sediments is between 320 m and 382 m.

The Serpukhovian stage is represented by light-grey, biomorphic detrital, foraminiferal-algal limestones with leached and vuggy areas. The thickness of Serpukhovian sediments ranges between 99 m and 204 m.

The Middle section is defined in the structure of Bashkirian and Moscovian stages.

The Bashkirian stage is represented only by the Lower Bashkirian substage, the overlying sediments are absent as a result of the Pre-Vereyski erosion. It is composed of light-grey, organogenic detrital, oolitic and over-crystallized limestones. The thickness of Bashkirian sediments is between 27 m and 119 m.

The Moscovian stage is represented within the limits of the oil accumulation only by the Vereyski horizon. The Kashirsko-Myachkovskiy part of the section is absent as a result of Pre-Asselian erosion.

The Vereyski horizon is lithologically represented by dark-grey to black argillites, with a bituminous substance. The top of the Vereyski sediments is associated with the "C2vr" reflector. The thickness of the Vereyski sediments amounts to between 23 m and 143 m.

The Vereyski horizon is a regional seal for Lower Bashkirian oil and gas accumulations, as revealed in the zone of Visean-Bashkirian carbonate flange scarp (Daryinskoye, Rostoshinskoye).

Permian System

The Lower part is represented by two types of sediments; the Lower section carbonates in the structure of the Asselian, Sakmarian and Artinskian stages and the Upper section evaporates of the Kungurian stage. The base of the Permian is associated with the "P2" reflector.

Asselian and Artinskian stages are lithologically homogeneous and are represented by limestones and grey dolomites to dark-grey, massive, sturdy dolomites, with organogenic and cloddy areas. The top of the Artinskian stage is associated with the "P1_10" reflector. The thickness of the Asselian and Artinskian rock series is between of 599 m and 872 m.

The Kungurian stage is represented by two series: The Lower series sulphate-carbonates of the Filipovski horizon and the Upper series evaporites with sulphate and terrigenous interlayers of the Irenski formation.

Sediments of the Filipovski horizon are represented by anhydrates with dolomite interlayers. The top of sediments of the Filipovski horizon is associated with the "S" reflector. The thickness of Filipovski horizon sediments ranges between 140 m and 440 m.

Sediments of the Irenski formation are represented by alternative layers of salt and anhydrites. The top of the Irenski formation is associated with the "VI" reflector. The thickness of the Irenski formation is between 721 m and 1,179 m.

Post salt Paleozoic sediments occur with an unconformity on the Kungurian halogen series and are composed of inter bedded series of sand, clayey, carbonate and salt-bearing rocks. The thickness of these sediments amounts is between 788 m and 1142 m.

Mesozoic and Cenozoic strata

Lithologically, they are mainly represented by terrigenous rocks with the inter-beds of carbonate rocks in Jurassic and Cretaceous accumulations. The total thickness of Mesozoic-Cenozoic accumulations is between 627 m and 718 m.

Hydrocarbon Systems

Basic regional Information

In the north margin of the Pre-Caspian Basin, the carbonates are divided by terrigenous rocks. The stratigraphic complexes are basic oil and gas bearing complexes in the pre-salt Paleozoic reservoirs, e.g. Middle Devonian carbonates, Givetian-Lower Fransian terrigenous, Upper Devonian- Tournaisian carbonates, Lower Visean terrigenous, Visean-Lower Bashkirian carbonates, Upper Bashkirian-Vereiski terrigenous, and Moscovian-Artinskian carbonates.

Discoveries of oil in the giant Karachaganak gas-condensate field, commercial gas-condensate accumulations in Biski and Afoninski sediments of the Zaikinsko-Rostoshinskoye and Vishnyovskoye field groups (Russia), and the Chinarevskoye field are from the Middle Devonian carbonate complex. Chernoyarski claystones above the Afoninski horizon form a regional seal for this complex.

Discovery of the Prigranichnoye oil field (Western Kazakhstan) and Dolinnoye field (Russia) is from the Givetian-Lower Frasnian terrigenous complex.

A series of small fields in Russia produce from the Lower Visean terrigenous complex.

The discovery of the Daryinskoye oil field and the Rostoshenskoye gas field is from the Visean- Lower Bashkirian carbonate complex. The Moscovian age Vereiski horizon terrigenous accumulations are the regional seal for this complex.

The fields restricted to a chain of Teplovsk-Tokaryovsk local uplifts are connected with the Moscovian-Artinskian carbonate complex. Artinskian accumulations are the main productive horizon for this complex. The sulphate accumulations in Filipovski horizon and salt-bearing accumulations in Irenski series form the seals.

Source Rock

Middle Devonian-Upper Frasnian: Relatively abyssal siliceous-argillaceous-carbonate layers are enriched with Total Organic Content (TOC) which ranges from 1.07% to 4.3%. Kerogen is type II and the Sedimentation situation is anoxic. When measuring the Middle Devonian-Upper Frasnian section with the data from wells, rock mass enriched with kerogen appears to be not less than 200 m thick. These accumulations are good source rocks.

Nevertheless, Upper Frasnian-Tournaisian accumulations that formed in a relatively abyssal condition are enriched with a Type II kerogen. Sedimentation occurred in an anoxic environment. TOC content varies from 0.04% to 1.1%. Within this rock mass carbonates account for 70% with the remaining clays and sand. TOC content is up to 4-10%. These rocks are good source rocks.

Maturation and Generation

The geological development of the Pre-Caspian Basin encouraged hydrocarbon generation, migration, and accumulation of oil and gas into various reservoirs and traps. Some of the researchers studying geochemical characteristics for pre-salt Paleozoic of the northern Pre-Caspian margin, indicate a significant organic matter (OM) content in Middle Devonian and Lower Carboniferous formations. In those accumulations, average OM content in terrigenous rocks varies from 0.8% to 1.0% per rock. Mainly OM is sapropelic-humic type; in carbonates it does not usually exceed - 0.3%, OM is sapropelic type chiefly. Content of Chloroform bitumen varies from 0.005% to 0.035% and alcohol- benzol bitumen from 1.2% to 1.5%. Such a composition is characteristic of source rocks.

In the Early Mesozoic, D2-Cl Sediments enriched with organic matter were submerged at depths with optimum temperature and high pressure conditions corresponding to MK3, MK4 katagenesis stages which promoted the maturation of organic matter. In the northern Pre-Caspian margin, submergence depth at the top is between 3 km and 6 km and between 4 km to 6.5 km at the bottom.

Present depths of the lower boundary of katagenesis zones in the regions with different temperatures for the Pre-Caspian Basin are shown in the Table below:

	KATAGENESIS STAGES			
	MK1; MK2 R0=0.5-0.8	MK2; Mk3 R0=0.8-l.l	MK3; MK4 R0=l. 1-1.5	MK4; MK5 R0=1.5-2.0
SUBSURFACE TEMPERATURE °C				
Low (40-70°C)	3.0 km	5.5 km	7.5 km	10.5 km
Average (70-90°C)	2.0 km	4.0 km	6.0 km	9.0 km
High(90-110°C)	1.0 km	2.5 km	4.5 km	7.5 km

Table 1: Katagenesis Stages

In the Pre-Caspian margins, including the northern margin with the Chinarevskoye protrusion, temperatures of 94-113°C enabled the maturation and generation of hydrocarbons.

The Middle Devonian and Lower Carboniferous source rocks generated hydrocarbons during and after the accumulation of Kungurian evaporites.

In the northern area of the present Pre-Caspian Basin, the pre-salt accumulations are characterized by a low thermal field on average of 90-100°C at a depth of 5 km. Low values are also characteristic of paleotemperatures. For the most part of the northern margin the paleotemperature does not exceed 110°C at a depth of 5 km (i.e., difference between the present temperature and paleotemperature is 10-20°C. As a result, the katagenesis zone (R0 is up to 1.2) occurs in a wide depth range from 2.5 km to 8-8.5 km.

Anomalism coefficient 1.1-1.2 is characteristic for the layer pressure. Thus, in the Chinarevskoye field the layer pressure is 59 MPa at a depth of 5.1 km.

Burial depth of Middle Devonian Biski, Afoninski gas-condensate and Tournaisian oil gas condensate formations in the Chinarevskoye field in productive wells 4 and 10 is respectively: 5,060 m, 5,017 m; 4,796 m, 4,852 m; 4,257 m, 4,275 m. Layer pressures - 593 atm Biski, 580 atm Afoninski, 491 atm Tournaisian, layer temperatures - 113°C Biski, 105-110°C Afoninski, 94°C (Qt).

Migration

Hydrocarbon migration from Middle Devonian and Lower Carboniferous source rocks took place from deeper submerged zones of the Pre-Caspian Basin. Conducting channels (non-consolidation, fractures, etc.) were the most probable hydrocarbon migration paths from the source rocks. Through these channels hydrocarbons migrate upwards and fill the reservoirs in the traps in their path. As the tectonic activity decreases, hydrocarbon conducting channels close and seal up the accumulations.

Even though the Chinarevskoye high is located in a separation zone of the Pre-Caspian and Buzuluk depressions, this does not exclude hydrocarbon migration from submerged areas of the Buzuluk depression. Possible evidence of this is that Tournaisian accumulation oil extracted from well 106 in the Dolinnaya area, is similar in composition to Chinarevskoye oil.

Basic Information on Chinarevskoye field

Reservoirs and hydrocarbon Presence

The Chinarevskoye field is a multi-formation structure. It has tested hydrocarbons at significant rates from:

1. **Lower Permian Fillipovski** horizons at 2,700 to 2,900 m, are limestones and dolomitic limestones.
2. **Lower Permian Artinski-Asselski** horizons at 3,100-3,500m, are carbonates with terrigenous interlayers and cherts
3. **Upper Carboniferous-Bashkirian** horizon at 3,600-3,700m, are limestones and dolomitic limestones
4. **Lower Carboniferous Tournaisian** formation at about 4,200 m depth is a limestone with a gross thickness of about 200 m.
5. **Middle Devonian Givetian** (Mullinski, Ardatovski and Vorobyovski) horizons at about 5,000 m depth, are sandstones with carbonate cements.

6. **Middle Devonian Biski and Afoninski** formations at a depth of approximately 5,000 m with a gross thickness of 200 m are limestones and dolomitic limestones.

So far, the following accumulations have been mapped.

- Tournaisian North (consist of 4 independent reservoirs T1gas, T1oil, T2oil and T3oil)
- Tournaisian South (T1gas, T2oil)
- Bashkirian Northeast, West and South
- Biski Afoninski North (consisting of 2 independent reservoirs D2af and D2bs)
- Biski Afoninski West (consisting of 2 independent reservoirs D2af and D2bs)
- Mullinski South
- Mullinski Northeast
- Ardatovski Northeast and South

Hydrocarbons have been tested by cased and/or open-hole tests in five stratigraphic units:

- Permian Artinski-Asselski horizons
- Permian Fillipovski horizon
- Devonian Vorobyovski horizon
- Devonian Famennian horizon
- Carboniferous Radaevski horizon

The following potential reservoirs have been identified:

- Devonian Pashiski horizon
- Devonian Chernoyarski horizon

Seals

The seal for the Lower Permian reservoirs are anhydrites, argillites and tight carbonate rocks. In the Lower Carboniferous Tournaisian reservoir tight carbonates are locally sealed. The vertical seals for the Middle Devonian Givetian reservoirs are claystones and argillites which belong to different stratigraphic units depending on the Frasnian unconformity. The seal for the Biski-Afoninksi formations are Chernoyarski claystones and argillites. They represent a regional seal. A carbonaceous claystone exists between the Biski and Afoninski horizons which could be a local seal.

Source rock

The main source rocks are the Chernoyarski claystones. They are represented by deep-marine sediments which contain a Type II kerogen. Directly below the Frasnian unconformity lie the Pashiyski und Kynovski claystones and argillites which were accumulated in former sedimentation troughs and could be present in the Chinarevskoye field area. These rocks also have a good generation potential. Another possible source rock of the Lower Carboniferous and Upper Famennian are the carbonaceous mudstones of the Domanikovskaya formation which occur north of the Chinarevskoye area in the Buzuluk depression.

Seismic Control—mapping of accumulations and prospects

The Chinarevskoye license area is covered by approximately 400 kilometers of 2-D seismic lines and by a 462 km2 3-D seismic survey Figure 6). There are two primary sets of 2-D seismic data comprising a total of 41 lines. One survey was acquired during 1985 and 1986, and a second survey was conducted in 1989 through 1991. The lines are on a 1 by 1.8 kilometer grid with dip lines running north-northeast to south-southwest and strike lines running west-northwest to east- southeast. Seismic coverage density is 1.33 kilometers per km^2. The 2-D seismic data was reprocessed, and data quality is fair to very good.

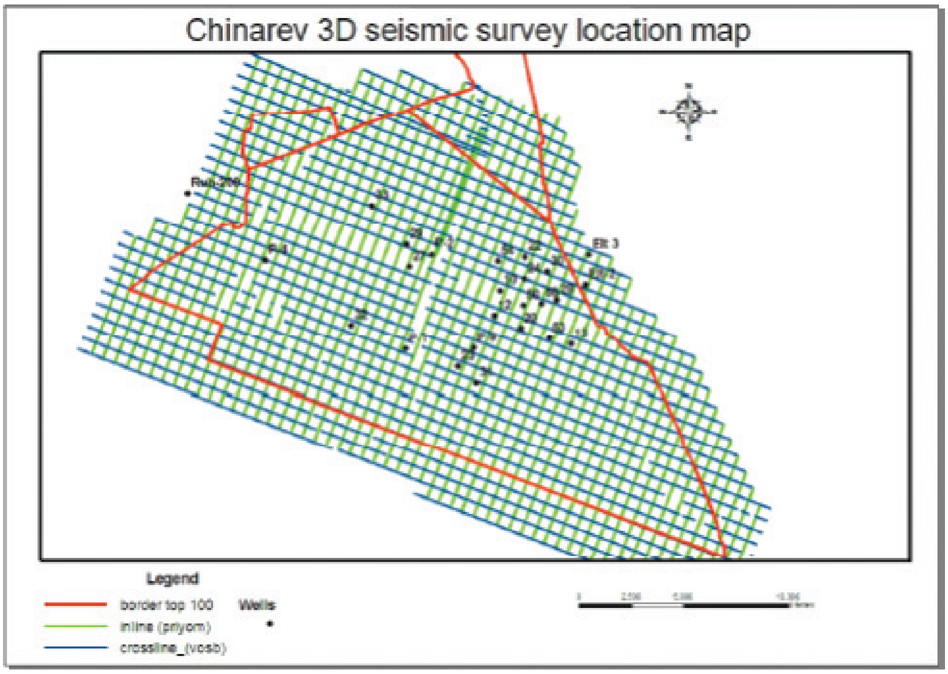


Figure 6: Chinarevskoye 3-D Seismic Survey Location Map

The 3-D seismic survey was acquired and processed by GEOTEX in 1998, and the data quality is very good. The major mapping horizons are easily correlated, and faults are well defined

Teknica Overseas Ltd. completed a first interpretation of the 3-D seismic survey in year 1999. This interpretation was reviewed in 2003 by Netherland Sewell Associates Int. (NSAI) for their independent reserves report[3] and extended the structural mapping for volumetric calculations to the Biski and Afoninski formations.

NSAI conducted inversion processing on a 100 km^2 area of the eastern portion of the 3-D seismic data and a resulting acoustic impedance volume was converted to depth using the velocity field output by the inversion. The inversion volume was used to construct a net pay isopach map of the Tournaisian interval. The Tournaisian net pay thickness map and the structure maps of Biski and Afoninski were later used by Ryder Scott for the reserves estimations in 2004 and 2006. In 2004 and 2005 several geological and geophysical studies were carried out by different companies (KaspiMunaiGaz, NIPIneftegaz, OilGeoconsulting and Tamko). The first structure maps for the Givetian reservoir horizons were created (OilGeoconsulting) which were used for the first reserves estimation of the Givetian. These maps were also used by Ryder Scott for their 2006 reserves estimates.

In 2006 a reprocessing and re-interpretation of the 3D seismic was carried out at the PGS-GIS Geophysical Services Center and AGR Petroleum (former RES) both located in Almaty. Sophisticated processing and interpretation techniques enabled an accurate time domain mapping of the reservoirs below the Kungurian salt. The final report, including new geological maps for all reservoirs, was received in May, 2007. The mapping was reviewed by Ryder Scott and the maps were used for our Competent Persons Report (CPR) 2007.

3 *NSA report 2003:* Estimate of reserves and future revenues to the Zhaikmunai LLP interest in certain oil and gas properties located in Chinarevskoye field Republic of Kazakhstan as of September 30, 2003; Netherland, Sewell and Associated, Inc (NSA)

The Figure below demonstrates data quality and structural style of the reprocessed 3D seismic survey.

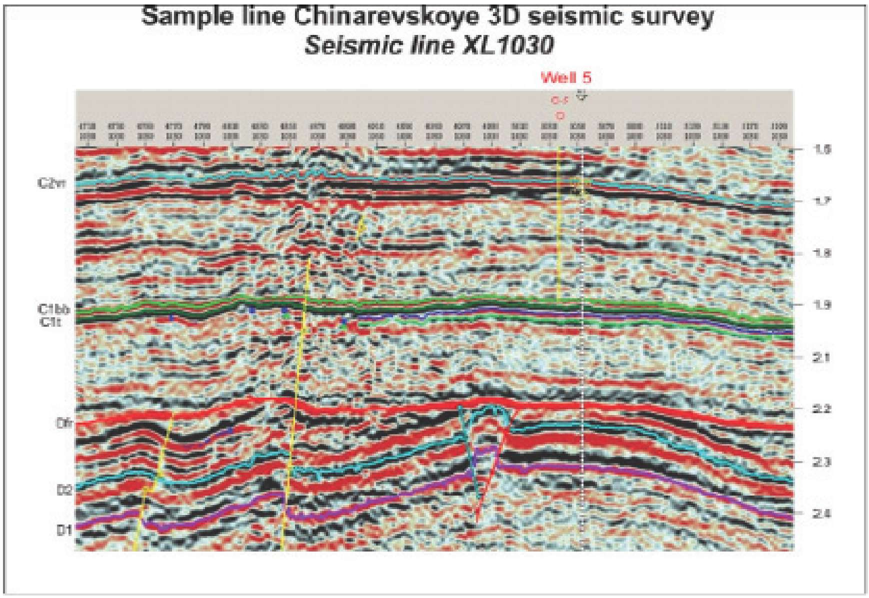


Figure 7: Sample Line Chinarevskoye- 3-D Seismic

However, the depth mapping below the Frasnian unconformity, based on this work, required improvement. Therefore, a new velocity cube was created by AGR in 2008 and after pre-stack depth migration the new depths maps for the Middle Devonian horizons were of much better quality (Figure 8). These maps were reviewed by Ryder Scott and used for the in-place volume calculations for the 2008 reserves estimates. Since then the maps have been updated on a yearly basis by taking into account the results of the drilled wells. The maps used for this report are from Reservoir Evaluation Services Ltd (RES) 2012 update.

A seismic re-processing was carried out by RES in 2013 which resulted in a new pre-stack time migration cube. Based on the re-processing and on the new wells, a new velocity model is being developed followed by a time depths conversion which should enable a more accurate mapping of the faults and the compartmentalization of the reservoir. The interpretation of the re-processed seismic should be finalized in March 2014. Zhaikmunai expects that the new interpretation will not only provide a more precise structural model of the reservoirs, but also help to clarify the distribution of the terrigenous Devonian reservoirs.

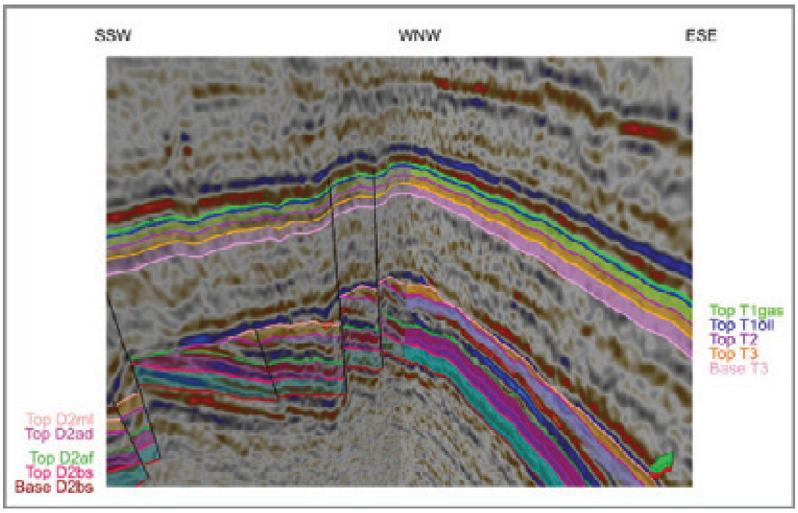


Figure 8: Seismic Section Through Tournaisian and Devonian Reservoirs

As of August 31, 2013 the following reservoirs were mapped within the Chinarevskoye license area:

Lower Carboniferous Tournaisian stage-4 reservoir horizons (T1gas, T1 oil, T2 and T3).

Middle Devonian Givetian stage-2 formations (D2ml—Mullinski, D2ad—Ardatovski).

Middle Devonian Eifelian stage-2 formations (D2af-Afoninski, D2bs- Biski).

Lower Permian—2 formations (P1ar-as—Artinski-Asselski, P1fl—Fillipovski).

For these accumulations structure maps, thickness, net thickness and net pay thickness maps have been created by RES, Almaty.

Tournaisian reservoir:

- Northern accumulation—4 reservoir horizons T1gas, T1 oil, T2 and T3
- Southern accumulation—3 reservoir horizons T1, T2 and T3

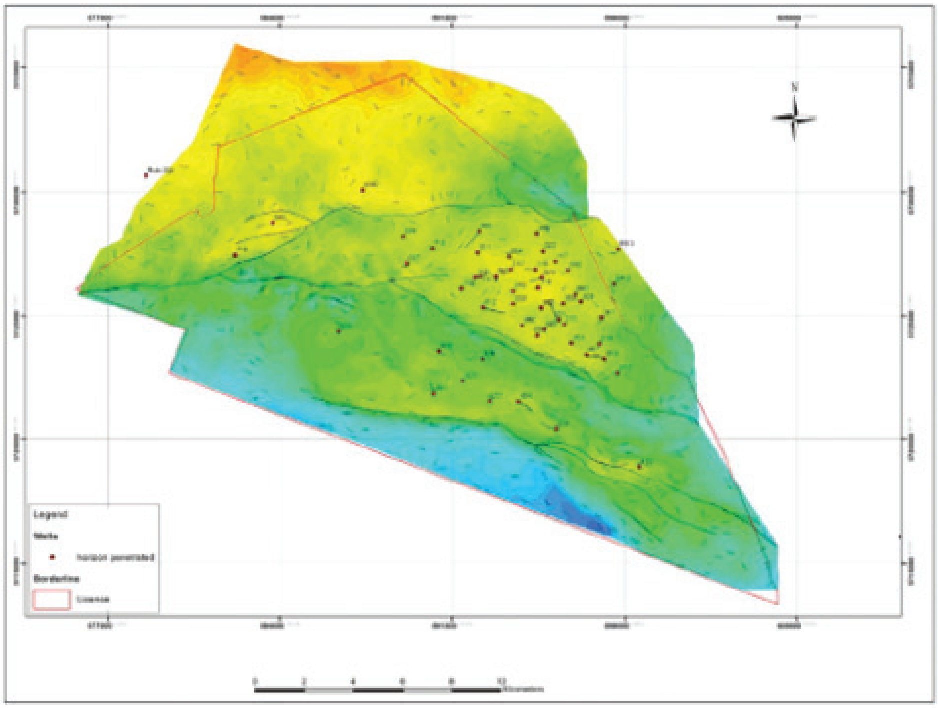


Figure 9: Tournaisian T1gas Structure Map

- Tournaisian North: The horizon T1 consists of two hydrodynamically independent reservoirs. The upper reservoir T1 gas is gas condensate bearing. It overlays the oil bearing reservoir T1 oil
- Tournaisian South: (Area exploration wells 23, 31, 32 & P9). The T1 horizon consists of a single gas condensate bearing reservoir, T1gas.

Biski and Afoninski reservoirs:

- Biski/Afoninski Northeast Area (Well 10 and Well 20)
- Biski/Afoninski West Area (Well 4 and Well 33)

Well 4 successfully tested the Biski in the western upthrown fault block, which was also confirmed by the appraisal well 33. Both wells tested gas condensate both in the Biski and the Afoninski in the western area. Well 45 also proved hydrocarbon bearing of this reservoir horizon.

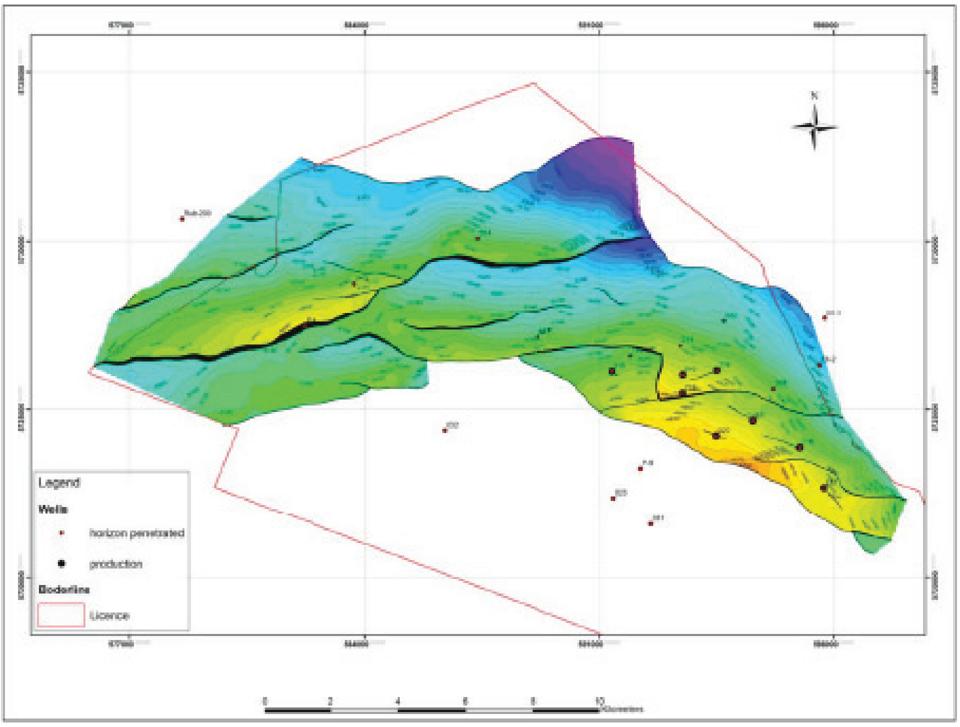


Figure 10: Biski Structure Map

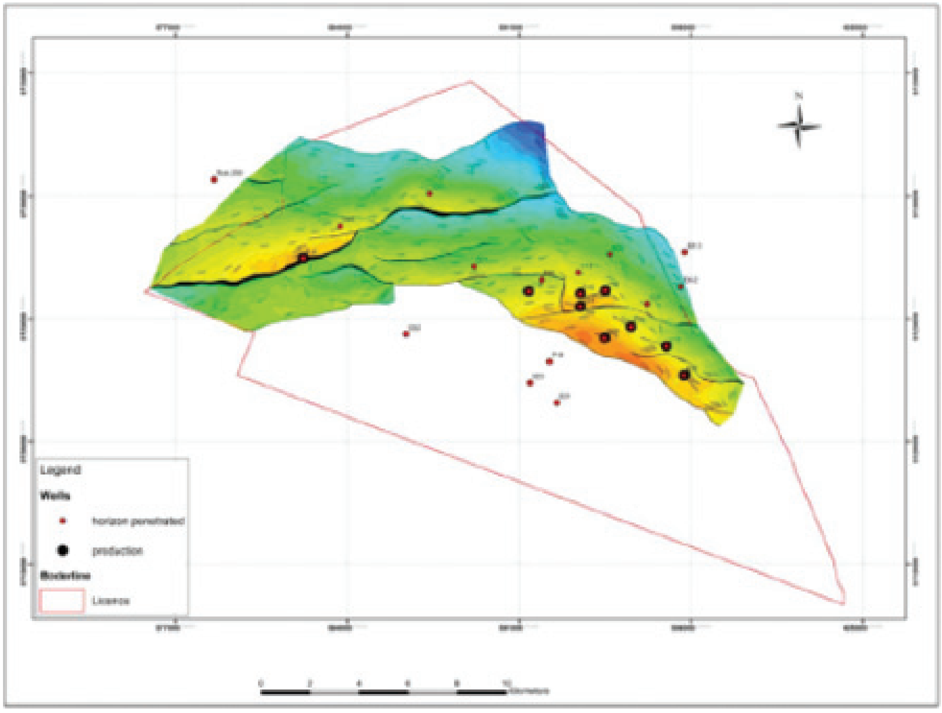


Figure 11: Afoninski Structure Map

Givetian reservoir:

Mullinski horizon

- Area Givetian Mullinski West
- Area Givetian Mullinski Northeast
- Area Givetian Mullinski South

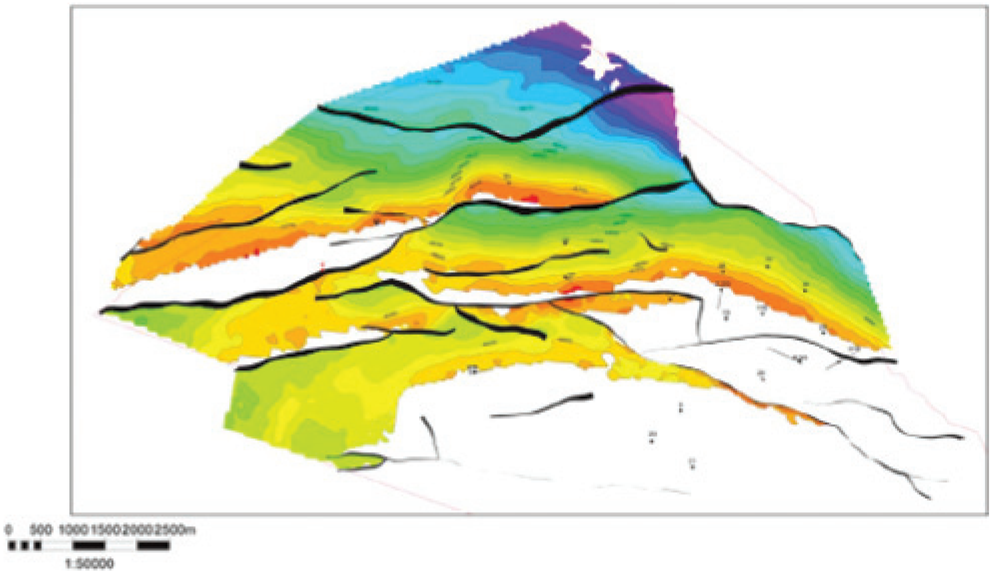


Figure 12: Structure Map Givetian Mullinski Reservoir

- Mullinski West: Based on the results of appraisal wells 33 and 45 only contingent resources have been assigned to the reservoir.
- Mullinski NE: Well 54 tested oil in this reservoir and extended the discovery made by well 22. Production test results show that stable production rates of 80 m^3/d of oil can be reached when using an appropriate choke size. A dynamic modeling study for Chinarevskoye gas condensate horizons[4], conducted by Schlumberger in 2008, has indicated that the production rates from vertical wells can be significantly increased by the use of horizontal wells. Well 57 was side tracked and deviated into Mullinski horizon. Unfortunately, the drilling technology used was not successful which led to a reservoir damage. Therefore, a new technological appraisal well will be drilled in 2016.
- Mullinski South: The Mullinski South was tested by well 32 in May 2008. A commingled PLT of the Givetian Vorobyovski and Ardatovski/Mullinski horizons was conducted on May 22, 2008. This PLT showed that the light oil inflow of 145 m3/day came from the Mullinski/Ardatovski interval.

Ardatovski horizon

- Area Ardatovski West
- Area well Ardatovski Northeast
- Ardatovski South

4 Chinarevskoye Field, Compositional Simulation Study, Republic of Kazakhstan, Data & Consulting Services, Almaty, Republic of Kazakhstan

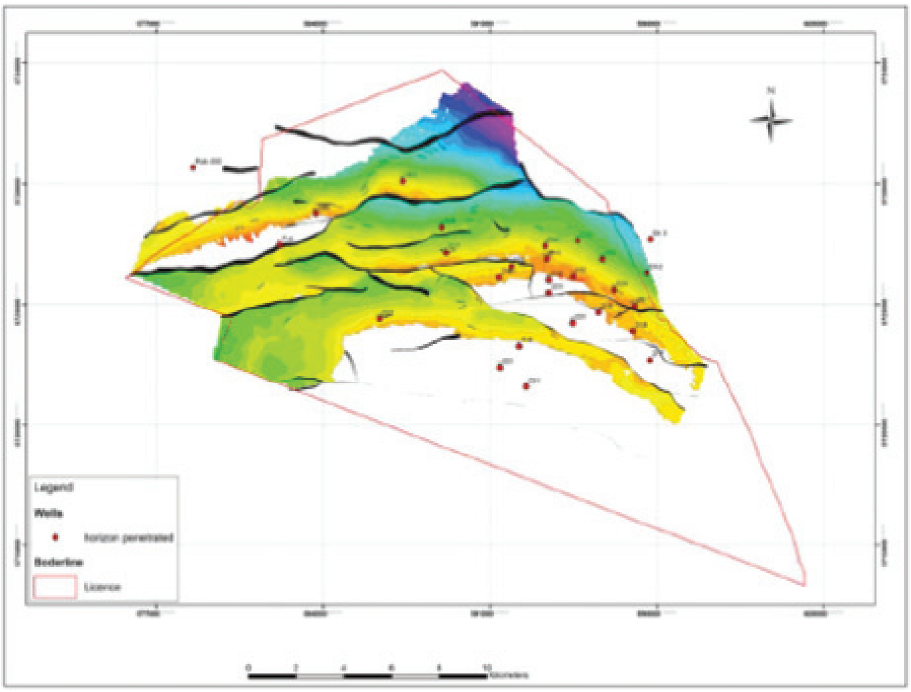


Figure 13 Structure Map Givetian Ardatovski Reservoir

- Ardatovski West: was downgraded to resources based on the casing test results of well 33, where PLT showed water inflow from the lower part of this horizon.
- Ardatovski NE: was discovered in 2006 by well 28. A long term production test was carried out and there was practically no decline in the gas production during this test period. It has been in commercial production since May 2011. Currently, the wells 28, 213 and 115 are producing from this area.
- Ardatovski South: The Ardatovski South was tested in a commingled Givetian DST test in well 32 in May 2008. Originally, it was assumed that inflow came from the Mullinski part of the reservoir, while log re-interpretation showed that the inflow came mainly from the Ardatovski horizon (see also Mullinski South).

Characteristics of Hydrocarbons

Tournaisian oil horizons: Under surface conditions the average oil density is 822 kg/m^3, the sulphur content is 0.01%, mercaptans are 0.015%. The GOR for the horizon T2 and T3 is 130 m^3/m^3 and for horizon T1 oil it ranges between 170-190 m^3/m^3. The average content of methane from separator gas is 60.99%, ethane - 18.14%, propane - 10.3%, butane - 3.55%, C5+ - 1.53%. The H2S content is 1.1 mol%.

Tournaisian gas condensate horizons: The fluid characteristics come from a PVT analysis of the gas condensate of well 23. The content of methane in the reservoir fluid is 67.56%, ethane - 11.48%, propane - 4.53%, butane - 2.56%, pentane + higher - 10.86%. Content of acid components in gas are: carbon dioxide - 0.73%, hydrogen sulphide - 0.15%, nitrogen - 2.11%. The density of stable condensate is 774.7 kg/m3. The condensate yield is 659 g/m^3.

Ardatovski horizon: The fluid characteristics come from a PVT analysis of the gas condensate from well 28 with perforations at 4,864-4,873 m. The content of methane in the reservoir fluid is 80.48%, ethane - 7.74%, propane - 3.34%, butane - 1.34%, pentane + higher - 5.57%. Content of acid components in the gas are: carbon dioxide - 1.11%, hydrogen sulphide - 0.00%, nitrogen - 0.37%. The density of stable condensate is 754.6 kg/m3. The condensate yield is 300 g/m^3.

Mullinski horizon: The fluid characteristics come from a PVT analysis of the gas condensate of well 22. The content of methane in the reservoir fluid is 58.26%, ethane - 14.58%, propane - 7.39%, butane - 3.72%, pentane + higher - 14.05%. Content of acid components in gas are: carbon dioxide - 1.66%, hydrogen sulphide - 0.00%, nitrogen - 0.34%. The density of stable liquid phase is 775.1 kg/m^3. The condensate yield is 898 g/m^3.

Biski and Afoninski horizons: The fluid characteristics of the Biski and the Afoninski horizons vary slightly. This is because of the 400 m hydrocarbon column height. Since the produced gas condensate will be from both the Biski and the Afoninski reservoirs in a commingled stream, the following fluid characteristics are given as an average for both horizons. They come from a PVT analysis of a commingled stream from well 20. The content of methane in the reservoir fluid is 64.38%, ethane - 14.43%, propane - 4.72%, butane - 2.17%, pentane + higher - 11.64%. Content of acid components in the gas are: carbon dioxide - 1.60%, hydrogen sulphide - 0.00%, nitrogen - 1.00%. The density of stable condensate is 760 kg/m3. The condensate yield is 681 g/m3.

Bashkirian oil horizons: After standard separation the oil density is 794 kg/m3, the sulphur content is 0.4%, paraffin is 4.81%. The GOR is 167 m^3/m^3. The average content of methane from separator gas is 49.9%, ethane - 13.9%, propane/butane - 20.6%, C5+ - 8.2%. The H_2S content is 1.1 mol%.

Drilling History

A total of 56 exploration and production/injection wells have been drilled in the Chinarevskoye field. At end of August 2013, 29 are producing, 3 are injectors, 5 are drilling, 8 are on test or awaiting decisions, 3 are suspended and 2 wells are abandoned. All 6 wells drilled during the Soviet era have been plugged and abandoned, including the discovery well 4.

In well 4, hydrocarbons were discovered in the Middle Devonian Eifelian stage in the Afoninski formation in 1991. The discovery of the Lower Carboniferous Tournaisian reservoir was in 1992 in well 10. This well also successfully tested the Middle Devonian Eifelian stage Afoninski and Biski formations. In 2003, well 22 discovered the Middle Devonian Givetian stage Mullinski reservoir. In 2004, well 20 successfully tested the Lower Permian reservoir. The Middle Devonian Givetian stage Ardatovski reservoir was successfully tested in well 28 in 2006. In 2007, well 54 found oil in the Middle Carboniferous Bashkirian formation. In May 2008 this interval was tested by an open hole test in well 51. A successful casing test was carried out in well 31 in the Upper Devonian Famennian reservoir in the southern area. Well 33 successfully tested the Biski/Afoninski and the Tournaisian in the western area and well 32 tested the Mullinski reservoir in the southern area. Well 115 tested gas condensate in the Middle Devonian Givetian stage Vorobyovski horizon.

In the Northern part of the field (Northeast or Central areas) 4 wells were drilled before the license contract period (5, 10, 12 and 13). Three of these wells (10, 12, and 13) were later reactivated. Wells 12 and 13 were deepened by directional drilling into the main Tournaisian reservoir and 3 wells were drilled thereafter: 20, 22 and 24 during the first exploration period. Appraisal wells 28, 29, 30 and 27 were drilled in 2006/07. Wells 28 and 30 are currently producing from the Tournaisian, well 27 will test the Biski/Afoninski reservoir tested after workover. Wells 50, 51, 52, 54, 56, 62 and 115 have been finalized as production wells and further production wells will be drilled back to back over the coming years. Well 115 will be converted to an injection well in 2010. The Tournaisian production well 53 was recompleted as an injector in December 2008. A third injection well—well 121 was drilled in 2008 and is currently awaiting workover. Two other injection wells of the development plan, well 61 and 57 had already been drilled in the 1st half of 2008. However, the injection tests in well 61 have not been successful to date because of various geological and technical issues.

Outside the Northern accumulation a total of 5 wells (P1, P2, P9, 4 and 7) were drilled during the Soviet era. All of them were plugged and abandoned because of technical or geological issues. Included in this group is well 4, the "discovery well" of the Chinarevskoye field.

In the Southern block, appraisal well 23 was drilled in 2005 and successfully tested gas condensate in the Tournaisian T1 in February 2006 and oil in May 2007 in the T2. Two appraisal wells, well 31 and 32 were drilled and tested in 2007-2008. Well 32 had a non-commercial inflow from the Tournaisian T1 reservoir, but successfully tested the Middle Devonian Mullinski/Ardatovski reservoir. Well 31 successfully tested the Tournaisian and discovered a gas condensate accumulation in the Devonian Famennian reservoirs. In 2012, it tested successfully the Carboniferous Bobrikovski reservoir. During 2011-2013 wells 401, 402, 404, 406, 407 and outstep well 410 were drilled.

In the Western block, exploration well 33 was drilled in 2007-2008. The well successfully tested the Biski/Afoninski in this part of the Chinarevskoye field and is now producing from in the Tournaisian reservoir. Well 45 was drilled as an appraisal well in this block in 2011. Tests were carried out in 6 stratigraphic units. Commercial inflow was obtained from the Bashkirian horizon.

As of August 2013, a total of 56 wells had been drilled. Currently, 5 wells are drilling (223, 208, 402, 59, 60). Six wells are plugged & abandoned (P-1, P-2, P-9, 4, 5, 7). Twenty nine are producing (oil wells 10, 22, 54, 51, 52, 62, 65, 63, 56, 30, 115-B, 116, 67, 33, 24-B, 57, gas condensate wells 23, 401, 404, 406, 28, 115, 213, 119, 215, 20, 218, 217, 216).

An overview of the exploration and production wells drilled in the Chinarevskoye block is shown in Figure 14 below.

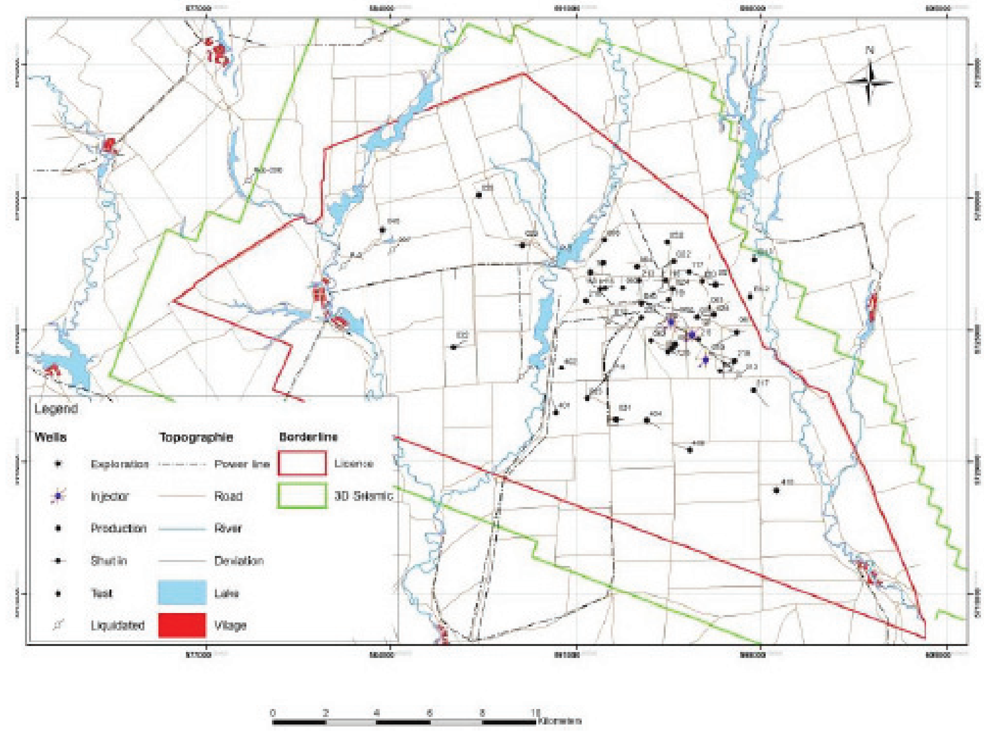


Figure 14: Chinarevskoye Well Location Map and Well Status as of August 2013

Production History

In the Northern area, 16 wells are currently producing from the Tournaisian reservoir. The first production was in 2000 from well 10.

By August 31, 2013, a total of 3,500,438 tons of oil (about 8.47 million barrels of oil) has been produced from this area (see Table 2 and Figure 15). The highest production from the Tournaisian is achieved after an acid treatment. Acid treatments have become a standard procedure for well stimulation and production increases. A comprehensive work over program was carried out in 2006- 2007 to increase oil production from the old wells and to reduce the gas production from these wells. The installation of double packers to isolate the gas condensate horizon T1gas from the oil horizons and to enable use of gas lift for oil production has become a standard procedure for the Tournaisian Northeast reservoir.

Table 2: Chinarevskoye Crude Oil Production 2000-2013 (in metric tons)

	2000	2001	2002	2003	2004	2005	2006
Month/year							
January	0	3,104	4,945	6,249	11,402	10,566	9,270
February	0	2,570	4,331	6,964	10,172	8,133	9,586
March	0	3,623	4,839	8,647	9,903	8,812	8,852
April	0	3,626	6,462	6,155	10,141	8,706	8,971
May	0	4,235	7,818	6,379	10,081	8,697	8,491
June	0	4,589	7,378	6,211	9,175	9,279	9,142
July	0	4,529	7,258	13,458	8,857	9,415	12,498
August	0	4,505	6,738	15,133	9,299	8,195	12,067
September	3,394	4,281	6,322	13,383	8,639	8,687	13,837
October	3,517	4,302	6,851	14,554	8,889	8,823	14,964
November	3,311	4,448	6,436	10,748	8,256	8,932	14,752
December	3,252	4,918	5,814	11,805	10,634	9,421	16,267
Total	**13,473**	**48,730**	**75,194**	**119,686**	**115,447**	**107,665**	**138,698**

	2007	2008	2009	2010	2011	2012	2013
Month/year							
January	18,300	18,925	28,083	31,594	30,982	53,025	69,471
February	16,047	18,770	27,276	26,414	21,182	49,695	70,496
March	18,941	21,255	32,014	26,939	24,587	56,700	78,171
April	19,123	20,669	28,882	25,225	34,506	55,410	72,692
May	16,687	17,911	27,796	30,146	32,512	56,811	74,265
June	17,956	16,828	26,629	29,409	35,481	58,962	72,926
July	18,564	15,811	27,261	40,593	34,522	69,512	72,014
August	21,171	26,312	28,231	31,750	32,792	65,556	75,388
September	20,629	26,406	27,290	31,955	36,504	61,856	0
October	18,108	28,300	32,435	27,586	36,054	58,028	0
November	21,389	19,054	28,406	31,749	41,205	67,320	0
December	22,184	11,921	29,749	28,483	40,593	65,171	0
Total	**229,099**	**242,162**	**344,052**	**361,844**	**400,921**	**718,045**	**585,422**
Grand Total				**3,500,438**			

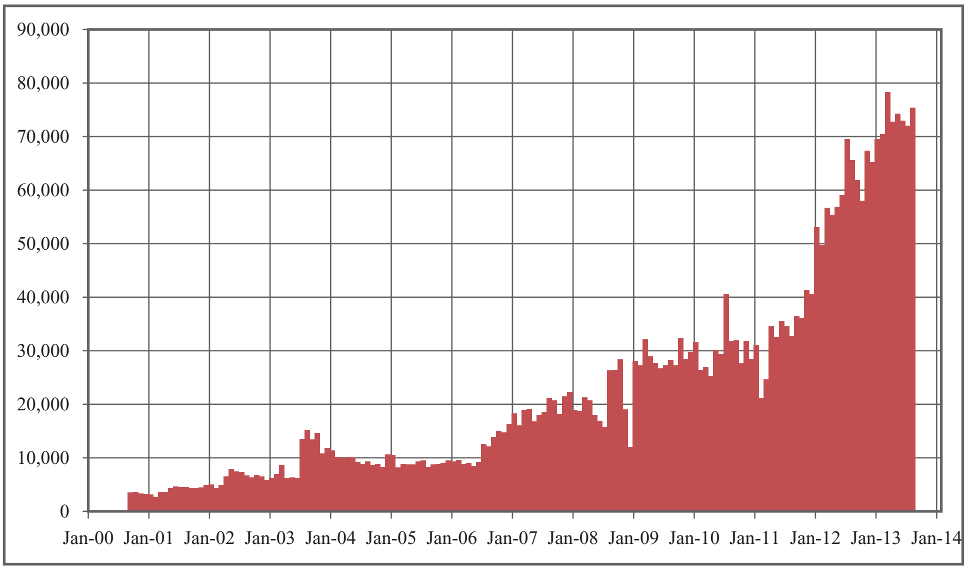


Figure 15: Chinarevskoye Oil Production (in metric tons per month)

Nearly all associated gas and non-associated gas produced by the oil and gas condensate wells has been utilized since Gas Treatment Facility started operations in May 2011.

Six drilling rigs are currently in the field, 1 UNGG, 2 Saipem rigs, 2 Xibo and 1 Sun drilling rig.

General Assumptions

The production profiles cover the full license period until December 31, 2032 for all accumulations except the Tournaisian North where production phase ends as of December 31, 2031. Oil production comes from Tournaisian North, Bashkirian and Permian wells. Gas production is currently obtained from Tournaisian South, Ardatovski North, Biski & Afoninski Northeast wells. Production from Mullinski will start in 2016. The third train will be commissioned in July 2016. Tournaisian water injection project will be continued. In addition to the 3 existing injection wells, 3 new injectors will be drilled and one production well shall be converted to injector in 2017.

For the oil accumulations the LPG and the condensate volumes were calculated based on the composition of the separator gas and the gas from oil degassing. For the gas-condensate accumulations the LPG and condensate volumes were calculated from the gas composition of the gas produced, taking into account the changes in the composition due to the pressure decline of the reservoir.

Specific Assumptions for Production Profile Modeling

Tournaisian North

- Type of reservoir: carbonates with vuggy and intracrystalline porosity
- Number of layers: 4 independent reservoirs, T1g, T1o, T2 and T3
- The upper layer T1g is a gas condensate layer, the three reservoirs below are oil reservoirs
- Development type: Oil production with initial artificial gas lift by perforation T1g reservoir, water injection since 2009.
- Total wells: 38, including 1 highly deviated well, three existing injectors, three new injectors and one converted production well are planned to be used as injectors. Not more than 27 wells will be producing simultaneously from the reservoirs.
- A Secondary to Primary recovery is assumed to be 1:1 based on analogous waterflood performance of fields with similar reservoir properties located in the Permian Basin, West Texas, United States.
- See Figures 16 and 17 and Table 3

Tournaisian South

- Type of reservoir: carbonates with vuggy and intracrystalline porosity
- Number of layers: 3 independent reservoirs, T1, T2 and T3
- The upper layer T1 is a gas condensate layer, the T2 reservoir below is and oil reservoir, reservoir T3 has not been tested yet
- Development type: Production planned only from the T1 gas condensate layer: Total production wells: 10 vertical wells, Maximum 8 wells are producing simultaneously from this reservoir

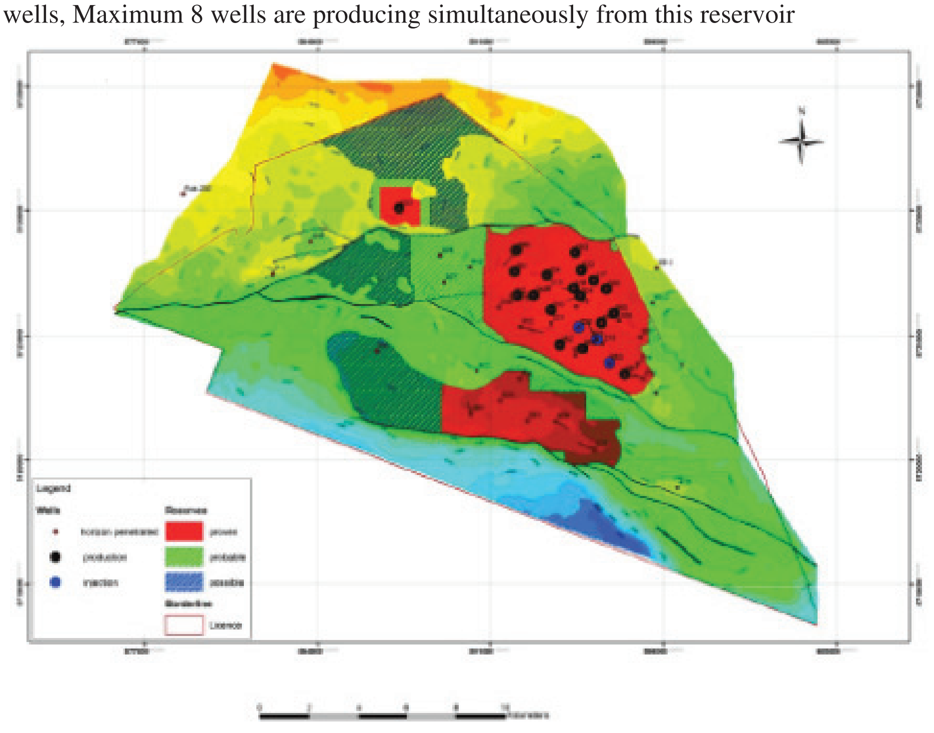


Figure 16: Reserves and Well Location Map Tournaisian T1 Gas Reservoir

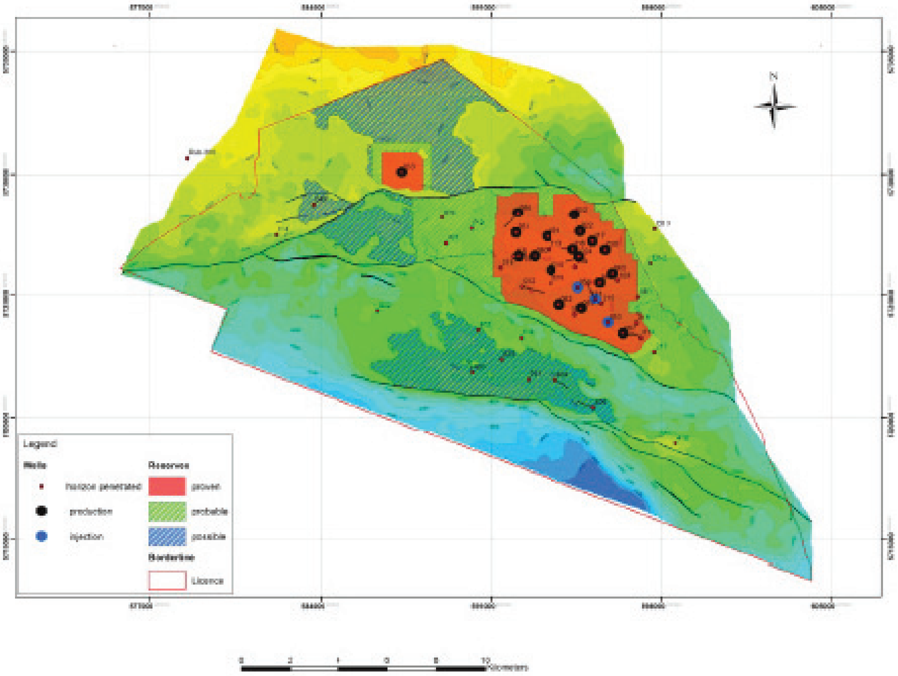


Figure 17: Reserves and Well Location Map Tournaisian T1 Oil Reservoir

Table 3: Reservoir Parameters Tournaisian Reservoirs

Fractiles **Layer**	**Parameter**	**Unit**	**P90**	**P50**	**P10**	**Average**
T1 gas	N/G		0.632	0.697	0.752	0.696
	Phi	%	4.28	4.97	5.61	5.22
	GThk	m	12.6	13.2	13.8	13.2
	NThk	m	8.3	9.0	10.0	9.1
T1 oil	N/G		0.455	0.528	0.603	0.525
	Phi	%	3.24	3.58	3.96	3.60
	GThk	m	36.4	37.1	37.8	37.1
	NThk	m	16.0	18.2	21.0	18.3
T2	N/G		0.446	0.499	0.561	14.904
	Phi	%	3.85	4.41	4.97	4.65
	GThk	m	33.1	33.8	34.5	33.8
	NThk	m	14.9	17.0	19.6	17.2
T3	N/G		0.314	0.499	0.561	0.501
	Phi	%	2.72	2.98	3.25	3.13
	GThk	m	49.0	50.6	51.8	50.5
	NThk	m	16.9	20.8	24.8	20.8

Biski & Afoninski

- Type of reservoir: carbonates with vuggy and intracrystalline porosity
- Number of layers: 2 independent reservoirs, Afoninski and Biski
- Both reservoirs are gas condensate layers
- Total wells: 28 horizontal wells (horizontal section= 950m), 14 of which will be drilled in the Northern area and 14 in the Western area
- See Figure 18 and 19 and Table 4

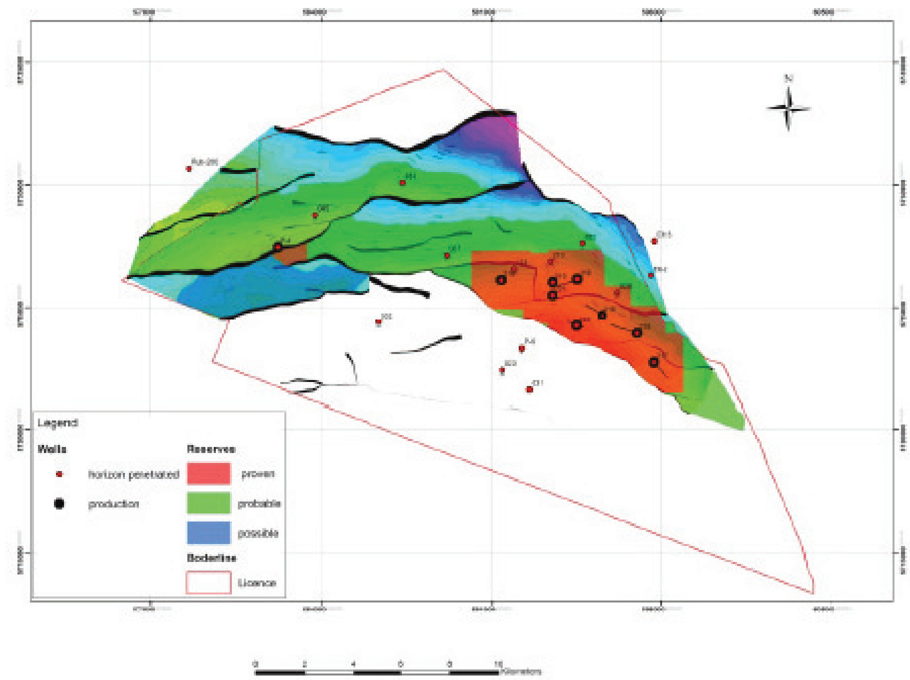


Figure 18: Reserves Status Map Middle Devonian Afoninski Horizon

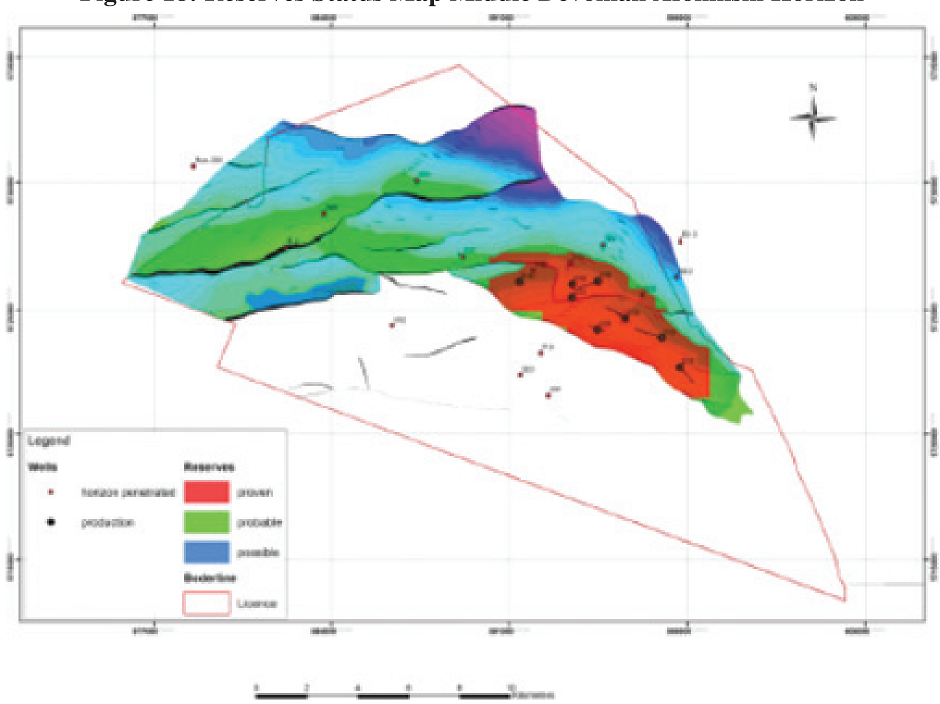


Figure 19: Reserves Status Map Middle Devonian Biski Horizon

Table 4: Reservoir Parameters Biski and Afoninski

Fractiles Layer	Parameter	Unit	P90	P50	P10	Average
Biski 1	N/G					
	Phi	%	4.25	4.44	4.25	0.00
	GThk	m	21.6	22.6	21.6	0.0
	NThk	m	9.2	11.0	9.2	0.0
Biski 2	N/G		0.399	0.479	0.401	0.000
	Phi	%	4.66	5.15	4.65	0.00
	GThk	m	25.5	26.7	25.6	0.0
	NThk	m	10.1	11.9	10.2	0.0
Biski 3	N/G		0.301	0.369	0.300	7.827
	Phi	%	4.19	4.65	4.19	0.00
	GThk	m	24.4	25.3	24.5	0.0
	NThk	m	7.8	9.3	7.8	0.0
Biski 4	N/G		0.341	0.415	0.342	0.000
	Phi	%	4.50	4.80	4.49	0.00
	GThk	m	20.7	21.7	20.7	0.0
	NThk	m	6.2	7.4	6.2	0.0
Biski 5	N/G		0.341	0.415	0.342	0.000
	Phi	%	4.93	5.64	4.94	0.00
	GThk	m	14.4	15.2	14.4	0.0
	NThk	m	3.9	4.9	3.9	0.0
Afoninski 1	N/G		0.385	0.445	0.523	0.451
	Phi	%	5.60	5.97	6.24	5.94
	GThk	m	22.6	23.4	24.3	23.4
	NThk	m	8.8	10.3	11.9	10.3
Afoninski 2	N/G		0.045	0.056	0.065	0.056
	Phi	%	4.86	5.01	5.23	5.03
	GThk	m	24.5	25.6	26.7	25.6
	NThk	m	1.2	1.4	1.7	1.4
Afoninski 3	N/G		0.128	0.056	0.065	4.321
	Phi	%	5.60	6.00	6.27	5.98
	GThk	m	33.3	34.7	36.3	34.8
	NThk	m	4.3	5.4	6.5	5.4
Afoninski 4	N/G		0.332	0.386	0.445	0.389
	Phi	%	7.63	8.18	8.72	8.16
	GThk	m	17.1	17.5	18.0	17.6
	NThk	m	5.8	6.8	7.8	6.8
Afoninski 5	N/G		0.334	0.404	0.480	0.405
	Phi	%	3.83	4.38	4.97	4.60
	GThk	m	20.5	21.3	22.1	21.3
	NThk	m	6.9	8.9	10.8	8.9

Givetian—Mullinski and Ardatovski Reservoirs

- Type of reservoir: clastic reservoirs with low porosities.
- Number of layers: Mullinski up to 3 sandstone layers, which can be locally separated by silt and claystones, Ardatovski presents a massive clastic reservoir. Reservoir quality increases from the bottom towards the top reservoir,
- The Mullinski is a volatile oil layer, and the Ardatovski a gas condensate reservoir
- Development type: In Northeast Mullinski, 11 horizontal wells will be drilled and the South Mullinski it will be developed by 1 horizontal wells. In Northeast Ardatovski, it will be developed by 5 vertical wells and in the South production will come from one well,
- See Figures 20 and 21 and Table 5

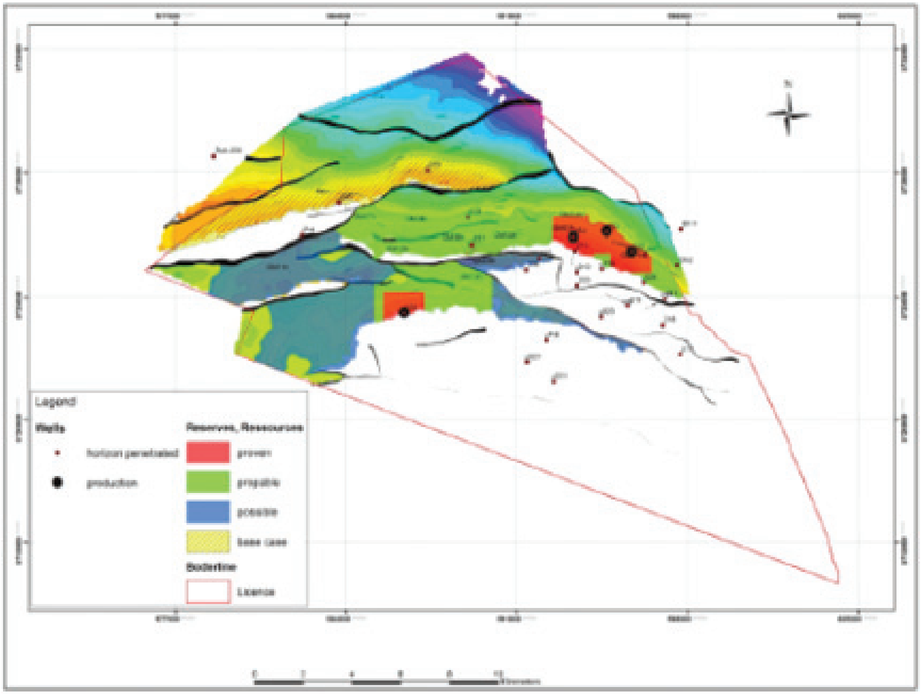


Figure 20: Reserves Status Map Middle Devonian Mullinski Horizon

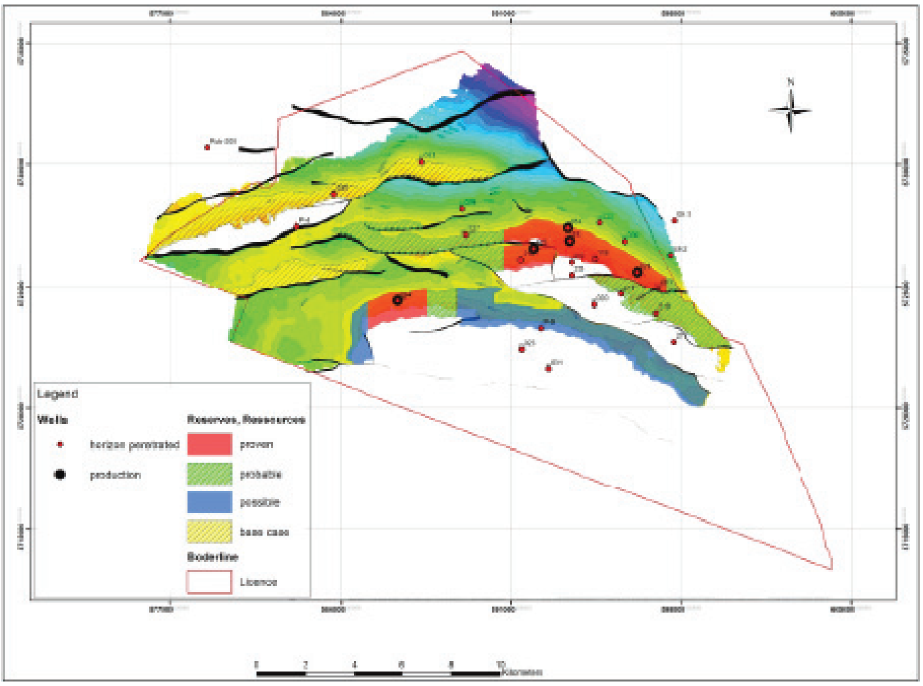


Figure 21: Reserves Status Map Middle Devonian Ardatovski Horizon

Table 5: Reservoir Parameters Givetian

Fractiles Layer	Parameter	Unit	P90	P50	P10	Average
Ardatovski	N/G		0.323	0.388	0.451	0.389
	Phi	%	6.34	6.56	6.79	6.56
	GThk	m	53.2	55.0	56.8	55.0
	NThk	m	16.4	18.6	21.1	18.8
Mullinski	N/G		0.133	0.160	0.184	0.159
	Phi	%	9.35	10.65	12.29	10.75
	GThk	m	41.9	46.8	50.8	46.6
	NThk	m	8.2	10.0	11.6	10.0

Bashkirian

- Type of reservoir: carbonates with porous and porous-vuggy porosity
- Number of layers: 2 independent reservoirs, Afoninski and Bisrous-ki
- Both reservoirs are oil layers
- See Figure 22 for reserves status and Bashkirian structure map

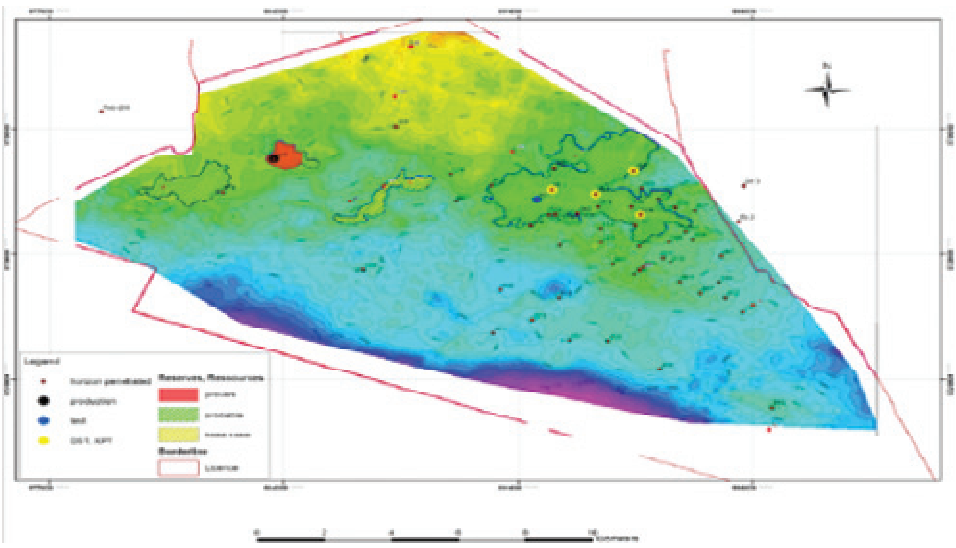


Figure 22: Reserves Status Map Middle Carboniferous Bashkirian Horizon

Additional Exploration Potential

Possible Reserves

Possible Reserves may be assigned to areas of a reservoir adjacent to Probable where data control and interpretations of available data are progressively less certain. Frequently, this may be in areas where geoscience and engineering data are unable to clearly define the area and vertical reservoir limits of commercial production from the reservoir by a defined project. Possible estimates also include incremental quantities associated with project recovery efficiencies beyond that assumed for Probable.

In addition to the estimated 2P reserves, additional appraisal and exploration potential exists in the Lower Permian, Biski/Afoninski, Tournaisian, Bashkirian and Givetian.

Lower Permian

- Number of reservoirs: 2 independent reservoirs, Artinski-Asselski and Filipovski
- Type of reservoir: dolomites with intercrystalline porosity, slightly fractured and stylolitic seams and dolomitic limestones with intraparticle, vuggy and fracture porosity (Fillipovski)
- Both reservoirs are oil bearing

- The resource reserves status of the Middle Carboniferous Bashkirian horizon is presented in Figure 23 below.

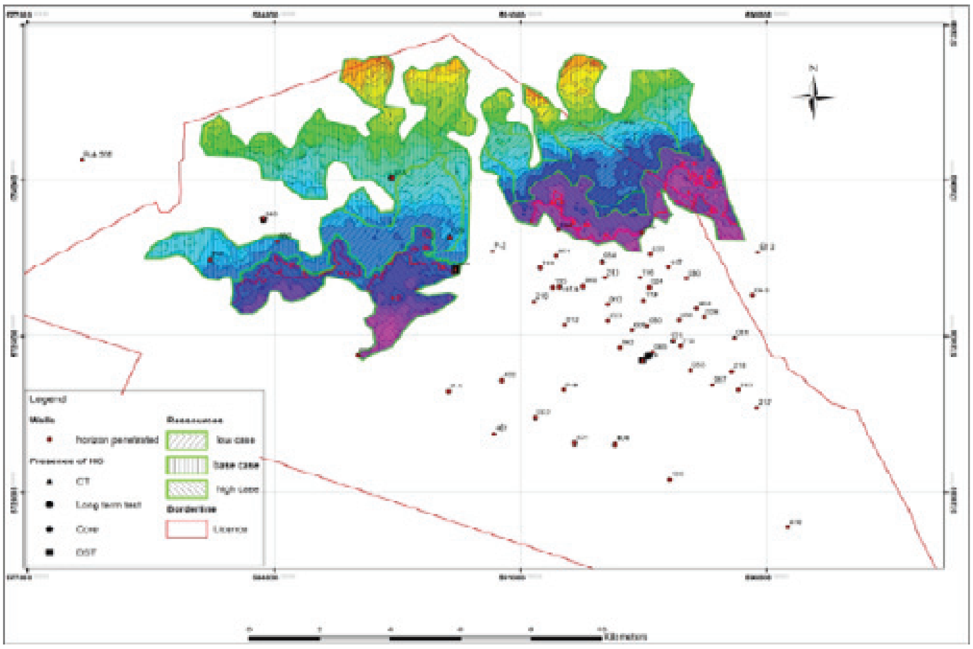


Figure 23: Reserves Status Map Middle Carboniferous Bashkirian Horizon

The possible reserves estimated as of August 31, 2013 amount to 34.6 million barrels of liquids and 249 billion cubic feet of sales gas. A breakdown of the possible reserves audited by Ryder Scott is provided in Table below.

Table 6 Possible Reserves (Gross) as of August 31, 2013

	Sales Gas	Oil/ Condensate	Plant Products	TOTAL
	(MMcf)	*(bbls)*	*(bbls)*	*(boe)*
Biski/Afoninski—SW	99,672	4,774,687	4,726,390	26,113,142
Ardatovski South	17,574	436,214	554,924	3,920,207
Tournaisian	89,093	11,605,907	4,508,311	30,962,983
Mullinski—South	35,039	3,544,267	2,007,439	11,391,490
Fillipovski	4,356	1,662,308	277,973	2,666,320
Famennian—South	3,600	300,000	200,000	1,100,000
Total	**249,334**	**22,323,384**	**12,275,038**	**76,154,142**

In Southwestern part of the Chinarevskoye field possible reserves were mapped in the Biski/Afoninski.

The Tournaisian West possible reserves are associated with most of the volume since only well 33 has tested hydrocarbons in the west area.

The Mullinski West was downgraded from possible reserves to prospective reserves following the questionable test in well 33 and the results of well 45.

For the Famennian South possible reserves were assigned based on the successful test in well 31. They are not included in the current business plan of Zhaikmunai.

Prospective Resource

In addition to the estimated 3P reserves several more prospects were mapped in the Givetian, Bashkirian and Lower Permian reservoirs.

The additional potential of hydrocarbon resources remaining in such prospects in the License area has been audited by Ryder Scott. The resources were estimated for each stratigraphic horizon and each prospect.

The location of the prospects within the Chinarevskoye License area are shown in Figures 20-23.

Ryder Scott included resource estimations for the Givetian (Mullinski West and Ardatovski West and SW) and the Lower Permian and Bashkirian prospects for the Chinarevskoye License. The Mullinski West was downgraded to prospective resources following the questionable test in well 33 and the unclear results in well 45.

Based on the results of the probabilistic calculations, the overall exploration potential in these prospects through summation of best estimates (base case) amounted to 84.3 million barrels of oil equivalent. Detailed figures are given in Table 7 below:

Table 7: Resource Expectations for Mapped Prospects in the Chinarevskoye Area

	Gas	Oil + Condensate + Plant Products	Total
	(Bcf)	*(MMBbls)*	*(MMBOE)*
Area			
Ardatovski	28.1	1.6	6.3
Mullinski	42.2	6.7	13.7
Bashkirian	1.1	0.6	0.8
Permian	103.6	46.2	63.4
Total	**175.1**	**55.1**	**84.3**

Trident License Description

Summary

Zhaikmunai holds an interest in certain oil and gas properties in the three new fields, Rostoshinskoye field, Yuzhno-Gremyachinskoye field and Darinskoye field located in the Republic of Kazakhstan. Zhaikmunai entered into both a License and Production Sharing Agreement ("pSa") with the Republic of Kazakhstan in March 2013. The PSA sets out the parameters for the exploration and development of the field and the fees, basis for production sharing, and the taxes payable to the Republic of Kazakhstan.

Location and License Commitments

The area is situated in the steppe zone within southern branches of Common Szyrt which represent a steeply-sloping and undulating plain dissected by river valleys into individual elevations. Absolute elevations vary within 50-100 m regularly descending from north southward.

Hydrographic system of the area is represented by the Ural River, its large tributary—the Chagan River, other smaller rivers such as Derkul, Barbastau and other small tributaries, as well as small lakes, dam ponds and temporary streams drying up in summer. The available water resources are used for technical purposes and irrigation, and less for drinking water supply. The sources of drinking water are groundwater of flood-plain and above flood-plain deposits of the rivers. The Ural River is navigable and at the same time is a spawning area for valuable species of fish, including sturgeons. The navigation period on the Ural River lasts mainly from the end of April till late October.

The climate of the area is continental and arid. Positive average monthly temperature is observed for seven months a year while the negative temperature occurs for five months. The average monthly temperature ranges between -14°C in January and +23°C in July. The absolute minimum temperature of air is minus 39°C, and the absolute maximum is plus 40°C.

The average annual amount of precipitation is roughly 295 mm, and 260 mm in dry years. The average thickness of the snow cover is small (15-25cm). The snow cover is formed in late November and melts in early April. Southward winds prevail in the area, they have higher velocities during winter months (up to 5.9 m/sec), than in summer (3.6 m/sec).

The operations area is characterized by intensive agriculture with irrigated (about 10%) and dry land farming.

The forest and shrubby cover is developed along rivers and in artificial windbreaks. The natural vegetation cover consisting mainly of grass, gramineous plants and miscellaneous herbs typical for dry steppes (sheep's fescue, feather grass, sagebrush, etc.) has been preserved in flood plains only. The fauna is represented chiefly by rodents; forests are inhabited by elks, roe deers, boars, wolves, etc.

The main settlements are Uralsk town, urban settlements Peremetny, Derkul, Darinskoe, and villages Rostoshi, Furmanovo, Zelyony, Ulyanovsky, Gremyachy, etc. The population is employed mainly in agriculture, and in the town and large settlements—at processors. Furthermore, there are enterprises of power generation, food, electronic, machine-building, etc. industry in the town.

Central-Asia Central-Russia trunk railway crosses the southern part of the area. The road network is represented by motor roads connecting Uralsk with the nearest large settlements in Kazakhstan and Russia: Aktyubinsk, Atyrau, Samara, Saratov and Orenburg. Moreover, there is an extensive network of highways, earth and country roads that connects different settlements. The area is crossed by Atyrau-Samara petroleum pipeline, Orenburg-Western Europe gas pipeline and two 220 KW power transmission lines.

The contract granting the right to use the subsurface in the Republic of Kazakhstan for the exploration and production of hydrocarbons in the Rostoshinskoye, Darinskoye and Yzhno- Gremiachenskoye fields was issued to Zhaikmunai in March 1, 2013.

The license encompasses the following blocks:

Rostoshinskoye field:

- XIV-10-A(partially), B(partially)

Darinskoye field:

- XI11-11 -A(partially), D(partially)

Y.Gremiachenskoye field:

- XII I-9-F(partially),XI V-9-C(partially)

For Darinskoye, the field the contract was issued originally to company "*AmurNeftInvest*" and its original duration was for a period of 25 years. The first 6 years of exploration is followed by a 19 years production period.

Next, the contract was transferred to Company "*Geoinvest-K*" in December 2006. This company has changed the original duration of the exploration period only to 8 years and 6 month.

For Yuzhno-Gremyachinskoye field, the contract was issued to the same company "*AmurNeftInvest*" and its original duration was for a period of 25 years. The 5 years of exploration period is followed by a 20 year production period.

Next, the contract was transferred to Company "*Yuzhno-Gremyachenskoye*" in December 2006. This company has changed the original duration of the contract. The first 8 years of exploration is followed by an 18 year production period.

For Rostoshinskoye field, the contract was issued to company "TNG Company" and its original duration was for a period of 15 years. The first 3 years of exploration is followed by a 12 year production period. This company changed the original duration of the exploration period to 6 years.

The contract was transferred to Zhaikmunai in March 2013. Zhaikmunai has changed the original duration of the contract. The first 8 years is designated as exploration is followed by a 20 year period of production.

Zhaikmunai has the rights to the all three contracts with the above mentioned durations from March 1, 2013.

The contracts are combined License and Production Sharing Agreement with the Kazakh government. It includes a Minimum Work Program and a Minimum Capital Investment requirement.

For Darinskoye the original Minimum Work Program was:

- 3D seismic acquisition
- 3D data processing and interpretation
- Interpretation of the old existing well data

- Reopening well #1
- Reopening well #2
- Drilling appraisal well #6
- Drilling appraisal well #7
- Drilling appraisal well #8
- Drilling appraisal well #9
- Initiate the test production project to Kazakh Authority
- The Minimum Work Program amounts to $20,000,000 US.

For Yuzhno-Gremyachinskoye the original Minimum Work Program was:

- 3D seismic acquisition
- 3D data processing and interpretation
- Interpretation of the old existing well data
- Reopening well #2
- Reopening well #1
- Deepening well #1
- Drilling appraisal well #6
- Initiate the test production project to Kazakh Authority
- The Minimum Work Program amounts to $22,550,000 US.

For Rostoshinskoye the original Minimum Work Program was:

- 3D seismic acquisition
- 3D data processing and interpretation
- Interpretation of the old existing well data
- Drilling appraisal well #3
- Initiate the test production project to Kazakh Authority

The Minimum Work Program amounts to $13,420,000 US.

Zhaikmunai, after getting subsoil user rights, has already changed the exploration period for Rostoshinskoe field to February 8, 2015 with the Minimum Work Program. The minimum work program consists of two stages.

The First stage:

- 3D seismic acquisition
- 3D data processing and interpretation
- Interpretation of the old existing well data
- Reopening well #1
- Drilling appraisal well #3
- Initiate the test production project to Kazakh Authority

The Second stage:

- Drilling dependent appraisal well #4
- The First stage amounts to $21,305,000 US.
- The Second stage amounts to $31,305,000 US.

For the Darinskoye and Yuzhno-Gremyachinskoye fields, Zhaikmunai is in the process of prolongation the exploration period and changing Minimum Work programs accordingly with Ministry of oil and gas.

The appraisal projects for the both fields have been approved by Ministry and the supplementary is in the final stage to be signed by Ministry.

The new Minimum work programs are included within the approved appraisal projects. The minimum work programs consist of two stages for both fields.

For Darinskoye:

The first stage:

- Re-processing and re-interpretation of existing 3D data
- Reopening well #1
- Reopening well #2
- Initiate the test production project to Kazakh Authority

The second stage:

- Drilling dependent appraisal well #8
- The First stage amounts to $9,355,000 US.
- The Second stage amounts to $20,355,000 US.

For Yuzhno-Gremyachinskoye:

The first stage:

- Re-processing and re-interpretation of existing 3D data
- Reopening well #2
- Reopening well #1
- Deepening well #2
- Drilling dependent appraisal well #6
- Initiate the test production project to Kazakh Authority

The second stage:

- Drilling dependent appraisal well #7
- The First stage amounts to $13,600,000 US.
- The Second stage amounts to $33,600,000 US.

Geology

Stratigraphy

The sedimentary cover of the area consists of the subsalt, saliferous and post salt megalithic complexes of deposits. The subsalt part of the sedimentary cover is divided into eight litho-stratigraphic complexes that reflect the alternation of prevailing carbonate and siliceous beds in the Kungurian Paleozoic (from the bottom upwards):

1. Mainly clastic Lower Devonian,
2. Carbonate Eifelian,
3. Clastic (clastic-carbonate) Givetian-Lower Frasnian,
4. Carbonate Upper Frasnian-Tournaisian,
5. Clastic (clastic-carbonate) Kosvinian-Bobrikovskian,
6. Carbonate Visean-Lower Bashkirian,
7. Clastic Upper Bashkirian -Lower Moscovian,
8. Carbonate Moscovian-Artinskian.

Seismic Control—Mapping of Accumulations and Prospects

The Pre-Caspian zone was vastly studied by 2D seismic since 1984 when the pilot development of Karachaganak field has commenced. (Indicated in Figure 24.)

Seismic

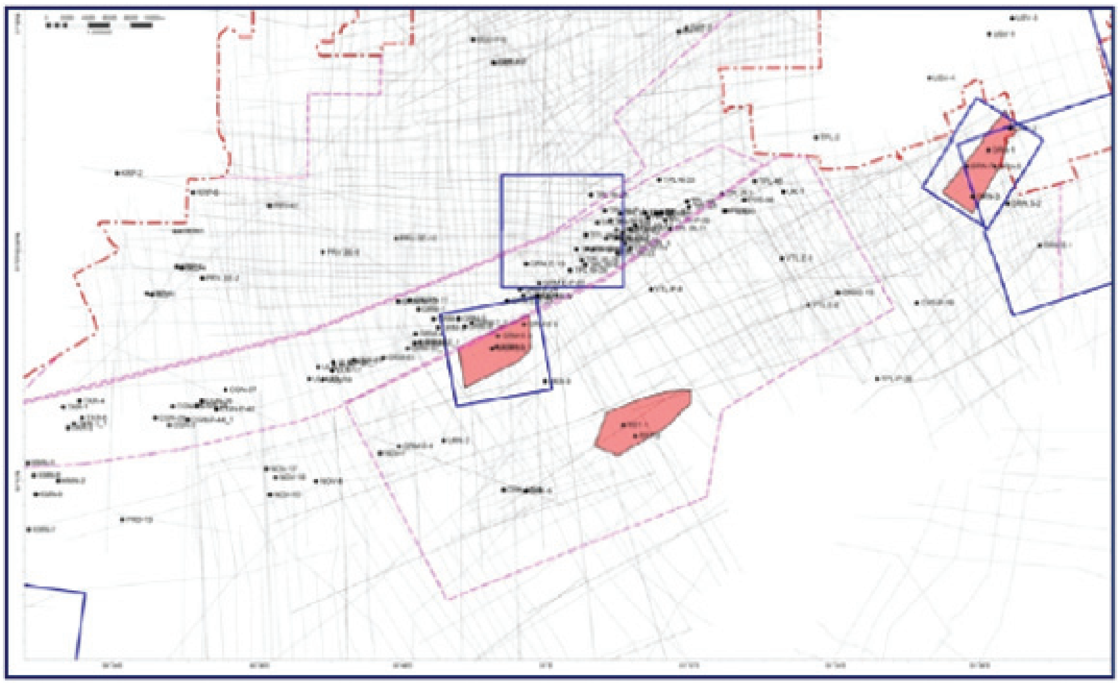


Figure 24: Proposed 3D Acquisition Program

Darinskoye and Yuzhno-Gremyachinskoye were subjects of 3D acquisition.

Yuzhno-Gremyachinskoye 3D data was interpreted and based on the interpretation following main horizons were mapped as shown in Figures 25 and 26:

1. The Upper Permian Hydrochemical (P2hydr)
2. The Upper Permian Kalinovian (P2kl)

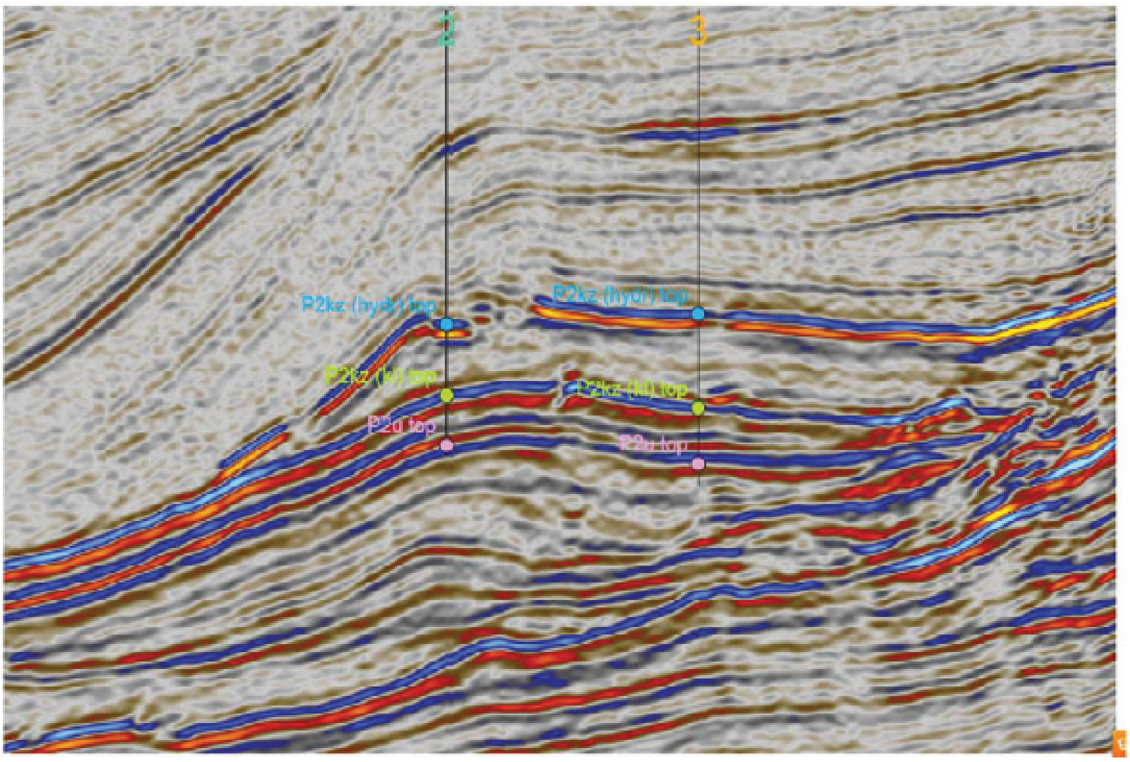


Figure 25: Upper Permian Hydrochemical (P2hydr) and Kalinovian (P2kl)

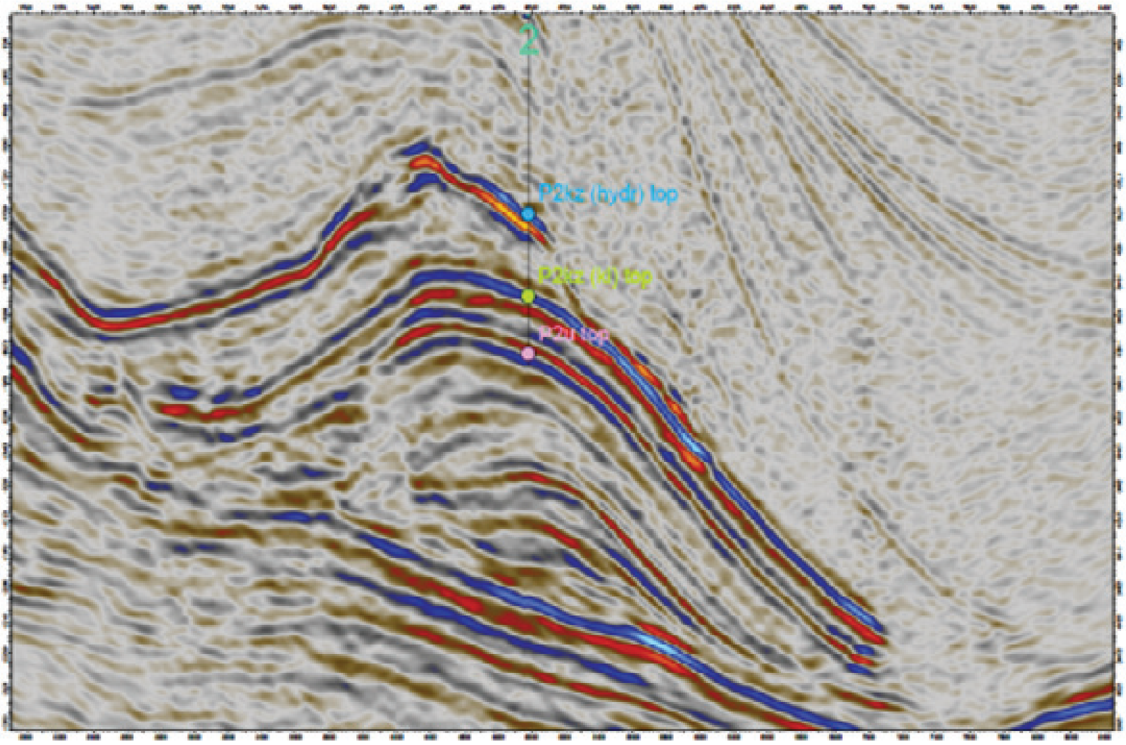


Figure 26: Upper Permian Hydrochemical (P2hydr) and Kalinovian (P2kl)

Darinskoye 3D data was feasibly studied and now under the re-processing process. Rostoshinskoye only have the 2D seismic data

Escarpment Zone Schematics

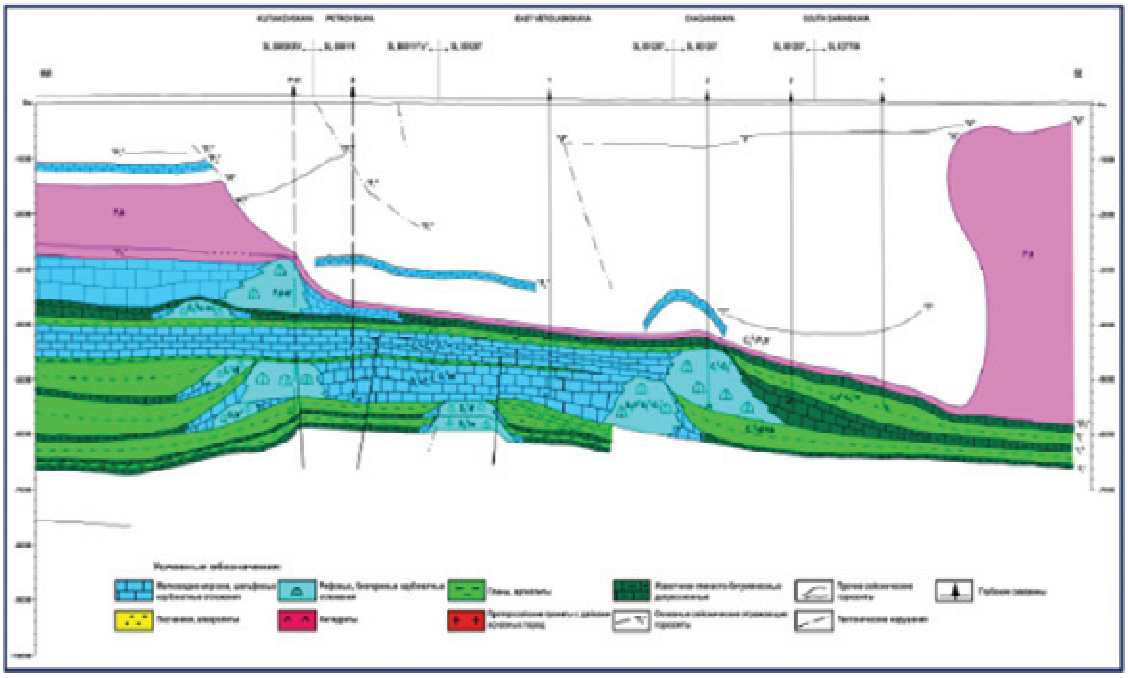
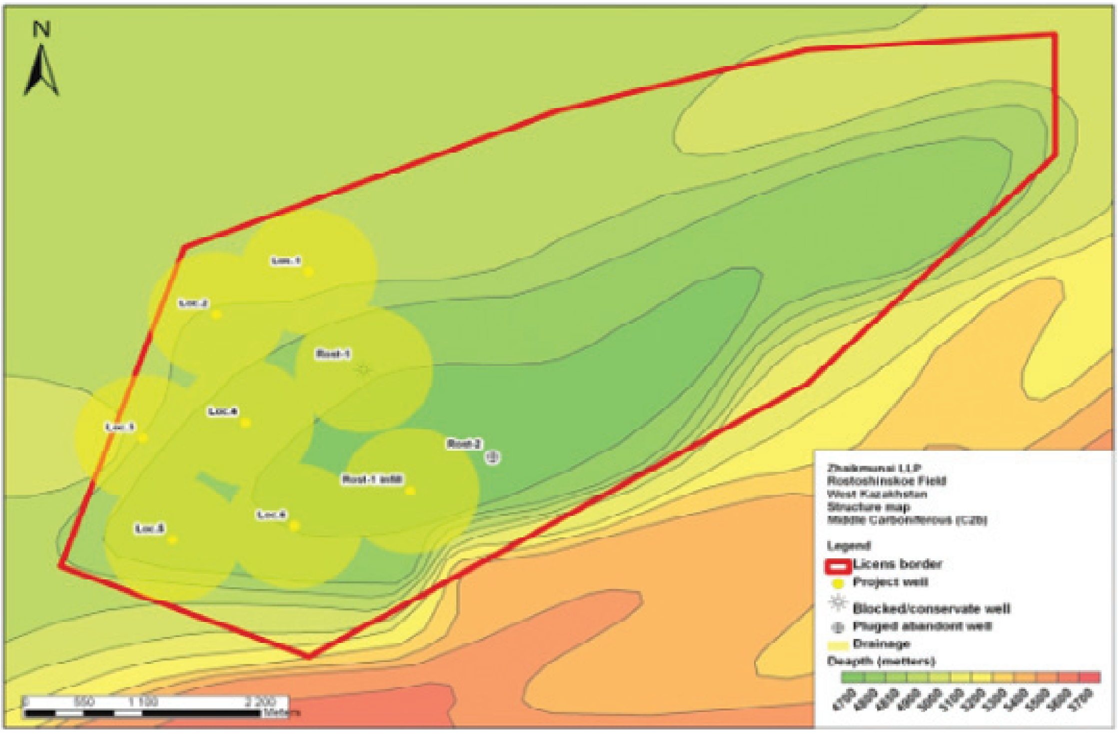
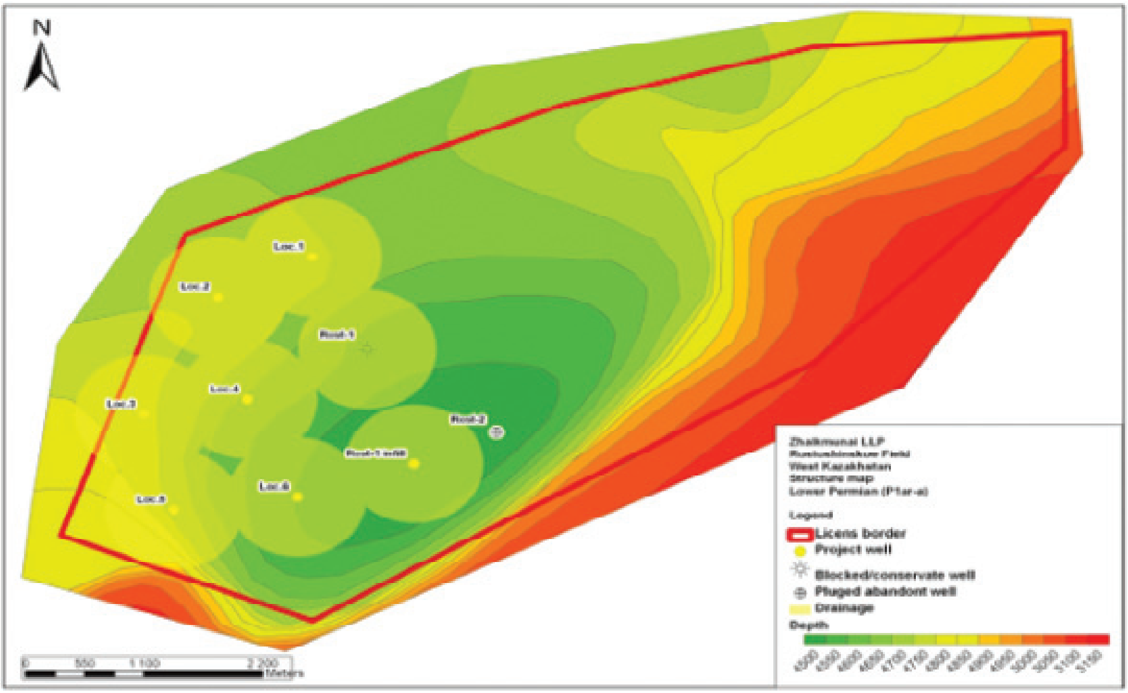


Figure 27: Geological and geophysical knowledge diagram

Mapping of Accumulations

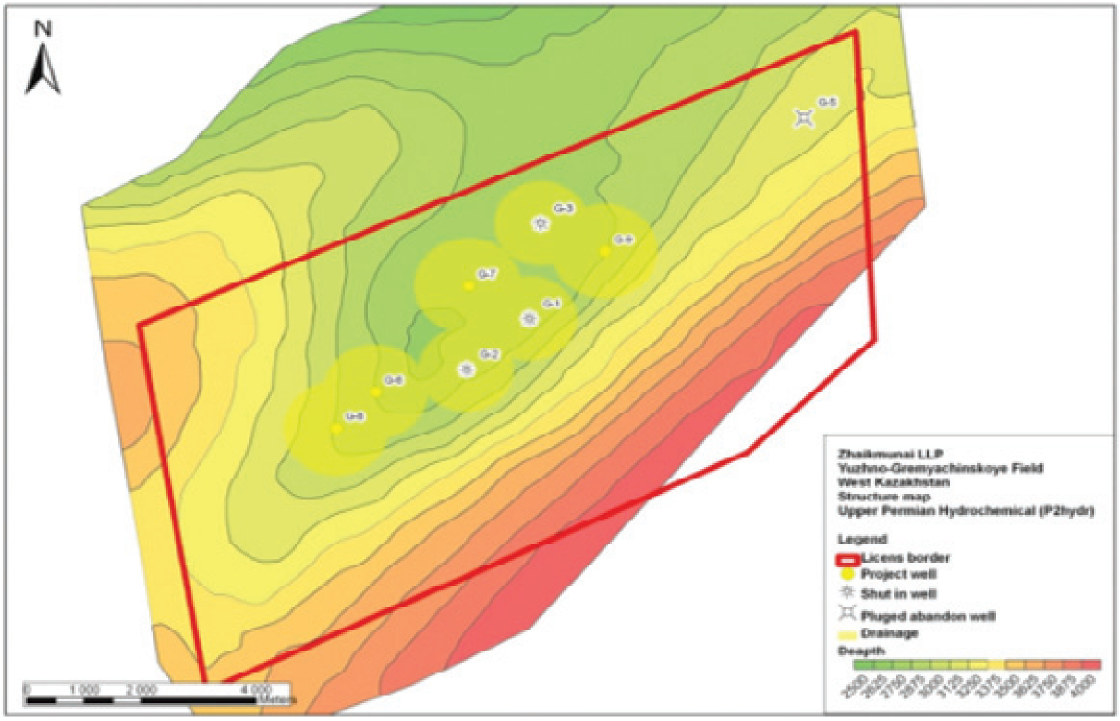
Rostoshinskoye

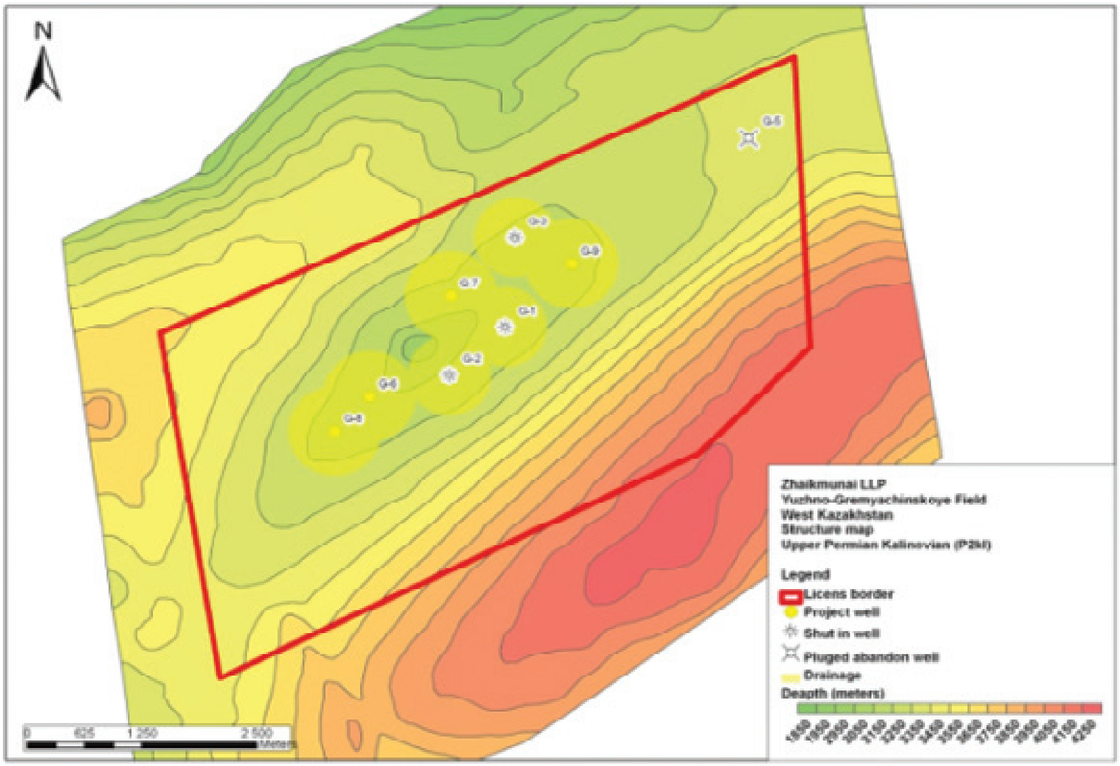




Upper Figure 28 and Lower Figure 29: Lower Permian (P1ar-a) and Middle Carboniferous (C2b) Structure

Y.Gremiachenskoye





Upper Figure 30 and Lower Figure 31: Upper Permian Kalinovian (P2kl) and Hydrochemical (P2hydr) Structure

Darinskoye

Figure 32: Middle Carboniferous (C2b) Structure

Tests Results

Table 8: Rostoshinskoye has tested successfully from well Rost-1 in following intervals.

Horizon	Testing intervals				d choke, MM	ΔP, Mna	Rate		
	MD, M		TVD., M				Gas thnd. M³/day	Gas thnd. M³/day	Gas thnd. M³/day
	Top	Bottom	Top	Bottom					
C2b	4715	4738	-4650	-4673	4	26.1	54.66		2
					6	35	73.78		7.5
					8	37.1	79.55		10.5
C2b	4670	4692	-4605	-4627	4		63.1		1.8
					5		91.81		4.3
					6		119.35		8.7
P1ar-a	4624	4645	-4559	-4580	4	30.7	41.3	0.2	1.5
					5	35.2	53.4	0.25	3.2
					6	39	57.6	0.25	5.8
P_2kz kl	4281	4346	-4216	-4281		27.5	32.9		
P_1fl+P1ar- a+C2	4600	4715	-4535	-4650		26.7	+		
P_1ar-a	4633	4716	-4568	-4651		28.7	112.2		

Table 9: Darinskoye has tested successfully from well Dar-1 and Dar-2 in following intervals.

Horizon	Testing intervals				d choke, MM	ΔP, Mna	Rate		
	MD, M		TVD., M				Gas thnd. M^3/day	Gas thnd. M^3/day	Gas thnd. M^3/day
	Top	Bottom	Top	Bottom					
C_2b	4259	4266	4208.98	4215.98	8	14.7	3.81	54.2	3
					6	12.7	2.56	44.1	2.5
					4	9.7	1.04	34.2	2
C_2b	4259	4266	4259	4266	6		1.2	25.7	0.4
							0.6	9.5	1.5
					4.4		1.2	11	0.3
							0.6	9	1.2
C_2b	4242	4255	4186.89	4199.89	6	10.9	171.1	17.5	—
					8	18.5	214.8	26.3	—
					10	23.2		31.8	2.3
					12	26.6	250.6	33.4	shows
					14	28.4	252.6	34.6	shows
					10	23.2	248.1	31.8	2.3

Table 10: Y.Gremyachinskoye has tested successfully from well G-2 in following intervals.

Horizon	Testing intervals				d choke, MM	ΔP, Mna	Rate		
	MD, M		TVD., M				Gas thnd. M^3/day	Gas thnd. M^3/day	Gas thnd. M^3/day
	Top	Bottom	Top	Bottom					
$P_2 kz^{kl}$	3158	3167	3084.49	3093.49	4	43.91	3.19	13.05	0.6
	3177	3184	3103.49	3110.49	5	46.15	3.36	13.2	1.5
					6	46.45	3.57	13.48	2
					4	39.5	5.57	22.5	1.58
					5	44.15	6.13	25	1.85
					6	46.51	6.5	26	2.5
					7	48.63	6.68	26.2	2.7

The possible reserves estimated as of August 31, 2013 amount to 13.1 million barrels of liquids and 122 billion cubic feet of sales gas. A breakdown of the possible reserves audited by Ryder Scott is provided in Table below.

Table 11: Possible Reserves as of August 31, 2013

Possible Reserves in the Trident Area as of August 31, 2013

Field Area	Sales Gas	Oil/Condensate	Plant Products	Total
	(MMcf)	*(Bbls)*	*(Bbls)*	*(BOE)*
Daryinskoye	14,404	4,068,317	433,009	6,901,993
Rostoshinskoye	72,896	0	0	12,149,333
Yuzhno-Gremyachenskoye	35,174	8,656,630	0	14,518,963
Total	**122,474**	**12,724,947**	**433,009**	**33,570,289**

Site Visit

The last site visit was conducted during June 21–30, 2009.

Standards of Independence and Professional Qualification

Ryder Scott is an independent petroleum engineering consulting firm that has been providing petroleum consulting services throughout the world for over seventy-five years. Ryder Scott is employee-owned and maintains offices in Houston, Texas; Denver, Colorado; and Calgary, Alberta, Canada. We have over eighty engineers and geoscientists on our permanent staff. By virtue of the size of our firm and the large number of clients for which we provide services, no single client or job represents a material portion of our annual revenue.

We do not serve as officers or directors of any privately-owned or publicly-traded oil and gas company and are separate and independent from the operating and investment decision-making process of our clients. This allows us to bring the highest level of independence and objectivity to each engagement for our services.

Ryder Scott actively participates in industry related professional societies and organizes an annual public forum focused on the subject of reserves evaluations and SEC regulations. Many of our staff have authored or co-authored technical papers on the subject of reserves related topics. We encourage our staff to maintain and enhance their professional skills by actively participating in ongoing continuing education.

Prior to becoming an officer of the Company, Ryder Scott requires that staff engineers and geoscientists have received professional accreditation in the form of a registered or certified professional engineer's license or a registered or certified professional geoscientist's license, or the equivalent thereof, from an appropriate governmental authority or a recognized self-regulating professional organization.

We are independent petroleum engineers with respect to Zhaikmunai LLP. Neither we nor any of our employees have any interest in the subject properties and neither the employment to do this work nor the compensation is contingent on our estimates of reserves and resources for the properties which were reviewed.

The results of this study, presented herein, are based on technical analysis conducted by teams of geoscientists and engineers from Ryder Scott. The professional qualifications of the undersigned, the technical person primarily responsible for overseeing, reviewing and approving the evaluation of the reserves information discussed in this report, are included as an attachment to this letter.

Ryder Scott would like to acknowledge Alex Erber, Daniela Erber and Igor Druzhinin without whose professional assistance and support in the preparation of this report would have been extremely difficult.

General

Ryder Scott is an independent petroleum engineering consulting firm that has been providing petroleum consulting services throughout the world for over seventy-five years. Ryder Scott is employee-owned and maintains offices in Houston, Texas; Denver, Colorado; and Calgary, Alberta, Canada. We have over eighty engineers and geoscientists on our permanent staff. By virtue of the size of our firm and the large number of clients for which we provide services, no single client or job represents a material portion of our annual revenue. We do not serve as officers or directors of any privately-owned or publicly-traded oil and gas company and are separate and independent from the operating and investment decision-making process of our clients. This allows us to bring the highest level of independence and objectivity to each engagement for our services.

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We are independent petroleum engineers with respect to Zhaikmunai LLP. Neither we nor any of our employees have any interest in the subject properties and neither the employment to do this work nor the compensation is contingent on our estimates of reserves for the properties which were reviewed.

The results of this study, presented herein, are based on technical analysis conducted by teams of geoscientists and engineers from Ryder Scott. The professional qualifications of the undersigned, the technical person primarily responsible for overseeing the evaluation of the reserves information discussed in this report, are included as an attachment to this letter.

The estimates of reserves presented herein are based upon a detailed study of the properties in which Zhaikmunai LLP holds the right to conduct its hydrocarbon production and exploration activities however; we have not made any field examination of the property. No consideration was given in this report to potential environmental liabilities which may exist nor were any costs included for potential liability to restore and clean up damages, if any, caused by past operating practices. Nostrum Oil & Gas LP has informed us that they have provided to us all of the accounts, records, geological and engineering data, and reports and other data required for this report. This report reflects the terms of the Production Sharing Agreement between the Republic of Kazakhstan and Zhaikmunai LLP. This report reflects the royalty payment to the Republic of Kazakhstan, the cost oil provisions, profit oil provisions and production bonus payments as set out in the Production Sharing Agreement.

Zhaikmunai LLP has assured us of their intent and ability to proceed with the development activities described in this report.

Terms of Usage

This Competent Person's Report was prepared by Ryder Scott Company L.P. for the exclusive use and sole benefit of Nostrum Oil & Gas plc (the "**Issuer**"), Nostrum Oil & Gas LP and Deutsche Bank AG, London Branch as described in the first paragraph of this letter and may not be put to other use without our prior written consent for such use. The data, work papers, and maps used in the preparation of this report are available for examination by authorized parties in our offices. Please contact us if we can be of further service.

Very truly yours,

RYDER SCOTT COMPANY, L.P.
TBPE Firm Registration No. F-1580

James L. Baird, P.E.
Colorado License No. 41521
Managing Senior Vice President

JLB(DCR)/pl

Professional Qualifications of Primary Technical Person

The conclusions presented in this report are the result of technical analysis conducted by teams of geoscientists and engineers from Ryder Scott Company L.P. James Larry Baird was the primary technical person responsible for overseeing the estimate of the reserves.

Mr. Baird, an employee of Ryder Scott Company L.P. (Ryder Scott) since 2006, is a Managing Senior Vice President and also serves as Manager of the Denver office, responsible for coordinating and supervising staff and consulting engineers of the company in ongoing reservoir evaluation studies worldwide. Before joining Ryder Scott, Mr. Baird served in a number of engineering positions with Gulf Oil Corporation (1970-73), Northern Natural Gas (1973-75) and Questar Exploration & Production (1975-2006). For more information regarding Mr. Baird's geographic and job specific experience, please refer to the Ryder Scott Company website at www.ryderscott.com/Experience/Employees.

Mr. Baird earned a Bachelor of Science degree in Petroleum Engineering from the University of Missouri at Rolla in 1970 and is a registered Professional Engineer in the States of Colorado and Utah. He is also a member of the Society of Petroleum Engineers.

In addition to gaining experience and competency through prior work experience, the Colorado and Utah Board of Professional Engineers recommend continuing education annually, including at least one hour in the area of professional ethics, which Mr. Baird fulfills. As part of his 2011 continuing education hours, Mr. Baird attended an internally presented sixteen hours of formalized training as well as an eight hour public forum. Mr. Baird attended the 2010 and 2011 RSC Reserves Conference and various professional society presentations specifically on the new SEC regulations relating to the definitions and disclosure guidelines contained in the United States Securities and Exchange Commission Title 17, Code of Federal Regulations, Modernization of Oil and Gas Reporting, Final Rule released January 14, 2009 in the Federal Register. Mr. Baird attended an additional sixteen hours of formalized in-house training during 2011, 2012 and 2013 covering such topics as the SPE/WPC/AAPG/SPEE Petroleum Resources Management System, reservoir engineering, geoscience and petroleum economics evaluation methods, reserve reconciliation processes, overviews of the various productive basins of North America, evaluations of resource play reserves, procedures and software and ethics for consultants. Mr. Baird was a keynote speaker, presenting the Changing Landscape of the SEC Reporting, at the 2009 Unconventional Gas International Conference held in Fort Worth, Texas.

Based on his educational background, professional training and more than 40 years of practical experience in the estimation and evaluation of petroleum reserves, Mr. Baird has attained the professional qualifications as a Reserves Estimator and Reserves Auditor set forth in Article III of the "Standards Pertaining to the Estimating and Auditing of Oil and Gas Reserves Information" promulgated by the Society of Petroleum Engineers as of February 19, 2007.As Adapted From:

PETROLEUM RESOURSES CLASSIFICATION AND DEFINITIONS

As Adapted From:

2007 PETROLEUM RESOURCES MANAGEMENT SYSTEM (SPE-PRMS)1

Sponsored by:

SOCIETY OF PETROLEUM ENGINEERS (SPE),

WORLD PETROLEUM CONGRESS (WPC)

AMERICAN ASSOCIATION OF PETROLEUM GEOLOGISTS (AAPG)

AND

SOCIETY OF PETROLEUM EVALUATION ENGINEERS (SPEE)

PREAMBLE

Reserve and resource classification systems are intended to allow the evaluator to follow the progression of changes in the exploration and production life cycle of a reservoir, field, or project that arise as a result of obtaining more technical information or as a result of a change in the economic status. Most systems incorporate terminology to describe the progression of a project from the delineation of an initial prospect, to the confirmation of the prospect through exploration drilling, onto the appraisal and development phase, and finally from initial production through depletion. These reserve and resource definitions thus provide the decision making framework to manage risk and uncertainty through the classification and categorization of the recoverable hydrocarbon volumes.

The term “resources” is generally applied to “all quantities of petroleum (recoverable and unrecoverable) naturally occurring on or within the Earth’s crust, discovered and undiscovered, plus those quantities already produced”.

The term “reserves” is a subset of resources generally applied to the discovered “quantities of petroleum anticipated to be commercially recoverable from known accumulations from a given date forward under defined conditions”.

All reserve and resource estimates involve some degree of uncertainty. The uncertainty depends chiefly on the amount of reliable geologic and engineering data available at the time of the estimate and the interpretation of these data. Estimates will generally be revised as additional geologic or engineering data becomes available or as economic conditions change.

Estimation of reserves and resources is done under conditions of uncertainty. The method of estimation is called deterministic if a single best estimate of reserves and resources is made based on known geological, engineering, and economic data. The method of estimation is called probabilistic when the known geological, engineering, and economic data are used to generate a range of estimates and their associated probabilities. Because of the differences in uncertainty, caution should be exercised when aggregating quantities of petroleum from different reserves and/or resource classifications.

Reserves and resources may be attributed to either natural energy or improved recovery methods. Improved recovery methods include all methods for supplementing natural energy or altering natural forces in the reservoir to increase ultimate recovery. Examples of such methods are pressure maintenance, cycling, waterflooding, thermal methods, chemical flooding, and the use of miscible and immiscible displacement fluids. Other improved recovery methods may be developed in the future as petroleum technology continues to evolve.

Reserves and resources may be attributed to either conventional or unconventional petroleum accumulations under the SPE-PRMS. Petroleum accumulations are considered as either conventional or unconventional based on the nature of their in-place characteristics, extraction method applied, or degree of processing prior to sale. Examples of unconventional petroleum accumulations include coalbed or coalseam methane (CBM/CSM), basin-centered gas, shale gas, gas hydrates, natural bitumen and oil shale deposits. These unconventional accumulations may require specialized extraction technology and/or significant processing prior to sale. The SPE-PRMS acknowledges unconventional petroleum accumulations as reserves and resources regardless of their in-place characteristics, the extraction method applied, or the degree of processing required.

Reserves and resources do not include quantities of petroleum being held in inventory and may be reduced for usage, processing losses and/or non-hydrocarbons that must be removed prior to sale.

SPE-PRMS

In March 2007, the Society of Petroleum Engineers (SPE), World Petroleum Council (WPC), American Association of Petroleum Geologists (AAPG), and Society of Petroleum Evaluation Engineers (SPEE) jointly approved the "Petroleum Resources Management System" (SPE-PRMS). The SPE- PRMS consolidates, builds on, and replaces guidance previously contained in the 2000 "Petroleum Resources Classification and Definitions" and the 2001 "Guidelines for the Evaluation of Petroleum Reserves and Resources" publications.

Reference should be made to the full SPE-PRMS for the complete definitions and guidelines as the following definitions, descriptions and explanations rely wholly or in part on excerpts from the SPE- PRMS document (passages excerpted in their entirety from the SPE-PRMS document are denoted in italics herein). For convenience, Table 1: "Recoverable Resources Classes and Sub-Classes" from the SPE-PRMS has been reproduced in full and included as an attachment to this document.

The SPE-PRMS incorporates the petroleum initially-in-place as well as the recoverable and unrecoverable petroleum quantities into a common resource classification framework. *Petroleum is defined as a naturally occurring mixture consisting of hydrocarbons in the gaseous, liquid, or solid phase.*

The SPE-PRMS defines the major resources classes: Production, Reserves, Contingent Resources, and Prospective Resources, as well as Unrecoverable petroleum. The basic classification scheme requires establishment of criteria for a petroleum discovery and thereafter the distinction between commercial (Reserves) and sub-commercial projects (Contingent Resources) in known accumulations. Under this classification scheme, estimated recoverable quantities from accumulations that have yet to be discovered are termed Prospective Resources. Further, the SPE-PRMS includes all types of petroleum whether currently considered "conventional" or "unconventional".

Figure 1 shown at the end of this document is a graphical representation of the SPE, WPC, AAPG and SPEE resources classification system. The SPE-PRMS "classifies" reserves and resources according to project maturity and increasing chance of commerciality (vertical axis) and "categorizes" reserves and resources according to the range of uncertainty (horizontal axis) *of the estimated quantities potentially recoverable from an accumulation by a project*. The following definitions apply to the major subdivisions within the resources classification:

Recoverable petroleum resources as described herein may be classified into one of three principal resource classifications: Prospective Resources, Contingent Resources, or Reserves. The distinction between Prospective and Contingent Resources depends on whether or not there exists one or more wells and other data indicating the potential for moveable hydrocarbons (e.g. the discovery status). Discovered petroleum resources may be classified as either Contingent Resources or as Reserves depending on the chance that if a project is implemented it will reach commercial producing status (e.g. chance of commerciality). The distinction between various "classifications" of Resources and Reserves relates to their discovery status and increasing chance of commerciality as described herein.

The SPE-PRMS Section 1.1 and Appendix A define the following terms:

TOTAL PETROLEUM-INITIALLY-IN-PLACE

Total Petroleum-Initially-in-Place is that quantity of petroleum which is estimated to exist originally in naturally occurring accumulations. Total Petroleum-Initially-in-Place is, therefore, that quantity of petroleum which is estimated, as of a given date, to be contained in known accumulations, plus those quantities already produced therefrom, plus those estimated quantities in accumulations yet to be discovered.

Total Petroleum-Initially-in-Place may be subdivided into Discovered Petroleum-Initially-in-Place and Undiscovered Petroleum-Initially-in-Place, with Discovered Petroleum-Initially-in-Place being limited to known accumulations.

It is recognized that not all of the Petroleum-Initially-in-Place quantities may constitute potentially recoverable resources since the estimation of the proportion which may be recoverable can be subject to significant uncertainty and will change with variations in commercial circumstances, technological developments and data availability.

Given the aforementioned constraints, a portion of the Petroleum-Initially-in-Place may need to be classified as Unrecoverable.

DISCOVERED PETROLEUM-INITIALLY-IN-PLACE

Discovered Petroleum-Initially-in-Place is that quantity of petroleum which is estimated, as of a given date, to be contained in known accumulations prior to production.

Discovered Petroleum-Initially-in-Place may be subdivided into Commercial and Sub-commercial categories, with the estimated potentially recoverable portion being classified as Reserves and Contingent Resources respectively, as defined below.

KNOWN ACCUMULATION

The SPE-PRMS defines an accumulation as *an individual body of petroleum-in-place*. For an accumulation to be considered as "known", it must have been discovered. A discovery is defined as *one petroleum accumulation or several petroleum accumulations collectively, which have been penetrated by one or several exploratory wells which have established through testing, sampling, and/or logging the existence of a significant quantity of potentially moveable hydrocarbons. The SPE- PRMS states in this context, "significant" implies that there is evidence of a sufficient quantity of petroleum to justify estimating the in-place volume demonstrated by the well(s) and for evaluating the potential for economic recovery. Known accumulations may contain Reserves and/ or Contingent Resources.*

RESERVES

Reserves are defined as those quantities of petroleum which are anticipated to be commercially recoverable by application of development projects to known accumulations from a given date forward under defined conditions. Reserves must further satisfy the following criteria: they must be discovered, recoverable, commercial, and remaining (as of the evaluation date) based on the development project(s) applied.

Reserves are categorized in *accordance with the level of certainty associated with the estimates (horizontal axis shown in Figure 1) and may be further sub-classified based on project maturity and/or characterized by development and production status (Refer to Figure 2 at the end of this document). Reference should be made to the full SPE-PRMS for the complete definitions and guidelines*.

CONTINGENT RESOURCES

Contingent Resources are those quantities of petroleum which are estimated, as of a given date, to be potentially recoverable from known accumulations, but the applied project(s) are not yet considered mature enough for commercial development due to one or more contingencies. Contingent Resources may include, for example, projects for which there is currently no viable market, or where commercial recovery is dependent on the development of new technology, or where evaluation of the accumulation is insufficient to assess commerciality.

Contingent Resources are categorized according to the range of technical uncertainty associated with the estimates (horizontal axis shown in Figure 1) may be further sub-classified based on project maturity and/or characterized by their economic status (Refer to Figure 2 at the end of this document). Reference should be made to the full SPE-PRMS for the complete definitions and guidelines.

UNDISCOVERED PETROLEUM-INITIALLY-IN-PLACE

Undiscovered Petroleum-Initially-in-Place is that quantity of petroleum which is estimated, as of a given date, to be contained in accumulations yet to be discovered.

The estimated potentially recoverable portion of Undiscovered Petroleum-Initially-in-Place is classified as Prospective Resources, as defined below.

PROSPECTIVE RESOURCES

Prospective Resources are those quantities of petroleum which are estimated, as of a given date, to be potentially recoverable from undiscovered accumulations by application of future projects. Prospective Resources have both an associated chance of discovery and a chance of development.

Prospective Resources are categorized in accordance with the level of certainty associated with recoverable estimates assuming their discovery and development and may be further sub-classified based on project maturity (Refer to Figure 2 at the end of this document). Reference should be made to the full SPE-PRMS for the complete definitions and guidelines.

UNRECOVERABLE

Unrecoverable is a term that refers to that portion of Discovered or Undiscovered Petroleum Initially-in-Place quantities which is estimated, as of a given date, not to be recoverable by future development projects. A portion of these quantities may become recoverable in the future as commercial circumstances change or technological developments occur; the remaining portion may never be recovered due to physical/chemical constraints represented by subsurface interaction of fluids and reservoir rocks.

ADDITIONAL TERMS USED IN RESOURCES CLASSIFICATION (SPE-PRMS)

CHANCE OF COMMERCIALITY

The SPE-PRMS Section 2.1, Table 1 and Appendix A define the following terms relating to commerciality:

The "Chance of Commerciality", as denoted in the SPE-PRMS and as shown in Figure 1, is the chance that the project will be developed and reach commercial producing status.

The chance of commerciality is determined by the probability of a discrete event occurring. In the context of the SPE-PRMS, the discrete event is comprised of one of several conditions, as noted below, which impact the project's commercial viability.

The commercial viability of a development project is dependent on a forecast of the conditions that will exist during the time period encompassed by the project's activities. Commerciality is not solely determined based on the economic status of a project which refers to the situation where the income from an operation exceeds the expenses involved in, or attributable to, that operation. Conditions as noted in the SPE-PRMS include technological, economic, legal, environmental, social, and governmental factors. While economic factors can be summarized as forecast costs and product prices, the underlying influences include, but are not limited to, market conditions, transportation and processing infrastructure, fiscal terms and taxes.

A development project may include one or many wells and associated production and processing facilities. One project may develop many reservoirs, or many projects may be applied to one reservoir. An accumulation or potential accumulation may be subject to several separate and distinct projects that are at different stages of exploration or development. Thus, an accumulation may have recoverable quantities in several resource classes simultaneously.

COMMERCIALITY APPLIED TO RESERVES

Commerciality as applied to Reserves must be based upon all of the following criteria:

- *Evidence to support a reasonable timetable for development.*
- *A reasonable assessment of the future economics of such development projects meeting defined investment and operating criteria.*
- *A reasonable expectation that there will be a market for all or at least the expected sales quantities of production required to justify development.*
- *Evidence that the necessary production and transportation facilities are available or can be made available.*
- *Evidence that legal, contractual, environmental and other social and economic concerns will allow for the actual implementation of the recovery project being evaluated.*
- *High confidence in the commercial producibility of the reservoir.*

To be included in a Reserves class, a project must be sufficiently defined to establish its commercial viability. There must be a reasonable expectation that all required internal and external approvals will be forthcoming.

In general, quantities should not be classified as Reserves unless there is evidence of *firm intention that the accumulation will be developed and placed on production within a reasonable time frame. In certain circumstances, reserves may be assigned even though development may not occur for some time. A reasonable time frame for the initiation of development depends on the specific circumstances and varies according to the scope of the project*. The SPE-PRMS recommends *five years as a benchmark, but notes that a longer time frame could be applied where, for example, development of economic projects are deferred at the option of the producer for, among other things, market-related reasons, or to meet contractual or strategic objectives*.

For a project to be included in a Reserves class *there must be a high confidence in the commercial producibility of the reservoir as supported by actual production or formation tests. In certain cases, Reserves may be assigned on the basis of well logs and/or core analysis that indicate that the subject reservoir is hydrocarbon-bearing and is analogous to reservoirs in the same area that are producing or have demonstrated the ability to produce on formation tests*.

COMMERCIALITY APPLIED TO CONTINGENT RESOURCES

Estimated recoverable quantities from known accumulations that are not yet considered mature enough for commercial development as denoted by meeting all of the aforementioned conditions should be classified as Contingent Resources.

Based on assumptions regarding future conditions and their impact on economic viability, projects currently classified as Contingent Resources may be broadly divided into two groups:

- ***Marginal Contingent Resources*** are those quantities associated with technically feasible projects that are either currently economic or projected to be economic under reasonably forecasted improvements in commercial conditions but are not committed for development because of one or more contingencies.
- ***Sub-Marginal Contingent Resources*** are those quantities associated with discoveries for which analysis indicates that technically feasible development projects would not be economic and/or other contingencies would not be satisfied under current or reasonable forecasted improvements in commercial conditions. These projects nonetheless should be retained in the inventory of discovered resources pending unforeseen major changes in commercial conditions.

Those discovered in-place volumes for which a feasible development project cannot be defined using current or reasonably forecast improvements in technology are classified as Unrecoverable.

RESOURCES CATEGORIZATION (SPE-PRMS)

All estimates of the quantities of petroleum potentially recoverable from an accumulation classified as having Prospective or Contingent Resources or Reserves involve uncertainty. The relative degree of uncertainty may be conveyed by placing the estimated quantities into one of several "categories" as described herein.

The SPE-PRMS Section 2.2 and Appendix A define the following terms:

RANGE OF UNCERTAINTY

The Range of Uncertainty, as denoted in the SPE-PRMS and as shown in Figure 1, reflects a range of estimated quantities potentially recoverable from an accumulation by a project. Evaluators may assess recoverable quantities and categorize results by uncertainty using the deterministic incremental (risk-based) approach, the deterministic scenario (cumulative) approach, or probabilistic methods.

DETERMINISTIC METHODS (SPE-PRMS)

RESERVES

For reserves, the range of uncertainty can be reflected as discrete incremental quantities termed Proved, Probable and Possible or expressed in cumulative terms as 1P (Proved), 2P (Proved plus Probable), and 3P (Proved plus Probable plus Possible), respectively.

CONTINGENT RESOURCES

For Contingent Resources, the range of uncertainty is generally expressed in deterministic scenario (cumulative) terms as 1C, 2C, 3C, respectively or in terms of probability using probabilistic methods. While the SPE-PRMS categorization scheme does not specifically prohibit the use of discrete incremental quantities for Contingent Resources, the SPE-PRMS does not denote the terms to be applied to these discrete incremental quantities.

PROSPECTIVE RESOURCES

For Prospective Resources, the range of uncertainty is generally expressed in deterministic scenario (cumulative) terms as low, best and high estimates or in terms of probability using probabilistic methods. As in the case of Contingent Resources, the SPE-PRMS categorization scheme does not specifically denote terms to be applied to discrete incremental quantities for Prospective Resources.

INCREMENTAL TERMS FOR CONTINGENT AND PROSPECTIVE RESOURCES (RYDER SCOTT)

Should evaluators choose to characterize the range of uncertainty for Contingent Resources or Prospective Resources in discrete incremental quantities, they should denote such quantities as such and provide sufficient detail in their report to allow an independent evaluator or auditor to clearly understand the basis for estimation and categorization of the recoverable quantities. For reports prepared by Ryder Scott Company (Ryder Scott), the range of uncertainty for discrete incremental quantities of Contingent Resources shall be termed 1C Incremental (1Ci), 2C Incremental (2Ci) and 3C Incremental (3Ci) and in the case of Prospective Resources shall be termed Low Estimate Incremental (LEi), Best Estimate Incremental (BEi) and High Estimate Incremental (HEi) where (i) denotes a specific incremental quantity.

BEST ESTIMATE

Uncertainty in resource estimates is best communicated by reporting a range of potential results. However, if it is required to report a single representative result, the "best estimate" is considered the most realistic assessment of recoverable quantities. The term "best estimate" is used here as a generic expression for the estimate considered being closest to the quantity that will actually be recovered from the accumulation between the date of the estimate and the time of abandonment. In the case of reserves, the best estimate is generally considered to represent *the sum of Proved and Probable estimates (2P). It should be noted that under the incremental (risk-based) approach for Reserves, discrete estimates are made for the quantities in each category for Proved and Probable, and they should not be aggregated without due consideration of their associated risk*. In the case of Contingent Resources and Prospective Resources, the best estimate would be represented by the 2C and Best Estimate, respectively. If probabilistic methods are used, this term would generally be a measure of central tendency of the uncertainty distribution (most likely/mode, median/P50 or mean). The terms "Low Estimate" and "High Estimate" should provide a reasonable assessment of the range of uncertainty in the Best Estimate.

PROBABILISTIC METHODS (SPE-PRMS)

If probabilistic methods are used, these estimated quantities should be based on methodologies analogous to those applicable to the definitions of Reserves, Contingent Resources and Prospective Resources; therefore, in general, the resulting probabilities should correspond to the deterministic terms as follows:

- There should be at least a 90% probability (P90) that the quantities actually recovered will equal or exceed the 1P, 1C or Low Estimate.
- There should be at least a 50% probability (P50) that the quantities actually recovered will equal or exceed the 2P, 2C or Best Estimate.
- There should be at least a 10% probability (P10) that the quantities actually recovered will equal or exceed the 3P, 3C or High Estimate.

COMPARABILITY OF SIMILAR RESERVES AND RESOURCE CATEGORIES

As indicated in Figure 1, the 1C, 2C and 3C Contingent Resource estimates and the Low, Best and High Prospective Resource estimates of potentially recoverable volumes should reflect some comparability with the reserves categories of Proved (1P), Proved plus Probable (2P) and Proved plus Probable plus Possible (3P), respectively. *While there may be a significant risk that sub-commercial or undiscovered accumulations will not achieve commercial production, it is useful to consider the range of potentially recoverable volumes independently of such a risk.*

Without new technical information, there should be no change in the distribution of technically recoverable volumes and their categorization boundaries when conditions are satisfied sufficiently to reclassify a project from Contingent Resources to Reserves.

AGGREGATION

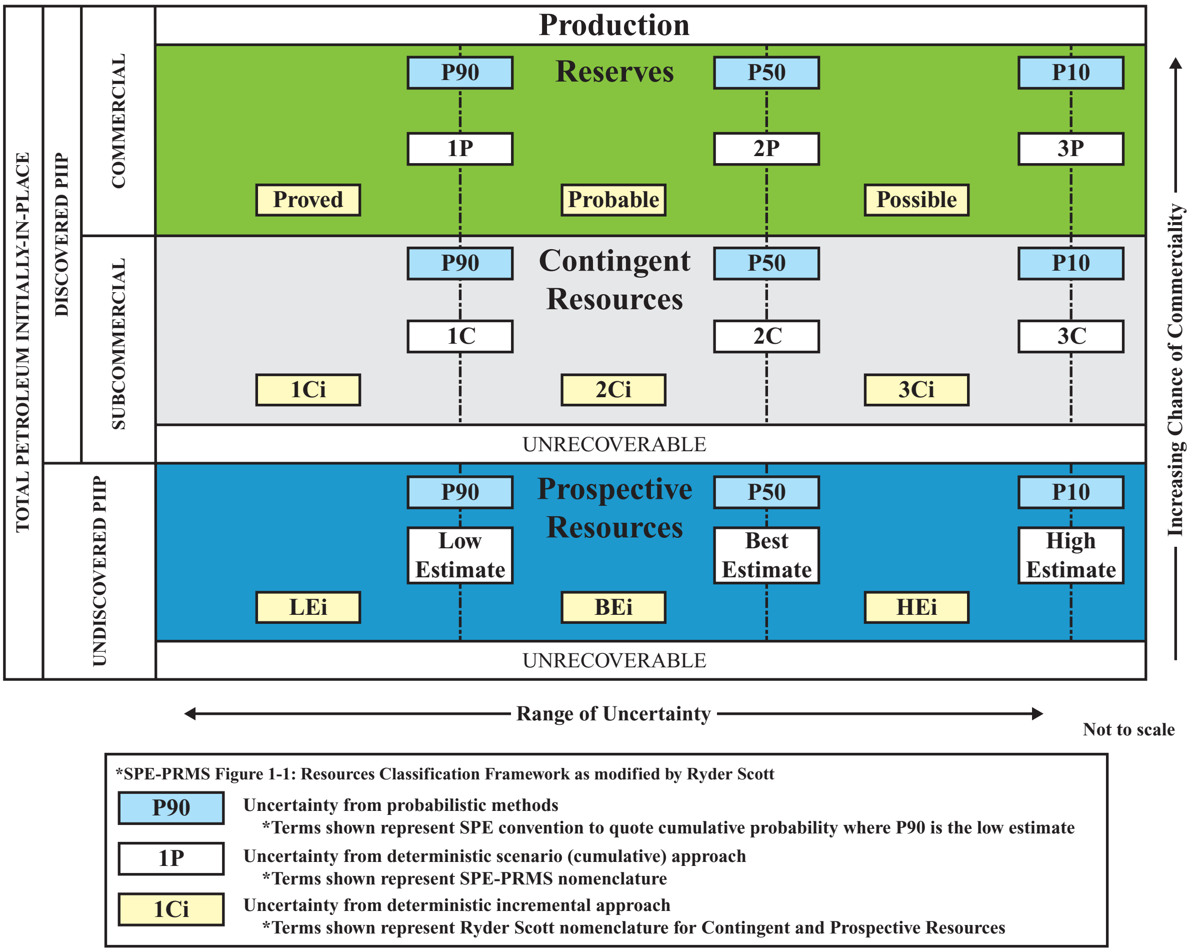
Petroleum quantities classified as Reserves, Contingent Resources or Prospective Resources should not be aggregated with each other without due consideration of the significant differences in the criteria associated with their classification. In particular, there may be a significant risk that accumulations containing Contingent Resources or Prospective Resources will not achieve commercial production. Similarly, reserves and resources of different categories should not be aggregated with each other without due consideration of the significant differences in the criteria associated with their categorization.

RESOURSES CLASSIFICATION SYSTEM(SPE-PRMS)

GRAPHICAL REPRESENTATION

Figure 1 is a graphical representation of the SPE, WPC, AAPG, SPEE resources classification system. The horizontal axis represents the "Range of Uncertainty" in the estimated potentially recoverable volume for an accumulation by a project, whereas the vertical axis represents the "Chance of Commerciality", that is, the chance that the project will be developed and reach commercial producing status.

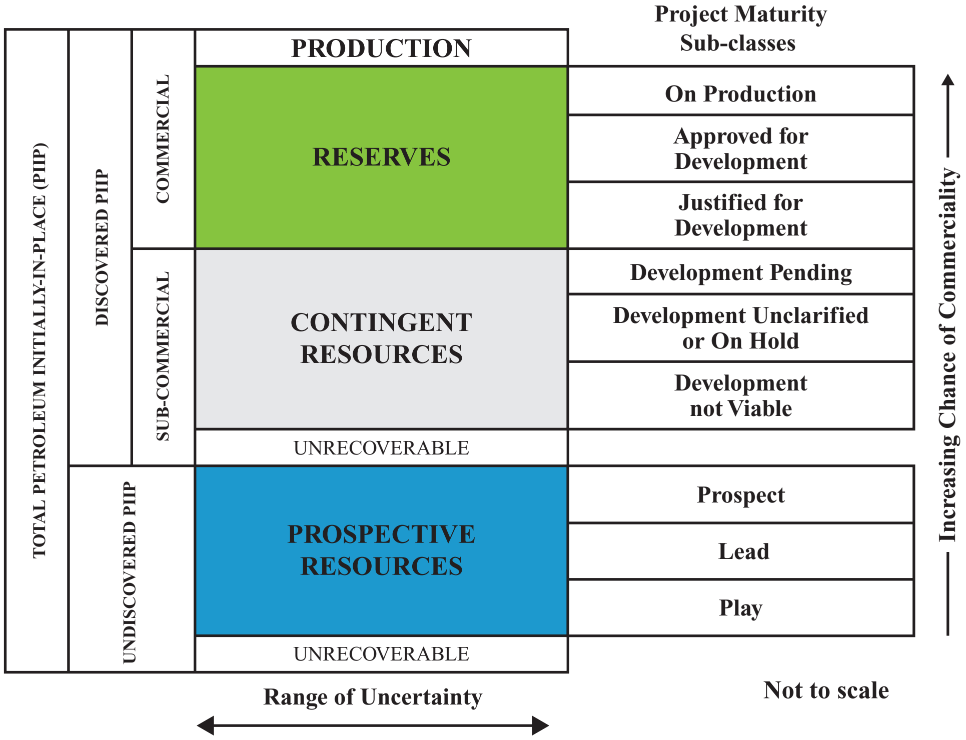
Figure 1
SPE, WPC, AAPG, SPEE
RESOURCES CLASSIFICATION SYSTEM*



INCREMENTAL TERMS FOR CONTINGENT AND PROSPECTIVE RESOURCES AS DEFINED BY RYDER SCOTT

Should evaluators choose to characterize the range of uncertainty for Contingent Resources or Prospective Resources in discrete incremental quantities, they should denote such quantities as such and provide sufficient detail in their report to allow an independent evaluator or auditor to clearly understand the basis for estimation and categorization of the recoverable quantities. For reports prepared by Ryder Scott Company (Ryder Scott), the range of uncertainty for discrete incremental quantities of Contingent Resources shall be termed 1C Incremental (1Ci), 2C Incremental (2Ci) and 3C Incremental (3Ci) and in the case of Prospective Resources shall be termed Low Estimate Incremental (LEi), Best Estimate Incremental (BEi) and High Estimate Incremental (HEi) where (i) denotes a specific incremental quantity.

Figure 2
SPE, WPC, AAPG, SPEE
PROJECT MATURITY SUB-CLASSES



[1] Petroleum Resources Management System prepared by the Oil and Gas Reserves Committee of the Society of Petroleum Engineers (SPE); reviewed and jointly sponsored by the World Petroleum Council (WPC), the American Association of Petroleum Geologists (AAPG), and the Society of Petroleum Evaluation Engineers (SPEE), March 2007.

Table 1: Recoverable Resources Classes and Sub-Classes

Class/ Sub-Class	Definition	Guidelines
Reserves	Reserves are those quantities of petroleum anticipated to be commercially recoverable by application of development projects to known accumulations from a given date forward under defined conditions.	Reserves must satisfy four criteria: they must be discovered, recoverable, commercial and remaining based on the development project(s) applied. Reserves are further subdivided in accordance with the level of certainty associated with the estimates and may be sub-classified based on project maturity and/or characterized by their development and production status. To be included in the Reserves class, a project must be sufficiently defined to establish its commercial viability. There must be a reasonable expectation that all required internal and external approvals will be forthcoming, and there is evidence of firm intention to proceed with development within a reasonable time frame.

Class/ Sub-Class	Definition	Guidelines
		A reasonable time frame for the initiation of development depends on the specific circumstances and varies according to the scope of the project. While 5 years is recommended as a benchmark, a longer time frame could be applied where, for example, development of economic projects are deferred at the option of the producer for, among other things, market-related reasons, or to meet contractual or strategic objectives. In all cases, the justification for classification as Reserves should be clearly documented. To be included in the Reserves class, there must be a high confidence in the commercial producibility of the reservoir as supported by actual production or formation tests. In certain cases, Reserves may be assigned on the basis of well logs and/or core analysis that indicate that the subject reservoir is hydrocarbon-bearing and is analogous to reservoirs in the same area that are producing or have demonstrated the ability to produce on formation tests
On Production	The development project is currently producing and selling petroleum to market.	The key criterion is that the project is receiving income from sales, rather than the approved development project necessarily being complete. This is the point at which the project "chance of commercially" can be said to be 100%. The project "decision gate" is the decision to initiate commercial production from the project.
Approved for Development	All necessary approvals have been obtained, capital funds have been committed, and implementation of the development project is under way.	At this point, it must be certain that the development project is going ahead. The project must not be subject to any contingencies, such as outstanding regulatory approvals or sales contracts. Forecast capital expenditures should be included in the reporting entity's current or following year's approved budget. The project "decision gate" is the decision to start investing capital in the construction of production facilities and/or drilling development wells.
Justified for Development	Implementation of the development project is justified on the basis of reasonable forecast commercial conditions at the time of reporting, and there are reasonable expectations that all necessary approvals/contracts will be obtained.	In order to move to this level of project maturity, and hence have reserves associated with it, the development project must be commercially viable at the time of reporting, based on the reporting entity's assumptions of future prices, costs, etc. ("forecast case") and the specific circumstances of the project. Evidence of a firm intention to proceed with development within a reasonable time frame will be sufficient to demonstrate commerciality. There should be a development plan in sufficient detail to

Class/ Sub-Class	Definition	Guidelines
		support the assessment of commerciality and a reasonable expectation that any regulatory approvals or sales contracts required prior to project implementation will be forthcoming. Other than such approvals/contracts, there should be no known contingencies that could preclude the development from proceeding within a reasonable timeframe (see Reserves class). The project "decision gate" is the decision by the reporting entity and its partners, if any, that the project has reached a level of technical and commercial maturity sufficient to justify proceeding with development at that point in time.
Contingent Resources	Those quantities of petroleum estimated, as of a given date, to be potentially recoverable from known accumulations by application of development projects, but which are not currently considered to be commercially recoverable due to one or more contingencies.	Contingent Resources may include, for example, projects for which there are currently no viable markets, or where commercial recovery is dependent on technology under development, or where evaluation of the accumulation is insufficient to clearly assess commerciality. Contingent Resources are further categorized in accordance with the level of certainty associated with the estimates and may be sub-classified based on project maturity and/or characterized by their economic status.
Development Pending	A discovered accumulation where project activities are ongoing to justify commercial development in the foreseeable future.	The project is seen to have reasonable potential for eventual commercial development, to the extent that further data acquisition (e.g. drilling, seismic data) and/or evaluations are currently ongoing with a view to confirming that the project is commercially viable and providing the basis for selection of an appropriate development plan. The critical contingencies have been identified and are reasonably expected to be resolved within a reasonable time frame. Note that disappointing appraisal/ evaluation results could lead to a re-classification of the project to "On Hold" or "Not Viable" status. The project "decision gate" is the decision to undertake further data acquisition and/or studies designed to move the project to a level of technical and commercial maturity at which a decision can be made to proceed with development and production.
Development Unclarified or on Hold	A discovered accumulation where project activities are on hold and/or where justification as a commercial development may be subject to significant delay.	The project is seen to have potential for eventual commercial development, but further appraisal/ evaluation activities are on hold pending the removal of significant contingencies external to the project, or substantial further appraisal/ evaluation activities are required to clarify the potential for eventual commercial development. Development may be subject to a significant

Class/ Sub-Class	Definition	Guidelines
		time delay. Note that a change in circumstances, such that there is no longer a reasonable expectation that a critical contingency can be removed in the foreseeable future, for example, could lead to a re-classification of the project to "Not Viable" status. The project "decision gate" is the decision to either proceed with additional evaluation designed to clarify the potential for eventual commercial development or to temporarily suspend or delay further activities pending resolution of external contingencies.
Development Not Viable	A discovered accumulation for which there are no current plans to develop or to acquire additional data at the time due to limited production potential.	The project is not seen to have potential for eventual commercial development at the time of reporting, but the theoretically recoverable quantities are recorded so that the potential opportunity will be recognized in the event of a major change in technology or commercial conditions. The project "decision gate" is the decision not to undertake any further data acquisition or studies on the project for the foreseeable future.
Prospective Resources	Those quantities of petroleum which are estimated, as of a given date, to be potentially recoverable from undiscovered accumulations.	Potential accumulations are evaluated according to their chance of discovery and, assuming a discovery, the estimated quantities that would be recoverable under defined development projects. It is recognized that the development programs will be of significantly less detail and depend more heavily on analog developments in the earlier phases of exploration.
Prospect	A project associated with a potential accumulation that is sufficiently well defined to represent a viable drilling target.	Project activities are focused on assessing the chance of discovery and, assuming discovery, the range of potential recoverable quantities under a commercial development program.
Lead	A project associated with a potential accumulation that is currently poorly defined and requires more data acquisition and/or evaluation in order to be classified as a prospect.	Project activities are focused on acquiring additional data and/or undertaking further evaluation designed to confirm whether or not the lead can be matured into a prospect. Such evaluation includes the assessment of the chance of discovery and, assuming discovery, the range of potential recovery under feasible development scenarios.
Play	A project associated with a prospective trend of potential prospects, but which requires more data acquisition and/or evaluation in order to define specific leads or prospects.	Project activities are focused on acquiring additional data and/or undertaking further evaluation designed to define specific leads or prospects for more detailed analysis of their chance of discovery and, assuming discovery, the range of potential recovery under hypothetical development scenarios.

1 "Petroleum Resources Management System, prepared by the Oil and Gas Reserves Committee of the Society of Petroleum Engineers (SPE); reviewed and jointly sponsored by the World Petroleum Council (WPC), the American Association of Petroleum Geologists (AAPG), and the Society of Petroleum Evaluation Engineers (SPEE), March 2007

PETROLEUM RESERVES and RESOURCES STATUS DEFINITIONS and GUIDELINES As

Adapted From:
PETROLEUM RESOURCES MANAGEMENT SYSTEM (SPE-PRMS)

Sponsored and Approved by:
SOCIETY OF PETROLEUM ENGINEERS (SPE),
WORLD PETROLEUM COUNCIL (WPC)
AMERICAN ASSOCIATION OF PETROLEUM GEOLOGISTS (AAPG)
SOCIETY OF PETROLEUM EVALUATION ENGINEERS (SPEE) RESERVES

RESERVES

Reserves status categories define the development and producing status of wells and reservoirs. The SPE-PRMS Table 2 defines the reserves status categories as follows:

DEVELOPED RESERVES (SPE-PRMS DEFINITIONS)

Developed Reserves are expected quantities to be recovered from existing wells and facilities.

Reserves are considered developed only after the necessary equipment has been installed, or when the costs to do so are relatively minor compared to the cost of a well. Where required facilities become unavailable, it may be necessary to reclassify Developed Reserves as Undeveloped. Developed Reserves may be further sub-classified as Producing or Non-Producing.

Developed Producing

Developed Producing Reserves are expected to be recovered from completion intervals that are open and producing at the time of the estimate.

Improved recovery reserves are considered producing only after the improved recovery project is in operation.

Developed Non-Producing

Developed Non-Producing Reserves include shut-in and behind-pipe Reserves.

Shut-In

Shut-in Reserves are expected to be recovered from:

(1) completion intervals which are open at the time of the estimate but which have not yet started producing;

(2) wells which were shut-in for market conditions or pipeline connections; or

(3) wells not capable of production for mechanical reasons.

Behind-Pipe

Behind-pipe Reserves are expected to be recovered from zones in existing wells which will require additional completion work or future re-completion prior to start of production.

In all cases, production can be initiated or restored with relatively low expenditure compared to the cost of drilling a new well.

UNDEVELOPED RESERVES (SPE-PRMS DEFINITIONS)

Undeveloped Reserves are quantities expected to be recovered through future investments.

Undeveloped Reserves are expected to be recovered from:

(1) new wells on undrilled acreage in known accumulations;

(2) deepening existing wells to a different (but known) reservoir;

(3) infill wells that will increase recovery; or

(4) where a relatively large expenditure (e.g. when compared to the cost of drilling a new well) is required to

(a) recomplete an existing well; or

(b) install production or transportation facilities for primary or improved recovery projects.

CONTINGENT RESOURCES

Contingent Resources may include, for example, projects for which there are currently no viable markets, or where commercial recovery is dependent on technology under development, or where evaluation of the accumulation is insufficient to clearly assess commerciality. Contingent resource status categories may address the development and producing status of wells and reservoirs or may reflect the project maturity and/or be characterized by their economic status as noted in the SPE-PRMS Table 1 and Figure 2.

PROSPECTIVE RESOURCES

Prospective resources are by definition undeveloped as they are potentially recoverable from undiscovered accumulations. Prospective resource status categories reflect project maturity as noted in the SPE-PRMS Table 1 and Figure 2.

PART 16
TAXATION

1. Netherlands taxation

The following discussion, subject to the limitations set forth below, describes material tax considerations of the Netherlands relating to your acquisition, ownership and disposition of the Ordinary Shares. This discussion is based on laws, regulations, rulings and decisions as at the date of this Prospectus in effect in the Netherlands, which, in each case, may change. Any change could apply retroactively and could affect the continued validity of this discussion. This discussion does not purport to be a complete analysis of all tax considerations in the Netherlands, and this discussion does not describe all of the tax considerations that may be relevant to you or your situation, particularly if you are subject to special tax rules. You should consult your own tax advisors about the tax consequences of holding the Ordinary Shares, including the relevance to your particular situation of the considerations discussed below, as well as of state, local and other tax laws. This discussion assumes that each transaction relating to the Ordinary Shares is at arm's length.

1.1 *General*

The following is a general summary of certain Netherlands tax consequences of the acquisition, holding and disposal of Ordinary Shares. This summary does not purport to describe all possible tax considerations or consequences that may be relevant to a Shareholder or prospective Shareholder of Ordinary Shares and does not purport to deal with the tax consequences applicable to all categories of investors, some of which (such as investors that are subject to taxation in Bonaire, Sint Eustatius and Saba and trusts or similar arrangements) may be subject to special rules. In view of its general nature, it should be treated with corresponding caution. Holders or prospective Shareholders of Ordinary Shares should consult with their own tax advisers with regard to the tax consequences of investing in the Ordinary Shares in their particular circumstances. The discussion below is included for general information purposes only.

Except as otherwise indicated, this summary only addresses Netherlands domestic tax legislation and published regulations, as in effect on the date hereof and as interpreted in published case law until this date, without prejudice to any amendment introduced at a later date and implemented with or without retroactive effect.

Please note that the summary in this section does not describe the Netherlands tax consequences for:

(i) Shareholders of Ordinary Shares if such Shareholders, and in the case of individuals, his/her partner or certain of their relatives by blood or marriage in the direct line (including foster children), have a substantial interest (in Dutch: "*aanmerkelijk belang*") or deemed substantial interest in the Company under the Netherlands Income Tax Act 2001 (In Dutch: "*Wet inkomstenbelasting 2001*"). Generally speaking, a Shareholder in a company is considered to hold a substantial interest in such company, if such holder alone or, in the case of individuals, together with his/her partner and certain relatives by blood in the direct line (as defined in the Netherlands Income Tax Act 2001), directly or indirectly, holds (i) an interest of 5% or more of the total issued and outstanding capital of that company or of 5% or more of the issued and outstanding capital of a certain class of shares of that company; or (ii) rights to acquire, directly or indirectly, such interest; or (iii) certain profit sharing rights in that company that relate to 5% or more of the company's annual profits and/ or to 5% or more of the company's liquidation proceeds. A deemed substantial interest may arise if a substantial interest (or part thereof) in a company has been disposed of, or is deemed to have been disposed of, on a non-recognition basis as a result of applying a tax facility (rollover facility);

(ii) pension funds, investment institutions (in Dutch: "*fiscale beleggingsinstellingen*"), exempt investment institutions (in Dutch: "*vrijgestelde beleggingsinstellingen*") (as defined in the Netherlands Corporate Income Tax Act 1969) and other entities that are exempt from Netherlands corporate income tax; and

(iii) Shareholders of Ordinary Shares who are individuals for whom the Ordinary Shares or any benefit derived from the Ordinary Shares are a remuneration or deemed to be a remuneration for activities performed by such Shareholders or certain individuals related to such Shareholder (as defined in the Netherlands Income Tax Act 2001).

1.2 ***Dividend withholding tax***

1.2.1 ***Withholding requirement***

The Company is required to withhold 15% Dutch dividend tax in respect of dividends paid on the Ordinary Shares. Under the Dutch Dividend Tax Act of 1965 (*Wet op de dividendbelasting 1965*), dividends are defined as the proceeds from shares, which include:

(a) proceeds in cash or in kind including direct or indirect distributions of profit;

(b) liquidation proceeds, proceeds on redemption of the Ordinary Shares and, as a rule, the consideration for the repurchase of the Ordinary Shares by the Company in excess of its average paid-in capital recognised for Dutch dividend tax purposes, unless a particular statutory exemption applies;

(c) the nominal value of Ordinary Shares issued to a holder of Ordinary Shares or an increase in the nominal value of the Ordinary Shares, except when the (increase in the) nominal value of the Ordinary Shares is funded out of the Company's paid-in capital as recognised for Dutch dividend tax purposes; and

(d) partial repayments of paid-in capital for tax purposes, if and to the extent there are qualifying profits (***'zuivere winst'***), unless the General Meeting has resolved in advance to make such repayment and provided that the nominal value of the Ordinary Shares concerned has been reduced by an equal amount by way of an amendment of the Articles of Association and the paid-in capital is recognised as capital for Dutch dividend tax purposes.

1.2.2 ***Residents of the Netherlands***

If a Shareholder is a resident of the Netherlands or a deemed resident of the Netherlands or is an individual who has opted to be treated as a resident for the purposes of the Netherlands Income Tax Act 2001, Dutch dividend tax which is withheld with respect to proceeds from the Ordinary Shares will generally be creditable and/or refundable for Dutch corporate income tax or Dutch income tax purposes if the Shareholder is the beneficial owner (as described below) thereof.

1.2.3 ***Non-residents of the Netherlands***

If a Shareholder is a resident of a country other than the Netherlands, and if a treaty for the avoidance of double taxation with respect to taxes on income is in effect between the Netherlands and that country, and such Shareholder is the beneficial owner (as described below) of the proceeds from the Ordinary Shares and a resident for the purposes of such treaty, the Shareholder may, depending on the terms of that particular treaty, qualify for full or partial relief at source or for a refund in whole or in part of the Dutch dividend tax. The non-resident of the Netherlands Shareholder, depending on the tax legislation of its country of residence, may obtain a tax credit, in part or in full, of the Dutch dividend tax withheld. Non-Dutch resident Shareholders should consult their own tax advisers concerning their tax liabilities and tax credit opportunities.

A refund of the Dutch dividend tax may under circumstance be available to entities resident in another Member State of the European Union, provided these entities are not subject to corporate income tax there and would not be subject to Dutch corporate income tax if they were tax-resident in the Netherlands.

1.2.4 ***Beneficial owner***

A recipient of proceeds from the Ordinary Shares will not be entitled to any exemption, reduction, refund or credit of Dutch dividend tax if such recipient is not considered to be the beneficial owner of such proceeds. The recipient will, inter alia, not be considered the beneficial owner of these proceeds, if, in connection with such proceeds, the recipient has paid a consideration as part of a series of transactions in respect of which it is likely that:

(a) the proceeds have in whole or in part accumulated, directly or indirectly, to a person or legal entity that would:

    (i) as opposed to the recipient paying the consideration, not be entitled to an exemption from dividend tax; or

    (ii) in comparison to the recipient paying the consideration, to a lesser extent be entitled to a lower rate or refund of dividend tax; and

(b) such person or legal entity has, directly or indirectly, retained or acquired an interest in shares, profit sharing certificates or loans, comparable to the interest it had in similar instruments prior to the series of transactions being initiated.

1.2.5 *Reduction of Dutch withholding tax upon redistribution of foreign dividends*

Provided certain conditions are met, the Company may apply a reduction of the withholding tax imposed on certain qualifying dividends distributed by the Company, if the Company has itself received dividends from certain qualifying non-Dutch subsidiaries, which dividends were subject to withholding tax upon distribution to the Company. The reduction of the Dutch withholding tax imposed on these dividends that are distributed by the Company is equal to the lesser of:

(a) 3% of the amount of the dividends distributed by the Company that are subject to withholding tax; and

(b) 3% of the gross amount of the dividends received during a certain period from the qualifying non-Dutch subsidiaries.

The reduction is applied to the Dutch dividend tax that the Company must pay to the Dutch tax authorities and not to the amount of the Dutch dividend tax that the Company must withhold.

1.3 *Taxes on income and capital gains*

1.3.1 *Residents of the Netherlands*

Generally speaking, if the Shareholder of the Ordinary Shares is an entity that is a resident or deemed to be resident of the Netherlands for Netherlands corporate income tax purposes, any income derived from the Ordinary Shares or any gain or loss realized on the disposal or deemed disposal of the Ordinary Shares is subject to Netherlands corporate income tax at a rate of 25% (a corporate income tax rate of 20% applies with respect to taxable profits up to 200,000, the bracket for 2014).

If a Shareholder of the Ordinary Shares is an individual, resident or deemed to be resident of the Netherlands for Netherlands income tax purposes (including the non-resident individual Shareholder who has made an election for the application of the rules of the Netherlands Income Tax Act 2001 as they apply to residents of the Netherlands), any income derived from the Ordinary Shares or any gain or loss realized on the disposal or deemed disposal of the Ordinary Shares is taxable at the progressive income tax rates (with a maximum of 52%), if:

(i) the Ordinary Shares are attributable to an enterprise from which the Shareholder of the Ordinary Shares derives a share of the profit, whether as an entrepreneur or as a person who has a co-entitlement to the net worth of such enterprise without being an entrepreneur or a shareholder (as defined in the Netherlands Income Tax Act 2001); or

(ii) the Shareholder of the Ordinary Shares is considered to perform activities with respect to the Ordinary Shares that go beyond ordinary asset management (in Dutch: "*normaal, actief vermogensbeheer*") or derives benefits from the Ordinary Shares that are (otherwise) taxable as benefits from other activities (in Dutch: "*resultaat uit overige werkzaamheden*").

If the above-mentioned conditions (i) and (ii) do not apply to the individual Shareholder of the Ordinary Shares, such Shareholder will be taxed annually on a deemed income of 4% of his/her net investment assets for the year at an income tax rate of 30% (leading to a net effective tax rate on investment assets of 1.2%). The net investment assets for the year are the fair market value of the investment assets less the allowable liabilities on 1 January of the relevant calendar year. The Ordinary Shares are included as investment assets. A tax free allowance may be available to decrease the amount of net investment assets on which the tax is levied. Actual interest income or an actual gain or loss in respect of the Ordinary Shares is as such not subject to Netherlands income tax.

1.3.2 *Non-residents of the Netherlands*

A Shareholder of the Ordinary Shares that is neither resident nor deemed to be resident of the Netherlands nor has made an election for the application of the rules of the Netherlands Income Tax Act 2001 as they apply to residents of the Netherlands will not be subject to Netherlands taxes on income or capital gains in respect of any income derived from the Ordinary Shares or in respect of any gain or loss realized on the disposal or deemed disposal of the Ordinary Shares, provided that:

(i) such Shareholder does not have an interest in an enterprise or deemed enterprise (as defined in the Netherlands Income Tax Act 2001 and the Netherlands Corporate Income Tax Act 1969, including, but not limited to, article 17-3-c) which, in whole or in part, is either effectively managed in the Netherlands or carried on through a permanent establishment, a deemed permanent establishment or a permanent representative in the Netherlands and to which enterprise or part of an enterprise the Ordinary Shares are attributable;

(ii) in the event the Shareholder is an individual, such Shareholder does not carry out any activities in the Netherlands with respect to the Ordinary Shares that go beyond ordinary asset management and does not derive benefits from the Ordinary Shares that are (otherwise) taxable as benefits from other activities in the Netherlands; and

(iii) such Shareholder does not have an interest in an enterprise in the Netherlands other than by way of the holding of securities and is not a managing director or part of a supervisory board of an enterprise in the Netherlands.

A Shareholder of an Ordinary Share should not become subject to taxation in the Netherlands by reason only of the execution, delivery or enforcement of the Ordinary Shares or the performance by the Company of its obligations under the Ordinary Shares.

1.4 ***Value added tax (VAT)***

No Netherlands VAT should be payable by the Shareholders of the Ordinary Shares on any payment in consideration for the issue or transfer of the Ordinary Shares or with respect to the payment of any dividends by the Company.

1.5 ***Other taxes and duties***

No Dutch registration tax, customs duty, transfer tax, stamp duty, capital tax or any other similar documentary tax or duty will be payable in the Netherlands by a Shareholder in respect of or in connection with the subscription, issue, placement, allotment, delivery or transfer of the Ordinary Shares.

2. United Kingdom taxation

2.1 ***General***

The following comments do not constitute legal or tax advice and are intended only as a general guide to certain UK tax considerations under current UK tax law and published practice of HM Revenue & Customs as at the date of this Prospectus (both of which are subject to change at any time, possibly with retrospective effect) and do not purport to be a complete analysis of all potential UK tax consequences of holding the Ordinary Shares. They relate only to certain limited aspects of the UK taxation treatment of Shareholders and are intended to apply only to dividends and disposals of shares in a company tax resident in the Netherlands and Shareholders who are resident and, if individuals, also domiciled in (and only in) the UK for UK taxation purposes (except insofar as express reference is made to the treatment of non-UK residents), who are absolute beneficial owners of Ordinary Shares and any dividends paid in respect of them, who hold their Ordinary Shares as investments (otherwise than through an Individual Savings Account or a Self Invested Personal Pension) and not as securities to be realised in the course of a trade and who do not directly or indirectly control, together with connected or associated persons, more than 10% of the voting power or share capital in the Company. They may not apply to certain classes of investors, such as dealers in securities, insurance companies and collective investment schemes, Shareholders who are exempt from taxation and Shareholders who have (or are deemed to have) acquired their Ordinary Shares by virtue of an office or employment. Such persons may be subject to special rules. The following summary is based on the assumption that the Company is solely resident in the Netherlands for the purposes of tax.

Any person who is in doubt as to their tax position or is subject to tax in a jurisdiction other than the UK is strongly recommended to consult their own professional adviser.

2.2 ***Taxation of dividends***

(a) UK withholding tax

The Company is not required to withhold United Kingdom tax when paying a dividend (although note the comments in paragraph 1.2.1 of this Part 16 relating to Dutch withholding tax). Liability to UK tax on dividends will depend upon the individual circumstances of a Shareholder.

(b) Credit for Dutch withholding tax

Shareholders' attention is drawn to the statements regarding Dutch withholding tax which are contained in paragraph 1.2.1 of this Part 16. If a Shareholder receives a dividend on Ordinary Shares and the dividend is paid subject to Dutch withholding tax, credit for such Dutch withholding tax may be available for set-off against a liability to UK corporation tax or UK income tax on the dividend. The amount of such credit will normally be equal to the lesser of the amount withheld and the liability to UK tax on the dividend. Such credit will not normally be available for set-off against an Shareholder's liability to UK tax other than on the dividend and, to the extent that such credit is not set-off against UK tax on the dividend, the credit will be lost. Credit will not be available to the extent that the Dutch withholding tax can be minimized or repaid by taking reasonable steps under a double tax treaty or a provision of Dutch law (in which regard see section 1.2 of this Part 16).

(c) *UK resident Shareholders*

An individual Shareholder who is resident for tax purposes in the UK and who receives a dividend from the Company will generally be entitled to a tax credit equal to one-ninth of the amount of the dividend (before deduction of Dutch withholding tax, if any), which is equivalent to 10% of the aggregate of the dividend and the tax credit (the "gross dividend"), and will be subject to income tax on the gross dividend. An individual UK resident Shareholder who is subject to income tax at a rate or rates not exceeding the basic rate will be liable to tax on the gross dividend at the rate of 10%, so that the tax credit will satisfy the income tax liability of such a Shareholder in full. Where the tax credit exceeds the Shareholder's tax liability the Shareholder cannot claim repayment of the tax credit from HM Revenue & Customs.

An individual UK resident Shareholder who is subject to income tax at the higher rate will be liable to income tax on the gross dividend at the rate of 32.5% to the extent that such sum, when treated as the top slice of that Shareholder's income, exceeds the threshold for higher rate income tax but is below the threshold for the additional rate of income tax. After taking into account the 10% tax credit, a higher rate taxpayer will therefore be liable to additional income tax of 22.5% of the gross dividend, equal to 25% of the dividend (gross of any Dutch withholding tax), to the extent that the gross dividend falls within the threshold for taxation at the higher rate (subject to credit for Dutch withholding tax (if any) which as discussed above may be available for set-off against a liability to UK tax).

If and to the extent the gross dividend is received by an individual UK resident Shareholder who is subject to income tax at the additional rate (which applies to taxable non-savings and savings income in excess of £150,000), that individual will be subject to tax on the gross dividend at the dividend additional rate, currently 37.5%, to the extent that the gross dividend exceeds the threshold for the additional rate when treated as the top slice of that Shareholder's income. In the same way as in relation to a Shareholder who is subject to income tax at the higher rate, the 10% tax credit may be set off against part of his liability. This will have the effect that the Shareholder will have to account for tax equal to 27.5% of the gross dividend, or approximatley 30.6% of the dividend (gross of any Dutch withholding tax), to the extent that the gross dividend falls within the threshold for taxation at the additional rate (subject to credit for Dutch withholding tax (if any) which as discussed above may be available for set-off against a liability to UK tax).

Such individual UK resident Shareholder may be entitled to credit for any withholding tax suffered at source in the Netherlands on any dividends received from the Company.

(d) *UK Corporate Shareholders*

UK resident corporate Shareholders who are within the charge to UK corporation tax will be subject to UK corporation tax on dividends paid on the Ordinary Shares by the Company (at the current rate of 21% for the financial year 2014/2015 reducing to 20% for the financial year 2015/2016) unless (subject to special rules for such Shareholders that are small companies) the dividends fall within an exempt class and certain other conditions are satisfied, in which case the dividends should be exempt from UK corporation tax. It is likely that most dividends paid on the Ordinary Shares to UK resident corporate Shareholders would fall within one or more of the exempt classes of dividend qualifying for exemption from UK corporation tax, although it should be noted that the exemptions are not comprehensive and are also subject to anti-avoidance rules.

It is possible for a corporate Shareholder within the charge to UK corporation tax to elect for exemption not to apply such that the dividend would be taxable. In such circumstances, such corporate Shareholder may be able to claim credit for any withholding tax suffered at source in the Netherlands on any dividends received from the Company.

2.3 *Taxation of chargeable gains*

(a) *UK resident Shareholders*

A disposal or deemed disposal of Ordinary Shares by a Shareholder who is resident in the UK for UK taxation purposes for (in the case of a corporate Shareholder) the relevant accounting period or (in the case of an individual Shareholder) at any time in the relevant tax year may give rise to a chargeable gain or an allowable loss for the purposes of UK taxation of chargeable gains, depending on the Shareholder's circumstances and subject to any available exemption or relief.

For a UK resident corporate Shareholder within the charge to UK corporation tax, indexation allowance may be available to reduce the amount of chargeable gain realised on a subsequent disposal but not to generate or increase an allowable loss.

In the case of a Shareholder who is an individual, indexation allowance is not available and chargeable gains are generally liable to UK capital gains tax at the applicable rate (currently either 18% or 28% depending on the individual's circumstances). An individual Shareholder is currently entitled to an annual exemption from UK taxation of chargeable gains up to £11,000 in the 2014/2015 tax year.

(b) *Non-UK resident Shareholders*

A Shareholder who is not resident in the UK for UK taxation purposes will not generally be subject to UK taxation of capital gains on the disposal or deemed disposal of Ordinary Shares unless they are carrying on a trade in the UK through a permanent establishment in the UK to which the Ordinary Shares are attributable (in the case of a corporate Shareholder) or carrying on a trade, profession or vocation in the UK through a branch or agency in the UK to which the Ordinary Shares are attributable (in the case of an individual Shareholder).

A Shareholder who is an individual and who acquired Ordinary Shares whilst resident in the UK for UK taxation purposes, who ceases to be resident for UK tax purposes in the UK for a period of less than five tax years and who disposes of all or part of his Ordinary Shares during that period (i.e. the period of temporary non-UK residence) may be liable, on his return to the UK, to UK taxation of chargeable gains (subject to any available exemption or relief). Shareholders who are in any doubt about their tax position should consult their own professional tax advisers.

2.4 ***Stamp duty and stamp duty reserve tax ("SDRT")***

The statements below summarise the current position and are only intended as a general guide to UK stamp duty and SDRT. Special rules apply, for example, to agreements made by broker dealers and market makers in the ordinary course of their business and to certain categories of person (such as certain persons providing clearance services or issuing depositary receipts) who may be liable to stamp duty or SDRT at a higher rate or may, although not primarily liable for SDRT, be required to notify and account for it. Investors are strongly advised to consult their own professional advisers.

(a) *General*

The issue of Ordinary Shares by the Company direct to persons acquiring Ordinary Shares and the admission of the Ordinary Shares to trading on the Official List will not be subject to any stamp duty or SDRT.

Stamp duty at the rate of 0.5% (rounded up to the next multiple of £5) of the amount or value of the consideration given is generally payable on an instrument transferring Ordinary Shares. An exemption from stamp duty is available on an instrument transferring Ordinary Shares where the amount or value of the consideration is £1,000 or less, and it is certified on the instrument that the transaction effected by the instrument does not form part of a larger transaction or series of transactions for which the aggregate consideration exceeds £1,000.

A charge to SDRT will also arise on an unconditional agreement to transfer Ordinary Shares (at the rate of 0.5% of the amount or value of the consideration payable). However, if within six years of the date of the agreement becoming unconditional an instrument of transfer is executed pursuant to the agreement, and stamp duty is paid on that instrument, any SDRT already paid will be refunded (generally, but not necessarily, with interest) provided that a claim for repayment is made, and any outstanding liability to SDRT will be cancelled.

Transfers to certain categories of person are not liable to stamp duty or SDRT and transfers to others, for example, certain persons providing clearance services or issuing depositary receipts, may give rise to a charge at a higher rate. Where Ordinary Shares are to be issued or transferred to a provider of depository receipt or clearance service arrangements, specialist advice should be sought.

The liability to pay stamp duty or SDRT is generally satisfied by the purchaser or transferee.

(b) *CREST*

Paperless transfers of the Ordinary Shares within the CREST system are generally liable to SDRT, rather than stamp duty, at the rate of 0.5% of the amount or value of the consideration payable. SDRT on relevant transactions is generally settled within the CREST system, collected and accounted for by Euroclear. Deposits of shares into CREST will generally not be subject to SDRT or stamp duty, unless the transfer into CREST is itself for consideration in money or money's worth.

3. U.S. Federal Income Taxation

3.1 ***Introduction***

The following is a description of the principal U.S. federal income tax consequences that may be relevant with respect to the acquisition, ownership and disposition of the Ordinary Shares by a U.S. Holder (as defined below). This description addresses only the U.S. federal income tax considerations of holders that purchase the Ordinary Shares pursuant to the international offering and that will hold such Ordinary Shares for cash as capital assets. This description does not address tax considerations applicable to holders that may be subject to special tax rules, including:

(i) banks, financial institutions or insurance companies;

(ii) real estate investment trusts, regulated investment companies or grantor trusts;

(iii) dealers or traders in securities, commodities or currencies;

(iv) tax-exempt entities;

(v) persons that received the Ordinary Shares as compensation for the performance of services;

(vi) persons that will hold the Ordinary Shares as part of a "hedging," "conversion" or constructive sale transaction or as a position in a "straddle" for U.S. federal income tax purposes;

(vii) certain former citizens or residents of the United States;

(viii) persons that have a "functional currency" other than the U.S. Dollar; or

(ix) holders that own or are deemed to own 10% or more, by voting power or value, of the Ordinary Shares.

Moreover, this description does not address the U.S. federal estate and gift or alternative minimum tax consequences of the acquisition, ownership and disposition of the Ordinary Shares.

This description is based on the Internal Revenue Code, U.S. Treasury Regulations and judicial and administrative interpretations thereof, in each case as in effect and available on the date of this Prospectus. All of the foregoing is subject to change, which change could apply retroactively and could affect the tax consequences described below.

For purposes of this description, a "**U.S. Holder**" is a beneficial owner of the Ordinary Shares that, for U.S. federal income tax purposes, is:

(i) an individual citizen or resident of the United States;

(ii) a corporation (or other entity treated as a corporation for U.S. federal income tax purposes) created or organised in or under the laws of the United States or any state thereof, including, the District of Columbia;

(iii) an estate, the income of which is subject to U.S. federal income taxation, regardless of its source; or

(iv) a trust if such trust validly elected to be treated as a U.S. person for U.S. federal income tax purposes or if (1) a court within the United States is able to exercise primary supervision over its administration and (2) one or more U.S. persons have the authority to control all of the substantial decisions of such trust.

If a partnership (or any other entity treated as a partnership for U.S. federal income tax purposes) holds Ordinary Shares, the tax treatment of the partnership and a partner in such partnership will generally depend on the status of the partner and the activities of the partnership. Such a partner or partnership should consult its own tax adviser as to the U.S. federal income tax consequences of acquiring, holding, retiring or otherwise disposing of Ordinary Shares.

You should consult your own tax adviser with respect to the U.S. federal, state, local and foreign tax consequences of acquiring, owning or disposing of Ordinary Shares.

U.S. TREASURY DEPARTMENT CIRCULAR 230

PURSUANT TO U.S. TREASURY DEPARTMENT CIRCULAR 230, THE COMPANY HEREBY INFORMS HOLDERS THAT THE DESCRIPTION SET FORTH HEREIN WITH RESPECT TO U.S. FEDERAL TAX ISSUES WAS NOT INTENDED OR WRITTEN TO BE USED, AND SUCH DESCRIPTION CANNOT BE USED, BY ANY TAXPAYER FOR THE PURPOSE OF AVOIDING ANY PENALTIES THAT MAY BE IMPOSED ON THE TAXPAYER UNDER THE U.S. INTERNAL REVENUE CODE. SUCH DESCRIPTION WAS WRITTEN TO SUPPORT THE PROMOTION OR MARKETING OF THE ORDINARY SHARES. EACH TAXPAYER SHOULD SEEK ADVICE BASED ON THEIR PARTICULAR CIRCUMSTANCES FROM AN INDEPENDENT TAX ADVISER.

3.2 ***Distributions on the Ordinary Shares***

Subject to the discussion below under "—*Passive Foreign Investment Company Considerations*", the gross amount of any distribution of cash or property (other than certain distributions, if any, of the Company's Ordinary Shares distributed *pro rata* to all the Company's shareholders), with respect to the Ordinary Shares will be included in a U.S. Holder's income as foreign-source dividend income to the extent such distributions are paid out of the Company's current or accumulated earnings and profits as determined under U.S. federal income tax principles. Subject to the discussion below under "—*Passive Foreign Investment Company Considerations*", to the extent, that the amount of any distribution by the Company exceeds the Company's current and accumulated earnings and profits as determined under U.S. federal income tax principles, it will be treated first as a tax-free return of a U.S. Holder's adjusted tax basis in its Ordinary Shares and thereafter as capital gain. The Company does not maintain calculations of its earnings and profits under U.S. federal income tax principles. Accordingly, U.S. Holders should assume that any distribution made by the Company (other than, as discussed above, a distribution of shares) will be treated as a dividend for U.S. federal income tax purposes.

Subject to the discussion below under "—*Passive Foreign Investment Company Considerations*," non-corporate U.S. Holders may qualify for the lower rates of taxation with respect to dividends on Ordinary Shares applicable to long-term capital gains (*i.e.*, gains from the sale of capital assets held for more than one year), provided that certain conditions are met, including certain holding period requirements and the absence of certain risk reduction transactions. Such reduced rate shall not apply if the Company is a PFIC (as defined below) for the taxable year in which the Company pays a dividend, or was a PFIC for the preceding taxable year. Dividends will not be eligible for the dividends received deduction generally allowed to corporate U.S. Holders.

If you are a U.S. Holder, the amount of any cash dividend paid in the currency other than U.S. Dollar ("**Non-U.S. Currency**") to you will be included in your gross income in an amount equal to the U.S. Dollar value of the Non-U.S. Currency received, calculated by reference to the exchange rate in effect on the date the dividend is actually or constructively received by you, regardless of whether the payment in Non-U.S. Currency is in fact converted into U.S. Dollars at that time. If the Non-U.S. Currency received as a dividend is converted into U.S. Dollars on the date of receipt, you generally should not recognise foreign currency gain or loss with respect to such dividend. If the Non-U.S. Currency received as a dividend is not converted into U.S. Dollars on the date of receipt, you will have a tax basis in the Non-U.S. Currency equal to the U.S. Dollar value on the date of receipt. Any foreign currency gain or loss realised on a subsequent conversion or other disposition of the Non-U.S. Currency will be treated as U.S. source ordinary income or loss. The amount of any distribution of property other than cash will be the fair market value of such property on the date of distribution.

The amount of a dividend on the Ordinary Shares will include any amounts that the Company withholds in respect of UK taxes. Subject to applicable limitations, some of which vary depending upon the U.S. Holder's circumstances, UK income taxes withheld from dividends on the Ordinary Shares will be creditable against the U.S. Holder's U.S. federal income tax liability. The rules governing foreign tax credits are complex, and U.S. Holders should consult their tax advisers regarding the creditability of foreign taxes based on their particular circumstances. In lieu of claiming a foreign tax credit, U.S. Holders may, at their election, deduct foreign taxes, including any UK tax withheld from dividends on the Ordinary Shares, in computing their taxable income, subject to generally applicable limitations under U.S. federal income tax law. An election to deduct foreign taxes instead of claiming foreign tax credits applies to all taxes paid or accrued in the taxable year to foreign countries and possessions of the United States.

3.3 *Sale or Exchange of Ordinary Shares*

Subject to the discussion below under "*—Passive Foreign Investment Company Considerations*", a U.S. Holder will generally recognise gain or loss on the sale or exchange of Ordinary Shares equal to the difference between the amount realised on such sale or exchange and such holder's adjusted tax basis in such Ordinary Shares. Such gain or loss will generally be capital gain or loss. Such capital gain or loss will be long-term capital gain or loss if such holder's holding period for the Ordinary Shares exceeds one year. For non-corporate U.S. Holders, the U.S. income tax rate applicable to net long-term capital gain currently will not exceed 20%. The deductibility of capital losses is subject to significant limitations.

A U.S. Holder's initial tax basis in Ordinary Shares will be the U.S. Dollar value of the Non-U.S. Currency denominated purchase price determined on the date of purchase. If the Ordinary Shares are treated as traded on an "established securities market," a cash basis U.S. Holder or, if it elects, an accrual basis U.S. Holder, will determine the U.S. Dollar value of the cost of such Ordinary Shares by translating the amount paid at the spot rate of exchange on the settlement date of the purchase. Such an election by an accrual basis U.S. Holder must be applied consistently from year to year and cannot be revoked without the consent of the Internal Revenue Service. If a U.S. Holder converts U.S. Dollars to Non-U.S. Currency and immediately uses that currency to purchase Ordinary Shares, such conversion generally will not result in taxable gain or loss.

With respect to the sale or exchange of Ordinary Shares, the amount realised generally will be the U.S. Dollar value of the payment received determined on (1) the date of receipt of payment in the case of a cash basis U.S. Holder and (2) the date of disposition in the case of an accrual basis U.S. Holder. If the Ordinary Shares are treated as traded on an "established securities market," a cash basis taxpayer, or, if it elects, an accrual basis taxpayer, will determine the U.S. Dollar value of the amount realised by translating the amount received at the spot rate of exchange on the settlement date of the sale.

If a UK tax is imposed on the sale or other disposition of the Ordinary Shares, a U.S. Holder's amount realised will include the gross amount of the proceeds of the sale or other disposition before deduction of any UK tax. Because a U.S. Holder's gain from the sale or other disposition of the Ordinary Shares will generally be U.S.-source gain, and a U.S. Holder may use foreign tax credits to offset only the portion of U.S. federal income tax liability that is attributable to foreign source income, a U.S. Holder may be unable to claim a foreign tax credit with respect to any UK tax on gains. In lieu of claiming a foreign tax credit, U.S. Holders may make an election to deduct foreign taxes, including the UK tax, in computing their taxable income, subject to generally applicable limitations under U.S. law. U.S. Holders should consult their tax advisers as to whether any UK tax on gains may be creditable against the U.S. Holder's U.S. federal income tax on foreign-source income from other sources.

3.4 *Passive Foreign Investment Company Considerations*

A non-U.S. corporation will be classified as a "passive foreign investment company" ("**PFIC**") for U.S. federal income tax purposes in any taxable year in which, after applying certain look-through rules, either:

(i) at least 75% of its gross income is "passive income" (the "**Gross Income Test**"); or

(ii) at least 50%, of the average value of its gross assets is attributable to assets that produce "passive income" or are held for the production of passive income.

Passive income for this purpose generally includes dividends, interest, royalties, rents and certain gains from commodities (other than commodities sold in an active trade or business) and securities transactions.

The PFIC rules do not specify how "gross income" is to be determined for purposes of applying the Gross Income Test. The Internal Revenue Service, however, has issued a private letter ruling (the "**Ruling**") which stands for the proposition that the gross income of a PFIC should be determined under the provisions of the Code that apply to the determination of the gross income of a foreign corporation. Under these rules, the "gross income" of a manufacturing business means total sales less the cost of goods sold, plus any income from investments and from incidental or outside operations or sources. The Ruling also holds that a company whose passive income did not exceed the sum of (i) total sales less cost of goods sold, plus (ii) income from investments and other incidental income will not be treated as a PFIC under the Gross Income Test. Although the Ruling can only be relied on by the taxpayer that sought the Ruling, rulings of this type provide useful guidance as to the Internal Revenue Service's position on various issues.

Based on certain estimates of the Company's gross income and gross assets and the nature of the Group's business, the Company believes that it will not be classified as a PFIC in 2014. The Company also does not expect to be a PFIC in the foreseeable future, provided that more than 25% of the Company's gross income is not passive income. No ruling will be obtained from the Internal Revenue Service with respect to the Company being classified as not a PFIC, and there can be no assurance that the Internal Revenue Service or the courts would agree with this classification. Moreover, because the PFIC status of a foreign corporation depends upon the composition of its income and assets and the market value of its assets (including, among others, less than 25% owned equity investments) from time to time, there can be no assurance that the Company will not be considered a PFIC for any taxable year.

Under certain attribution rules, if the Company is a PFIC, U.S. Holders will be deemed to own their proportionate share of the Company's subsidiaries that are PFICs (such subsidiaries referred to as "**lower-tier PFICs**"), and will be subject to U.S. federal income tax in the manner discussed below on (1) a distribution to the Company on the shares of a lower-tier PFIC and (2) any disposition by the Company of shares of a lower-tier PFIC, both as if the holder directly held the Ordinary Shares of such lower-tier PFIC.

If an entity is treated as a PFIC for any taxable year during which a U.S. Holder holds (or, as discussed in the previous paragraph, is deemed to hold) its shares, the holder will be subject to adverse U.S. federal income tax rules. In general, if a U.S. Holder disposes of shares of a PFIC (including an indirect disposition or a constructive disposition of shares of a lower-tier PFIC), any gain recognised or deemed recognised by the holder would be allocated rateably over the holder's holding period for the Ordinary Shares. The amounts allocated to the taxable year of disposition and to years before the entity became a PFIC, if any, would be taxed as ordinary income. The amount allocated to each other taxable year would be subject to tax at the highest rate in effect for such taxable year for individuals or corporations, as appropriate, and an interest charge would be imposed on the tax attributable to such allocated amounts. Further, any distribution in respect of shares of a PFIC (or a distribution by a lower-tier PFIC to its shareholders that is deemed to be received by a U.S. Holder) in excess of 125% of the average of the annual distributions on such shares received or deemed to be received during the preceding three years or the holder's holding period, whichever is shorter, would be subject to taxation in the manner described above.

If the Company is classified as a PFIC, a U.S. Holder may be able to avoid the rules described above by making a mark-to-market election, provided the Ordinary Shares are treated as regularly traded on a qualified exchange or other market within the meaning of the applicable U.S. Treasury Regulations. U.S. Holders should consult their own tax advisers regarding the potential availability and consequences of a mark-to-market election. The Company does not intend to provide information to enable U.S. Holders to make a "qualified electing fund" election, which otherwise could allow a U.S. Holder to avoid the PFIC rules described above.

If a U.S. Holder owns Ordinary Shares during any year in which the Company is a PFIC, the U.S. Holder generally must file an IRS Form 8621 with respect to the Company, generally with the U.S. Holder's federal income tax return for that year.

U.S. Holders should consult their own tax advisers regarding the potential application of the PFIC rules.

3.5 *Backup Withholding Tax and Information Reporting Requirements*

U.S. backup withholding tax and information reporting requirements may apply to certain payments to certain holders of Ordinary Shares. Information reporting generally will apply to payments of dividends on, and to proceeds from the sale or redemption of, Ordinary Shares made within the United States, or by a U.S. payor or U.S. middleman, to a holder of Ordinary Shares, other than an exempt recipient (including a payee that is not a U.S. person that provides an appropriate certification and certain other persons). A payor will be required to withhold backup withholding tax from any payments of dividends on, or the proceeds from the sale or redemption of, Ordinary Shares within the United States, or by a U.S. payor or U.S. middleman, to a holder, other than an exempt recipient, if such holder fails to furnish its correct taxpayer identification number or otherwise fails to comply with, or establish an exemption from, such backup withholding tax requirements. The backup withholding tax rate is currently 28%.

Any amounts withheld under the backup withholding tax rules will be allowed as a refund or a credit against your U.S. federal income tax liability provided the required information is furnished to the Internal Revenue Service.

Certain U.S. Holders who are individuals are required to report information relating to an interest in the Company's Ordinary Shares, subject to certain exceptions (including an exception for Ordinary Shares held in accounts maintained by certain financial institutions). U.S. Holders are urged to consult their tax advisers regarding the effect, if any, of new U.S. federal income tax legislation on their ownership and disposition of the Company's Ordinary Shares.

3.6 ***Medicare Tax***

Certain U.S. Holders who are individuals, estates or trusts are required to pay a 3.8% tax on, among other things, dividends and capital gains from the sale or other disposition of shares of common stock.

4. Isle of Man

Holders of Ordinary Shares resident in the Isle of Man will, depending upon their particular circumstances, be liable to Manx income tax on dividends received from the Company. Holders of Ordinary Shares resident outside the Isle of Man will have no liability to Manx income tax on dividends received from the Company. There is no capital gains tax, inheritance tax, stamp duty or stamp duty reserve tax in the Isle of Man. A probate fee may be payable in respect of the estate of a deceased holder of Ordinary Shares resident in the Isle of Man, up to a current maximum of £7,500.

PART 17
ADDITIONAL INFORMATION

1. Persons Responsible

1.1 The Company and the Directors, whose names and functions are set out in paragraph 1 of Part 9 "*Directors, Managers and Corporate Governance*", accept responsibility for this Prospectus and declare that having taken all reasonable care to ensure that such is the case, the information contained in this Prospectus is, to the best of their knowledge, in accordance with the facts and contains no omission likely to affect its import.

1.2 Ryder Scott Company L.P. accepts responsibility for the Competent Person's Report and its letter set out in Part 15 "*Competent Person's Report*". To the best of the knowledge of Ryder Scott Company L.P. (which has taken all reasonable care to ensure that such is the case) the information contained therein is in accordance with the facts and contains no omission likely to affect its import.

2. Incorporation and Share Capital

2.1 The Company was incorporated and registered in England and Wales, as a public company, on 3 October 2013, under the Companies Act, with the name Nostrum Oil plc and with registered number 8717287. On 24 April 2014, the name of the Company was changed to Nostrum Oil & Gas plc.

2.2 The principal legislation under which the Company operates is the Companies Act.

2.3 The liability of the members of the Company is limited. The Company's registered office and principal place of business in the UK is 4th Floor, 53-54 Grosvenor Street, London, W1K 3HU, United Kingdom and its telephone number is +44 203 445 0285. The Company's website is located at www.nostrumoilandgas.com.

2.4 The Ordinary Shares will be in registered form and their ISIN code is GB00BGP6Q951. The Ordinary Shares will be allotted and issued under the Companies Act.

2.5 The Company was incorporated with a share capital of £50,002.00 divided into two ordinary shares of £1.00 each and 50,000 redeemable non-voting preference shares of £1.00 each (the "**Redeemable Shares**"). The Company does not have authorised share capital. These ordinary shares were issued on incorporation to Nostrum Oil & Gas LP and NOGGL. The Redeemable Shares were issued on incorporation to NOGGL. On 29 November 2013 NOGGL subscribed for an additional 360,000 Redeemable Shares for £1.00 each. On 19 May 2014, Nostrum Oil & Gas LP and Thomas Hartnett (as nominee in his capacity as company secretary) subscribed for 100,000 Ordinary Shares. The two ordinary shares of £1.00 each have been converted into and redesignated as subscriber shares (the "**Subscriber Shares**"), the rights attaching to which will be deferred once the Ordinary Shares in connection with the Scheme are admitted to the Official List and to trading on the Main Market of the London Stock Exchange. It is expected that the 410,000 Redeemable Shares will be redeemed following the Scheme becomes effective and that the Subscriber Shares will be repurchased by the Company at their nominal value and then cancelled following the Scheme becoming effective.

2.6 The following table sets out the issued ordinary share capital of the Company as at the date of this Prospectus, as at 31 December 2013 (being the date of the latest audited financial information contained in this Prospectus) and as it is expected to be immediately following Admission:

	31 December 2013		Date of this Prospectus		Admission	
	Number of Ordinary Shares	Share capital	Number of Ordinary Shares	Share capital	Number of Ordinary Shares	Share capital(1)
Issued Ordinary Shares (fully paid)	2	£2.00	100,000	£33,528.67	188,182,958	£63,095,238
Issued Subscriber Shares	—	—	2	£ 2.00	—	—

(1) Based on an indicative exchange rate of £1.00=U.S.$1.68.

2.7 Immediately following Admission, it is expected that at least 25% of the Company's issued ordinary share capital will be held in public hands (within the meaning of paragraph 6.1.19 of the Listing Rules).

2.8 By a series of ordinary and special resolutions duly passed by the shareholders at a general meeting of the Company on 19 May 2014:

(a) subject to the Scheme becoming effective, the Articles will be adopted in substitution for, and to the exclusion of, the existing articles of association of the Company;

(b) a new class of ordinary shares of £0.01 each be created;

(c) the two original ordinary shares of £1.00 each in the share capital of the Company and which are issued and paid up have been converted into and designated as subscriber shares of £1.00 each having the rights and being subject to the conditions as set out in the articles of association;

(d) subject to the Scheme becoming effective, the capital of the Company will be reduced by cancelling paid up capital to the extent of the amount of share premium upon each of the issued Ordinary Shares at that time (but with the nominal amount of each of these issued Ordinary Shares remaining at £0.01 each);

(e) in addition to the authorities contained in Paragraph 2.8(f) below, the Directors are generally and unconditionally authorised for the purpose of section 551 of the Companies Act to exercise all the powers of the Company to allot Ordinary Shares up to a maximum aggregate nominal amount of £1,881,829.58 in connection with the Scheme, provided that such power shall expire at the earlier of the conclusion of the Company's annual general meeting in 2015 and 30 June 2015;

(f) subject to Admission, and in addition to the authorities set out in Paragraph 2.8(e) above, the Directors are generally and unconditionally authorised for the purpose of section 551 of the Companies Act to exercise all the powers of the Company to allot new shares in the Company or to grant rights to subscribe for or to convert any security into new shares in the Company:

   (i) up to a maximum aggregate nominal amount of £620,000.00 (representing 62,000,000 Ordinary Shares, which is less than one-third of the issued ordinary share capital of the Company at Admission); and

   (ii) in addition to the amount referred to in paragraph (i) above, up to an aggregate nominal amount of £1,240,000.00 (representing 124,000,000 Ordinary Shares) in relation to an allotment of equity securities (within the meaning of section 560(1) of the Companies Act) in connection with a rights issue,

   for a period expiring at the earlier of the conclusion of the Company's annual general meeting in 2015 and 30 June 2015. The aggregate amount in (ii) represents less than two-thirds of the issued ordinary share capital of the Company as at Admission and is consistent with the current guidance issued by the Association of British Insurers;

(g) in addition to the authorities contained in paragraph 2.8(h) below, the Directors are empowered pursuant to section 570 of the Companies Act to allot equity securities (within the meaning of section 560(1) of the Companies Act) for cash pursuant to the authority conferred by Paragraph 2.8(e) above as if section 561 of the Companies Act did not apply to the allotment, provided that the power conferred by this resolution is limited to the allotment of up to 188,182,958 Ordinary Shares in connection with the Scheme, such power to expire at the earlier of the conclusion of the Company's annual general meeting in 2015 and 30 June 2015;

(h) subject to Admission, and in addition to the authorities set out in Paragraph 2.8(g) above, the Directors are empowered pursuant to section 570 of the Companies Act to allot equity securities (within the meaning of section 560(1) of the Companies Act) for cash:

   (i) pursuant to the authority conferred by Paragraph 2.8(f)(i) above as if section 561 of the Companies Act did not apply to the allotment, provided that the power conferred by this resolution is limited to:

      (A) an allotment of equity securities in connection with a pre-emptive offer; or

      (B) an allotment of equity securities otherwise than in connection with a pre-emptive offer up to a nominal amount not exceeding in aggregate £93,000.00 (representing 9,300,000 Ordinary Shares, which is less than 5% of the issued ordinary share capital of the Company at Admission), and

   (ii) pursuant to the authority given by the resolution referred to in Paragraph 2.8(f)(ii) above as if section 561 of the Companies Act did not apply to the allotment provided that the power conferred by this resolution is limited to an allotment of equity securities in connection with a rights issue,

   such power to expire at the earlier of the conclusion of the Company's annual general meeting in 2015 and 30 June 2015;

(i) subject to Admission, the Company is generally and unconditionally authorised to make market purchases (within the meaning of section 693(4) of the Companies Act) of its own shares, subject to the following conditions:

(i) the maximum aggregate number of Ordinary Shares authorised to be purchased is 18,600,000 (representing less than 10% of the issued ordinary share capital of the Company at Admission);

(ii) the minimum price (exclusive of expenses payable by the Company in connection with the purchase) which may be paid for an Ordinary Share is an amount equal to its nominal value;

(iii) the maximum price (exclusive of expenses payable by the Company in connection with the purchase) which may be paid for each Ordinary Share purchased under this authority is an amount equal to the higher of:

(A) 105% of the average of the middle market quotations for Ordinary Shares as derived from the London Stock Exchange's Daily Official List for the five business days immediately preceding the day on which the share is contracted to be purchased; and

(B) the higher of the price of the last independent trade of an Ordinary Share and the highest current independent bid for an Ordinary Share as stipulated by Article 5(1) of Commission Regulation (EC) of 22 December 2003 implementing the Market Abuse Directive as regards exemptions for buy-back programmes and stabilisation of financial instruments (No 2273/2003);

(iv) this authority shall expire at the earlier of the conclusion of the Company's annual general meeting in 2015 and 30 June 2015 unless such authority is renewed prior to such time;

(j) subject to Admission, the Company is authorised in accordance with the Articles to call general meetings on 14 clear days' notice;

(k) conditional upon Admission, the phantom option plan for up to 10% of the issued share capital of the Company as of the date of Admission is approved; and

(l) the purchase by the Company of the Preference Shares from NOGGL at their nominal value is approved.

2.9 Save as disclosed in this Part 17 "*Additional Information*":

(a) no share or loan capital of the Company has, since incorporation of the Company, been issued or agreed to be issued, or is now proposed to be issued, fully or partly paid, either for cash or for consideration other than cash, to any person;

(b) no convertible securities, exchangeable securities or securities with warrants have been issued by the Company;

(c) none of the Redeemable Shares or the Subscriber Shares will be listed or traded on any stock exchange;

(d) no commissions, discounts, brokerages, or other special terms have been granted by the Company in connection with the issue or sale of any such share or loan capital; and

(e) no share or loan capital of the Company is under option or agreed conditionally or unconditionally to be put under option.

2.10 It is expected that, on Admission, the market capitalisation of the Ordinary Shares will be in excess of £700,000.

3. Memorandum of Association

In accordance with section 8 of the Companies Act, the memorandum of association of the Company consists of a simple statement that the subscribers wish to form a company and subscribe for two Ordinary Shares in total. Pursuant to the Companies Act, unless a company's articles provide otherwise, a company's objects are unrestricted. The Company's objectives are not restricted by its Articles.

4. Articles of Association

The Articles are available for inspection at the address specified below in paragraph 20 of this Part 17 "*Additional Information*".

The Articles of the Company include provisions to the following effect:

4.1 **Share Rights**

Subject to the provisions of the Companies Act and without prejudice to any rights attached to any existing shares or class of shares, any share may be issued with such rights or restrictions as the Company may by ordinary resolution determine or, subject to and in default of such determination, as the Board shall determine.

Subject to the provisions of the Companies Act and without prejudice to any rights attached to any existing shares or class of shares, the Board may issue shares which are to be redeemed or are liable to be redeemed at the option of the Company or the holder. Subject to the Articles and to the Companies Act, all the shares for the time being in the capital of the Company are at the disposal of the Board.

4.2 **Voting Rights**

Subject to any rights or restrictions attached to any shares, and any rights or restrictions detailed in the notice of the meeting, on a show of hands every member who is present in person shall have one vote and on a poll every member present in person or by proxy shall have one vote for every share of which he is the holder.

No member shall be entitled to vote at any general meeting of the Company unless all moneys presently payable by him in respect of Ordinary Shares in the Company have been paid.

If at any time the Board is satisfied that any member, or any other person appearing to be interested in Ordinary Shares held by such a member, has been duly served with a notice under section 793 of the Companies Act and is in default for the prescribed period in supplying to the Company the information thereby required, or, in purported compliance with such a notice, has made a statement which is false or inadequate in a material particular, the Board may, in its absolute discretion at any time thereafter by notice to such member, direct that, in respect of the Ordinary Shares in relation to which the default occurred, the member shall not be entitled to attend or vote either personally or by proxy at a general meeting or at a separate meeting of the holders of that class of shares or on a poll.

4.3 **Dividends and Other Distributions**

Subject to the provisions of the Companies Act, the Company may by ordinary resolution declare dividends in accordance with the respective rights of the members, *provided that* no dividend shall exceed the amount recommended by the Board. Except as otherwise provided by the rights attached to shares, all dividends shall be declared and paid according to the amounts paid up on the shares on which the dividend is paid, but no amount paid on a share in advance of calls shall be treated for these purposes as paid on the share.

Subject to the provisions of the Companies Act, the Board may pay interim dividends if it appears to the Board that they are justified by the profits of the Company available for distribution.

The Board may also pay, at intervals determined by it, any dividend at a fixed rate if it appears to the Board that the profits available for distribution justify the payment. Dividends may be declared and paid in any currency or currencies that the board shall determine. If the Board acts in good faith it shall not incur any liability to the holders of shares conferring preferred rights for any loss they may suffer by the lawful payment of an interim dividend on any shares having deferred or non-preferred rights.

No dividend or other moneys payable in respect of a share shall bear interest against the Company unless otherwise provided by the rights attached to the share.

If at any time the Board is satisfied that any member, or any other person appearing to be interested in Ordinary Shares held by such member, has been duly served with a notice under section 793 of the Companies Act and is in default for the prescribed period in supplying to the Company the information thereby required, or, in purported compliance with such a notice, has made a statement which is false or inadequate in a material particular, then the Board may, in its absolute discretion at any time thereafter, serve a direction notice on such member and withhold payment from such member of any dividend otherwise payable, if the relevant Ordinary Shares represent at least a 0.25% interest in the Company's Ordinary Shares or any class thereof.

The Board may, if authorised by an ordinary resolution of the Company, offer to any holder of shares the right to elect to receive shares, credited as fully paid, instead of cash in respect of the whole, or some part (to be determined by the Board), of any dividend.

Any dividend which has remained unclaimed for 12 years from the date when it became due for payment shall, if the Board so resolves, be forfeited and cease to remain owing by the Company.

A liquidator may, with the sanction of a special resolution and any other sanction required by the Insolvency Act 1986, divide among the members in specie the whole or any part of the assets of the Company and may, for that purpose, value any assets and determine how the division shall be carried out as between the members or different classes of members.

4.4 Variation of Rights

Rights attached to any class of shares may be varied or abrogated with the written consent of the holders of three-quarters in nominal value of the issued shares of the class, or the sanction of a special resolution passed at a separate general meeting of the holders of the shares of the class.

4.5 Lien and Forfeiture

The Company shall have a first and paramount lien on every share (that is not a fully paid share) for all moneys payable to it (whether presently or not) in respect of that share. The Company may sell any share on which it has a lien if a sum in respect of which the lien exists is presently payable and is not paid within 14 clear days after notice has been sent to the holder of the share demanding payment and stating that if the notice is not complied with the share may be sold.

The Board may from time to time make calls on the members in respect of any moneys unpaid on their shares. Each member shall (subject to receiving at least 14 clear days' notice) pay to the Company the amount called on his shares. If a call or any instalment of a call remains unpaid in whole or in part after it has become due and payable, the board may give the person from whom it is due not less than 14 clear days' notice requiring payment of the amount unpaid together with any interest which may have accrued and any costs, charges and expenses incurred by the Company by reason of such non-payment. The notice shall name the place where payment is to be made and shall state that if the notice is not complied with the shares in respect of which the call was made will be liable to be forfeited.

4.6 Transfer of Shares

A member may transfer all or any of his certificated shares by an instrument of transfer in any usual form or in any form which the Board may approve. An instrument of transfer shall be signed by or on behalf of the transferor and, unless the share is fully paid, by or on behalf of the transferee. An instrument of transfer need not be under seal. The transferor shall remain the holder of the shares concerned until the name of the transferee is entered in the register in respect of the shares.

All transfers which are in uncertificated form shall be effected by means of the relevant system unless the CREST Regulations provide otherwise.

The Board may, in its absolute discretion, refuse to register the transfer of a certificated share which is not a fully paid share, *provided that* the refusal does not prevent dealings in shares in the Company from taking place on an open and proper basis. The Board may also refuse to register the transfer of a certificated share unless the instrument of transfer:

(a) is lodged, stamped (if stampable), at the office or at another place appointed by the Board, accompanied by the certificate for the share to which it relates and such other evidence as the Board may reasonably require to show the right of the transferor to make the transfer;

(b) is in respect of one class of share only; and

(c) is in favour of not more than four persons.

If the Board refuses to register a transfer of a share in certificated form, it shall send the transferee notice of its refusal within two months after the date on which the instrument of transfer was lodged with the Company.

No fee shall be charged for the registration of any instrument of transfer or other document relating to or affecting the title to a share.

Subject to the provisions of the CREST Regulations, the Board may permit the holding of shares in any class of shares in uncertificated form and the transfer of title to shares in that class, by means of a relevant system and may determine that any class of shares shall cease to be a participating security.

If a notice is given to a member in respect of a share, which is subsequently transferred, a person entitled to that share is bound by the notice if it was given to the member before the person entitled to that share was entered into the register as the holder of that share.

4.7 **General Meetings**

The Board shall convene and the Company shall hold general meetings as annual general meetings in accordance with the requirements of the Companies Act. The Board may call general meetings whenever and at such times and places as it shall determine.

4.8 **Directors**

(a) *Appointment of Directors*

Unless otherwise determined by ordinary resolution, the number of Directors shall be not less than two but shall not be subject to any maximum in number. Directors may be appointed by ordinary resolution of Shareholders at a general meeting, by the Board or, if there is only one Director, by such Director.

(b) *No Share Qualification*

A Director shall not be required to hold any shares in the capital of the Company by way of qualification.

(c) *Retirement of Directors*

At every annual general meeting all the Directors appointed by the Board or, if there is only one Director, by such Director at the date of the notice convening the annual general meeting shall retire from office. If the Company does not fill the vacancy at the meeting at which a director retires, the retiring director shall be deemed to have been re-appointed unless at the meeting it is resolved not to fill the vacancy or unless a resolution for the re-appointment of the director is put to the meeting and lost.

(d) *Remuneration of Directors*

The emoluments of any Director holding executive office for his services as such shall be determined by the Board, and may be of any description.

The ordinary remuneration of the Non-Executive Directors for their services (excluding amounts payable under any other provision of these Articles) shall be such amount as the Board may from time to time determine. Subject thereto, each such Director shall be paid a fee (which shall be deemed to accrue from day to day) at such rate as may from time to time be determined by the Board. In addition, any Non-Executive Director who performs special services which in the opinion of the Board are outside the scope of the ordinary duties of a Director may be paid such extra remuneration as the Board may determine.

In addition to any remuneration to which the Directors are entitled under the Articles, they may be paid all travelling, hotel and other expenses properly incurred by them in connection with their attendance at meetings of the Board or committees of the Board, general meetings or separate meetings of the holders of any class of shares or of debentures of the Company or otherwise in connection with the discharge of their duties.

The Board may provide benefits, whether by the payment of gratuities or pensions or by insurance or otherwise, for any past or present Director or employee of the Company or any of its subsidiary undertakings or any body corporate associated with, or any business acquired by, any of them, and for any member of his family or any person who is or was dependent on him.

(e) *Permitted Interests of Directors*

Subject to the provisions of the Companies Act, and *provided that* he has disclosed to the Board the nature and extent of his interest, a Director, notwithstanding his office:

(i) may be a party to, or otherwise interested in, any transaction or arrangement with the Company in which the Company is otherwise interested;

(ii) may act by himself or his firm in a professional capacity for the Company (otherwise than as auditor), and he or his firm shall be entitled to remuneration for professional services as if he were not a Director;

(iii) may be a director or other officer of, or employed by, or a party to any transaction or arrangement with, or otherwise interested in, any body corporate in which the Company is (directly or indirectly) interested as shareholder or otherwise or with which he has such a relationship at the request or direction of the Company; and

(iv) shall not, by reason of his office, be accountable to the Company for any benefit which he derives from any such office or employment, or from any such transaction or arrangement, or from any interest in any such body corporate if the acceptance, entry into or existence of which has been approved by the Board or properly disclosed and no such transaction or arrangement shall be liable to be avoided on the ground of any such interest or benefit.

(f) *Restrictions on Voting*

A Director shall not vote on any resolution of the Board concerning a matter in which he has an interest which can reasonably be regarded as likely to give rise to a conflict with the interests of the Company, but these prohibitions shall not apply to:

(i) the giving of a guarantee, security or indemnity in respect of money lent or obligations incurred by him or any other person at the request of, or for the benefit of, the Company or any of its subsidiary undertakings;

(ii) the giving of a guarantee, security or indemnity in respect of a debt or obligation of the Company or any of its subsidiary undertakings for which the Director has assumed responsibility (in whole or part and whether alone or jointly with others) under a guarantee or indemnity or by the giving of security;

(iii) a contract, arrangement, transaction or proposal concerning an offer of shares, debentures or other securities of the Company or any of its subsidiary undertakings for subscription or purchase, in which offer he is or may be entitled to participate as a holder of securities or in the underwriting or sub-underwriting of which he is to participate;

(iv) a contract, arrangement, transaction or proposal concerning any other body corporate in which he or any person connected with him is interested, directly or indirectly, and whether as an officer, shareholder, creditor or otherwise, if he and any persons connected with him do not to his knowledge hold an interest (as that term is used in sections 820 to 825 of the Companies Act) representing 1% or more of either any class of the equity share capital of such body corporate (or any other body corporate through which his interest is derived) or of the voting rights available to members of the relevant body corporate (any such interest being deemed to be a material interest in all circumstances);

(v) a contract, arrangement, transaction or proposal for the benefit of employees of the Company or of any of its subsidiary undertakings which does not award him any privilege or benefit not generally accorded to the employees to whom the arrangement relates; and

(vi) a contract, arrangement, transaction or proposal concerning any insurance which the Company is empowered to purchase or maintain for, or for the benefit of, any Directors or for persons who include Directors.

4.9 **Borrowing Powers**

The Board may exercise all the powers of the Company to borrow money, to guarantee, to indemnify, to mortgage or charge its undertaking, property, assets (present and future) and uncalled capital, and to issue debentures and other securities whether outright or as collateral security for any debt, liability or obligation of the Company or of any third party.

4.10 **Indemnity of Officers**

Subject to the provisions of the Companies Act, but without prejudice to any indemnity to which the person concerned may otherwise be entitled, every Director or other officer of the Company shall be indemnified out of the assets of the Company against any liability incurred by him for negligence, default, breach of duty or breach of trust in relation to the affairs of the Company, or any associated company, and any other liability incurred by or attaching to him in relation to or in connection with his duties, powers or office, including in connection with the activities of the Company or an associated company in its capacity as a trustee of an occupational pension scheme but this shall not apply to any liability owed to the Company or associated company and shall not provide for or entitle any such person to indemnification to the extent that it would cause this provision, or any element of it, to be treated as void under the Companies Act. This indemnity shall extend to all costs, changes, losses, expense and liabilities incurred by him in relation thereto.

5. Reduction of Share Capital

5.1 The Ordinary Shares will be issued with a nominal value of £0.01 per Ordinary Share and a share premium calculated by reference to the market capitalisation of the Partnership on the close of business on the date of the Special General Meeting. The Directors intend to implement a reduction of capital of the Company such that the entire amount standing to the credit of the Company's share premium account arising in connection with the Scheme is cancelled and to re-characterise the reserve arising as a distributable reserve that will be available to the Company to be distributed as dividends or applied toward any other lawful purpose (the "**Reduction of Capital**"). The Reduction of Capital is intended to create distributable reserves for the Company of an amount substantially similar in amount to those available to Nostrum Oil & Gas LP.

5.2 By a special resolution passed at a general meeting of the Company held on 19 May 2014, the holders of the Ordinary Shares approved, conditional upon the Scheme becoming or being declared wholly unconditional, a reduction of the entire amount standing to the credit of the Company's share premium account arising in connection with the Scheme and a re-characterisation of the reserve arising as a distributable reserve that will be available to the Company to be distributed as dividends or applied toward any other lawful purpose.

5.3 The Reduction of Capital will only become effective if it is approved by the High Court pursuant to the Companies Act. As soon as reasonably practicable following the date of the this Prospectus, the Directors intend to apply to the High Court to approve the Reduction of Capital. It is expected that the hearing of the High Court to approve the Reduction of Capital will be held in the third quarter of 2014, subject to the Scheme having become or been declared wholly unconditional.

5.4 As a newly incorporated company, the Company has few creditors, all of whom are expected to consent to the Reduction of Capital. It is not expected that the High Court will require any special measures to be put in place to protect creditors, and the reserves created by the Reduction of Capital will be available for distribution.

6. Subsidiary Undertakings and Investments

6.1 The Group comprises the Company and its subsidiary undertakings. The Company has the following significant subsidiaries, all of which are directly or indirectly owned by the Company and which are likely to have a significant effect on the assessment of the Company's assets and liabilities, profits and losses:

Company name	Principal Activity	Country of registration	Country of operation	%
Nostrum Oil Coöperatief U.A.	Holding entity	Netherlands	Netherlands	100
Zhaikmunai LLP	Crude oil and gas exploration and production	Kazakhstan	Kazakhstan	100
Zhaikmunai Finance B.V.	Finance Subsidiary	Netherlands	Netherlands	100
Zhaikmunai International B.V.	Finance Subsidiary	Netherlands	Netherlands	100
Zhaikmunai Netherlands B.V.	Finance Subsidiary	Netherlands	Netherlands	100
Nostrum Oil & Gas Finance B.V.	Finance Subsidiary	Netherlands	Netherlands	100
Nostrum Oil B.V.	Finance Subsidiary	Netherlands	Netherlands	100

6.2 The percentage interests shown opposite the names of the subsidiaries of the Company represent both ownership interests and voting rights.

7. Premises/Property

7.1 The following are the principal premises owned or leased or used by the Group:

Property Address	Use	Tenure	Term Expires	Yearly Rent
59/2 Prospekt Evrazia, Uralsk, Republic of Kazakhstan	Offices	Leasehold	2029	U.S.$180,000
Gustav Mahlerplein 23B, 1082 MS, Amsterdam, The Netherlands	Offices	Leasehold	31 January 2016	EUR 43,000

8. Interests of Directors and Senior Management

8.1 None of the Directors or senior managers has any business interests nor performs any activities outside the Group which are significant with respect to the Group. No Director or senior manager has any conflict of interest between his duties to the Company and any private interests or other duties. There are no family relationships between any of the Directors or senior managers, except that Mr Everaert's spouse is the sister of Mr Monstrey's spouse.

8.2 Interests in the Ordinary Shares of the Company

As at the date of this Prospectus, the Common Unit/GDR ownership and any options over such Common Units or GDRs held by the Directors and senior managers in respect of the limited partnership interests in the Partnership are as follows:

	Number of existing Common Units/GDRs	Number of Common Units/GDRs over which options held pursuant to the Phantom Option Plan	Total
Director			
Frank Monstrey	51,190,476	—	51,190,476
Kai-Uwe Kessel	10,000	1,100,974	1,110,974
Jan-Ru Muller	—	190,130	190,130
Eike von der Linden	12,000	—	12,000
Atul Gupta	—	—	—
Sir Christopher Codrington, Bt.	—	—	—
Mark Martin	—	—	—
Piet Everaert	17,000	—	17,000
Pankaj Jain	19,700	—	19,700
Senior managers	1,000	500,325	501,325

As at the date of Admission, the share ownership and any options over such shares held by the Directors and senior managers in respect of the share capital of the Company is expected to be as follows:

	Number of Ordinary Shares	Number of Ordinary Shares over which options held pursuant to the Phantom Option Plan	Total
Director			
Frank Monstrey	51,190,476	—	51,190,476
Kai-Uwe Kessel	10,000	1,100,974	1,110,974
Jan-Ru Muller	—	190,130	190,130
Eike von der Linden	12,000	—	12,000
Atul Gupta	—	—	—
Sir Christopher Codrington, Bt.	—	—	—
Mark Martin	—	—	—
Piet Everaert	17,000	—	17,000
Pankaj Jain	19,700	—	19,700
Senior managers	1,000	500,325	501,325

Thomas Hartnett, the company secretary of the Company, holds 50,001 Ordinary Shares as at the date of this Prospectus for the purposes of the structuring of the Scheme. These Ordinary Shares will be acquired by the Partnership at their subscription value in connection with the Scheme before the Company acquires any indirect interest in Zhaikmunai LLP and prior to Admission.

8.3 Interests in Transactions

Save for the related party transactions set out in the financial information set out in Part 14 "*Historical Financial Information*", as set out in paragraph 4 of Part 10 "*Principal Shareholders and Related Party Transactions*" and as set out in paragraph 8 of this Part 17 "*Additional Information*" of this Prospectus, no Director has or has had any interest in any transaction which is or was unusual in its nature or conditions or is or was significant to the business of the Group and which was effected by the Company in the current or immediately preceding financial year of the Company or which was effected in an earlier financial year and remains in any respect outstanding or unperformed.

8.4 **Directorships and Partnerships**

Set out below are the directorships and partnerships in which the Directors and members of the senior management are currently directors or partners or have been directors or partners at any time in the five years prior to the date of this Prospectus:

Name	Current directorships/partnerships	Former directorships/partnerships held in the last five years
Frank Monstrey	Probel Capital Management N.V. Oostendse Investerings Vennootschap N.V. Magorium NV Tensor Holding VOF Tensor Property Investments S.A.R.L. Expression Inc Septemium Investments S.A. Tensor Capital Partners LP Tensor Carry Holdings LLC Tensor Asset Management N.V. Thyler Holdings Limited B.M. Lumina Claremont Holdings C.V. Claremont Holdings Limited Camden Holdings Ltd Secap Holdings Ltd Roding Investments S.A. Orior Trading Ltd Selag Holdings S.A. B.M. Samara B.M. Elata B.M. Clara Nedmac BV Thyler Holdings BV Septinvest BV Sepol Holdings GmbH RusPetro plc Crest Capital Management N.V.	None
Kai-Uwe Kessel	BelGerAs, S.A. Gervanca Investments Sarl Cavendish	None
Jan-Ru Muller	Telco B.V.	None
Eike von der Linden	Linden Advisory & Consulting Services Appleton Resources Ltd Schüllermann und Partner AG Energy Bidco Limited Energy Bidco Holdings Limited	GLR Resources Jordan Energy & Mining Ltd
Atul Gupta	Seven Energy Vetra Energy	Dominion Petroleum PLC Burren Energy PLC Villiers Limited Strand Oil and Gas Limited Nammax Oil & Gas Limited Roslindale Limited
Sir Christopher Codrington, Bt.	Navarino Services Ltd	None
Mark Martin	None	Exillon Energy PLC
Piet Everaert	VWEW Advocaten VOF BVBA Piet Everaert	None
Pankaj Jain	RMG Properties ABN Heritage KSS Global	None

Name	Current directorships/partnerships	Former directorships/partnerships held in the last five years
Thomas Hartnett	Thomas Hartnett BVBA Cabot Consulting Ltd. Probel Capital Management N.V.	None
Jan Laga	Probel Capital Management Jan Laga BVBA	Koramic Industries
Thomas Richardson	TDR Enterprises Holding Ltd. TDR Investments Ltd. TDR Enterprises Ltd.	None

8.5 **Receiverships, Liquidations and Administrations**

None of the Directors or senior managers has, in the five years immediately preceding the date of this Prospectus:

(i) received any convictions in relation to fraudulent offences;

(ii) been declared bankrupt or been the subject of an individual voluntary arrangement or been associated with any bankruptcy, receivership or liquidation in his capacity as a director or senior manager of another company;

(iii) been a partner or senior manager in a partnership which has been subject to a compulsory liquidation, administration or a partnership voluntary arrangement; or

(iv) been subject to any official public incrimination and/or sanction by statutory or regulatory authorities (including designated professional bodies) or been disqualified by a court from acting as a director or member of the administrative, management or supervisory bodies of a company or entity or from acting in the management or conduct of the affairs of any company or entity.

9. Directors' Service Contracts and Letters of Appointment

9.1 The Directors and their functions are set out in Part 9 "*Directors, Management and Corporate Governance*".

9.2 **Executive Directors**

General

Mr. Monstrey, Mr. Kessel and Mr. Muller were appointed as Directors of the Company on incorporation. The appointment of each of the Executive Directors as statutory directors will continue until the Company's first annual general meeting and their ongoing appointment is subject to being re-elected as a director at each subsequent annual general meeting. Each Executive Director may be required to resign as a statutory director at any time in accordance with the Articles or for any regulatory reason such as the revocation of any approvals required from the FCA. Each Executive Director or the Company may terminate the employment of the Executive Director at any time upon 12 month's written notice.

The Company makes no provision in respect of any pension for any Executive Director.

The Executive Directors are subject to certain restrictive covenants during the term of their executive service contract and, with respect to the undertaking not to disclose or use confidential information, at any time thereafter. The Executive Directors are not permitted to take up any office or employment with, or have any direct or indirect interest in any firm or company which is in direct or indirect competition with the Company or any other member of the Group or any company in which any member of the Group has an interest, without the consent of the Board. Their executive service contract also contains provisions relating to share dealings and non-competition and non-solicitation covenants in relation to relevant Group companies for six months from the date of termination of the relevant executive service contracts. The executive directors' services and senior management's services are invoiced based on the service agreement between Probel and Nostrum pursuant to which such executive directors and senior management provide services to the Group.

Frank Monstrey

Mr. Monstrey was appointed as Executive Chairman of the Company under a service agreement with the Company dated 19 May 2014; his services are also provided pursuant to a service agreement with Probel in relation to the provision of services to Nostrum Oil & Gas group companies. His period of appointment with the Company is deemed to have commenced on 3 October 2013. The services of Mr. Monstrey are remunerated with an annual fee of U.S.$931,500, variable by agreement from time to time, together with a bonus as may be awarded by the Board in its discretion from time to time, taking into account the recommendations of its Remuneration Committee.

Kai-Uwe Kessel

Mr. Kessel was appointed as Chief Executive Officer of the Company under a service agreement with the Company dated 19 May 2014; his services are also provided pursuant to a service agreement with Probel in relation to the provision of services to Nostrum Oil & Gas group companies. His period of appointment with the Company is deemed to have commenced on 3 October 2013. The services of Mr. Kessel are remunerated with an annual fee of U.S.$928,000, variable by agreement from time to time, together with a bonus as may be awarded by the Board in its discretion from time to time, taking into account the recommendations of its Remuneration Committee.

Jan-Ru Muller

Mr. Muller was appointed as Chief Financial Officer of the Company under a service agreement with the Company dated 19 May 2014; his services are also provided pursuant to a service agreement with Probel in relation to the provision of services to Nostrum Oil & Gas group companies. His period of appointment with the Company is deemed to have commenced on 3 October 2013. The services of Mr. Muller are remunerated with an annual fee of U.S.$557,000, variable by agreement from time to time, together with a bonus as may be awarded by the Board in its discretion from time to time, taking into account the recommendations of its Remuneration Committee.

9.3 **Non-Executive Directors**

The appointment of each of the Non-Executive Directors as Directors of the Company commenced on 19 May 2014 and will continue until the Company's first annual general meeting. Each appointment is for an initial term of three years, subject to being re-elected as a director at each annual general meeting, save that a Non-Executive Director or the Company may terminate the appointment at any time upon one month's written notice, or the Non-Executive Director may be required to resign at any time in accordance with the Articles, the Corporate Governance Code or for any regulatory reason such as the revocation of any approvals required from the FCA. These appointments are otherwise subject to the provisions of the Articles and the terms of reference of the Board committees.

The Non-Executive Directors are subject to certain restrictive covenants during the appointment and, with respect to the undertaking not to disclose or use confidential information, at any time thereafter. The relevant agreements contain provisions relating to confidentiality, share dealings and conflicts of interest. The Non-Executive Directors are required to devote sufficient time to the affairs of the Company as is necessary to perform their respective duties. The Non-Executive Directors are not permitted to take up any office or employment with, or have any direct or indirect interest in any firm or company which is in direct or indirect competition with the Company. Upon termination of the appointment, and where such termination is for any reason other than due to the Non-Executive Director's gross misconduct, material breach of the terms of the appointment, act of fraud or dishonesty or wilful neglect of the Non-Executive Director's duties, the Non-Executive Director will be paid a pro rated amount of his fees in respect of the period between the beginning of the quarter in which termination took place and the termination date. Otherwise, none of the Non-Executive Directors is entitled to any damages for loss of office and no fee shall be payable in respect of any unexpired portion of the term of the appointment.

The Non-Executive Directors are each entitled to an annual fee of U.S.$100,000 paid quarterly.

The Non-Executive Directors are also entitled to reimbursement of reasonable expenses. There is no entitlement to participate in Company pension plans or share option plans.

9.4 Save as disclosed in paragraphs 9.1 to 9.3 above, there are no existing or proposed service agreements or letters of appointment between the Directors and any members of the Group.

9.5 **Directors' and Senior Management Compensation**

Under the terms of their service contracts and applicable incentive plans, in the year ended 31 December 2013, the aggregate compensation, including bonuses and benefits in kind, granted to the Directors and Senior Management who served during 2013 was U.S.$4,873,000. The executive directors' services and senior management's services are invoiced based on the service agreement between Probel and Nostrum.

In the financial year ended 31 December 2013, the Directors and Senior Managers received the compensation and benefits set out below (in U.S.$ thousands):

Name	Salary/Fee	Benefits in kind	Pension	Annual Bonus	Total
Frank Monstrey	931.5[1]	—	—	—	931.5[1]
Kai-Uwe Kessel	928[1]	12	—	293[1]	1233[1]
Jan-Ru Muller	557[1]	—	—	183[1]	740[1]
Eike von der Linden	100	—	—	—	100
Atul Gupta	100	—	—	—	100
Sir Christopher Codrington, Bt.	—	—	—	—	—
Mark Martin	—	—	—	—	—
Piet Everaert	100	—	—	—	100
Pankaj Jain	100	—	—	—	100
Jan Laga	441[1]	—	—	97[1]	538[1]
Thomas Hartnett	620[1]	—	—	183[1]	803[1]
Thomas Richardson	195[1]	—	—	57[1]	252[1]

(1) Converted into U.S. Dollars from Euro at the exchange rate reported by the European Central Bank as at 31 December 2013 of U.S.$1.38 per Euro.

9.6 There is no arrangement under which any Director has waived or agreed to waive future emoluments nor has there been any waiver of emoluments during the financial year immediately preceding the date of this Prospectus.

9.7 There were no amounts set aside or accrued to provide pension, retirement or other benefits to the Directors and senior managers of the Group for the year ended 31 December 2013.

9.8 Save as disclosed in this paragraph 9, there have been no changes to the emoluments or the terms of employment of the Directors or senior management within the six months prior to the date hereof.

10. Employees, Employee Share Schemes and Pensions

10.1 As at 31 December 2013, the Group employed 907 people. The table below sets out the number of full time employees employed by the Group at the end of each of the last three financial years:

	Year ended		
Location	31 December 2013	31 December 2012	31 December 2011
Chinarevskoye Field	633	656	577
Uralsk	274	218	170
Total	**907**	**874**	**747**

10.2 Phantom Option Plan

The Partnership currently operates one option plan (the "**Phantom Option Plan**" or "**Plan**"). The Phantom Option Plan was initially adopted by the board of directors of the General Partner on 27 March 2008 and subsequently amended on 24 July 2008 and 14 August 2008.

As of 31 March 2014, options relating to 2,827,413 GDRs remain outstanding (the "**Subsisting Options**"), each with a Base Value of up to U.S.$10.00 (the "**Base Value**").

Each Subsisting Option is a right for its holder to receive on exercise a cash amount equal to the difference between (i) the aggregate Base Value of the GDRs to which the Subsisting Option relates; and (ii) their aggregate market value on exercise.

Pursuant to Rule 6.2 of the Plan, in the event of a transaction or change in the structure of the Partnership which would affect the value of any option granted under the Plan, the board of directors of the General Partner shall, acting reasonably and objectively, direct the Trustee to make such adjustments to the options under the Plan as the board considers appropriate in order to ensure that Optionholders are not prejudiced.

Accordingly, the board of directors of the General Partner has directed the Trustee to adjust, and the Trustee has so adjusted, each Subsisting Option, subject to and conditional upon Admission, so that each Subsisting Option is, from the date of Admission, a right for each holder to receive on exercise a cash amount equal to the excess of (i) the market value on the date of exercise of the number of Ordinary Shares to which it relates, being the same as the number of GDRs to which it previously related; over (ii) the Base Value of the same number of Ordinary Shares which Base Value is unchanged, except that it will be stated in £sterling and not US$.

Each Subsisting Option shall be governed by the Plan, as amended by the board of directors of the General Partner and adopted by the Board, subject to and conditional upon Admission.

The principal features of the Plan (as amended) are as follows:

Operation

The Plan is administered by the Trustee, which is responsible for granting rights under the Plan. Each right entitles holders (the "**Optionholders**") to receive, on exercise, a cash amount equal to the excess of the market value on the exercise date of the Ordinary Shares to which it relates over the value of the same number of Ordinary Shares at the date of grant (the "**Option**"). The Plan is discretionary and only operates in those years as the Board determines. Options under the Plan may be granted as required by the Board.

Eligibility

All employees, executive directors of, and consultants to, a member of the Group are eligible to participate in the Plan at the discretion of the Board. However, to date, participation has only been offered to a limited number of senior employees, executive directors, and consultants of members of the Group.

Grant of Options

The Trustee may grant Options to an employee or executive director as requested by the Board.

No payment is required for the grant of Options. Options will not be taken into account in determining an Optionholder's pension rights. Options are not transferable, other than to associated parties or on death.

The aggregate number of Ordinary Shares in respect of which Options may be outstanding under the Plan will not exceed 5,000,000 Ordinary Shares.

Exercise of Options

Options are normally exercisable at the following times:

- as to 20% of the Ordinary Shares in respect of which an Option is granted, from the first anniversary of the date of grant;
- as to a further 20% of the Ordinary Shares in respect of which an Option is granted, from the second anniversary of the date of grant;
- as to a further 20% of the Ordinary Shares in respect of which an Option is granted, from the third anniversary of the date of grant;
- as to a further 20% of the Ordinary Shares in respect of which an Option is granted, from the fourth anniversary of the date of grant; and
- as to the remaining 20% of the Ordinary Shares in respect of which an Option is granted from the fifth anniversary of the date of grant.

The Trustee will satisfy an Option by paying to the Optionholder on exercise an amount equal to the excess of the value of the Ordinary Shares in respect of which it is being exercised at the date of exercise over the market value of the same number of Ordinary Shares on the date of grant (minus any amounts required to be withheld). In relation to the grant of Options to date, the vesting of such Options is not subject to any performance targets. The Board may, however, determine that any Options granted in the future should be subject to performance targets.

Cessation of Employment

- If an Optionholder dies whilst in employment with a member of the Group, his legal representatives shall be entitled to exercise his Options (whether vested or not) during the 12 month period following the date of his death. After this period, the Options will lapse, to the extent that they have not been exercised.
- If an Optionholder leaves employment by reason of injury, disability, redundancy, retirement or the sale of the business for which he works to a third party, his Options may generally be exercised at any time up to the tenth anniversary of the date of grant.
- If an Optionholder gives notice of termination of his employment or consultancy, his Options will lapse to the extent that they have not vested on the date of cessation and any portion that remains outstanding but unexercised after 12 months following such cessation will lapse.

Corporate Events

(a) Takeover

In the event of a takeover of the Company all of the Options shall be deemed to have vested and the Board shall direct the Trustee in writing to allow each Optionholder to exercise his Options at any time from the date of the change of control up to the tenth anniversary of the date of grant. Any Options which have not been exercised will lapse at the end of this period.

(b) Merger, demerger

In the event of a merger, dividend in specie, super dividend, stock split, dilutive issuance, demerger or other transaction or change in the structure of the Company which would affect the value of any Option, the Board shall, acting reasonably and objectively, direct the Trustee to make such adjustments as it considers appropriate in order to ensure that Optionholders are not prejudiced.

(c) Winding-up

In the event of a voluntary winding-up of the Company, Options may, subject to satisfaction of any performance conditions, be exercised during the period between the date of notice of a meeting to consider a resolution for the voluntary winding-up of the Company and the date on which the winding-up becomes effective. To the extent that any Options have not been exercised at the expiry of this period, the Options will lapse.

Alterations to the Plan

Subject to the discretion of the Board in relation to certain matters as set out in the rules of the Plan, the decision of the Trustee shall be final and binding in all matters relating to the Plan.

Termination of the Plan

The Plan shall terminate on 27 March 2018. Expiry of the Plan shall not affect Options already granted.

10.3 **Nostrum Benefit Trust**

The Nostrum Benefit Trust is a discretionary trust established in Jersey for the benefit of employees, Executive Directors, and secondees of the Company and its subsidiaries from time to time. The trustee of the Trust is Ogier Employee Benefit Trustee Limited, a company which is independent of and unrelated to the Company (the "**Trustee**").

The Trustee has subscribed for GDRs on a cash free basis (and will receive Ordinary Shares in respect of such GDRs pursuant to the Scheme). It is expected that the Trustee will satisfy Options on exercise by the Optionholders and will acquire and sell Ordinary Shares for this purpose.

10.4 **Pension Scheme**

The Group currently has no pension plans in place.

11. Legal and Arbitration Proceedings

There are no governmental, legal or arbitration proceedings (including any such proceedings which are pending or threatened of which the Company is aware), which during the previous 12 months may have, or have had in the recent past significant effects on the Company and/or the Group's financial position or profitability.

12. Material Contracts

The following contracts are all the material contracts (not being contracts entered into in the ordinary course of business) which have been entered into within the two years prior to the date of this Prospectus by members of the Group and the contracts (not being contracts entered into in the ordinary course of business) entered into at any time by members of the Group which contain provisions under which any member of the Group has an obligation or entitlement which is or may be material to the Group as at the date of this Prospectus:

12.1 Licences

The Group has entered into the Licences described in Part 7 "*Information on the Group—The Licence and the PSA*" of this Prospectus.

12.2 Relationship Agreements

The Company has entered into the Relationship Agreements with each of Claremont and KSS Global described at paragraphs 2 and 3 of Part 10 "*Principal Shareholders and Related Party Transactions*" of this Prospectus.

12.3 Financing agreements

The Licence Holder has issued the 2019 Bonds and the New 2019 Bonds. The following is a summary of certain provisions of the 2019 Bonds and the New 2019 Bonds. The Licence Holder had previously issued the 2015 Bonds which were redeemed in full on 14 April 2014.

2019 Bonds

Overview

On 13 November 2012, Zhaikmunai International B.V. (the "**2019 Initial Issuer**") issued the 2019 Bonds. Under the terms of the indenture relating to the 2019 Bonds, Zhaikmunai LLP (the "**2019 Issuer**") was permitted, subject to certain conditions, to be substituted for the 2019 Initial Issuer as issuer of the 2019 Bonds.

On 5 April 2013, in preparation for the substitution, the shares in Zhaikmunai International B.V. were transferred to the 2019 Issuer, and on 24 April 2013, the 2019 Issuer was substituted for Zhaikmunai International B.V. as issuer of the 2019 Bonds pursuant to a supplemental indenture.

As part of the Scheme, the Company and Co-op will enter into a supplemental indenture pursuant to which each will guarantee the 2019 Bonds on a senior basis and the Company shall assume all of the obligations of the Partnership under the indenture governing the 2019 Bonds following which the Partnership will be released from all obligations thereunder.

Listing

The 2019 Bonds are admitted to the Official List and trading on the Global Exchange Market, which is the exchange regulated market of the Irish Stock Exchange and admitted to trading in the "rated debt securities" category of the official list of the KASE.

Interest and Maturity

The 2019 Bonds bear interest at the rate of 7.125% per year. Interest on the 2019 Bonds is payable on 14 May and 13 November of each year. The 2019 Bonds mature on 13 November 2019.

Redemption

The 2019 Issuer may redeem some or all of the 2019 Bonds at any time on or after 13 November 2016 at established redemption prices (being 103.5625% of nominal principal amount until and including

12 November 2017, 101.78125% until and including 12 November 2018 and 100% from and including 13 November 2018 onwards) plus accrued and unpaid interest to the redemption date. Prior to 13 November 2016, all or part of the 2019 Bonds may be redeemed in whole or in part at a price equal to 100% of the principal amount of the 2019 Bonds to be redeemed plus accrued and unpaid interest to the redemption date and a "make whole" premium.

In addition, prior to 13 November 2016, up to 35% of the aggregate principal amount of 2019 Bonds may be redeemed with the proceeds of certain equity offerings at a redemption price equal to 107.125% of the principal amount of the 2019 Bonds to be redeemed, plus accrued and unpaid interest to the redemption date, so long as at least 65% of the original principal amount of the 2019 Bonds (including Additional Notes as defined in the indenture relating to the 2019 Bonds) remains outstanding after each such redemption and each such redemption occurs within 90 days after the closing of the relevant equity offering.

In the event of certain developments affecting taxation, the 2019 Bonds may also be redeemed in whole, but not in part, at any time, at a redemption price of 100% of the principal amount of the 2019 Bonds plus accrued and unpaid interest and additional amounts to the date of redemption.

Upon the occurrence of certain events defined as constituting a change of control, the issuer of the 2019 Bonds will be required to offer to repurchase the 2019 Bonds at 101% of their principal amount, plus accrued and unpaid interest to the date of purchase.

Guarantees and Security

The 2019 Bonds are jointly and severally guaranteed on a senior basis by the Partnership and all of its subsidiaries (other than the 2019 Issuer). The 2019 Bonds constitute senior obligations of the 2019 Issuer and the guarantors and will rank equally with all of the 2019 Issuer's and the guarantors' other senior indebtedness.

The 2019 Bonds do not benefit from any security.

Ranking

The 2019 Bonds:

- constitute general senior obligations of the 2019 Issuer;
- rank senior in right of payment to all existing and future subordinated obligations of the 2019 Issuer;
- rank equally in right of payment to any future senior indebtedness of the 2019 Issuer, without giving effect to collateral arrangements; and
- effectively rank junior to any existing or future indebtedness of the 2019 Issuer secured by property or assets to the extent of the value of such property or assets.

Certain Covenants and Events of Default

The indenture governing the 2019 Bonds contains a number of covenants that, among other things, restrict, subject to certain exceptions, the ability of the Partnership (which following the Scheme shall be replaced by the Company) and its restricted subsidiaries to:

- incur or guarantee additional indebtedness and issue certain preferred stock;
- create or incur certain liens;
- make certain payments, including dividends or other distributions;
- prepay or redeem subordinated debt or equity;
- make certain investments;
- create encumbrances or restrictions on the payment of dividends or other distributions, loans or advances to and on the transfer of assets to the Partnership (or, following the Scheme, the Company) or any of its restricted subsidiaries;
- sell, lease or transfer certain assets including shares of restricted subsidiaries;
- engage in certain transactions with affiliates;
- enter into unrelated businesses; and
- consolidated or merge with other entities.

Each of these covenants is subject to certain exceptions and qualifications.

In addition, the indenture governing the 2019 Bonds imposes certain requirements as to future subsidiary guarantors. In addition, the indenture governing the 2019 Bonds also contains certain customary information covenants and events of default.

New 2019 Bonds

Overview

On 14 February 2014, Nostrum Oil & Gas Finance B.V. (the "**New 2019 Initial Issuer**") issued the New 2019 Bonds. Under the terms of the indenture relating to the 2019 Bonds, Zhaikmunai LLP (the "**New 2019 Issuer**") was permitted, subject to certain conditions, to be substituted for the 2019 Initial Issuer as issuer of the 2019 Bonds.

On 6 May 2014, the New 2019 Issuer was substituted for the New 2019 Initial Issuer as issuer of the 2019 Bonds pursuant to a supplemental indenture.

As part of the Scheme, the Company and Nostrum Oil B.V. will enter into a supplemental indenture pursuant to which each will guarantee the New 2019 Bonds on a senior basis and the Company shall assume all of the obligations of the Partnership under the indenture governing the New 2019 Bonds following which the Partnership will be released from all obligations thereunder.

Listing

The New 2019 Bonds are admitted to the Official List and trading on the Global Exchange Market, which is the exchange regulated market of the Irish Stock Exchange and admitted to trading in the "rated debt securities" category of the official list of the KASE.

Interest and Maturity

The New 2019 Bonds bear interest at the rate of 6.375% per year. Interest on the 2019 Bonds is payable on 14 February and 14 August of each year. The New 2019 Bonds mature on 14 February 2019.

Redemption

The New 2019 Issuer may redeem some or all of the New 2019 Bonds at any time on or after 14 February 2017 at established redemption prices (being 103.1875% of nominal principal amount until and including 13 February 2018 and 100% from and including 14 February 2018 onwards) plus accrued and unpaid interest to the redemption date.

In addition, prior to 14 February 2017, the New 2019 Bonds Issuer may, at its option, on any one or more occasions redeem up to 35% of the aggregate principal amount of the New 2019 Bonds with the net cash proceeds of one or more equity offerings at a redemption price of 106.375% of the principal amount thereof, plus accrued and unpaid interest, if any, to the redemption date (subject to the right of holders of record on the relevant record date to receive interest due on the relevant interest payment date); provided that (1) at least 65% of the original principal amount of the New 2019 Bonds (including Additional Notes as defined in the indenture relating to the New 2019 Bonds) remains outstanding after each such redemption; and (2) the redemption occurs within 90 days after the closing of the related equity offering.

In addition, the New 2019 Bonds may be redeemed, in whole or in part, at any time prior to 14 February 2017 at the option of the New 2019 Bonds Issuer upon not less than 30 nor more than 60 days' prior notice mailed by first-class mail to each holder of New 2019 Bonds at its registered address, at a redemption price equal to 100% of the principal amount of the New 2019 Bonds redeemed plus the Applicable Premium (as defined below) as of, and accrued and unpaid interest to, the applicable redemption date (subject to the right of holders of record on the relevant record date to receive interest due on the relevant interest payment date). Applicable Premium means, with respect to any New 2019 Bond on any applicable redemption date, the greater of: (1) 1.0% of the principal amount of such New 2019 Bond; and (2) the excess, if any, of: (a) the present value at such redemption date of (i) the redemption price of such New 2019 Bond at 14 February 2017 plus (ii) all required interest payments (excluding accrued and unpaid interest to such redemption date) due on such New 2019 Bond through 14 February 2017 computed using a discount rate equal to the United States treasury rate as of such redemption date plus 50 basis points; over (b) the principal amount of such

New 2019 Bond. In the event of certain developments affecting taxation, the 2019 Bonds may also be redeemed in whole, but not in part, at any time, at a redemption price of 100% of the principal amount of the New 2019 Bonds plus accrued and unpaid interest and additional amounts to the date of redemption.

Upon the occurrence of certain events defined as constituting a change of control, the issuer of the New 2019 Bonds will be required to offer to repurchase the New 2019 Bonds at 101% of their principal amount, plus accrued and unpaid interest to the date of purchase.

Guarantees and Security

The New 2019 Bonds are jointly and severally guaranteed on a senior basis by the Partnership and all of its subsidiaries (other than the New 2019 Issuer). The New 2019 Bonds constitute senior obligations of the New 2019 Issuer and the guarantors and will rank equally with all of the New 2019 Issuer's and the guarantors' other senior indebtedness.

The New 2019 Bonds do not benefit from any security.

Ranking

The New 2019 Bonds:

- constitute general senior obligations of the New 2019 Issuer;
- rank senior in right of payment to all existing and future subordinated obligations of the New 2019 Issuer;
- rank equally in right of payment to any future senior indebtedness of the New 2019 Issuer, without giving effect to collateral arrangements; and
- effectively rank junior to any existing or future indebtedness of the New 2019 Issuer secured by property or assets to the extent of the value of such property or assets.

Certain Covenants and Events of Default

The indenture governing the New 2019 Bonds contains a number of covenants that, among other things, restrict, subject to certain exceptions, the ability of the Partnership (which following the Scheme shall be replaced by the Company) and its restricted subsidiaries to:

- incur or guarantee additional indebtedness and issue certain preferred stock;
- create or incur certain liens;
- make certain payments, including dividends or other distributions;
- prepay or redeem subordinated debt or equity;
- make certain investments;
- create encumbrances or restrictions on the payment of dividends or other distributions, loans or advances to and on the transfer of assets to the Partnership (or, following the Scheme, the Company) or any of its restricted subsidiaries;
- sell, lease or transfer certain assets including shares of restricted subsidiaries;
- engage in certain transactions with affiliates;
- enter into unrelated businesses; and
- consolidated or merge with other entities.

Each of these covenants is subject to certain exceptions and qualifications.

In addition, the indenture governing the New 2019 Bonds imposes certain requirements as to future subsidiary guarantors. In addition, the indenture governing the New 2019 Bonds also contains certain customary information covenants and events of default.

12.4 Scheme Agreements

In connection with the Scheme, members of the Group have entered into the following agreements:

(a) The Company, Co-op, the Partnership, the General Partner, NOGGL, Nostrum Oil BV and VTB entered into the Scheme Implementation Agreement dated 20 May 2014. The Scheme Implementation

Agreement provides the framework for the Company, the Partnership, NOGGL, all relevant Group parties and VTB to take all steps necessary or otherwise reasonably required for the Scheme and to undertake the actions set out in the agreed step plan to implement the Scheme, including sending the Scheme Document to Limited Partners, convening the Special General Meeting and making all necessary distributions to limited partners in the Partnership. The Board and the General Partner have the ability to revise any step as may be reasonably required in order to be able to effect the Scheme as approved by Limited Partners. The Scheme Implementation Agreement also includes certain undertakings regarding the conduct of business of the Group prior to Admission. The Scheme Implementation Agreement may be terminated if any of the conditions to the Scheme are not satisfied (or if permitted waived) by 31 July 2014.

(b) The Company and VTB entered into the PLC Facility Agreement dated 20 May 2014 in respect of the financing of the acquisition of the Group by the Company. Pursuant to the PLC Facility Agreement, VTB will (subject to, *inter alia*, satisfaction of customary conditions precedent, including the approval of the Scheme by Limited Partners) lend an amount equal to the Funding Amount to the Company on an intra-day basis in order to finance the acquisition of the Group pursuant to the Scheme. The amount borrowed under the PLC Facility Agreement will bear interest at a rate per annum equal to 1.50% and the Company will be required to pay:

- a commitment fee, on the facility amount at a rate of 1.00% per annum on undrawn commitments, calculated on the basis of a 60 calendar day commitment period, with (A) a fee in respect of a 30 calendar day commitment period being payable within 5 business days after the date of the PLC Facility Agreement and (B) a fee payable on additional days of commitment beyond 30 calendar days payable as a condition precedent to drawdown;
- a drawdown fee at a rate of 0.10% of the amount utilised; and
- an upfront fee at a rate of 0.30% of the facility amount.

The facility will be secured by an English law control accounts security agreement to be entered into between the Company, VTB as account bank and VTB as security agent in relation to the accounts into which the Funding Amount will be paid (the "**PLC Control Accounts**").

The PLC Facility Agreement contains customary information and negative undertakings from the Company, subject to certain agreed exceptions. The PLC Facility Agreement also requires the Company to observe certain customary positive undertakings as well as those relating to maintenance and dealings with the PLC Control Accounts. The PLC Facility Agreement contains customary events of default (subject, prior to the intra-day funding being made, in certain cases to agreed grace periods, thresholds and other qualifications) the occurrence of which would allow the lenders to accelerate all or part of the outstanding utilisations and/or terminate their commitments.

(c) NOGGL and VTB entered into the NOGGL Facility Agreement dated 20 May 2014 in respect of the financing of the acquisition of the Special Limited Partner Interest by NOGGL. Pursuant to the NOGGL Facility Agreement, VTB will (subject to, *inter alia*, satisfaction of customary conditions precedent, including the approval of the Scheme by Limited Partners) lend an amount equal to the SLP Subscription Amount to NOGGL on an intra-day basis (but with a maturity date of up to 5 calendar days from the utilisation date) in order to finance the acquisition of the Special Limited Partner Interest by NOGGL. The amount borrowed under the NOGGL Facility Agreement will bear interest at a rate per annum equal to 1.50% and NOGGL will be required to pay:

- a commitment fee, on the facility amount at a rate of 1.00% per annum on undrawn commitments, calculated on the basis of a 60 calendar day commitment period, with (A) a fee in respect of a 30 calendar day commitment period being payable within 5 business days after the date of the NOGGL Facility Agreement and (B) a fee payable on additional days of commitment outstanding beyond 30 calendar days payable as a condition precedent to drawdown;
- a drawdown fee at a rate of 0.10% of the amount utilised; and
- an upfront fee at the rate of 0.30% of the facility amount.

The facility will be secured by an English law debenture to be entered into between NOGGL, VTB as account bank and VTB as security agent under which NOGGL will grant security over (i) the account into which the SLP Subscription Amount will be paid (the "**NOGGL Control Account**") and (ii) its rights against the Company under a deed of assignment to be entered into between NOGGL and the Company relating to the assignment of the Special Limited Partner Interest from NOGGL to the Company.

The NOGGL Facility Agreement contains customary information and negative undertakings from NOGGL, subject to certain agreed exceptions. The NOGGL Facility Agreement also requires NOGGL to observe certain customary positive undertakings as well as those relating to maintenance and dealings with the NOGGL Control Account. The NOGGL Facility Agreement contains customary events of default (subject, prior to the funding being made, in certain cases to agreed grace periods, thresholds and other qualifications) the occurrence of which would allow the lenders to accelerate all or part of the outstanding utilisations and/or terminate their commitments. Each of Co-op and the Partnership have agreed to guarantee the obligations of NOGGL under the NOGGL Facility Agreement.

12.5 **Sponsor's Agreement**

On 20 May 2014, the Company, the Partnership and the Sponsor entered into a sponsor's agreement (the "**Sponsor's Agreement**"). Pursuant to the Sponsor's Agreement, the Sponsor has agreed to act as sponsor to the Company in connection with the application for admission of the Ordinary Shares to the Official List and the publication of this Prospectus.

Under the terms of the Sponsor's Agreement, the Company and the Partnership have agreed to provide the Sponsor with certain customary indemnities, undertakings, representations and warranties. The indemnities provided by the Company and the Partnership indemnify the Sponsor against, *inter alia*, claims made against it or losses incurred by it, subject to certain exceptions. In addition, the Sponsor's Agreement provides the Sponsor with the right to terminate the Sponsor's Agreement before Admission in certain specified circumstances typical for an agreement of this nature, in which case the Sponsor's Agreement will lapse.

13. Working Capital

It is the opinion of the Company that the Group has sufficient working capital for its present requirements, which is for at least the next 12 months from the date of this Prospectus.

14. No Significant Change

Except for the issuance by the Group on 14 February 2014 of the New 2019 Bonds in a principal amount of U.S.$400 million and the redemption by the Group on 14 April 2014 of the outstanding 2015 Bonds in principal amount of U.S.$92.5 million, there has been no significant change in the financial or trading position of the Group since 31 December 2013, the end of the most recent financial period for which historical financial information has been published.

No material changes have occurred since 16 December 2013, the date of the 2013 Ryder Scott Report, the omission of which would make the 2013 Ryder Scott Report misleading.

15. General

15.1 The expenses of the Scheme and Admission are estimated at approximately U.S.$32 million (including VAT) and are payable by the Company.

15.2 The Group is dependent upon the exploration and production licences and agreements summarised in Part 7 "*Information on the Group*" of this Prospectus. The Directors believe that there are no patents, contracts or new manufacturing processes which are of fundamental importance to the Group's business or profitability.

15.3 The financial information contained in this Prospectus does not amount to statutory accounts within the meaning of section 240 of the 1985 Act or section 434 of the Companies Act (as applicable).

15.4 Other than as disclosed in Part 14 "*Historical Financial Information*" of this Prospectus, the Company has no major encumbrances over any existing or planned material tangible, fixed assets.

15.5 Deutsche Bank AG, London Branch is the Company's sponsor and broker and is authorised by the PRA and regulated in the UK by the PRA and the FCA.

16. Authorisations and Consents

16.1 Ryder Scott Company L.P. has given and not withdrawn its written consent to the issue of this Prospectus with the inclusion of the Competent Person's Report, and the mineral reserves and resources estimates set out in this Prospectus, in the form and context in which they appear, and has authorised the contents of the Competent Person's Report and the mineral reserves and resources estimates set out in this Prospectus, for the purposes of paragraph 5.5.3R(2)(f) of the Prospectus Rules and for the purpose of paragraph 23.1 of Annex I of the Prospectus Directive Regulation.

16.2 Ernst & Young Advisory LLP (Kazakhstan) has given and not withdrawn its written consent to the inclusion in this Prospectus of its accountant's report on the Group as included in Part 14 "*Historical Financial Information*" of this Prospectus in the form and context in which it appears, and has authorised the contents of its report on the Group for the purposes of paragraph 5.5.3R(2)(f) of the Prospectus Rules issued by the FCA.

17. Auditors

By resolution of the shareholders dated 19 May 2014, Ernst & Young LLP, whose address is One More London Place, London SE1 2AF was appointed as the auditor of the Company. Ernst & Young LLP is registered to carry out audit work by the Institute of Chartered Accountants in England and Wales.

18. Competent Person

Ryder Scott Company L.P., whose registered office is at 621 Seventeenth Street, Suite 1550, Denver, Colorado 80293, United States, are petroleum consultants who provide a complete range of geological, geophysical and engineering services.

19. Irrevocable undertakings

In connection with the Scheme, the Partnership and the Company have received irrevocable undertakings to vote in favour of the amendment of the Limited Partnership Agreement and the Scheme (the "**Irrevocable Undertakings**") from (i) Claremont and its affiliates in respect of, in aggregate, 51,190,476 Existing Securities, (ii) KSS Global in respect of 50,000,000 Existing Securities and (iii) Dehus Dolman Nominees Limited and its affiliates in respect of 28,906,483 Existing Securities, representing in aggregate 69.13% of the existing Common Units as at the date of this Prospectus.

Each of the providers of the Irrevocable Undertakings have undertaken:

- to vote or otherwise exercise all voting rights attaching to the Common Units in favour of the resolutions to be proposed at the Special General Meeting of the Partnership; and
- not to sell, transfer, charge, pledge or grant any option over or otherwise dispose of any of the relevant Common Units (or enter into any agreement to do any such acts).

The undertaking from KSS Global to vote in favour of the resolutions to be proposed at the Special General Meeting of the Partnership is conditional upon receipt of consent from its lenders.

Each of the Irrevocable Undertakings will lapse if the Scheme lapses or is withdrawn or if the Scheme has not become effective by 5.30pm (London time) on 31 July 2014 or such later time or date as the Partnership and the Company agree.

20. Documents Available for Inspection

Copies of the following documents may be inspected at the head office of the Company at 4th Floor, 53-54 Grosvenor Street, London W1K 3HU and at Gustav Mahlerplein 23B, 1082 MS, Amsterdam, The Netherlands during usual business hours on any weekday (Saturdays, Sundays and public holidays excepted) from the date of publication of this Prospectus until Admission:

(a) the memorandum of association and Articles of the Company;

(b) the consent letters referred to in paragraph 16 above;

(c) the accountant's report at Part 14 "*Historical Financial Information*" of this Prospectus;

(d) the Competent Person's Report at Part 15 "*Competent Person's Report*" of this Prospectus;

(e) the Scheme Document; and

(f) this Prospectus

PART 18
DEFINITIONS AND GLOSSARY

DEFINITIONS

The following definitions apply throughout this Prospectus, unless the context otherwise requires:

"**1999 Amendments**"	Law No. 467 1 "Concerning the Introduction of Amendments and Additions to Several Legislative Acts on the Subsoil and Petroleum Operations in the Republic of Kazakhstan" amending the Old Subsoil Law
"**2004/2005 Amendments**"	Law No. 2 III on "Introduction of Amendments and Additions to Certain Legal Acts on Subsoil Use and Petroleum Operations" dated 1 December 2004, and Law No. 79 3 on "Introduction of Amendments and Additions to Certain Legal Acts on Subsoil Use and Performance of Petroleum Operations in Kazakhstan" dated 14 October 2005 amending the Old Subsoil Law
"**2007 Amendments**"	new legislation amending the Old Subsoil Law which came into force on 3 November 2007
"**2009 Tax Code**" or "**Tax Code**"	the Code of the Republic of Kazakhstan "On Taxes and Other Payments into the Budget" dated 10 December 2008, no. 99-IV, as amended
"**2013 Ryder Scott Report**" or "**Competent Person's Report**"	the competent person's report by Ryder Scott Company L.P. set out in Part 15 "*Competent Person's Report*" of this Prospectus
"**2010 PD Amending Directive**"	means Directive 2010/73/EU
"**2015 Bonds**"	the U.S.$450,000,000 10.50% bonds due 2015 issued by Nostrum which were redeemed on 14 April 2014
"**2015 Guarantees**"	the joint and several guarantee by the 2015 Guarantors in respect of the 2015 Bonds
"**2015 Guarantors**"	Nostrum Oil & Gas LP and all of its subsidiaries other than the 2015 Issuer, and with effect from Admission, Nostrum Oil & Gas plc and its subsidiaries other than the 2015 Issuer
"**2015 Initial Issuer**"	Zhaikmunai Finance B.V.
"**2015 Issuer**"	Zhaikmunai LLP
"**2019 Bonds**"	the U.S.$560,000,000 7.125% bonds due 2019 issued by Nostrum
"**2019 Guarantees**"	the joint and several guarantee by the 2019 Guarantors in respect of the 2019 Bonds
"**2019 Guarantors**"	Nostrum Oil & Gas LP and all of its subsidiaries other than the 2019 Issuer, and with effect from Admission, Nostrum Oil & Gas plc and its subsidiaries other than the 2019 Issuer
"**2019 Initial Issuer**"	Zhaikmunai International B.V.
"**2019 Issuer**"	Zhaikmunai LLP
"**Admission**"	the admission of the issued Ordinary Shares of the Company to the premium listing segment of the Official List becoming effective in accordance with the Listing Rules and admission to trading having been granted and becoming effective on the London Stock Exchange's Main Market

“**Admission and Disclosure Standards**”	the current edition of the Admission and Disclosure Standards of the London Stock Exchange
“**AMEC**”	AMEC Overseas (Cyprus) Limited
“**Amersham**”	Amersham Oil LLP
“**Amersham Acquisition Agreement**”	The purchase agreement dated 19 May 2014 between SEPOL AG and Co-op for the acquisition by Coop of the entire issued share capital of Amersham for a consideration of €1.69 million
“**Articles**”	the articles of association of the Company to be adopted with effect from Admission
“**Audit Committee**”	the audit committee of the Board
“**Base Value**”	has the meaning given to such term in paragraph 10.2 of Part 17 “*Additional Information*”
“**Board**”	the board of directors of the Company from time to time including a duly constituted committee thereof
“**Bribery Act**”	the United Kingdom Bribery Act 2010
“**CA2006 Scheme**”	a scheme of arrangement under Part 26 of the Companies Act
“**Chinarevskoye Field**”	the Chinarevskoye oil and gas condensate field in North-Western Kazakhstan
“**City Code**”	the United Kingdom City Code on Takeovers and Mergers
“**Claremont**”	Claremont Holdings C.V. and its affiliates
“**Claremont Director**”	a director nominated to the Board by Claremont
“**Claremont Relationship Agreement**”	the relationship agreement dated 19 May 2014 between the Company and Claremont which will, conditional upon Admission, regulate (in part) the degree of control that Claremont and its affiliates may exercise over the management of the Company, details of which are set out in paragraph 2 of Part 10 “*Principal Shareholders and Related Party Transactions*”
“**Clearstream**”	Clearstream Banking S.A.
“**Common Units**”	common units representing fractional parts of the rights and obligations of all Limited Partners in the Partnership
“**Companies Act**”	the United Kingdom Companies Act 2006, as amended
“**Company**”	Nostrum Oil & Gas plc
“**Competent Authority**”	the Ministry of Oil and Gas of the Republic of Kazakhstan
“**Competition Law**”	the Kazakhstan Competition law dated 25 December 2008
“**Controlling Legal Entity**”	has the meaning given to such term in Part 8 “*Industry and Regulatory Overview—Regulation in Kazakhstan—Regulation of subsoil use rights in Kazakhstan—Regulation of subsoil use rights—The State’s Pre-emptive Right*”
“**Co-op**”	Nostrum Oil Coöperatief U.A. (a new intermediate holding entity of the Group)
“**Co-op Subscription Amount**”	the market capitalisation of the Partnership as at the close of business on the date of the Special General Meeting
“**Corporate Governance Code**”	the UK Corporate Governance Code published in September 2012 by the Financial Reporting Council

"**Cost Oil**"	denotes an amount of crude oil produced in respect of which the market value is equal to Nostrum's monthly expenses that may be deducted pursuant to the PSA
"**CPC**"	Caspian Pipeline Consortium
"**CREST**"	the relevant system (as defined in the Uncertified Securities Regulations 2001 (SI 2001 No. 3755) operated by Euroclear UK & Ireland Limited
"**CREST Regulations**"	the Uncertificated Securities Regulations 2001 (SI 2001 No. 3755)
"**CSCES**"	the Kazakhstan Committee on State Control of Emergency Situations and Industry Safety
"**Decree 948**"	Kazakh Government Decree #948 dated 19 July 2012 "On approval of Rules for determination of price for raw and commercial gas purchased by the national operator under the priority right of the state"
"**Development Plan**"	the Group's future drilling and infrastructure plans as more fully described in Part 7 "*Information on the Group—Subsoil Licences and Permits—The Licence and the PSA—Development Plan*"
"**Directors**"	the directors of the Company, whose names are set out in paragraph 1 "*Directors*" of Part 9 "*Directors, Managers and Corporate Governance*" of this Prospectus
"**Disclosure and Transparency Rules**"	the disclosure rules and transparency rules of the FCA and forming part of the FCA's Handbook of rules and guidance, as amended from time to time
"**EBIT**"	earnings before interest and taxation
"**EBITDA**"	earnings before interest, tax, depreciation and amortisation
"**ED Resolution**"	Resolution (No. 1036) adopted by the Kazakh Government on 15 October 2005, which approved a list of certain oil products on which an export customs duty was levied
"**Effective Date**"	the date on which the Scheme becomes effective, anticipated to be at 6.00 p.m. (London time) on 18 June 2014
"**Environmental Code**"	the Environmental Code dated 9 January 2007, as amended, of the Republic of Kazakhstan
"**EU**"	the European Union as established by the Treaty of Rome and amending treaties
"Euroclear"	Euroclear UK & Ireland Limited;
"**Exchange Act**"	United States Securities Exchange Act of 1934, as amended
"**Existing Securities**"	the Common Units and the GDRs
"**Existing Securityholders**"	holders of the Existing Securities
"**FCA**"	the UK Financial Conduct Authority
"**Facility Agreements**"	means the NOGGL Facility Agreement and the PLC Facility Agreement
"**FCPA**"	U.S. Foreign Corrupt Practices Act
"**FMSC**"	the Committee of the National Bank of Kazakhstan for Control and Supervision of the Financial Market and Financial Organisations
"**FSMA**"	the United Kingdom Financial Services and Markets Act 2000, as amended
"**Funding Amount**"	has the meaning given to such term in paragraph 4.3 of Part 6 "*Information on the Scheme*"

"**Gas Law**"	The Law on Gas and Gas Supply No.532 IV dated 9 January 2012 of the Republic of Kazakhstan
"**GBP**" or "**£**"	pound sterling
"**GDRs**"	global depositary receipts representing interests in the Common Units of Nostrum Oil & Gas LP
"**GDR Listing**"	The admission to the standard listing segment of the Official List and to trading on the Main Market of the London Stock Exchange
"**General Partner**"	NOGGL in its capacity as general partner of the Partnership
"**Gross Income Test**"	has the meaning given to such term in paragraph 2.4 of Part 16 "*Taxation*"
"**Group**" **or "Nostrum"**	Nostrum Oil & Gas LP and its subsidiaries, and with effect from Admission, Nostrum Oil & Gas plc and its subsidiaries
"**IFRS**"	International Financial Reporting Standards as adopted by the EU
"**Intra-Group Loan**"	the intra-group loan due from Zhaikmunai Netherlands B.V. to the Partnership which is equal in amount to U.S.$106,000,000
"**Irrevocable Undertakings**"	irrevocable undertakings to vote in favour of the amendment of the Limited Partnership Agreement and the Scheme given by certain Existing Securityholders to the Partnership and the Company
"**KASE**"	the Kazakhstan Stock Exchange
"**KASE Admission**"	the admission of all the Ordinary Shares to the third category of the "Shares" sector of the KASE's official list
"**Kazakh Government**"	the government of the Republic of Kazakhstan
"**Kazakhstan**"	the Republic of Kazakhstan
"**KCTS**"	Kazakhstan Caspian Transportation System
"**KPO**"	Karachaganak Petroleum Operations
"**KSS Global**"	KazStroyService Global B.V.
"**KSS Global Director**"	a director nominated to the Board by KSS Global
"**KSS Global Relationship Agreement**"	the relationship agreement dated 19 May 2014 between the Company and KSS Global which will, conditional upon Admission, regulate (in part) the degree of control that KSS Global and its affiliates may exercise over the management of the Company, details of which are set out in paragraph 3 of Part 10 "*Principal Shareholders and Related Party Transactions*"
"**Kyoto Protocol**"	the Kyoto Protocol to the United Nations Framework Convention on Climate Change
"**Licence**"	the subsoil use licence in respect of the Chinarevskoye Field held by the Licence Holder
"**Licence Holder**"	Zhaikmunai LLP

"**Licencing Law**"	the Kazakhstan Law "On Licencing" which came into force on 9 August 2007
"**Limited Partners**"	the limited partners in the Partnership
"**Limited Partnership Agreement**"	the amended and restated limited partnership agreement of the Partnership dated 23 May 2013
"**Listing Rules**"	the rules and regulations made by the FCA pursuant to Part VI FSMA, as amended from time to time
"**London Stock Exchange**"	London Stock Exchange plc
"**Lower-tier PFIC**"	has the meaning given to such term in paragraph 2.4 of Part 16 "*Taxation*"
"**Main Market**"	the main market for listed securities of the London Stock Exchange
"**MEP**"	the Kazakhstan Ministry of Environmental Protection
"**MEWR**"	the Kazakhstan Ministry of Environment and Water Resources
"**MINT**"	the Kazakhstan Ministry of Industry and New Technologies
"**MOG Consent**"	has the meaning given to such term in paragraph 4.5 of Part 6 "*Information on the Scheme*"
"**NBK**"	the National Bank of the Republic of Kazakhstan
"**NC KMG**"	JSC National Company KazMunayGas, the Kazakhstan state-owned oil and gas company
"**New 2019 Bonds**"	the U.S.$400,000,000 6.375% bonds due 2019 issued by Nostrum
"**New 2019 Guarantees**"	the joint and several guarantee by the New 2019 Guarantors in respect of the New 2019 Bonds
"**New 2019 Guarantors**"	Nostrum Oil & Gas LP and all of its subsidiaries other than the New 2019 Issuer, and with effect from Admission, Nostrum Oil & Gas plc and its subsidiaries other than the New 2019 Issuer
"**New 2019 Initial Issuer**"	Nostrum Oil & Gas Finance B.V.
"**New 2019 Issuer**"	Zhaikmunai LLP
"**New Subsoil Law**"	the law of the Republic of Kazakhstan "On Subsoil and Subsoil Use" dated 24 June 2010
"**NOGGL**"	Nostrum Oil & Gas Group Limited
"**NOGGL Control Accounts**"	has the meaning given to such term in paragraph 12.4(c) of Part 17 "*Additional Information*"
"**NOGGL Facility Agreement**"	the facility agreement dated 20 May 2014 between NOGGL (acting in its own capacity) and VTB
"**Nomination Committee**"	the committee of the Board which, *inter alia*, reviews senior appointments within the Group
"**Non-U.S. Currency**"	has the meaning given to such term in paragraph 2.2 of Part 16 "*Taxation*"
"**Objects**"	has the meaning given to such term in Part 8 "*Industry and Regulatory Overview—Regulation in Kazakhstan—Regulation of subsoil use rights in Kazakhstan—Regulation of subsoil use rights—The State's Pre-emptive Right*"

"**Official List**"	the Official List of the FCA
"**Old Subsoil Law**"	Kazakhstan Law No 2828 "On Subsoil and Subsoil Use" on 27 January 1996
"**Option**"	has the meaning given to such term in paragraph 10.2 of Part 17 "*Additional Information*"
"**Optionholder**"	has the meaning given to such term in paragraph 10.2 of Part 17 "*Additional Information*"
"**Ordinary Shares**"	the ordinary shares of £0.01 each in the capital of the Company
"**Overseas Persons**"	Existing Securityholders who are resident or located in, or citizens or nationals of, jurisdictions outside the United Kingdom and Isle of Man
"**p**"	Pence
"**Partnership**"	Nostrum Oil & Gas LP, an Isle of Man limited partnership
"**Personnel Agreement**"	the service agreement dated 1 January 2009 between Amersham and Nostrum pursuant to which certain personnel provide their services to the Group
"**PFIC**"	passive foreign investment company
"**Phantom Option Plan**" or "**Plan**"	the option plan operated by the Partnership
"**PLC Control Accounts**"	has the meaning given to such term in paragraph 12.4(b) of Part 17 "*Additional Information*"
"**PLC Facility Agreement**"	the facility agreement dated 20 May 2014 between the Company and VTB
"**PRA**"	the UK Prudential Regulation Authority
"**Pre-Admission Notification**"	has the meaning given to such term in paragraph 4.5 of Part 6 "*Information on the Scheme*"
"**Probel**"	Probel Capital Management N.V.
"**Probel Acquisition Agreement**"	the purchase agreement dated 30 December 2013 between ELETA Burgerlijke Maatschap, Petra Noé, Frank Monstrey and Co-op pursuant to which Co-op acquired the entire issued share capital of Probel
"**Probel Services Agreement**"	the service agreement dated 27 March 2007 between Probel and Nostrum pursuant to which senior managers provide their services to Nostrum
"**Profit Oil**"	the difference between Cost Oil and the total amount of crude oil produced each month by Nostrum
"**Prolag**"	Prolag BVBA
"**Prolag Services Agreement**"	the service agreement between Prolag and Nostrum, pursuant to which Prolag has agreed to provide certain commercial, marketing and other services to Nostrum
"**Prospectus Directive**"	means Directive 2003/71/EC as amended by the 2010 PD Amending Directive and any relevant implementing measure in each Relevant Member State
"**Prospectus Rules**"	the prospectus rules made by the FCA pursuant to Part VI of FSMA
"**Prospectus**"	this document

"**PSA**"	the production sharing agreement between Nostrum and the Republic of Kazakhstan in respect of the Chinarevskoye Field
"**PSA Law**"	Kazakhstan Law No. 68 III "On Production Sharing Agreements for Conducting Offshore Petroleum Operations", dated 8 July 2005
"**Redeemable Shares**"	has the meaning given to such term in paragraph 2.5 of Part 17 "*Additional Information*"
"**Reduction of Capital**"	has the meaning given to such term in paragraph 3.2 of Part 6 "*Information on the Scheme*"
"**Registrar**"	Capita Registrars Limited
"**Relationship Agreements**"	the Claremont Relationship Agreement and the KSS Global Relationship Agreement, details of which are set out in paragraphs 2 and 3 of Part 10 "*Principal Shareholders and Related Party Transactions*"
"**Remuneration Committee**"	the committee of the Board which, *inter alia*, determines the remuneration and employment terms of the Executive Directors
"**Reorganisation**"	the reorganisation of the Group implemented pursuant to the Scheme Implementation Agreement, details of which are set out in Part 6 "*Information on the Scheme*"
"**RoK Waiver**"	has the meaning given to such term in paragraph 4.5 of Part 6 "*Information on the Scheme*"
"**Rule 144A**"	Rule 144A under the Securities Act
"**Ruling**"	has the meaning given to such term in paragraph 2.4 of Part 16 "*Taxation*"
"**Ryder Scott**" or "**Competent Person**"	Ryder Scott Company L.P.
"**SCFD**"	the State Committee for Field Development
"**Scheme**"	the introduction of the Company as the new holding company of the Group and Admission
"**Scheme Document**"	the document describing the Scheme circulated to holders of the Common Units and GDRs
"**Scheme Implementation Agreement**"	the agreement to implement the Scheme entered into by the Company, Co-op, the Partnership, the General Partner and VTB
"**Scheme Record Date**"	the date of the Scheme Record Time
"**Scheme Record Time**"	5.00 p.m. on 17 June 2014 or such other date as may be notified by the Partnership pursuant to an announcement issued via a Regulatory Information Service
"**SDRT**"	means stamp duty reserve tax
"**SEC**"	U.S. Securities and Exchange Commission
"**Securities Act**"	U.S. Securities Act of 1933, as amended
"**Shareholder**"	a holder of Ordinary Shares
"**SLP Subscription Amount**"	U.S.$106,000,000

"**SPE**"	Society of Petroleum Engineers
"**Special General Meeting**"	the special general meeting of the Limited Partners of the Partnership to, *inter alia*, approve the Scheme
"**Special Limited Partner Interest**"	a new class of limited partner interests with priority rights to distributions of income and capital by the Partnership
"**Sponsor**" or "**Deutsche Bank**"	Deutsche Bank AG, London Branch
"**Sponsor's Agreement**"	the sponsor's agreement dated 20 May 2014 between the Company, the Partnership and the Sponsor
"State's Pre-Emptive Right"	the pre-emptive right of the Kazakhstan state in connection with any transfer of subsoil use rights and/or shares or participation interests in subsoil users, and/or any transfer of the shares or participation interests in a legal entity which can, directly or indirectly, affect or determine decisions of a subsoil user, if the core business of such controlling entity is related to subsoil use in Kazakhstan
"**Subscriber Shares**"	has the meaning given to such term in paragraph 2.5 of Part 17 "*Additional Information*"
"**Subsisting Option**"	the options relating to 2,762,348 GDRs under the Phantom Option Plan which remain outstanding as at the date of this Prospectus
"**Subsoil Use Agreement**"	the subsoil use agreements for the Rostoshinskoye, Darinskoye and Yuzhno-Gremyachenskoye fields
"**Takeover Offer**"	a takeover offer for the Company made in accordance with the City Code
"**Takeover Offer Shares**"	has the meaning given to such term in paragraph 4 of Part 9 "*Directors, Management and Corporate Governance*"
"**TCO**"	Tengizchevroil LLP
"**Trunk Pipeline Law**"	The Law on Trunk Pipeline No.20 V dated 22 June 2012 of the Republic of Kazakhstan
"Tenge" or "KZT"	Tenge, the lawful currency for the time being of the Republic of Kazakhstan
"**Trust**"	the Nostrum Employee Benefit Trust
"**Trustee**"	Ogier Employee Benefit Trustee Limited, a company which is independent of and unrelated to the Company, as trustee of the Nostrum Employee Benefit Trust
"**UK**"	the United Kingdom of Great Britain and Northern Ireland
"**United States**" or "**U.S.**" or "**USA**"	United States of America
"**USSR**" or "**Soviet Union**"	the Union of Soviet Socialist Republics
"**U.S.$**" or "**$**"	U.S. Dollars
"**VTB**"	VTB Capital plc
"**Water Code**"	the Water Code dated 9 July 2003 No. 481 of the Republic of Kazakhstan
"**Water Use Permit**" or "**WUP**"	the water use permit issued on 28 August 2008 to the Group which is valid until August 2030
"**WPC**"	World Petroleum Council

GLOSSARY

"**2D seismic**"	geophysical data that depicts the subsurface strata in two dimensions
"**3D seismic**"	geophysical data that depicts the subsurface strata in three dimensions. 3D seismic typically provides a more detailed and accurate interpretation of the subsurface strata than 2D seismic
"**AAPG**"	American Association of Petroleum Geologists
"**accumulation**"	an individual body of moveable petroleum. A known accumulation (one determined to contain reserves or contingent resources) must have been penetrated by a well
"**API**"	American Petroleum Institute
"**appraisal well**"	well drilled in order to assess characteristics (such as flow rate, volume) of a proved hydrocarbon accumulation
"**barrel**" or "**b**" or "**bbl**"	a stock tank barrel, a standard measure of volume for oil, condensate and natural gas liquids, which equals 42 U.S. gallons
"**block**"	an area of licensed territory comprising one or more licences
"**boe**"	barrels of oil equivalent
"**bopd**"	barrels of oil per day
"**boepd**"	barrels of oil equivalent per day
"**Brent**"	a particular type of crude oil that is light, sweet oil produced in the North Sea with most of it being refined in North-West Europe. Brent is a benchmark oil
"**contingent resources**"	those quantities of petroleum estimated, as of a given date, to be potentially recoverable from known accumulations by application of development projects, but which are not currently considered to be commercially recoverable due to one or more contingencies
"**crude oil**"	unrefined oil
"**DST**"	drill stem test
"**EP**"	an environmental permit
"**exploration well**"	a well drilled to find hydrocarbons in an unproved area or to extend significantly a known oil or natural gas reservoir
"**field**"	an area consisting of either a single reservoir or multiple reservoirs, all grouped on or related to the same individual geological structural feature and/or stratigraphic condition
"**formation**"	a body of rock that is sufficiently distinctive and continuous that it can be mapped
"**gross reserves**"	the total estimated petroleum to be produced from a field
"**hydrocarbons**"	compounds formed primarily from the elements hydrogen and carbon and existing in solid, liquid or gaseous forms

"**km**"	kilometre
"**km²**"	square kilometre
"**m**"	metres
"**mmboe**"	million barrels of oil equivalent
"**mmcf**"	gas in millions of cubic feet
"**net pay**"	net pay represents that portion of the reservoir containing oil and gas reserves that are anticipated to be economically recoverable for the particular reservoir drive mechanism
"**OPEC**"	Organisation of Petroleum Exporting Countries
"**petroleum system**"	geologic components and processes necessary to generate and store hydrocarbons, including a mature source rock, migration pathway, reservoir rock, trap and seal. Exploration plays and prospects are typically developed in basins or regions in which a complete petroleum system has some likelihood of existing
"**possible reserves**"	those unproved reserves which analysis of geosciences and engineering data indicate are less likely to be recoverable than probable reserves
"**probable reserves**"	those unproved reserves which analysis of geosciences and engineering data indicate are less likely to be recovered than proved reserves but more certain to be recovered than possible reserves
"**production**"	the cumulative quantity of petroleum that has been recovered at a given date
"**production well**"	a well drilled to obtain production from a proved oil or gas field. Production wells may be used either to extract hydrocarbons from a field or to inject water or gas into a reservoir in order to improve production
"prospect"	a project associated with a potential accumulation that is sufficiently well defined to represent a viable drilling target
"**prospective resources**"	those quantities of petroleum which are estimated, as of a given date, to be potentially recoverable from undiscovered accumulations
"**proved reserves**"	those quantities of petroleum which, by analysis of geological and engineering data, can be estimated with reasonable certainty to be commercially recoverable, from a given date forward, from known reservoirs and under current economic conditions, operating methods, and government regulations
"**reservoir**"	a subsurface body of rock having sufficient porosity and permeability to store and transmit fluids. A reservoir is a critical component of a complete petroleum system
"**seismic survey**"	a method by which an image of the earth's subsurface is created through the generation of shockwaves and analysis of their reflection from rock strata. Such surveys can be done in two or three dimensional form

"**SPE-PRMS**"	Petroleum Resources Management System of the Society of Petroleum Engineers, World Petroleum Council, American Association of Petroleum Geologists and Society of Petroleum Evaluation Engineers
"**SPEE**"	Society of Petroleum Evaluation Engineers
"**upstream**"	activities related to the exploration, appraisal, development and extraction of crude oil, condensate and gas
"**Urals**"	a benchmark Russian crude oil (used as a basis for pricing Russian export oil mixture), which trades at a discount to Brent crude, an international benchmark oil blend

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