This document comprises Supplementary Listing Particulars relating to OAO LUKOIL (the "Company") as required by the Listing Rules made under section 74 of the Financial Services and Markets Act 2000 and has been delivered for registration to the Registrar of Companies in accordance with section 83 of that Act.

This document is supplemental to and should be read in conjunction with the Listing Particulars, dated and published on July 31, 2000 (the "Listing Particulars"). Words and expressions defined in the Listing Particulars have the same meaning when used in this document, unless the context requires otherwise. Save as disclosed in this document, three has been no significant change affecting any matter contained in the Listing Particulars and no significant new matter has arisen in relation to the Company the inclusion of information in respect of which would have been required to be mentioned in the Listing Particulars if it had arisen at the time of its preparation.

This document and the Listing Particulars concern ordinary shares of nominal value 0.025 rubles each of the Company ("ordinary shares" or "common shares") and American depositary receipts issued pursuant to a deposit agreement amended and restated as of March 11, 1998 (the "Level 1 ADRs" or "ADRs"). Each ADR represents four ordinary shares.

The ADRs are of a specialist nature and should normally be bought and traded by investors who are particularly knowledgeable in investment matters.

Application has been made to the Financial Services Authority in its capacity as U.K. Listing Authority for a listing of the entire issued ordinary share capital of the Company and up to 150,000,000 Level 1 ADRs of the Company to be admitted to the Official List of the U.K. Listing Authority. Application has also been made to the London Stock Exchange plc (the "London Stock Exchange") for such ordinary shares and ADRs to be admitted to trading on the London Stock Exchange in accordance with the rules of the London Stock Exchange. It is expected that admission to the Official List will become effective and that unconditional dealings will commence in the ordinary shares and the Level 1 ADRs on August 6, 2002. All dealings before the announcement of unconditional dealings will be of no effect if admission does not take place and such dealings will be at the sole risk of the parties concerned.

The Company's Directors, whose names appear on page 1 of the Listing Particulars, accept responsibility for the information contained in this document. To the best of the knowledge and belief of the Directors (who have taken all reasonable care to ensure that such is the case), the information contained in this document is in accordance with the facts and does not omit anything likely to affect the import of such information.

A discussion of certain risks and factors that should be considered in connection with an investment in the ordinary shares and ADRs is set out in "Part 3 – Risk Factors" of the Listing Particulars.

OAO LUKOIL

(Organised as an Open Joint Stock Company under the laws of the Russian Federation)

INTRODUCTION

OF

850,563,255 ordinary shares of the Company

and

up to 150,000,000 Level 1 American Depositary Receipts; each representing 4 ordinary shares of the Company

---

Sponsor

MORGAN STANLEY & CO. INTERNATIONAL LIMITED

Morgan Stanley & Co. International Limited is advising the Company and no one else in relation to the Introduction and will not be responsible to anyone other than the Company for providing the protection afforded to customers of Morgan Stanley & Co. International Limited or for providing advice in relation to the Introduction, the contents of this document or any transaction or arrangement referred to herein.

SUPPLEMENTARY LISTING PARTICULARS DATED AUGUST 1, 2002

TABLE OF CONTENTS

Page

In these Listing Particulars, the terms "Company," "we," "us" and "our" refer to OAO LUKOIL and its consolidated subsidiaries and oil and gas-related companies, unless the context requires otherwise. References to ADRs or DRs refer to the Level 1 ADRs, the Reg S ADRs, the New 144A ADRs and the Existing 144A ADRs. References to "our shares," "our depositary shares" (or "our DSs"), "our depositary receipts," "our securities," or "our shareholders" or "our DR holders" means the ordinary shares, depositary shares, depositary receipts (representing depositary shares), securities, shareholders or DR holders, as the case may be, of OAO LUKOIL, unless the context requires otherwise. References to "our privatisation" and "our charter" relate only to OAO LUKOIL.

Part 1 – DIRECTORS, REGISTERED OFFICE AND ADVISERS

Directors
Vagit Yu. Alekperov (*President and Director*)
Valeri I. Graifer (*Non-Executive Chairman*)
Mikhail P. Berezhnoy (*Non-Executive Director*)
Oleg E. Kutafin (*Non-Executive Director*)
Ravil U. Maganov (*First Vice-President and Director*)
Vladimir V. Malin (*Non-Executive Director*)
Richard H. Matzke (*Non-Executive Director*)
Yury M. Medvedev (*Non-Executive Director*)
J. Mark Mobius (*Non-Executive Director*)
Igor V. Sherkunov (*Non-Executive Director*)
Nikolai A. Tsvetkov (*Non-Executive Director*)

Registered and Head Office
OAO LUKOIL
11 Sretensky Boulevard
101000 Moscow
Russia

Advisers

Legal Advisers to the Company
As to U.S. and Russian law
Akin, Gump, Strauss, Hauer & Feld, L.L.P.
Ducat Place II
7 Gasheka Street
123056 Moscow
Russia

As to English law
Akin, Gump, Strauss, Hauer & Feld
One Angel Court
London EC2R 7HJ
United Kingdom

Reporting Accountants
KPMG Limited
11 Gogolevsky Boulevard
119019 Moscow
Russia

KPMG Audit Plc
8 Salisbury Square
London EC4Y 8BB
United Kingdom

Reporting Oil and Gas Consultants
Miller and Lents, Ltd.
Twenty-Seventh Floor
1100 Louisiana
Houston, Texas 77002-5216
United States

Bankers to the Company
Petrocommerce Bank
24 Petrovka Street
103051 Moscow
Russia

Sponsor
Morgan Stanley & Co. International Limited
25 Cabot Square
Canary Wharf
London E14 4QA
United Kingdom

Legal Advisers to the Sponsor
As to English and Russian law
Linklaters
One Silk Street
London EC2Y 8HQ
United Kingdom

Depositary, Paying Agent and Registrar
The Bank of New York
One Canada Square
London E14 5AL
United Kingdom

Part 2 – KEY INFORMATION

This summary highlights selected information that has been extracted without material adjustment from this document and may not contain all of the information that is important to you. The basis on which information is presented in this document is set forth under " – Summary Reserves and Production Information." You should read this entire document carefully, especially the risks described under "Part 3 – Risk Factors" in this document.

OAO LUKOIL

We are the largest publicly traded oil company in the world in terms of proven crude oil reserves and we are Russia's largest producer of crude oil. Between 1999 and 2001 our estimated proven crude oil reserves increased approximately 14% and our estimated probable crude oil reserves increased approximately 28%, while our crude oil production remained stable, our natural gas production increased approximately 11% and our oil refining volume increased approximately 18%.

As of January 1, 2002 our estimated proven crude oil reserves were 14,576.5 mmbls (1,996.8 million tonnes) and our estimated proven natural gas reserves were 13,215.9 bcf (374.2 bcm), an aggregate of 16,779.1 mmboe. As of the same date, our estimated probable oil reserves were 6,657.4 mmbls (912.0 million tonnes) and our estimated probable natural gas reserves were 3,523.9 bcf (99.8 bcm), an aggregate of 7,244.7 mmboe. See "Part 5 – Business – Exploration and Production."

Highlights from our 2001 operations include:

- Our total production of crude oil averaged approximately 1.6 mmbls (214,580 tonnes) per day. Our domestic crude oil production of approximately 555.5 mmbls (76.1 million tonnes) accounted for over 20% of all Russian crude oil production.
- We refined 278.1 mmbls (38.1 million tonnes) of crude oil of which 215.3 mmbls (29.5 million tonnes) were refined at our four domestic refineries and 62.8 mmbls (8.6 million tonnes) were refined at our international refineries. We also refined 79.5 mmbls (10.9 million tonnes) under contract with third-party refineries, mainly at the Moscow refinery and the Salavatnefteorgsintez refinery in the Russian Republic of Bashkortostan.
- We sold 278.6 mmbls (38.2 million tonnes) of crude oil and 39.4 million tonnes of refined products.
- As of December 31, 2001 we owned or leased approximately 3,544 retail service stations, including 1,384 in Russia, 1,277 in the United States and 883 in countries of the CIS and eastern Europe.

Domestic Upstream Operations. As of the end of 2001 97% of our proven reserves were in Russia and in 2001 97% of our crude oil production came from our reserves in Russia. As of the end of 2001 our western Siberia proven reserves accounted for approximately 57% of our domestic proven reserves. We are developing new reserves in Russia, most notably in the Timan-Pechora region and the northern Caspian Sea region. We believe that these new areas will provide us with substantial additional reserves and a reserves portfolio that is more balanced geographically.

International Upstream Operations. We have significant upstream interests in what we believe are some of the world's most promising regions for oil production outside Russia, including Azerbaijan and Kazakstan. We also have upstream assets in the Middle East, North Africa and Colombia. As of the end of 2001 our international assets accounted for 3% of our total crude oil production and 3% of our crude oil reserves.

Oil Refining. We own four oil refineries in Russia, located in Perm, Volgograd, Ukhta and Nizhni Novgorod. These refineries have a combined refining capacity of approximately 860,000 barrels per day (43.0 million tonnes per year). We also own refineries in Ukraine, Bulgaria and Romania, which have a combined refining capacity of approximately 380,000 barrels per day (19.0 million tonnes per year). Our international refineries are in need of substantial renovation. Our refinery in Romania is currently not operating. See "Part 5 – Business – Refining, Marketing and Distribution – International Refineries." We intend to invest substantial amounts to upgrade our international oil refineries to improve utilisation rates and depth of refining to produce products that meet U.S. and European environmental standards. Once the upgrades are complete, we believe that these international refineries will provide attractive integration benefits with our target southeastern European markets.

Retail Marketing. As of December 31, 2001 we had a network of 1,384 LUKOIL-branded retail service stations in Russia and 883 stations in countries of the CIS and eastern Europe. Additionally, as of December 31, 2001, 393 and 16 LUKOIL-branded service stations were operated under franchise agreements in Russia and Europe, respectively. In 2001 we sold approximately 2.0 million tonnes of our own oil products through LUKOIL-branded service stations in Russia and 730,000 tonnes through owned and franchised stations in other countries of the CIS and eastern Europe. In January 2001 we completed the acquisition of Getty Petroleum Marketing Inc., or Getty, which currently has a network of 1,277 leased retail service stations in the northeastern United States. In 2002 we acquired 16 service stations in Cyprus. We believe that our presence in Cyprus will provide us with a new market for oil products produced at our Neftochim refinery in Bulgaria.

Natural Gas Reserves. As of January 1, 2002 we had total proven natural gas reserves of 13,215.9 bcf (374.2 bcm). Our upstream natural gas assets include a 60% interest in Yamalneftegazdobycha, or YNGD, which has estimated proven natural gas reserves of 8,222.5 bcf (232.9 bcm). We also have rights under a production sharing agreement with the government of Uzbekistan giving us a 45% interest in the Bukhara-Khiva and Gissa fields which we believe contain substantial recoverable natural gas reserves.

Gas Production and Processing. In 2001 we produced 183.6 bcf (5.2 bcm) of gas, of which 144.7 bcf (4.1 bcm) was petroleum gas and 38.8 bcf (1.1 bcm) was natural gas. Our downstream gas assets include three gas processing facilities: the Korobkovsky gas processing plant in the Volgograd Region; the Permneftegazpererabotka facility in the Perm Region; and the Usinsky gas processing plant in the Republic of Komi. We intend to acquire the Lokosovski gas processing plant in western Siberia subject to certain contractual conditions.

Petrochemicals. We are currently expanding our petrochemicals business through a joint venture relating to the LUKOR plant in Ukraine and a number of smaller acquisitions of petrochemicals services companies. Currently we have three petrochemicals plants in southern Russia and some petrochemicals production at our Neftochim refinery in Bulgaria. Together our petrochemicals plants manufactured approximately 1.2 million tonnes of petrochemicals in 2001. We intend to utilise our expanding natural gas production and processing operations increasingly as a source of feedstock for our petrochemicals operations.

Transportation. As of December 31, 2001 we had a fleet of 122 vessels, including nine ice-breaking tankers. In addition, we are investing in several pipeline projects, including the Caspian Pipeline Consortium international pipeline, various domestic crude and refined product pipelines and a joint venture with Conoco to study the feasibility of constructing a pipeline to transport oil from our fields in western Siberia through the Timan-Pechora region to our temporary terminal at Varandei Bay. We are also investing to increase our rail transportation capacity. See "Part 5 – Business – Oil Transportation."

We plan to finance these operations and investments with cash from operations and, where appropriate, bank facilities and offerings of equity or debt securities.

STRATEGY

Strategic Objectives

Our strategic objectives are to increase the profitability and value of the company by increasing our sustainable production of crude oil, natural gas and refined products, replacing our reserves at low cost, and improving returns on capital to levels comparable to our international peers.

We aim to maximise profitability and shareholder value through rigorous management of capital and costs, and have recently adjusted our operating model to focus on more efficient deployment of capital resources to achieve more attractive returns on capital employed. We believe that one of the competitive advantages that allows us to achieve this strategic objective is our ability to identify and develop low-cost upstream and downstream opportunities in our core Russian and international markets.

Execution of Our Strategy

We have recently initiated a comprehensive corporate development and restructuring program that we believe will better enable us to achieve our strategic goals of sustainable growth and value creation. Our major priorities for the restructuring are: (i) steps designed to deliver immediate benefits to the company's profitability and returns on investment; and (ii) a long-term program designed to sustain our growth and profitability.

SUMMARY CONSOLIDATED FINANCIAL INFORMATION

The following table sets forth a summary of our audited and unaudited consolidated financial information. You should read the following summary information together with "– Current Trading and Prospects," "Management's Discussion and Analysis of Financial Condition and Results of Operations" and our consolidated financial statements, including the notes to these financial statements.

The financial information contained herein has been extracted without material adjustment from our financial statements included in this document, which have been prepared in accordance with generally accepted accounting principles in the United States, or U.S. GAAP, other than, with respect to interim financial information, for normal year-end adjustments.

Investors should read this document as a whole and not rely solely on selected or summarised information.

	Year ended December 31,			Three months ended March 31,	
	1999	**2000**	**2001**	**2001**	**2002**
				(unaudited)	
	($ millions, except per share amounts)				
Consolidated Statement of Income Data:					
Revenues:					
Sales	$7,544	$13,210	$13,426	$3,335	$2,847
Equity share in income (loss) of affiliates	88	230	136	31	20
Total revenues	$7,632	$13,440	$13,562	$3,366	$2,867
Costs and other deductions:					
Operating expenses	$(2,622)	$(4,225)	$(4,671)	$(1,067)	$(1,053)
Selling, general and administrative expenses	(1,623)	(1,956)	(2,294)	(459)	(575)
Depreciation, depletion and amortisation	(598)	(838)	(886)	(208)	(237)
Taxes other than income taxes	(527)	(1,050)	(1,010)	(275)	(377)
Excise and export tariffs	(460)	(932)	(1,456)	(446)	(212)
Exploratory expense	(61)	(130)	(144)	(19)	(20)
Loss on disposal and impairment of assets	(49)	(247)	(153)	(1)	(22)
Income from operating activities	1,692	4,062	2,948	891	371
Interest expense	(192)	(198)	(257)	(62)	(67)
Interest and dividend income	73	209	146	53	32
Currency translation gain (loss)	(34)	1	(33)	(44)	(34)
Other non-operating (expense) income	(168)	71	31	84	21
Minority interest	(34)	(61)	(52)	(22)	(6)
Income before income taxes	1,337	4,084	2,783	900	317
Current income taxes	(390)	(790)	(861)	(240)	(108)
Deferred income taxes	115	18	187	20	34
Net income	$1,062	$3,312	$2,109	$680	$243
Basic earnings per share of common stock	$1.69	$4.83	$2.68	$0.95	$0.30
Diluted earnings per share of common stock	1.69	4.73	2.66	0.94	0.30

	As of December 31, 2001	As of March 31, 2002
Balance Sheet Data:		**(unaudited)**
Cash and cash equivalents	$ 1,170	$ 867
Working capital	1,851	1,721
Property, plant and equipment	12,296	12,485
Total assets	19,942	20,005
Long-term debt (including current portion)	2,426	2,477
Stockholders' equity	12,385	12,605

SUMMARY RESERVES AND PRODUCTION INFORMATION

The summary reserves and production information below, as well as the reserves and production information presented elsewhere in this document, except in "Part 4 – Management's Discussion and Analysis of Financial Condition and Results of Operations," "Part 7 – Financial Information" and unless otherwise specified, includes:

- the reserves and production information of our consolidated subsidiaries, even if we do not beneficially own 100% of their shares. For example, this means that we include in our proven reserves totals for 2001 approximately 1,510 mmbls, or approximately 9.4%, that we do not beneficially own (we have adopted this approach in order to make the reporting of our estimated reserves in these Listing Particulars consistent with the totals contained in the reserves report prepared by Miller and Lents dated May 20, 2002, hereinafter referred to as the "Reserves Report," which is included in Part 10; in Table IV of the SFAS No. 69, "Disclosures About Oil and Gas Producing Activities" section in our U.S. GAAP audited consolidated financial statements included in Part 7, we exclude these 9.4% minority interests, and you should read that section when evaluating our reserves totals);
- the reserves and production information relating to our share of our affiliated companies, which we account for using the equity method in our U.S. GAAP audited financial statements; and
- reserves and production information with respect to companies that we acquire during a given year on a full-year basis, regardless of the actual date that we completed the acquisitions, or whether they are consolidated or accounted for using the equity method. This approach differs from that taken in our U.S. GAAP financial statements, which accounts for acquisitions from the date of the completion of the acquisitions.

Unless otherwise specified, the reserves and production information in these Listing Particulars does not include information relating to:

- our assets or activities in Iraq; or
- any of the acquisitions or transactions that we have commenced or completed in 2002, including those relating to our joint exploration agreement with Ecopetrol or our potential acquisition of an interest in Hellenic Petroleum or the Gdansk refinery. See " – Recent Developments."

Other operating information, for example with respect to drilling and refining, is presented on the same basis as reserves and production information, except in "Part 4 – Management's Discussion and Analysis of Financial Condition and Results of Operations," "Part 7 – Financial Information" and unless otherwise specified.

We have extracted the following operating information without material adjustment from our management accounts and operating records, including the competent person's reserves reports prepared by Miller and Lents, Ltd., independent oil and gas consultants. We use this operating information in managing our business and we expect to continue to report on such operating information in our periodic and annual reports following admission of our ordinary shares and depositary receipts to the Official List.

	Year ended December 31,		
	1999	**2000**	**2001**
Reserves			
Crude oil (mmbls)			
Proven	13,498.4	12,954.3	14,576.5
Probable	5,571.6	5,969.1	6,657.4
Gas (bcf)			
Proven	3,907.5	3,624.7	13,215.9
Probable	1,264.2	1,099.0	3,523.9
Crude oil and gas (mmboe)			
Proven	14,162.7	13,558.6	16,779.1
Probable	5,786.5	6,155.9	7,244.7
Production			
Crude oil (mmbls/year)	551.8	567.5	571.6
Russia	539.0	552.4	555.5
International	12.8	15.1	16.1
Gas (bcf/year)	166.8	177.0	183.6
Total (mmboe)[1]	579.6	597.0	602.2

1 For the reasons described above, total production in accordance with U.S. GAAP was 479 mmboe, 529 mmboe and 532 mmboe for the years ended December 31, 1999, 2000 and 2001, respectively.

RESERVES MEASUREMENTS

This document contains information concerning our estimated oil and gas reserves from the Reserves Report, which is included in Part 10. The term "reserves" when used in connection with our reserves totals in this document means our proven and probable reserves together (unless otherwise specified). While this information has been prepared in accordance with the provisions set out in Chapter 19 of the Listing Rules of the U.K. Listing Authority, it is based on certain economic assumptions, and the amounts disclosed herein may prove to be incorrect. In particular, the Russian economy is more unstable and subject to more significant and sudden changes than the economies of many other countries, and thus economic assumptions in Russia are subject to a high degree of uncertainty. You should not place undue reliance on the ability of the Reserves Report to predict actual reserves or on comparisons of similar reports concerning companies established in places with more mature economic systems.

HYDROCARBON MEASUREMENTS

Our estimated reserves totals included in this document are taken directly from reserves reports prepared by Miller and Lents and are therefore presented in barrels. However, like many other Russian and European oil companies, we use the metric tonne, or tonne, as the standard unit of measurement for quantities of crude oil that we produce and sell. For convenience, certain amounts of crude oil have been translated from tonnes into barrels. These translations were made at the rate of 7.3 barrels per tonne of crude oil. Actual barrel amounts may vary from this convenience translation.

CURRENT TRADING AND PROSPECTS

The following table contains summary unaudited consolidated income statement data for the three months ended March 31, 2001 and 2002. You should read this information and the following analysis together with the discussion of our annual results contained in "Part 4 – Management's Discussion and Analysis of Financial Condition and Results of Operations" and our unaudited consolidated financial statements as of March 31, 2002 and for the three months ended March 31, 2001 and 2002 contained in "Part 7 – Financial Information."

	Three months ended March 31,			
	2001		**2002**	
Revenues	**($ millions, except per share amounts)**			
Sales	$ 3,335	99.1%	$ 2,847	99.3%
Equity share in income of affiliates	31	0.9%	20	0.7%
Total revenues	$ 3,366	100.0%	$ 2,867	100.0%
Costs and other deductions				
Operating expenses	$ (1067)	(31.7%)	$ (1,053)	(36.7%)
Selling, general and administrative expenses	(459)	(13.6%)	(575)	(20.1%)
Depreciation, depletion and amortization	(208)	(6.2%)	(237)	(8.3%)
Taxes other than income taxes	(275)	(8.2%)	(377)	(13.1%)
Excise and export tariffs	(446)	(13.3%)	(212)	(7.4%)
Exploration expense	(19)	(0.6%)	(20)	(0.7%)
Loss on disposal and impairment of assets	(1)	0.0%	(22)	(0.8%)
Income from operating activities	$ 891	26.5%	$ 371	12.9%
Interest expense	(62)	(1.8%)	(67)	(2.3%)
Interest and dividend income	53	1.6%	32	1.1%
Currency translation gain (loss)	(44)	(1.3%)	(34)	(1.2%)
Other non-operating income	84	2.5%	21	0.8%
Minority interest	(22)	(0.7%)	(6)	(0.2%)
Income before income taxes	$ 900	26.7%	$ 317	11.1%
Current income taxes	(240)	(7.1%)	(108)	(3.8%)
Deferred income taxes	20	0.6%	34	1.2%
Net income	$ 680	20.2%	$ 243	8.5%
Basic earnings per share of common stock	$ 0.95		$ 0.30	
Diluted earnings per share of common stock	0.94		0.30	

In the three months ended March 31, 2002 compared to the same period in 2001:

- *Revenues.* Our revenues decreased due to declines in revenues from the sale of both crude oil and refined products. The decline in revenues from sales of crude oil resulted from lower domestic and international prices. The decline in revenues from sales of refined products resulted from lower domestic and international prices offset in part by a significant increase in volumes sold, both internationally and domestically.
- *Operating expenses.* Our operating expenses decreased slightly, primarily due to a reduction in our costs of purchasing crude oil and refined products as a result of the decline in market prices. This decrease was partially offset by an increase in volumes purchased. In addition, our refining costs declined as a result of the closure of the Petrotel refinery in Romania in the second quarter of 2001.

  Our average operating costs per barrel extracted increased to $3.01 per barrel in the three months ended March 31, 2002 from $2.90 in the three months ended March 31, 2001. Extraction costs in the first quarter of 2002 decreased, however, compared to average 2001 extraction costs of $3.14 per barrel and peak extraction costs of $3.35 per barrel in the third quarter of 2001.
- *Selling, general and administrative.* Our selling, general and administrative costs increased, primarily due to increases in transportation costs and port costs as a result of higher volumes transported and higher tariffs and increases in staff costs, partly offset by a reduction in costs relating to achieving certain tax efficiencies. See “Part 4 – Management’s Discussion and Analysis of Financial Condition and Results of Operations – Certain Factors Affecting our Results and Operations – Tax Burden.”
- *Taxes other than income taxes.* Our taxes other than income taxes increased, primarily due to changes in tax legislation that replaced royalty, mineral replacement and oil excise taxes with one unified tax. See “Part 4 – Management’s Discussion and Analysis of Financial Condition and Results of Operations – Certain Factors Affecting our Results and Operations – Tax Burden.”
- *Excise and export tariffs.* Our excise and export tariffs declined significantly due to a 70% decrease in the average export tariff per tonne.
- *Income taxes.* Our effective income tax rate decreased slightly in the first quarter of 2002. The impact of the anticipated increase in our effective tax rate resulting from new tax legislation will not be felt until we report our year-end results. See “Part 4 – Management’s Discussion and Analysis of Financial Condition and Results of Operations – Certain Factors Affecting our Results of Operations – Tax Burden.”

In addition, in the three months from December 31, 2001 to March 31, 2002 our net debt increased to $2.8 billion from $2.3 billion, or 22%, primarily due to a reduction in our cash and cash equivalents.

Our businesses are performing, and trading since March 31, 2002 has been, in line with our Directors’ expectations. Our Directors view our future prospects with confidence and believe that our position as the largest publicly traded oil company in the world in terms of proven crude oil reserves, and the execution of our corporate development and restructuring program, will enable us to remain competitive in Russia, provide a platform for competing internationally with oil majors and deliver value to our shareholders.

RECENT DEVELOPMENTS

Since the beginning of 2002, we have begun implementing a restructuring plan designed to improve our operations and maximise shareholder value. The plan contemplates that we will undertake the following measures in the near term: (i) increase exports of crude oil and refined products; (ii) accelerate the development of our most productive fields; (iii) shut-in low-producing wells; (iv) apply enhanced oil recovery technologies; (v) seek competitive bids for oilfield services; (vi) divest non-core businesses and reduce headcount; (vii) strengthen performance-related pay; and (viii) streamline our administration.

We have also continued to execute our fundamental business strategies of expanding both our upstream and downstream businesses in Russia and internationally. In April 2002 we signed a joint exploration agreement with Ecopetrol, Colombia’s state-owned oil company, for the exploration and development of the Condor block in eastern Colombia. In May 2002 our consortium with the Latsis Group was selected as the preferred bidder for the acquisition of a 23.17% stake in Hellenic Petroleum, a Greek refining, marketing and distribution company that operates three refineries and supplies a substantial portion of the Greek market with petroleum products through a network of wholesale terminals and 1,537 service stations. On June 17, 2002 we, together with Rotch Energy, filed a joint application with Nafta Polska to acquire 75% of the Gdansk refinery. Our bid must be approved by Polish governmental authorities as a condition to completing the transaction.

DIVIDEND POLICY

Our Board of Directors recommends the payment of annual dividends to our shareholders, who approve such annual dividends by a majority vote at the annual shareholders' meeting. The annual dividend approved at the shareholders' meeting may not be more than the amount recommended by the Board of Directors. Annual dividends are distributed to shareholders entitled to participate in the annual shareholders' meeting. Dividends are not paid on treasury shares held by OAO LUKOIL.

At our annual general shareholders' meeting, or AGM, on June 27, 2002, our Board of Directors recommended and our shareholders approved dividends of 15.00 rubles ($.50) per ordinary share, which in the aggregate represented approximately 19% of our net profit for the 2001 financial year.

In 2001 we declared dividends in the amount of 59.16 rubles ($2.03) per preferred share and 8.00 rubles ($.27) per ordinary share, which in the aggregate represented approximately 11% of our net profit for the 2000 reporting year. In December 2001 we completed a series of share exchange transactions whereby we converted all outstanding shares of preferred stock into ordinary shares. In 2000 we declared dividends in the amount of 17.45 rubles ($.62) per preferred share and 3.00 rubles ($.11) per ordinary share, which in the aggregate represented approximately 11% of our net profit for the 1999 financial year.

FORWARD-LOOKING STATEMENTS

Certain statements in these Listing Particulars are not historical facts and are "forward-looking." These Listing Particulars contain certain forward-looking statements in various locations, including, without limitation, under the headings "Part 2 – Key Information," "Part 3 – Risk Factors," "Part 4 – Management's Discussion and Analysis of Financial Condition and Results of Operations" and "Part 5 – Business." We may from time to time make written or oral forward-looking statements in reports to shareholders and in other communications. Examples of such forward-looking statements include, but are not limited to:

- statements of our plans, objectives or goals, including those related to products or services;
- statements of future economic performance; and
- statements of assumptions underlying such statements.

Forward looking statements that may be made by us from time to time (but that are not included in this document) may also include projections or expectations of revenues, income (or loss), earnings (or loss) per share, dividends, capital structure or other financial items or ratios.

Words such as "believes," "anticipates," "expects," "estimates," "intends" and "plans" and similar expressions are intended to identify forward-looking statements but are not the exclusive means of identifying such statements.

By their very nature, forward-looking statements involve inherent risks and uncertainties, both general and specific, and risks exist that the predictions, forecasts, projections and other forward-looking statements will not be achieved. You should be aware that a number of important factors could cause actual results to differ materially from the plans, objectives, expectations, estimates and intentions expressed in such forward-looking statements. These factors include:

- inflation, interest rate and exchange rate fluctuations;
- the price of oil;
- the effects of, and changes in, Russian government policy;
- the effects of competition in the geographic and business areas in which we conduct operations;
- the effects of changes in laws, regulations, taxation or accounting standards or practices;
- our ability to increase market share for our products and control expenses;
- acquisitions or divestitures;
- technological changes; and
- our success at managing the risks of the aforementioned factors.

This list of important factors is not exhaustive. When relying on forward-looking statements, you should carefully consider the foregoing factors and other uncertainties and events, especially in light of the political, economic, social and legal environment in which we operate. Such forward-looking statements speak only as of the date on which they are made, and, subject to any continuing obligations under the Listing Rules of the U.K. Listing Authority, we do not undertake any obligation to update or revise any of them, whether as a result of new information, future events or otherwise. We do not make any representation, warranty or prediction that the results anticipated by such forward-looking statements will be achieved, and such forward-looking statements represent, in each case, only one of many possible scenarios and should not be viewed as the most likely or standard scenario.

Part 3 – RISK FACTORS

Investing in our shares or depositary shares involves a high degree of risk. You should carefully consider the risks and the other information contained in this document before you decide to invest in our shares or depositary shares. The trading price of our shares or depositary shares could decline due to any of these risks, and you could lose all or part of your investment. You should note that the risks described below are not the only risks we face. We have described only the risks we currently consider to be material. However, there may be additional material risks that we currently consider not to be material or of which we are not currently aware.

If any of the following risks were to materialise, our business, financial condition and results of operations could be materially adversely affected.

RISKS RELATING TO OUR BUSINESS

A substantial or extended decline in oil prices could have a material adverse effect on us.
Historically, prices for oil have fluctuated widely in response to changes in many factors. We do not and will not have control over the factors affecting prices for oil. These factors include:

- global and regional economic and political developments in resource-producing regions, particularly in the Middle East;
- global and regional supply and demand and expectations regarding future supply and demand;
- the ability of the Organisation of Petroleum Exporting Countries, or OPEC, and other producing nations to influence global production levels and prices;
- prices and availability of alternative fuels;
- Russian and foreign governmental regulations and actions, including with respect to taxes and export levels;
- global economic conditions;
- price and availability of new technology; and
- weather conditions.

It is impossible to predict future oil price movements with certainty. Declines in oil prices adversely affect our business, results of operations, financial condition, liquidity and our ability to finance planned capital expenditures. Lower oil prices also may reduce the amount of oil and natural gas that we can produce economically or reduce the economic viability of projects planned or in development.

We sell a significant portion of our crude oil and refined products in the Russian market, where prices have historically been lower than in the international market.
Historically, Russian crude oil prices were set by the Russian government at levels substantially below world market prices. While the Russian government ceased to control domestic crude oil prices directly in early 1995, domestic crude oil prices remain below international spot market price levels primarily due to large regional surpluses in Russia, increasing domestic supplies and low domestic demand resulting from Russia's economic weakness. Domestic prices for refined petroleum products also remain below international spot market prices for refined petroleum products.

We are dependent on Transneft, a state-owned company that controls substantially all of Russia's trunk pipeline system, for the transport of a significant portion of our crude oil, and our ability to export crude oil is limited by the system for allocating access to Transneft's pipelines.
Over 90% of the crude oil produced in Russia, and most of our crude oil, is transported through the Transneft system of trunk pipelines. Transneft is a state-owned oil pipeline monopoly. The Transneft pipeline system is subject to breakdowns and leakage. By using multiple pipelines, however, Transneft has generally avoided serious disruptions in the transport of crude oil, and to date, we have not suffered significant losses arising from the failure of the pipeline system. A significant disruption in the pipeline system would, however, have a material adverse effect on our results of operations.

Russian government authorities regulate access to Transneft's pipeline network. Pipeline capacity, including export pipeline capacity, is allocated quarterly to oil producers, generally in proportion to the amount of oil produced and delivered to Transneft's pipeline network in the prior quarter. Generally a Russian oil company is given an allocation for export that equals approximately 30% of its crude oil so produced and delivered. Limitations on access to the export pipelines constrain the ability of producers to export crude oil, and limited port, shipping and railway facilities represent further constraints on the export of crude oil. These constraints have had, and may continue to have, a significant impact on our cash flows and results of operations, since export prices are generally higher than domestic prices and we are more likely to receive payment in cash from our exports than from domestic sales.

In 2001 a Russian court ordered Transneft to stop accepting shipments of our crude oil in response to a lawsuit filed by one of our shareholders. This order was overturned quickly without causing a material adverse effect on our business. However, we cannot be certain that similar lawsuits will not be filed in the future or that any such lawsuits will be resolved in our favour. Any future disruption in our access to Transneft resulting from any such lawsuits could have a material adverse effect on our results of operations.

We must pay taxes to the Russian government and pay transportation expenses to Transneft to maintain our access to export pipelines and seaports. Any failure to pay such taxes or expenses could result in the termination or temporary suspension of our access to the export pipelines and seaports, which would materially adversely affect our results of operations.

A change in the blend of the oil transported through the Transneft pipeline network could affect the price we receive for our oil.

The oil that we transport through the Transneft pipeline network is blended with oil produced from other fields and by other oil companies transporting their oil through Transneft. The sales that we and all such other oil companies make in the export market are of the oil blend that results from the mixing in the system. Therefore, the price we get for our oil may be lower than the price we could get for oil of the same quality if we could transport our oil independently of Transneft. Additionally, the composition of the blend of oil sold into the marketplace through Transneft may change, which could reduce the marketability of the oil we produce.

Failure of the Russian government to permit access by independent gas producers to Russia’s natural gas transmission system for the export of gas may have a material adverse effect on our operations.

The Russian natural gas transmission system, which includes gas trunk pipelines for gas exports, is currently owned and operated by Russia’s gas monopoly, Gazprom. Russian independent gas producers are currently only able to access the gas transmission system subject to spare capacity availability and certain other criteria to effect domestic deliveries. The Russian government has, however, announced plans to allow Russian independent gas producers greater access to the gas transmission system, including to export gas through this system. The success of our strategy relating to the development of our gas operations is dependent on, among other things, the implementation of these plans. Accordingly, if the Russian government does not permit greater access by independent gas producers to Russia’s gas transmission systems, including for the export of gas, it may have a material adverse effect on our operations by limiting the effective use and value of our gas producing assets and our strategy to increase the share of natural gas in our operations.

The Russian government can mandate deliveries of crude oil and refined products at less than market prices, which could adversely affect our revenues and relationships with other customers.

The Russian government has the authority to direct us to deliver crude oil or refined products to certain government-designated customers, which generally take precedence over market sales. Government-directed deliveries may take several forms. We may be directed to make deliveries to government agencies, the military, railways, agricultural producers or remote regions, to specific consumers or refineries, or to domestic refineries in general. Additionally, some of our oil production licences provide that we are obligated to sell oil we produce to local government agencies. Government-directed deliveries may disrupt our relations with our customers, lead to delays in payments for crude oil and refined products or result in sales at below market prices. In 2001 we delivered approximately 4.3 million tonnes of refined petroleum products under such government-directed programs. See “Part 5 – Business – Refining, Marketing and Distribution – Refined petroleum product sales.”

Any failure to make government-directed deliveries may affect our ability to export our crude oil. For example, the Russian government has previously threatened to limit the access of Russian oil companies to export pipelines for failing to provide domestic refineries with steady supplies of oil. Any such revocation of export rights could materially adversely affect our business.

A portion of our domestic sales are settled through barter transactions, which reduces the amount of cash available for funding our operations and paying our indebtedness.

As is common with many Russian enterprises, from time to time we experience difficulties in receiving payment for the goods and services we supply domestically. As a result, we depend on various forms of non-cash settlement, including barter and promissory notes. In 2001 these transactions represented less than 10% of our total sales and were comprised primarily of transactions with RAO Unified Energy Systems and the Railways Ministry of the Russian Federation. Such transactions are inherently less efficient than cash transactions, as the proceeds cannot be used to fund operational or capital expenditures that are required to be made in cash.

The Russian tax system imposes substantial burdens on us and is subject to frequent change and significant uncertainty.

We are subject to a broad range of taxes imposed at the federal, regional and local levels, including but not limited to excise and export tariffs, income tax, mineral extraction taxes, royalty tax, sales tax, property tax, social taxes and road use tax, among others. We were subject to an effective income tax rate of 24% in 2001 and a total tax burden of 60% (calculated in accordance with U.S. GAAP).

Laws related to these taxes, such as the new Tax Code, have been in force for a short period relative to tax laws in more developed market economies; therefore, the government's implementation of these tax laws is often unclear or inconsistent. Accordingly, few precedents with regard to the interpretation of these laws have been established. Often, differing opinions regarding legal interpretation exist both between companies subject to such taxes and the government and within government ministries and organisations, such as the Ministry of Taxes and Duties and its various inspectorates, creating uncertainties and areas of conflict. Generally, tax declarations remain open and subject to inspection by tax and/or customs authorities for a period of three years following the tax year. The fact that a year has been reviewed by tax authorities does not close that year, or any tax declaration applicable to that year, from further review during the three-year period. These facts create tax risks in Russia substantially more significant than typically found in countries with more developed tax systems.

The taxation system in Russia is subject to frequent change and inconsistent enforcement at the federal, regional and local levels. In addition to our substantial tax burden, these conditions complicate our tax planning and related business decisions. For example, tax laws are unclear with respect to the deductibility of certain expenses and at times we have taken a position that is aggressive in this regard, but that we consider to be in compliance with current law. This uncertainty exposes us to significant fines and penalties and to enforcement measures despite our efforts at compliance, and could result in a greater than expected tax burden. Until the recent adoption of the new Tax Code, the system of tax collection was relatively ineffective, resulting in the continual imposition of new taxes in an attempt to raise government revenues. There can be no guarantee that the Tax Code will not be changed in the future in a way that reverses recent positive changes. These factors, plus the potential for government deficits, raise the risk of a sudden imposition of additional taxes on us. This could adversely affect us.

The Russian government has initiated a revision of the Russian tax system. The new tax system is intended to reduce the number of taxes and the overall tax burden on businesses and to simplify the tax laws. However, the revised tax system relies heavily on the judgments of local tax officials and fails to address many of the existing problems. Even if further reforms to tax legislation are enacted, they may not result in a reduction of the tax burden on Russian companies and the establishment of a more efficient tax system. Conversely, they may introduce additional tax collection measures. Accordingly, we may have to pay significantly higher taxes, which could have a material adverse effect on our business. See "Part 4 – Management's Discussion and Analysis of Financial Condition and Results of Operations."

Tax-planning initiatives used by us may be challenged by the tax authorities, which could expose us to substantial liabilities.

Historically, our results of operations have benefited significantly from the use of on-shore tax-planning initiatives. We believe that the tax-planning initiatives used by us complied with relevant tax regulations. In 2001 amendments to the Russian tax law began to reduce the number, scope and effectiveness of initiatives available to Russian companies. As a result, we were exposed to a significantly higher net tax burden in 2001 than in previous years, and our operating profits were adversely affected. In 2002 substantially all of the tax-planning initiatives that we formerly used were phased out, and we expect to pay higher taxes in 2002 and thereafter. Accordingly, our results of operations may be adversely affected.

In addition, if the various initiatives we have used to reduce our tax burden are successfully challenged by the Russian tax authorities, we will face significant losses associated with the assessed amount of tax underpaid and related interest and penalties, which would have a material impact on our financial condition and results of operations. See "Part 4 – Management's Discussion and Analysis of Financial Condition and Results of Operations."

Our exploration, development and production licences may be suspended or revoked prior to their expiration.

The licensing regime in Russia for the exploration, development and production of oil and gas is governed primarily by the Subsoil Law and regulations issued thereunder. Most of our licences provide that they may be terminated if we fail to comply with licence requirements, if we do not make timely payments of levies and taxes for the use of the subsoil, if we systematically fail to provide information, if we go bankrupt or if we fail to fulfill any capital expenditure and/or production obligations.

We may not be able to, or may voluntarily decide not to, comply with the licence requirements for some or all of our licence areas. If we fail to fulfill the specific terms of any of our licences or if we operate in the licence areas in a manner that violates Russian law, government regulators may impose fines on us or suspend or terminate our licences, any of which could have a material adverse effect on our operations and the value of our assets, or cause the price of our shares or depositary receipts to decline.

In early 2001 a commission operating under the Ministry of Natural Resources recommended to the administration of the Nenets Autonomous Region, or NAO, that development licences held by OAO Arkangelskgeoldobycha, or AGD, relating to three licence areas (four fields) be withdrawn or suspended because AGD had not met licence agreement requirements that specified that oil production on those fields must begin by early 2000. The licences subject to withdrawal or suspension relate to fields that account for approximately 786 mmbls or 65% of AGD's proven crude oil reserves. After negotiations with both the Ministry of Natural Resources and the local authorities of the NAO, we drafted amendments to the licence agreements that would bring us into compliance. In January 2002 the Ministry of Natural Resources signed the amendments. To date the NAO authorities have not signed the amendments. Although we believe that we can proceed with our operations in the licence areas on the basis of the amendment agreements signed by the Ministry of Natural Resources, in the absence of the NAO authorities' formal approval, we cannot assure you that one or more of our licences will not be revoked or suspended. Any such licence revocation or suspension could have a material adverse effect on our results of operations. Additionally, certain of AGD's development programs and production sharing agreements have not yet received necessary government approvals. A failure to obtain such approvals could result in a loss of these licences and a corresponding decrease in our available reserves.

If we fail to integrate our acquisitions successfully, our rate of expansion could slow and our results of operations and financial condition could suffer.

We have expanded our operations significantly through acquisitions since being privatised in 1993, both in Russia and internationally, and we expect to continue to do so in the future. Our key recent acquisitions include NORSI Oil (which we renamed LUKOIL-Volgonefteprodukt), which operates a 300,000 barrels per day refinery located in Nizhni Novgorod (October 2001); Bitech Petroleum Corporation, a public Canadian oil and gas company with upstream assets principally in the Russian Komi Republic and Egypt (September 2001); 60% of OAO Yamalneftegazdobycha (2001), a western Siberia gas company with proven gas reserves of approximately 8,222.5 bcf (232.9 bcm); Getty Petroleum Marketing Inc., a marketing and distribution company supplying and operating 1,277 retail outlets throughout the northeast region of the United States (2000-2001); LUK-Sintez Oil Ltd., which owns the Odessa refinery located in Ukraine (May 2000); 58% of LUKOIL Neftochim Burgas AD (1999-2000); and OAO KomiTEK, an integrated oil and gas company based in the Russian Komi Republic (September 1999).

The integration of these operations, and of businesses we may acquire in the future, requires significant time and effort of our senior management, who are also responsible for managing our existing operations. Integration of new businesses can be difficult, as our culture may differ from the cultures of the businesses we acquire, unpopular cost cutting measures may be required, and control over cash flows and expenditures may be difficult to establish. While we have generally been satisfied with the progress we have made in integrating the businesses we have acquired thus far, no assurance can be given that we will continue to be as successful in the future.

We may not be able to finance our planned capital expenditures.
Our business requires significant capital expenditures, including in exploration and development, production, transport, refining, and to meet our obligations under environmental laws and regulations. We expect to finance a substantial part of these capital expenditures out of cash flows from our operating activities. If international oil prices fall, however, we will have to finance more of our planned capital expenditures from outside sources, including bank borrowings and offerings of debt or equity securities in the international capital markets. If necessary, these financings may be secured by our exports of crude oil. Currently, the proceeds from export sales of approximately 36.5 mmbls of crude oil over a four-year time period ending in mid-2006 have been pledged as security for existing borrowings. See "Part 11 – Additional Information – Material Contracts." Nonetheless, no assurance can be given that we will be able to raise the financings required for our planned capital expenditures, on a secured basis or otherwise, on acceptable terms or at all. If we are unable to raise the necessary financing, we will have to reduce our planned capital expenditures. Any such reduction could adversely affect our ability to expand our business, and if the reductions are severe enough, could adversely affect our ability to maintain our operations at current levels.

Exploratory drilling involves numerous risks, including the risk that we will encounter no commercially productive oil or natural gas reservoirs.
We are exploring in various geographic areas, including western Siberia, European Russia, the Timan-Pechora region and areas in and around the Caspian Sea, where environmental conditions are challenging and costs can be high. The cost of drilling, completing and operating wells is often uncertain. As a result we may incur cost overruns or may be required to curtail, delay or cancel drilling operations because of a variety of factors, including unexpected drilling conditions, pressure or irregularities in geological formations, equipment failures or accidents, adverse weather conditions, compliance with governmental requirements and shortages or delays in the availability of drilling rigs and the delivery of equipment. Our overall drilling activity or drilling activity within a particular project area may be unsuccessful in that we may not find commercially productive reservoirs.

If we fail to acquire or find and develop additional reserves, our reserves and production will decline materially from their current levels.
Except to the extent we conduct successful exploration and development activities or acquire properties containing proven reserves, or both, our proven reserves will decline as oil is produced and reserves are depleted. In addition, the volume of production from oil and natural gas properties generally declines as reserves are depleted. Our future production is highly dependent upon our success in finding or acquiring and developing additional reserves. If we are unsuccessful, we may not meet our production targets, and our total proven reserves and production will decline, which could adversely affect our results of operations and financial condition.

Most of our international reserves, production and refining interests are located in politically, economically and legally unstable areas.
Approximately 3% of our proven oil reserves, which in 2001 accounted for approximately 3% of our production, are located outside Russia. Currently, our principal international upstream interests are in two states bordering the Caspian Sea: Azerbaijan and Kazakstan. We also have upstream interests in Egypt, Iraq and Colombia. We are exposed to significant political, economic and legal risks in these countries. There has been war and civil strife in and around the Caspian region and in Colombia for much of the 1990s and Iraq has been involved in international conflicts since 1980 (and activities there are subject to limitations under U.N. sanctions). Moreover, since the dissolution of the Soviet Union, the international legal status of the Caspian Sea has remained uncertain and is currently the subject of international negotiations that could have a material adverse effect on our interests there. We also have refining operations located outside of Russia, including in Ukraine, Bulgaria and Romania. As a result, we are exposed to certain political, economic and legal risks in these countries.

We may not be able to realise opportunities in Iraq because of U.N. sanctions.
The United Nations Security Council has directed member states to prohibit virtually all transactions with Iraq, except for (i) the provision of medical supplies or food for humanitarian purposes and (ii) transactions that are permitted under the U.N.'s "oil for food" program. Each member state is responsible for enforcing these restrictions on its nationals and companies organised under its laws. We have an interest in a production sharing agreement relating to the development of the second stage of the West Qurnah oil field in Iraq. This agreement calls for the parties to make a total investment of at least $6 billion on a *pro rata* basis. It is our policy to comply with the U.N. restrictions on doing business in Iraq, as implemented by the Russian Federation. As a result of the

sanctions we have delayed our performance of certain obligations under the agreement, which could cause us to lose our rights to the field. Recent articles in the press have reported that Iraq has begun developing the West Qurnah field independently and that the current Minister of Oil of Iraq has threatened to assign our rights under the production sharing agreement to another party. We cannot assure you that we will retain our rights under the production sharing agreement or that we will be able to begin developing the field when sanctions are lifted or at any time after that. Because of the uncertainties surrounding our development of this field, no operating information relating to it has been included in this document.

Negative actions or publicity against us by U.S. officials, private organisations or the public at large could adversely affect our operations and the price of our shares or depositary receipts.

We have purchased oil from Iraq pursuant to the U.N.'s "oil for food" program. In addition, as noted above, we are party to a production sharing agreement relating to the West Qurnah field in Iraq. In the United States, there are significant political sensitivities to issues associated with Iraq. Also, we have been the target of negative publicity in the U.S. relating to downstream assets in Lithuania. Negative actions or publicity against us in the U.S. by government officials, private organisations or the public at large could adversely affect our assets and operations, which may in turn adversely affect the price of our shares or depositary receipts.

We encounter competition from other oil companies in all areas of our operations, including the acquisition of licences, exploratory prospects and producing properties.

The oil industry is intensely competitive. We compete with other major Russian oil companies, as well as the major international oil companies. In Russia we compete for exploration and production opportunities with respect to licences and acquisitions of production companies. In refining, marketing and distribution, we compete on the basis of our refinery capacity and market share for our refined products. We also compete with other Russian oil and gas companies on the basis of our costs and efficiency. Currently our operating and selling, general and administrative expense levels are comparatively higher as a proportion of revenues than those of our key competitors in Russia. Many of our international competitors have substantially greater resources and have been operating in a market-based, competitive economic environment for a much longer time than we have. These international companies, especially those created by recent mergers, are developing strong market power through a combination of different factors, including:

- diversification and reduction of risk;
- financial strength necessary for capital-intensive developments;
- exploitation of benefits of integration;
- exploitation of economies of scale in technology and organisation;
- exploitation of mutual advantages of expertise, industrial infrastructure and reserves; and
- strengthening of positions as global players.

These companies may be able to pay more for exploratory prospects and productive oil properties and may be able to identify, evaluate, bid for and purchase a greater number of properties and prospects, including operatorships and licences, than our financial or human resources permit. For more information on the competitive environment, see "Part 5 – Business – Competition."

Our development projects involve many uncertainties and operating risks that can prevent us from realising profits and can cause substantial losses.

Our development projects may be delayed or unsuccessful for many reasons, including cost overruns, lower oil and gas prices, equipment shortages and mechanical difficulties. These projects will also often require the use of new and advanced technologies, which can be expensive to develop, purchase and implement, and may not function as expected. In addition, some of our development projects will be located in deep water, frozen or other hostile environments, or will involve production from challenging reservoirs, which can exacerbate such problems. The climate and topography of some of the regions where our fields are located limit access to certain fields and facilities during certain times of the year. During the summer and early fall, some fields are partially flooded and operating capacity is limited. If warmer weather starts earlier or ends later in the year, then our operating capacity is more limited than normal. Unusually warm or severe weather conditions could impede our development plans for our fields and facilities and otherwise negatively affect our results of operations.

We may not be able to produce economically some of our oil due to a lack of necessary transportation infrastructure when a field is in a remote location.

Our ability to exploit economically any reserves discovered will be dependent upon, among other things, the availability of the necessary infrastructure to transport oil and gas to potential buyers at a commercially acceptable price. Oil is usually transported by pipelines, tankers and rail to refineries. Natural gas is usually transported by pipelines to processing plants and end users. The transportation of oil and natural gas from our holdings in the northern Caspian region, Azerbaijan and Kazakstan faces a number of significant obstacles that could prevent sales to international markets. Such obstacles include capacity constraints, general political and economic instability and the necessity of obtaining approvals for pipelines from several governments that may not share a common development strategy. Additionally, our activities in northern Russia face transport constraints related to competition for pipeline access, the lack of infrastructure and the harsh weather conditions in that region, among other constraints.

We are not insured against all potential losses and could be seriously harmed by natural disasters or operational catastrophes.

Exploration for and production, refining and distribution of oil and natural gas is hazardous. Natural disasters, operator error or other occurrences can result in oil spills, blowouts, cratering, fires, equipment failure and loss of well control, which can injure or kill people, damage or destroy wells and production facilities, and damage property and the environment. Offshore operations are subject to marine perils (including severe storms, other adverse weather conditions and vessel collisions) and governmental regulations as well as interruptions or termination by governmental authorities based on environmental and other considerations. The insurance industry in Russia and certain other areas where we operate is in an early stage of development and, accordingly, is relatively limited. Many forms of insurance designed to protect against the above-noted perils, common in other parts of the world, are not yet generally available in some of the areas where we operate. We do not have full coverage for all of our plant facilities, for business interruption, for third-party liability in respect of property, and for environmental damage arising from accidents on our property or relating to our operations. Until we are able to obtain adequate insurance coverage, there is a risk that losses and liabilities arising from such events could significantly increase our costs and have a material adverse effect on our operations and financial condition.

The crude oil and natural gas reserves data in this document are only estimates, and our actual production, revenues and expenditures with respect to our reserves may differ materially from these estimates.

The oil and gas reserves data included elsewhere in this document represent only estimates primarily based on internal engineering analyses that are audited by independent petroleum engineers. The estimates were calculated using oil and gas prices in effect on the date of the reports. Any significant price changes will have a material effect on the actual reserves quantity and present values.

Petroleum engineering is a subjective process of estimating underground accumulations of oil and gas that cannot be measured in an exact manner. Estimates of the value and quantity of economically recoverable oil and gas reserves, rates of production, future net revenues and the timing of development expenditures necessarily depend upon a number of variable factors and assumptions, including the following:

- historical production from the area compared with production from other comparable producing areas;
- interpretation of geological and geophysical data;
- the assumed effects of regulations by governmental agencies;
- assumptions concerning future oil and gas prices; and
- assumptions concerning future operating costs, taxes, 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 reserves:

- the quantities of oil and gas that are ultimately recovered;
- the production and operating costs incurred;
- the amount and timing of future development expenditures; and
- future oil and gas sales prices.

Many of the factors, assumptions and variables involved in estimating reserves are beyond our control and may prove to be incorrect over time. This is especially true in relation to countries such as Russia, Kazakstan and Azerbaijan, where there is political and economic uncertainty. Results of drilling, testing and production after the date of the estimates may require substantial upward or downward revisions in our reserves data. Furthermore, 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 will vary from estimates and the variances may be material. Any downward adjustment could lead to lower future production and thus adversely affect our financial condition, future prospects and market value.

The discounted and undiscounted pre-tax future net revenues included elsewhere in this document should not be considered as the market value of the reserves attributable to our properties. Our actual pre-tax future net revenues will be affected by factors such as:

- the amount, timing and cost of actual production;
- supply, demand and price for oil and gas;
- cost and availability of transportation; and
- changes in governmental regulations (including taxation).

When converting natural gas reserves to oil reserves, a conversion rate of 6 mcf of gas per barrel of oil is used, which approximates the energy equivalent of gas to oil. However, this conversion results in an overstatement of the present value of the future net revenues attributable to our gas reserves because natural gas prices are lower than oil prices in Russia. In addition, the 10% discount factor we used to calculate our discounted pre-tax future net revenues is not necessarily the most appropriate discount factor based on the cost of capital in effect from time to time and risks associated with us and the oil and gas industry in general. Any substantial decline in projected net revenues resulting from production of reserves could have a material adverse effect on our financial position and results of operations.

We may incur material costs to comply with, or as a result of, health, safety and environmental laws and regulations.

Maintaining compliance with environmental laws and regulations in Russia and abroad could materially increase our costs. We incur and expect to continue to incur, substantial capital and operating costs to comply with increasingly complex laws and regulations covering the protection of the environment and human health and safety. These include costs to reduce certain types of air emissions and discharges to the sea and to remediate contamination at various owned and previously owned facilities and at third-party sites where our products or wastes have been handled or disposed.

In connection with our acquisition of OAO KomiTEK in 1999, we inherited significant environmental problems. We have agreed to remediate the consequences of oil spills that took place in the Usinsk Region of the Komi Republic in 1994. We are currently working toward the reclamation of more than 745 hectares of damaged and contaminated land. We estimate that the recovery program should be completed by 2005 at a total cost of approximately 710 million rubles ($23.6 million as of December 31, 2001), although we cannot be certain that this time-frame will not be extended or that this amount will not increase.

Our Petrotel refinery in Romania, which we purchased in 1998-1999, and our Neftochim refinery in Bulgaria, purchased in 1999, require the remediation of a substantial amount of environmental pollution that pre-dated our acquisition of these facilities. At the time of our acquisition of the Petrotel refinery, there was an understanding that the Romanian government would retain liability for existing environmental pollution at the site. In the purchase agreement, however, we agreed, as part of our investment to upgrade the facilities, to commit $11 million for environmental protection measures, which could include remediation. In connection with our acquisition of the Neftochim refinery, we understand that the Bulgarian government retains liability for remediation of existing environmental pollution at the site, estimated at approximately $80-100 million. Specifically, we understand that the Bulgarian government intends to commit $40 million in the first stage of remediation, of which we understand that $20 million is expected to be funded in 2003 pending the results of environmental surveys. There can be no assurance that the Romanian and Bulgarian governments will remediate the environmental pollution at these facilities in the way we expect. Accordingly, we could be exposed to additional remediation costs at these sites in excess of our planned expenditures.

Managed nuclear explosions were carried out within the Osinskoye oil field in 1969. This field is currently operated by LUKOIL-Permneft. Subsequent drilling allowed radioactively contaminated water to enter the oil reservoir, which eventually led to a ground-level radioactive contamination problem being identified in 1976. Between 1996 and 2001 we undertook a project at a cost of $6 million to manage and contain associated radiological risks, and we believe that no further material liability exists. Well management procedures are in place to maintain a buffer zone around the location of the nuclear explosions. We do not expect further ground water contamination of the surface soil.

New laws and regulations, the imposition of tougher requirements in licences, 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;
- install pollution control equipment;
- perform site clean-ups;
- curtail or cease certain operations; or
- pay fees or fines or make other payments for discharges or other breaches of environmental standards.

In addition, increasingly strict environmental requirements, including those relating to gasoline sulfur levels, diesel quality and aromatic content of gasoline (to become effective in 2005 in the European Union), affect product specifications and operational practices. Our refineries will not be able to meet certain strict petroleum product specifications, particularly those required by the European Union or the United States, without significant modification and capital expenditures. In addition, our refineries in Bulgaria and Romania will become subject to stricter regulations, including environmental regulations, in the event these countries are admitted to the European Union. If this happens we will have to make substantial investments to upgrade our refineries to comply with such regulations, including those that relate to asbestos, which is present at both such refineries. Although our plans call for significant expenditures to upgrade our refineries, we cannot assure you that we will have adequate resources to fulfill these plans. Failure to meet certain international standards at our refineries could have a material adverse effect on our business and results of operations. Our shipping operations are subject to extensive environmental and other regulations. Any violation of such regulations or failure to operate our shipping operations in an environmentally sound manner could expose us to administrative proceedings and private litigation and could have a material adverse effect on our business and results of operations.

We depend on key personnel, the loss of whom could have an adverse impact on our business.
Our growth and future success depend in significant part upon the continued contributions of a number of our key senior management and personnel, in particular our President and member of the Board of Directors, Vagit Yusufovich Alekperov. We cannot assure you that his services or the services of other key persons will continue to be available to us, and the loss of any one of them could have a material adverse effect on our business.

Our business operations could be disrupted if our existing and new management information systems fail to perform adequately.
We depend upon our management information systems to conduct our operations. We are in the process of upgrading and standardising our management information systems based on SAP R/3. We are also in the process of introducing new solutions to support our exploration and development activities and standardising and rationalising the accounting systems used at our subsidiaries. We have spent in excess of $100 million over the past few years on information systems. Implementation of major new systems and enhancements to existing systems could cause disruptions in our operations. If the implementation of our new management information systems is delayed or the systems fail to perform as anticipated, we could experience difficulties in conducting our operations or generating necessary financial and accounting information. Any of these or other systems-related problems could, in turn, adversely affect our net sales and profitability.

RISKS RELATING TO OUR FINANCIAL CONDITION

We face inflation risks that could adversely affect our results of operations.
The Russian economy has been characterised by high rates of inflation, including a rate of 84.5% in 1998, although it subsided to 18.6% in 2001. Certain of our costs, such as salaries, are sensitive to increases in the

general price level in Russia. Most of our revenues are either denominated in U.S. dollars or are linked to the U.S. dollar, and are affected primarily by the international price of oil. Accordingly, our operating margins could be adversely affected if the inflation of our ruble costs in Russia is not balanced by a corresponding devaluation of the ruble against the U.S. dollar or increase in oil prices.

We face foreign exchange risks that could adversely affect our results of operations.
Over the past ten years, the ruble has fluctuated dramatically against the U.S. dollar, in the great majority of instances falling in value (though in many periods appreciating in real terms). The Russian Central Bank has imposed various currency-trading restrictions in attempts to support the ruble (or to maintain a rate of devaluation that is in line with inflation). The effectiveness of these restrictions depends on many political and economic factors, including the ability of the Russian government and the Russian Central Bank to finance budget deficits without recourse to monetary emissions, to control inflation and to maintain sufficient foreign currency reserves to support the ruble.

While most of our revenues are either denominated in U.S. dollars or are correlated to U.S. dollar crude oil prices, most of our costs (other than debt service costs) are denominated in rubles. Our results of operations are therefore significantly affected by the relative movements of ruble inflation and exchange rates. In particular, our operating margins are generally adversely affected by a real appreciation of the ruble against the U.S. dollar (i.e., by an inflation rate that is higher than the rate at which the ruble is devaluing against the U.S. dollar) because this will generally cause our costs to increase in real terms relative to our revenues. On the other hand, our operating margins are generally positively affected by a real depreciation of the ruble against the U.S. dollar because this will generally cause our costs to decrease in real terms relative to our revenues.

The nominal depreciation of the ruble results in losses in the value of ruble-denominated monetary assets, such as ruble deposits and accounts receivable. The decline in the nominal value of the ruble against the U.S. dollar also reduces the U.S. dollar value of tax savings arising from tax incentives for capital investment and the depreciation of our property, plant and equipment since their basis for tax purposes is denominated in rubles at the time of the investment or acquisition. Increased tax liability would increase our total expenses.

The following table sets forth the rates of inflation in Russia, the rates of nominal devaluation of the ruble against the U.S. dollar and the rates of real change in the value of the ruble against the U.S. dollar for the periods shown and the year-end exchange rates.

	Year ended December 31,		
	1999	**2000**	**2001**
Inflation (CPI)	37%	20%	19%
Nominal depreciation (ruble v. dollar)	31%	4%	7%
Real appreciation (ruble v. dollar)	5%	13%	11%
Year-end exchange rate (ruble v. dollar)	27.00	28.16	30.14

Restrictive currency regulations may adversely affect our business and financial condition.
We have significant ruble revenues. The ruble is generally not convertible outside of Russia and the conversion of rubles into foreign currency in Russia is subject to Russian currency regulations. Russian currency regulations allow businesses to convert rubles into foreign currency only for certain purposes and require certain regulatory steps to be taken before conversion. Changes to the rules governing the conversion of rubles into foreign currency could make it more difficult for us to effect conversion.

We are currently required to repatriate foreign currency proceeds from our export sales and convert 50% of such proceeds into rubles. The percentage of proceeds we are required to convert into rubles may be increased or decreased from time to time by the Russian authorities. The restrictions on our ability to convert our ruble revenues into foreign currencies, or to reconvert to foreign currency the rubles we obtain pursuant to the mandatory repatriation and conversion requirements, may adversely affect our ability to pay overhead expenses outside Russia, meet debt obligations and efficiently carry on our business.

Restrictions on investments outside of Russia or in hard-currency-denominated instruments in Russia expose our cash holdings to devaluation.
Currency regulations established by Russian legislation restrict investments by Russian companies outside of Russia and in most hard-currency-denominated instruments in Russia, and there are only a limited number of available ruble-denominated instruments in which we may invest our excess cash. Any balances maintained in

rubles will give rise to losses if the ruble devalues against the U.S. dollar. Moreover, the obligors of our ruble-denominated investments may default, resulting in substantial losses for us.

Our need to convert rubles into hard currency could increase our costs when making payments in hard currency to suppliers and creditors and could cause us to default on our obligations to them.

Our major capital expenditures are generally denominated and payable in various foreign currencies, including U.S. dollars. To the extent such major capital expenditures involve the importation of equipment and related items, Russian legislation permits the conversion of ruble revenues into foreign currency. However, the market in Russia for the conversion of rubles into foreign currencies is limited. The scarcity of foreign currencies may tend to inflate their values relative to the ruble, and such a market may not continue to exist.

Additionally, any delay or other difficulty in converting rubles into a foreign currency to make a payment or any practical difficulty in the transfer of foreign currency could limit our ability to meet our payment and debt obligations, which could result in the acceleration of debt obligations and cross-defaults.

RISKS RELATING TO OUR SHARES

The Russian market for our shares is substantially smaller and less liquid, and as a result is significantly more volatile, than equity markets in the United Kingdom.

The principal market for our shares is the Russian Trading System, a screen-based over-the-counter trading system, used primarily by a network of broker-dealers. Liquidity in most issues fluctuates and bid/ask spreads advertised or offered by brokers can vary substantially. The Russian securities market, including the market for Russian equity securities, experienced a significant downturn in 1998. In that year, the RTS Index, an index of the shares of 65 major Russian companies (including OAO LUKOIL), fell by approximately 86% in U.S. dollar terms. This severe decline (resulting from the financial crisis in Russia in 1998, investor concerns with investments in emerging markets in general and in Russia in particular, and concerns about the further devaluation of the ruble), inflation and other factors, adversely affected, for a time, the ability of Russian companies to raise capital through the sale of equity or debt securities. The decline also renewed concerns about the stability and liquidity of the Russian financial markets. Although the Russian securities market has experienced a significant upward trend since 1999, this trend may not continue.

It may be difficult for you to repatriate your earnings from our ordinary shares and there is a risk that these earnings will fall in value.

Russian currency control legislation pertaining to the payment of dividends currently permits ruble dividends on common stock to be paid to a special ruble account of a non-resident shareholder, or its nominee, and, subject to the commercial risks described below, to be converted into U.S. dollars or another convertible currency and repatriated without restriction.

Although there is no restriction on the sale of our ordinary shares by a non-resident of Russia to another non-resident or to a Russian resident, Russian currency control legislation provides that a sale of our ordinary shares to a Russian resident must be made for rubles unless the Russian resident obtains a Central Bank licence authorising payment in U.S. dollars or another convertible currency. While many Russian commercial banks have the requisite licence, it is very difficult as a practical matter for other Russian residents to obtain one. Accordingly, if you wish to sell our ordinary shares to a Russian resident other than a licenced commercial bank, you will need to establish a special ruble account into which the ruble proceeds of the sale will be deposited and converted into U.S. dollars or another convertible currency and repatriated to you.

Your ability to arrange for the conversion of rubles into U.S. dollars or another convertible currency is subject to the availability of U.S. dollars or such other convertible currency in Russia’s currency markets. Although there is an existing market within Russia for the conversion of rubles into U.S. dollars and other convertible currencies, including the interbank currency exchange and over-the-counter and currency futures markets, liquidity is limited. At present, there is no market for the conversion of rubles into convertible currencies outside Russia. Moreover, there is currently no viable market in which to hedge ruble deposits or ruble-denominated investments.

Accordingly, if you are unable to convert your ruble dividends or ruble sale proceeds into U.S. dollars or another convertible currency, or if any such conversion is delayed, the value of your ruble deposits or ruble-denominated investments may decline, depending on the movement in the value of the ruble against the relevant convertible currency.

Russia's share registration system may provide less protection than registration systems in other countries. Currently there is no central registration system for ownership of shares in Russia, and the registration of share ownership is performed by commercial registrar companies that are not necessarily subject to effective government supervision. We have appointed NIKoil, a Russian licenced registrar, as registrar for all classes of our capital stock. Existing licensing conditions and regulations governing the activities of registrar companies have not been strictly enforced, and registrars generally have relatively low levels of capitalisation and inadequate insurance coverage. Consequently, our registrar's conduct may put our shareholders at risk and it may not have assets sufficient to compensate our shareholders for its errors or mistakes. Although under Russian law we remain liable to our shareholders for any errors or mistakes made by our registrar that affect our shareholders, this safeguard may be inadequate to protect our shareholders from loss.

You may be subject to Russian tax that might be withheld on trades of our shares.
Russian withholding tax on capital gains may arise from the disposition of Russian shares and securities, such as our ordinary shares, by non-resident holders. Russian tax authorities may attempt to apply withholding tax on capital gains derived from trading our shares (but not depositary shares, which are listed and sold on foreign exchanges). However, no procedural mechanism currently exists to collect any tax from capital gains with respect to sale of shares made by non-resident holders to a physical person or an entity other than a Russian resident (see "Part 11 – Additional Information – Taxation – Russian Tax Considerations" for definitions).

The Russian tax authorities require a Russian resident currently to withhold 20% (in case of holders that are legal entities) or 30% (in the case of holders who are individuals) of the capital gain earned by a non-resident holder on any security sold by such non-resident to a Russian resident if more than 50% of the assets in the Russian company whose security is being sold consist of immovable property and such Russian company's shares are not listed and sold on foreign exchanges. A refund of all or a portion of the tax withheld may be available if an exemption or lower rate of withholding tax is provided for by an applicable tax treaty. However, obtaining the benefits of any relevant tax treaties can be difficult due to the documentary requirements imposed by the Russian tax authorities. If any such tax is assessed, the value of our shares could be materially adversely affected. See "Part 11 – Additional Information – Taxation – Russian Tax Considerations – Taxation of Capital Gains."

Any non-Russian judgments or arbitral awards you may obtain against us may not be enforceable in Russia and you may have limited recourse against us and our directors or officers.
Most of our directors and executive officers and certain of the experts named in this document reside in Russia. A substantial amount of our assets and the assets of such persons are located in Russia. As a result, you may not be able to effect service of process on, or obtain or enforce a court judgment or arbitral award against, us or our officers and directors, or certain of the experts named in this document in jurisdictions outside of Russia. In addition, there is no U.K.-Russia or U.S.-Russia treaty providing for reciprocal enforcement of court judgments, including actions based on the civil liability provisions of English financial services law or U.S. securities laws. Similarly, you may not be able to obtain or enforce foreign court judgments against us on any basis. These limitations may deprive you of effective legal recourse for claims related to your investment in our shares.

Financial turmoil in emerging markets could have an adverse effect on our share price.
Financial turmoil in Russia and other emerging markets in 1997 and 1998 adversely affected market prices in the world's securities markets for companies that operate in those developing economies. Continued or increased financial downturns in these countries could cause further decreases in prices for our securities even if the Russian economy remains relatively stable.

The market price of our shares and DSs could be adversely affected by potential future sales.
The trading price of our shares and DSs could be adversely affected as a result of sales of substantial numbers of our shares in the public market, or by the perception that this could occur. These factors could also make it more difficult to raise capital through equity or equity-linked offerings.

The Government of the Russian Federation holds, directly or indirectly, approximately 114 million of our ordinary shares, representing 13.5% of our share capital and, through OAO Project Privatisation Company, which it controls, has publicly announced its intention to sell 50 million shares, or 5.9% of our share capital, in the form of DSs. Such sale and the perception of any future sales by the Government, could adversely affect the trading price of our DSs. In addition, our $350,000,000 high-yield premium exchangeable redeemable bonds become due in November 2003. To finance the redemption of these bonds we intend some time prior to November 2003 to exercise a put option entered into at the time of the issue of the bonds that will require a subsidiary of LUKOIL Garant, a related party, to purchase up to 7.9 million ordinary shares from us at a price substantially above current market price. LUKOIL Garant currently holds directly or indirectly approximately 100 million of our ordinary shares. If LUKOIL Garant or such subsidiary of LUKOIL Garant sells into the market the ordinary shares it holds and/or those it must buy from us if we exercise our put option, the trading price for our DSs could be adversely affected. In addition, certain of our Directors and executive officers hold through various entities significant amounts of our shares, which, if sold in the market, could adversely affect the trading prices of our shares or DSs. See "Part 6 – Management." Each of Capital Group and NIKoil also owns a substantial portion of our share capital and the same risks apply. See "Part 11 – Additional Information – Principal Interests in the Company."

BP acquired ARCO in April 2000. ARCO owned approximately 7% of our ordinary shares when it was acquired by BP. In 2001 BP reduced its acquired interest in our ordinary shares through a combined placement of DSs representing our ordinary shares and an offering of bonds exchangeable into DSs representing 23.5 million of our ordinary shares. The terms of these bonds allow BP, until February 9, 2003, to call the bonds in exchange for the shares if our shares trade at or above $18.75 for 20 consecutive trading days. After February 9, 2003, BP can call the bonds at any time. If BP calls these bonds in exchange for the DSs, the trading price for our DSs could be adversely affected.

Terrorist activity and global instability could have an adverse effect on our business and share price.
On September 11, 2001 terrorist attacks were conducted against multiple targets in the United States causing the loss of many lives and extensive property damage. These events and their aftermath have had a significant effect on international financial and commodities markets. Any future acts of terrorism of similar magnitude could have an adverse effect on the international financial and commodities markets, the global economy and world oil prices. A significant reduction in global oil consumption and/or world oil prices could materially adversely affect our business and results of operations.

RISKS RELATING TO OUR DEPOSITARY SHARES

Because under Russian law the depositary may be considered the owner of the shares underlying the DSs, these shares may be arrested or seized in legal proceedings in Russia against the depositary.
Because Russian law may not recognise DS holders as beneficial owners of the underlying shares, it is possible that DS holders could lose all their rights to those shares if the deposited shares in Russia are seized or arrested.

Russian law treats an unlicenced depositary as the owner of the shares underlying the DSs. This is different from the way other jurisdictions, such as the United Kingdom and the states of the United States, treat DSs. In those jurisdictions, although shares may be held in the depositary's name or to its order thereby making it the "legal" owner of the shares, the DS holders are the "beneficial," or real owners. In those jurisdictions, no action against the depositary, the legal owner, would result in the beneficial owners losing their shares. Because Russian law may not make the same distinction between legal and beneficial ownership, it may only recognise the rights of the unlicenced depositary in whose name the shares are held, not the rights of DS holders, to the underlying shares.

Thus, in proceedings brought against an unlicenced depositary, whether or not related to shares underlying DSs, Russian courts may treat those underlying shares as the assets of the depositary, open to seizure or arrest. We do not know yet whether the shares underlying DSs may be seized or arrested in a Russian legal proceeding against a depositary. In the past, in connection with a lawsuit filed against The Bank of New York, the plaintiff sought the seizure of various Russian companies' shares held by the bank's nominee in Russia. The lawsuit was settled with no impact on the shares or the DSs. In the event that this type of suit were successful in the future against a depositary bank, and if the shares are seized or arrested, the DS holders involved would lose their rights to the underlying shares.

Failure by the depositary to comply with Russian law could lead to the loss of your investment.
Given that under Russian law the depositary may be viewed as the full owner of the shares underlying the DSs, the depositary may need to comply with various Russian legal requirements regarding aggregate share ownership in a Russian company. For example, under Russian law, a person must receive the prior approval of the Russian Ministry for Anti-Monopoly Policy and Support of Enterpreneurship before holding more than 20% of voting rights of a company the size of OAO LUKOIL. The depositary for our DS programs, however, has not received such approval. This failure could lead to a judicial determination that the holding of ordinary shares by the depositary in excess of 20% of our total ordinary shares is null and void, which could result in DS holders losing their investment.

Because the rights of depositaries are not well developed in Russia, DS holders may be unable to exercise their voting rights and may not be able to obtain some of the benefits due to them as holders of DSs.
The Russian Federal Law on the Securities Markets provides that shares may be held only by owners, nominees or trust managers. Under Russian law, foreign depositary banks that provide nominee services in Russia without the appropriate depositary licences are deemed to be owners of the shares that they hold that underlie the DSs. Russian law does not provide for the ability of an owner of shares to split its vote on matters subject to a vote of the shareholders. Therefore, a foreign depositary bank may be unable to vote the shares it holds on behalf of DS holders other than as a block. This could result in a holder of our DSs effectively being unable to exercise voting rights if their vote does not correspond to the block vote submitted by the foreign depositary bank.

Voting rights with respect to DSs are further limited by the terms of the relevant depositary agreement, which may prevent or delay the ability of DS holders to exercise their rights.
DS holders may exercise such voting rights as they may have with respect to the ordinary shares represented by DSs only in accordance with the provisions of the relevant depositary agreement. However, there are practical limitations with respect to their ability to exercise their voting rights due to the additional procedural steps involved in communicating with them. For example, our charter requires us to notify shareholders at least 20 days in advance of any general meeting. Holders of our ordinary shares receive notice directly from us and are able to exercise their voting rights either by attending the meeting in person or voting by proxy.

DS holders by comparison do not receive notice directly from us. Rather, in accordance with the depositary agreement, we provide the notice to the depositary. In turn, the depositary mails to DS holders the notice of such meeting, voting instruction forms and a statement as to the manner in which instructions may be given by DS holders. To exercise their voting rights, DS holders must then instruct the depositary how to vote the shares underlying the DSs. Because of this extra procedural step involving the depositary, the process for exercising voting rights may take longer for DS holders than for holders of ordinary shares. If this occurs, DS holders generally will not be able to exercise any voting rights attaching to the DSs with respect to the ordinary shares that underlie them.

You may not be able to benefit from the U.K.-Russia or U.S.-Russia double tax treaties.
The Russian tax rules applicable to U.K. and U.S. holders of shares or DSs representing shares are characterised by numerous uncertainties and by an absence of interpretive guidance. Russian tax authorities have not provided any guidance regarding the treatment of DS arrangements, and there can be no guarantee as to how the Russian tax authorities will ultimately treat those arrangements. In particular, it is unclear whether Russian tax authorities will treat U.K. and U.S. DS holders as the beneficial owners of dividends and other proceeds relating to the underlying shares for purposes of the U.K.-Russia and U.S.-Russia double tax treaties. If the Russian tax authorities do not treat U.K. or U.S. DS holders as the beneficial owners of such dividends or proceeds, then the U.K. or U.S. DS holders would not be able to benefit from the provisions of the U.K.-Russia and U.S.-Russia double tax treaties.

RISKS RELATING TO THE RUSSIAN FEDERATION

Political Risks
Since 1991, Russia has sought to transform itself from a one-party state with a centrally planned economy to a pluralist democracy with a market-oriented economy. As a result of the sweeping nature of the reforms and the failure of some of them, the Russian political system remains vulnerable to popular dissatisfaction, as well as to unrest by particular social and ethnic groups. Significant political instability could have a material adverse effect on the value of foreign investments in Russia, including the value of our securities.

Governmental instability could adversely affect the value of investments in Russia.
The composition of the Russian government (the prime minister and the other heads of federal ministries) has at times been highly unstable. For example, six different prime ministers headed governments between March 1998 and May 2000. On December 31, 1999, President Yeltsin unexpectedly resigned and Vladimir Putin was subsequently elected president on March 26, 2000. President Putin has maintained governmental stability and the general direction of reform. However, there can be no assurance that the government will not change or adopt a different approach over time. The value of investments in Russia could be reduced and our prospects could be harmed if governmental instability recurs or if reform policies are reversed.

Conflict between federal and regional authorities and other conflicts could create an uncertain operating environment that would hinder our long-term planning ability and could adversely affect the value of investments in Russia.

The Russian Federation consists of 89 political units in addition to the federal government, some of which exercise considerable power over their internal affairs pursuant to agreements with the federal authorities. In practice, the division of authority between federal and regional governmental authorities remains uncertain and contested. This uncertainty could hinder the operation and the expansion of our business.

Additionally, ethnic, religious, historical and other divisions have, on occasion, given rise to communal tensions and military conflict. From 1994 to 1996 and since 1999, Russian military forces have been engaged in operations in Chechnya, bringing normal economic activity within Chechnya to a halt and disrupting the economy of the neighboring regions. The spread of violence, or political measures taken to counter violence, such as the imposition of a state of emergency, could hinder the operation and the expansion of our business.

Economic Risks

Economic instability in Russia could adversely affect our business.

Since the dissolution of the Soviet Union, the Russian economy has experienced at various times:

- significant declines in gross domestic product;
- hyperinflation;
- an unstable currency;
- high government debt relative to gross domestic product;
- a weak banking system providing limited liquidity to Russian enterprises;
- high levels of loss-making enterprises that continued to operate due to the lack of effective bankruptcy proceedings;
- significant use of barter transactions and illiquid promissory notes to settle commercial transactions;
- widespread tax evasion;
- growth of a black and grey market economy;
- pervasive capital flight;
- high levels of corruption and the penetration of organised crime into the economy;
- significant increases in unemployment and underemployment; and
- the impoverishment of a large portion of the Russian population.

The Russian economy has been subject to abrupt downturns. In particular, on August 17, 1998, in the face of a rapidly deteriorating economic situation, the Russian government defaulted on its ruble-denominated securities, the Central Bank stopped its support of the ruble and a temporary moratorium was imposed on certain hard currency payments. These actions resulted in an immediate and severe devaluation of the ruble and a sharp increase in the rate of inflation; a dramatic decline in the prices of Russian debt and equity securities; and an inability of Russian issuers to raise funds in the international capital markets.

These problems were aggravated by the near collapse of the Russian banking sector after the events of August 17, 1998, as evidenced by the revocation of the banking licences of a number of major Russian banks. This further impaired the ability of the banking sector to act as a consistent source of liquidity to Russian companies, and resulted in the losses of bank deposits in some cases.

There can be no assurance that recent trends in the Russian economy – such as the increase in the gross domestic product, a relatively stable ruble, and a reduced rate of inflation – will continue or will not be abruptly reversed. Moreover, the recent fluctuations in international oil and gas prices, the strengthening of the ruble in real terms relative to the U.S. dollar and the consequences of a relaxation in monetary policy, or other factors, could adversely affect Russia's economy and our business in the future.

Russia's physical infrastructure is in very poor condition, which could disrupt normal business activity.
Russia's physical infrastructure largely dates back to Soviet times and has not been adequately funded and maintained over the past decade. Particularly affected are the rail and road networks; power generation and transmission; communication systems; and building stock. During the winter of 2000-2001, electricity and heating shortages in Russia's far-eastern Primorye region seriously disrupted the local economy. In August 2000, a fire at the main communications tower in Moscow interrupted television and radio broadcasting and the operation of certain mobile phone companies for weeks. Road conditions throughout Russia are poor, with many roads not meeting minimum quality requirements. The federal government is actively considering plans to reorganise the nation's rail, electricity and telephone systems. Any such reorganisation may result in increased charges and tariffs while failing to generate the anticipated capital investment needed to repair, maintain and improve these systems.

The deterioration of Russia's physical infrastructure harms the national economy, disrupts the transportation of goods and supplies, adds costs to doing business in Russia and can interrupt business operations, and this could have a material adverse effect on our business.

Failure by the Russian government to restore access to international sources of funding or the international capital markets could have a material adverse effect on the value of investments in Russia.
Russia in the past has received substantial funding from several foreign governments and international organisations and through international capital markets transactions. After the events of August 17, 1998, none of the above sources of financing were available to Russia. If no further financing is made available, or if no agreement is reached with the Paris Club, the Russian government may not receive further financial support from international organisations and foreign governments and may not be able to repay its debts. Moreover, the Russian government has not raised financing on the international capital markets since July 1998.

The failure of the Russian government to obtain international funding, or to gain access to the international capital markets, could lead to direct or indirect monetary financing of any future budget deficit, putting further pressure on inflation and the value of the ruble, which in turn could have a material adverse effect on our business and the value of foreign investments in Russia.

Fluctuations in the global economy may adversely affect Russia's economy and our business.
Russia's economy is vulnerable to market downturns and economic slowdowns elsewhere in the world. As has happened in the past, financial problems or an increase in the perceived risks associated with investing in emerging economies could dampen foreign investment in Russia and adversely affect the Russian economy. Additionally, because Russia produces and exports large amounts of oil, the Russian economy is especially sensitive to the price of oil on the world market, and a decline in the price of oil could slow or disrupt the Russian economy. These developments could severely limit our access to capital and could adversely affect the purchasing power of our customers and thus our business.

Social Risks

Crime and corruption could disrupt our ability to conduct our business and could materially adversely affect our financial condition and results of operations.
The political and economic changes in Russia since the early 1990s have resulted in reduced policing of society and increased lawlessness. Reportedly, organised criminal activity has increased significantly since the dissolution of the Soviet Union, particularly in large metropolitan centers. Property crime in large cities has also increased substantially. In addition, the Russian and international press have reported high levels of official corruption in Russia and other countries of the Commonwealth of Independent States, or the CIS, including the bribing of officials for the purpose of initiating investigations by government agencies. Press reports have also described instances in which government officials have engaged in selective investigations and prosecutions to further interests of the government and individual officials. Additionally, published reports indicate that a significant number of Russian media regularly publish biased articles in return for payment. Our operations could be adversely affected by illegal activities, corruption or claims implicating us in illegal activities, which could materially adversely affect our business.

Social instability could increase support for renewed centralised authority, nationalism or violence and thus materially adversely affect our ability to conduct our business effectively.
The failure of the government and many private enterprises to pay full salaries on a regular basis and the failure of salaries and benefits generally to keep pace with the rapidly increasing cost of living have led in the past, and

could lead in the future, to labour and social unrest. For example, in 1998, miners in several regions of Russia, demanding payment of overdue wages, resorted to strikes that included blocking major railroads. Such labour and social unrest may have political, social and economic consequences, such as increased support for a renewal of centralised authority; increased nationalism, with restrictions on foreign involvement in the economy of Russia; and increased violence. Any of these could restrict our operations and lead to the loss of revenue, materially adversely affecting us.

Risks Relating to the Russian Legal System and Russian Legislation

Weaknesses relating to the Russian legal system and Russian legislation create an uncertain environment for investment and for business activity.
Russia is still developing the legal framework required by a market economy. Several fundamental Russian laws have only recently become effective. The recent nature of much of Russian legislation and the rapid evolution of the Russian legal system place the enforceability and underlying constitutionality of laws in doubt and result in ambiguities, inconsistencies and anomalies. In addition, Russian legislation often leaves substantial gaps in the regulatory infrastructure. Among the risks of the current Russian legal system are:

- since 1991, Soviet law has been largely, but not entirely, replaced by a new legal regime as established by the 1993 Federal Constitution, the 1995 Civil Code and by other federal laws, and by decrees, orders and regulations issued by the president, the government and federal ministries, which are, in turn, complemented by regional and local rules and regulations. These legal norms, at times, overlap or contradict one another;
- limited judicial and administrative guidance on interpreting Russian legislation;
- the relative inexperience of judges in interpreting Russian legislation;
- a high degree of discretion on the part of governmental authorities; and
- bankruptcy procedures that are not well developed and are subject to abuse.

All of these weaknesses could affect our ability to enforce our rights under contracts, or to defend ourselves against claims by others.

Lack of independence and inexperience of certain members of the judiciary and the difficulty of enforcing court decisions and governmental discretion in instigating, joining and enforcing claims could prevent us or you from obtaining effective redress in a court proceeding, including in respect of expropriation or nationalisation.
The independence of the judicial system and its immunity from economic, political and nationalistic influences in Russia remain largely untested. The court system is understaffed and underfunded. Judges and courts are generally inexperienced in the area of business and corporate law. Russia is a civil law jurisdiction and, as such, judicial precedents have no binding effect on subsequent decisions. In addition, most court decisions are not readily available to the public. Enforcement of court judgments can in practice be very difficult in Russia. All of these factors make judicial decisions in Russia difficult to predict and effective redress uncertain. Additionally, court claims are often used in furtherance of political aims. We may be subject to such claims and may not be able to receive a fair hearing. Additionally, court judgments are not always enforced or followed by law enforcement agencies.

These uncertainties also extend to property rights. During Russia’s transformation from a centrally planned economy to a market economy, legislation has been enacted to protect private property against expropriation and nationalisation. However, it is possible that due to the lack of experience in enforcing these provisions and due to political changes, these protections would not be enforced in the event of an attempted expropriation or nationalisation. Some government entities have tried to invalidate earlier privatisations. Expropriation or nationalisation of any of our entities, their assets or portions thereof, potentially with little or no compensation, would have a material adverse effect on us.

Unlawful or arbitrary government action may have an adverse effect on our business.
Government authorities have a high degree of discretion in Russia and at times exercise their discretion arbitrarily, without hearing or prior notice, and sometimes in a manner that is contrary to law. Moreover, the government also has the power in certain circumstances, by regulation or government act, to interfere with the performance of, nullify or terminate contracts. Unlawful or arbitrary governmental actions have included withdrawal of licences, sudden and unexpected tax audits, criminal prosecutions and civil actions. Federal and local government entities have also used

common defects in matters surrounding share issuances and registration as pretexts for court claims and other demands to invalidate such issuances and registrations and/or to void transactions, often for political purposes. Unlawful or arbitrary government action, if directed at us, could have a material adverse effect on our business.

Shareholder liability under Russian legislation could cause us to become liable for the obligations of our subsidiaries.

The Civil Code, the Federal Law on Joint Stock Companies and the Federal Law on Limited Liability Companies generally provide that shareholders in a Russian joint stock company and members of a Russian limited liability company are not liable for the obligations of the company and bear only the risk of loss of their investment. An exception to this rule, however, is when one company is capable of determining decisions of another company. A company capable of determining such decisions is called an effective parent. The company whose decisions are capable of being so determined is called an effective subsidiary. Under certain circumstances the effective parent bears joint and several responsibility for transactions concluded by the effective subsidiary in carrying out these decisions. In addition, an effective parent is secondarily liable for an effective subsidiary's debts if an effective subsidiary becomes insolvent or bankrupt resulting from the action or inaction of an effective parent. Accordingly, in our position as effective parent of the subsidiaries in which we own, directly or indirectly, more than 50% of the charter capital or for which we are capable of determining decisions, we could be liable for their debts, subject to the limitations described in "Part 11 – Additional Information – Liability of Shareholders." The total debt of our subsidiaries for which we are an effective parent, as of December 31, 2001 was $2.7 billion, excluding intercompany loans. This liability, which is secondary in the case of the subsidiary's insolvency or bankruptcy or joint and several with the liability of the subsidiary in the case of responsibility for transactions concluded by the subsidiary in carrying out our mandatory directions, could materially adversely affect us.

There is little effective protection of minority shareholders in Russia.

In general, minority shareholder protection under Russian law derives from supermajority or other special shareholder approval requirements for certain corporate action (including "interested party" transactions discussed in more detail below), as well as from the ability of a shareholder to demand that the company purchase the shares held by that shareholder if that shareholder voted against or abstained from voting on certain types of action. While these protections are similar to the types of protections available to minority shareholders in the U.K., in practice corporate governance standards for many Russian companies have proven to be poor, and minority shareholders in Russian companies have suffered losses due to abusive share dilutions, asset transfers and transfer-pricing practices. Shareholder meetings have been irregularly conducted, and shareholder resolutions have not always been respected by management.

In addition, where they apply, the supermajority shareholder approval requirement is met by a vote of 75% of all voting shares that are present at a shareholders' meeting. Thus, controlling shareholders owning slightly less than 75% of outstanding shares of a company may have a 75% or more voting power if certain minority shareholders are not present at the meeting. In situations where controlling shareholders effectively have 75% or more of the voting power at a shareholders' meeting, they are in a position to approve amendments to the charter of the company, which could be prejudicial to the interests of minority shareholders.

Disclosure and reporting requirements and anti-fraud legislation have been enacted in Russia only recently. Most Russian companies and managers are not accustomed to restrictions on their activities arising from these requirements. The concept of fiduciary duties of management or directors' duties to their companies or shareholders is also relatively new and is not well developed. Violations of disclosure and reporting requirements or breaches of fiduciary duties to us and our subsidiaries or to our shareholders could materially adversely affect the value of our securities.

While the Federal Law on Joint Stock Companies provides that shareholders owning not less than 1% of the company's ordinary shares may bring an action for damages on behalf of the company, Russian courts do not to date have experience with such suits. Russian corporate law does not contemplate class action litigation. Accordingly, a foreign investor's practical ability to pursue legal redress against us may be limited.

Some transactions between us and interested parties or affiliated companies require the approval of disinterested directors or shareholders and our failure to obtain approvals could cause our business to suffer.

We are required by Russian law and our charter to obtain the approval of disinterested directors or shareholders for certain transactions with "interested parties."

Under Russian law, the definition of an “interested party” includes members of the board of directors and members of any management body of a company, the CEO of the company, the managing company of the company (if any), and any person that owns, together with that person’s close relatives and affiliates, at least 20% of the company’s voting shares or a person who has the right to give mandatory instructions to the company if any of the above listed persons, or a close relative or affiliate of such person, is:

- a party to a transaction with the company, whether directly or as a representative or intermediary, or a beneficiary to the transaction;
- the owner, together with any close relatives and affiliates, of at least 20% of the shares in the company that is a counterparty to a transaction, whether directly or as a representative or intermediary, or a beneficiary to the transaction; or
- a member of the board of directors or any management body of the company or the managing company of such company that is a counterparty to a transaction, whether directly or as a representative or intermediary, or a beneficiary to the transaction.

Due to the technical requirements of Russian law, entities within our consolidated group may be deemed to be “interested parties” with respect to certain transactions between themselves. The failure to obtain necessary approvals for transactions within our consolidated group could adversely affect our business.

In addition, the concept of “interested parties” is defined with reference to the concepts of “affiliated persons” and “group of persons” under Russian law, which are subject to many different interpretations. Moreover, the provisions of Russian law defining which transactions must be approved as “interested party” transactions are subject to different interpretations. Although we have generally taken a reasonably conservative approach in applying these concepts, we cannot be certain that our application of these concepts will not be subject to challenge. Any such challenge could result in the invalidation of transactions that are important to our business.

Uncoordinated regulation of Russian capital markets could lead to insufficient protection of the rights of holders of our securities.

The Russian securities market is still developing and is regulated by several different authorities that are often in competition with each other. The regulations of these various authorities are not always coordinated and may be contradictory. This could reduce the protection available to holders of our securities.

Part 4 – MANAGEMENT’S DISCUSSION AND ANALYSIS OF FINANCIAL CONDITION AND RESULTS OF OPERATIONS

You should read the following discussion and analysis of our financial condition and results of operations as of December 31, 2000 and 2001 and for the years ended December 31, 1999, 2000 and 2001 in conjunction with our audited consolidated financial statements and related notes contained in “Part 7 – Financial Information.” A discussion of our current trading and prospects may be found in “Part 2 – Key Information – Current Trading and Prospects” and our unaudited financial statements as of March 31, 2002 and for the three months ended March 31, 2001 and 2002 may be found in “Part 7 – Financial Information.”

OVERVIEW

We are the largest publicly traded oil company in the world in terms of proven crude oil reserves and we are Russia’s largest producer of crude oil. In accordance with accounting principles generally accepted in the United States of America, or U.S. GAAP, for the year ended December 31, 2001, we had total sales of $13.4 billion (2000: $13.2 billion), net income of $2.1 billion (2000: $3.3 billion) and we produced approximately 532 mmboe (2000: 529 mmboe).

Our operations are divided into two main business segments:

- Exploration and Production, which includes our exploration, development and production operations relating to crude oil and natural gas. These activities are primarily located within Russia, with additional activities in Azerbaijan, Kazakstan, the Middle East, Northern Africa and Colombia; and
- Refining, Marketing and Distribution, which includes trading and sales of crude oil, natural gas and refined products, and refining and shipping operations.

Other businesses, which include petrochemicals, banking and finance, insurance, construction and other activities, are not significant to our overall results of operations and, therefore, are not discussed in detail in this section.

Each of our two main segments is dependent on the other, with a portion of the revenues of one segment being a part of the costs of the other. In particular, our Refining, Marketing and Distribution segment purchases crude oil from our Exploration and Production segment. The prices set for these purchases reflect a combination of factors, including our need for investment capital at different entities in the Exploration and Production segment, our tax planning initiatives, the rights of minority shareholders in those entities where minority interests remain and, to a more limited extent, market factors. Accordingly, an analysis of either of these segments on a stand-alone basis could give a misleading impression of that segment’s underlying financial position and results of operations. For this reason, we do not analyse either of our main segments separately in the discussion that follows, but we do present the financial data for each in Note 19 to our consolidated financial statements included herein. Due to the prices we set, we believe the profitability of our Exploration and Production segment may be understated and the profits of our Refining, Marketing and Distribution segment may be overstated in that presentation.

CRITICAL ACCOUNTING POLICIES

Our consolidated financial statements included herein have been prepared on the basis of U.S. GAAP. These financial statements are not our statutory financial statements, which are prepared annually and presented in accordance with Russian accounting regulations, or RAR. Differences exist between the requirements of RAR and those of U.S. GAAP. Accordingly, the consolidated financial statements under U.S. GAAP differ in material respects from our statutory financial statements. The accounting policies in this section refer to our accounting policies under U.S. GAAP.

We have adopted the U.S. dollar as our functional currency since the Russian economy is hyperinflationary and SFAS No. 52 “Foreign Currency Translation” requires us to use our reporting currency as our functional currency. We have chosen the U.S. dollar as our reporting currency as we believe that it is the currency in which we do the majority of our business, although inflationary pressures still need to be considered when reviewing our U.S. GAAP results. Our U.S. GAAP financial statements include accounting policies, which are specific to the oil and gas sector, such as those relating to accounting for oil and gas properties and abandonment and restoration costs. In this respect, where U.S. GAAP allows choice as to the accounting policies to be adopted, we have applied the policies which we consider to be best practice for oil and gas companies.

Principles of consolidation

The financial position and results of subsidiaries of which we directly or indirectly own more than 50% of the voting interest and which we control, are included with our financial position and results in the consolidated financial statements. All significant intercompany transactions are eliminated.

Other significant investments in companies of which we directly or indirectly own between 20% and 50% of the voting interest and over which we exercise significant influence but not control, are accounted for using the equity method of accounting.

In instances where we participate in non-corporate joint ventures, such as production sharing agreements, we include, in our consolidated financial statements, our proportionate interest in the income statements and balance sheets of the joint ventures. During 1999, 2000 and 2001, our investments, accounted for under this method, were the production sharing agreements relating to the Azeri-Chirag-Gunashli project in Azerbaijan and the Karachaganak project in Kazakstan.

Investments in other companies are included at cost or fair value.

Use of estimates

The preparation of financial statements, in accordance with U.S. GAAP, requires us to make estimates and assumptions that affect the reported amounts of assets, liabilities, revenues and expenses. Significant estimates and judgements regarding the probability that potential liabilities will crystallise include environmental and site restoration liabilities, taxation provisions and provisions against asset carrying values. Actual amounts could differ from such estimates and such amounts could materially affect our results of operations and financial condition.

Property, plant and equipment

Our oil and gas properties are accounted for using the successful efforts method of accounting, whereby the costs of property acquisitions, successful exploratory wells, development costs, and support equipment and facilities are capitalised. The costs of unsuccessful exploratory wells are expensed when a well is determined to be non-productive. Other exploratory expenditures, including geological and geophysical costs, are expensed as incurred.

Depreciation, depletion and amortisation of capitalised costs of oil and gas properties are calculated using the unit-of-production method based upon proven reserves for the cost of property acquisitions and proven developed reserves for exploration and development costs. Estimated costs of dismantling oil and gas production facilities, including abandonment and site restoration costs are included as a component of depreciation, depletion and amortisation.

Production and related overhead costs are expensed as incurred.

Impairment of long-lived assets

Long-lived assets, including oil and gas properties and goodwill, were assessed for possible impairment in accordance with Statement of Financial Accounting Standards, or SFAS, No. 121, “Accounting for the impairment of Long-Lived Assets and for Long-Lived Assets to Be Disposed Of,” prior to January 1, 2002, and in accordance with SFAS No. 144, “Accounting for the Impairment or Disposal of Long-Lived Assets” effective January 1, 2002. The standards require that long-lived assets with recorded values which are not expected to be recovered through future cash flows from these assets be written down to current fair value. Fair value is generally determined by reference to discounted estimated future net cash flows. Permanent impairment of the carrying value of long-lived assets is assessed by comparing the carrying value against the undiscounted projection of net future pre-tax cash flows. Where an assessment has indicated impairment in value, the long-lived assets are written down to their fair value, as determined by the discounted projection of net future pre-tax cash flows.

Proven oil and gas reserves

Estimates of our physical quantities of oil and gas reserves are determined by independent reserve engineers. Engineering estimates of the quantities of recoverable oil and gas fields are inherently imprecise and represent only approximate amounts because of the subjective judgments involved in developing such information. Despite the inherent imprecision in these engineering estimates, U.S. accounting rules require supplemental disclosure of “proven” oil and gas reserves estimates in order to facilitate understanding of the perceived value and future cash flows of a company’s oil and gas operations. The estimation of proven oil and gas reserves is also important to the income statement, because the proven oil and gas reserves estimate for a field serves as the denominator in the units-of-production calculation of depreciation, depletion and amortisation of the capitalised costs of the field.

Proven oil and gas reserves are the estimated quantities of crude oil, natural gas and natural gas liquids which geological and engineering data demonstrate with reasonable certainty to be recoverable in future years from known reservoirs under existing economic and operating conditions. The process of estimating oil and gas reserves is very complex, requiring significant decisions in the evaluation of all available geological, geophysical, engineering and economic data. Estimated oil and gas reserves are based on available reservoir data and are subject to future revision. Significant portions of our undeveloped reserves require the installation or completion of related infrastructure facilities such as pipelines and the drilling of development wells. Proven reserves estimates are updated annually and take into account recent production and seismic information about each field.

Revenue recognition

Revenues from the production and sale of crude oil and petroleum products are recognised when title passes to customers. Revenues from non-cash sales are recognised at the fair market value of the crude oil and petroleum products sold.

Foreign currency translation

The accounting records of our operations in the Russian Federation are maintained in rubles, and we prepare our statutory financial statements and reports in that currency in accordance with the laws of the Russian Federation.

For operations in the Russian Federation, hyperinflationary economies or operations where the U.S. dollar is the functional currency, monetary assets and liabilities have been translated into U.S. dollars at the rate prevailing at each balance sheet date. Non-monetary assets and liabilities have been translated into U.S. dollars at historical rates. Revenues, expenses and cash flows have been translated into U.S. dollars at rates that approximate actual rates at the date of the transaction. Translation differences resulting from the use of these rates are included in the consolidated statement of income.

For the majority of operations outside the Russian Federation, the U.S. dollar is the functional currency. For certain other operations outside the Russian Federation where the U.S. dollar is not the functional currency and the economy is not hyperinflationary, assets and liabilities are translated into U.S. dollars at the exchange rates prevailing at each balance sheet date and revenues and expenses are translated at average exchange rates for the year. Resulting translation adjustments are reflected as a separate component of stockholders' equity.

As of the December 31, 2000 and 2001 balance sheet dates, exchange rates of 28.16 and 30.14 rubles, respectively, to the U.S. dollar have been used for translation purposes.

Derivative financial instruments

We have not historically made significant use of derivative financial instruments. Effective January 1, 2001, we adopted SFAS No. 133, "Accounting for Derivative Instruments and Hedging Activities" and SFAS No. 138, "Accounting for Certain Derivative Instruments and Hedging Activities – An Amendment of FASB Statement 133." SFAS No. 133 and SFAS No. 138 established new accounting and reporting standards for derivative instruments and hedging activities and require recognition of all derivatives as assets or liabilities in the balance sheet and measurement of those instruments at fair value. The effect of the adoption of these standards on our operations and consolidated financial statements was not material because of our limited use of derivative instruments.

Contingencies

Certain conditions may exist as of balance sheet dates, which may result in losses but the impact of which will only be resolved when one or more future events occur or fail to occur.

General Contingencies

If our assessment of a contingency indicates that it is probable that a material loss will arise and the amount of the liability can be estimated, then the estimated liability is accrued and charged to the consolidated statement of income. If our assessment indicates that a potentially material loss is not probable, but is reasonably possible, or is probable, but cannot be estimated, then the nature of the contingent liability is disclosed in the notes to the consolidated financial statements. Loss contingencies considered remote are generally not disclosed unless they involve guarantees, in which case the nature of the guarantee is disclosed.

Environmental
Estimated losses from environmental remediation obligations are generally recognised no later than completion of remedial feasibility studies. We accrue for losses associated with environmental remediation obligations when such losses are probable and reasonably estimable. Such accruals are adjusted as further information becomes available or circumstances change. Costs of expected future expenditures for environmental remediation obligations are not discounted to their present value. See “Part 5 – Business – Health, Safety and Environment.”

Taxation
The taxation systems in the Russian Federation and other emerging markets where we operate are relatively new and are characterised by numerous taxes and changing legislation, which may be applied retroactively and is sometimes unclear, contradictory and subject to interpretation. Taxes are subject to review and investigation by a number of authorities, which may impose severe fines, penalties and interest charges. We implement tax planning and management strategies based on our understanding of legislation existing at the time of implementation and provide for income tax liabilities in accordance with our understanding of the legislation. However, the relevant authorities may have differing interpretations of such legislation. We assess the status of our tax reviews and investigations in process by the tax authorities and consider the need to accrue additional liabilities and/or disclose such matters on the basis of the methodology described above under “– General Contingencies.” See also “– Certain Factors Affecting Our Results of Operations – Tax Burden.”

Recent accounting pronouncements
In June 2001 the Financial Accounting Standards Board, or FASB, issued SFAS No. 141, “Business Combinations.” SFAS No. 141 requires that the purchase method of accounting be used for all business combinations initiated after June 30, 2001 and specifies that certain intangible assets be recognised apart from goodwill. We adopted SFAS No. 141 during 2001.

Effective January 1, 2002 we adopted SFAS No. 142, “Goodwill and Other Intangible Assets.” Under SFAS No. 142, goodwill and intangible assets with indefinite useful lives are no longer amortised, but are instead tested for impairment at least annually. SFAS No. 142 requires that intangible assets with definite useful lives be amortised over their respective estimated useful lives. Beginning January 1, 2002, effective with the adoption of SFAS No. 142, we discontinued the amortisation of goodwill.

In connection with the transitional goodwill impairment test required by SFAS No. 142, we are required to perform an assessment of whether there is an indication that goodwill is impaired as of the adoption date. To perform this assessment, we are first required to determine the fair value of our reporting units and compare such fair value to each reporting unit’s carrying value by June 30, 2002. If the reporting unit’s carrying value exceeds its fair value, an indication exists that the reporting unit’s goodwill may be impaired and we must perform the second step of the transitional impairment test. In the second step, we must compare the implied fair value of our reporting unit’s goodwill to its carrying value, both of which are to be measured as of January 1, 2002. The second step is required to be completed as soon as possible, but no later than the end of 2002. Any transitional impairment will be recognised as the cumulative effect of a change in accounting principle in our 2002 consolidated statement of income. We are currently completing the transitional impairment test. As of January 1, 2002 we had unamortised goodwill of $221 million.

In July 2001 the FASB issued SFAS No. 143, “Accounting for Asset Retirement Obligations.” SFAS No. 143 requires entities to record the fair value of a liability for an asset retirement obligation in the period in which it is incurred and a corresponding increase in the carrying amount of the related long-lived asset. Subsequently, the liability will be accreted for for the passage of time and the related asset will be depreciated over its estimated useful life. We are required to adopt SFAS No. 143 effective January 1, 2003. We are currently evaluating the impact of adopting SFAS No. 143.

Effective January 1, 2002 we adopted SFAS No. 144, “Accounting for the Impairment or Disposal of Long-Lived Assets.” SFAS No. 144 addresses financial accounting and reporting for the impairment or disposal of long-lived assets. The adoption of this standard had no significant impact on our consolidated financial statements.

In April 2002 the FASB issued SFAS No. 145, “Rescission of FASB Statements No. 4, 44, and 64, Amendment of FASB Statement No. 13 and Technical Corrections.” SFAS No. 145 primarily addresses income statement classification of gains and losses on extinguishments of debt and accounting for certain lease modifications that have economic effects similar to sale-leaseback transactions. We are required to adopt SFAS No. 145 effective January 1, 2003. We are currently evaluating the impact of adopting SFAS No. 145.

Major acquisitions and structural changes

Our financial condition and results of operations have been affected by acquisitions in each of the years in the three-year period ended December 31, 2001. Each of these acquisitions was accounted for using the purchase method of accounting and was reflected in our consolidated financial statements from the date of acquisition.

In a series of transactions from April 1998 through December 1999, we acquired an 87.3% interest in the Petrotel refinery in Romania. We are in the process of acquiring an additional 6% of Petrotel for $32 million.

In September 1999 we acquired OAO KomiTEK and minority interests held in the KomiTEK group of companies for $619 million, in exchange for LUKOIL shares. KomiTEK is an integrated oil and gas company operating primarily in the Komi Republic of the Russian Federation.

In October 1999 we acquired 58% of Neftochim Burgas AD, which owns the Neftochim refinery in Burgas, Bulgaria, for an effective purchase price of $81 million. During 2000, we purchased our local partner’s carried interest for $45 million in cash and deferred payments of $42 million to be paid over seven years. During the second quarter of 2002, we purchased an additional 12.7% of Neftochim for $30 million, taking our current shareholding to 70.7%.

In May 2000 we acquired 97% of the Odessa Oil Refinery in Ukraine, for $20 million.

In June 2000 we acquired a further 7% of OAO RITEK for $1 million, thereby increasing our ownership stake to 51%. Prior to this acquisition, RITEK was recorded as an associated company using the equity method of accounting. RITEK is an exploration and production company operating in western Siberia.

In June 2000 we acquired a further 14% of ZAO LUKOIL-Perm in exchange for 54% of our interest in OAO Vatoil, a 100% subsidiary conducting exploration and development operations in western Siberia, thereby increasing our ownership stake in LUKOIL-Perm to 64% and reducing our effective interest in Vatoil from 100% to 80%. Prior to this acquisition, LUKOIL-Perm was recorded as an associated company using the equity method of accounting. In October, 2001 we increased our ownership stake in LUKOIL-Perm to 73%. LUKOIL-Perm is an exploration and production company operating in European Russia and western Siberia.

In December 2000 we acquired 72% of Getty Petroleum Marketing Inc. for $53 million. In January 2001, we acquired the remaining 28% for $20 million. Getty is a marketing and distribution company that owns 1,277 retail outlets throughout the northeast and mid-Atlantic regions of the United States.

In December 2000 we acquired a further 32% of OAO KomiArcticOil for $44 million, thereby increasing our ownership stake in it to 53%. Prior to this acquisition, KomiArcticOil was recorded as an associated company using the equity method of accounting. KomiArticOil is an exploration and production company operating in the Komi Republic of Russia.

During 2001 we acquired 74.1% of the shares in OAO Arkhangelskgeoldobycha, or AGD, through a number of transactions. In January 2001, we acquired a 15.7% interest in AGD for $39 million. In March 2001, we acquired 58.4% of the shares in AGD in exchange for 14,930,172 of our ordinary shares and cash consideration of $130 million. AGD is a Russian oil and gas exploration company operating predominantly within the Timan-Pechora region of northern Russia.

In March 2001 we exchanged 720,364 ordinary shares for the remaining 13% and 22% minority shareholdings of OAO LUKOIL Ukhtaneftepererabotka, or the Ukhta refinery, and OAO LUKOIL Kominefteproduct, respectively, taking our interest in each of these companies to approximately 99%. The Ukhta refinery is an oil refinery and LUKOIL Kominefteproduct is a marketing and distribution company. Both companies operate primarily in the Komi Republic of Russia.

In May and December 2001 we acquired 25% and then 35%, respectively, of the share capital of OAO Yamalneftegazdobycha, or YNGD, for $104 million in total. Prior to the December acquisition, YNGD was recorded as an associated company using the equity method of accounting. YNGD is a Russian oil and gas exploration company with significant proved undeveloped reserves predominantly within the Yamal-Nenetsky Autonomous District of northern Russia.

In September 2001 we acquired 100% of the share capital of Bitech Petroleum Corporation for $77 million. Bitech is a Canadian oil exploration company with operations primarily in the Komi Republic of Russia and Egypt.

CERTAIN FACTORS AFFECTING OUR RESULTS OF OPERATIONS

In addition to the factors that may affect the petroleum industry generally, our results of operations are also affected by certain factors specific to operating in the Russian Federation.

The price of crude oil and refined products

The price at which we can sell crude oil and refined products is the primary driver of our revenues. International crude oil and refined product prices increased significantly in 1999 and 2000, whereas they decreased significantly throughout 2001.

World crude oil prices trended upward through most of 2000 on demand growth and limited worldwide supply and eased somewhat late in 2000 as major crude oil exporting countries increased output and global demand growth began to slow. Slow demand growth due to the global economic slowdown and concern over worldwide production and storage levels contributed to the decline in crude prices in 2001.

Substantially all of the crude oil that we sell for export is Urals blend. The following table shows the yearly average crude oil export prices for 1999, 2000 and 2001:

	Year ended December 31,		
	1999	**2000**	**2001**
Crude oil (average $ per barrel Urals blend – export)..................	$17.10	$27.10	$24.50

Source: Platts

Domestic crude oil prices

Crude oil prices in Russia have remained below world levels primarily due to constraints on the ability of Russian oil companies to export their crude oil, which has led to large regional surpluses in Russia, increased domestic supplies and reduced domestic prices. We bear the Russian transportation costs on all of our export sales and most of our domestic sales. Transportation costs vary widely depending on the origin and destination of the crude oil.

Because substantially all crude oil is produced in Russia by vertically integrated oil companies such as ours, there is no concept of a benchmark domestic market price for crude oil. Most transactions are between affiliated entities or are directed by the Government with little regard to market considerations. There is also a market within Russia for residual crude oil that is produced but not refined or exported by one of the vertically integrated oil companies. Prices for this oil are generally determined on a transaction-by-transaction basis against a background of world market prices, but with no direct reference or correlation. At any time there may exist significant price differences between regions for similar quality crude as a result of the regional imbalances referred to above and competitive and economic conditions in those regions.

We realised for our domestic crude oil sales average prices of $10.83 per barrel in 2001, $16.25 per barrel in 2000 and $5.73 per barrel in 1999.

Domestic refined product prices

Domestic prices for refined products are determined to some extent by world market prices, but they are also directly affected by local demand, competition and prices imposed on government-directed sales. The portion of our domestic refined product sales subject to governmental direction is approximately 23% of domestic tonnes sold but represents less than 17% of our domestic sales revenue from refined products. We realised for our domestic refined products sales average prices of $141.80 per tonne in 2001, $135.33 per tonne in 2000 and $41.27 per tonne in 1999.

Access to markets

The Russian Government places restrictions on access to the Transneft crude oil export pipeline network, which limits our ability to export via this method. The principal reasons for this are:

- a need to ensure that sufficient oil remains in Russia to meet domestic requirements, including supplies to various government controlled or strategically important institutions across the Russian Federation; and
- capacity constraints of the crude oil pipeline network.

Access to the crude oil export pipeline network is allocated quarterly, based on recent volumes produced and delivered through the pipeline and proposed export destinations, and allocations are typically in the region of 30% of production. If a company fails to deliver sufficient oil to meet its allocation it may lose a portion of its access rights.

Occasionally the Government increases export pipeline allocations under arrangements whereby oil companies provide crude oil or refined products to organisations participating in government construction and improvement projects in return for additional export pipeline access. As a result of our participation in these and other government projects, we have exported through Transneft approximately 36% of our crude oil production during the past two years.

Additional constraints on crude oil exports include the lack of deep-water ports and a poorly developed and expensive rail network within Russia.

In addition, constraints are experienced in the sale of oil products as follows:

- Government intervention – the Russian Government requires the supply of products to certain strategically important organisations and projects, such as the military and agricultural entities, and to the remote regions of the Russian Federation;
- Export duties – although there are no formal export quotas placed on the export of oil products, the Russian Government varies duties to influence volumes exported; and
- Rail tankers – historically rail tankers were supplied by the Ministry of Railways and well maintained tankers were plentiful, but this is no longer the case. We are seeking to expand our rail delivery capacity to further decrease our reliance on Transneft. See "Part 5 – Business – Refining, Marketing and Distribution – Refined Petroleum Product Sales."

The U.S. dollar-ruble exchange rate and inflation

A substantial part of our revenues are either denominated in U.S. dollars or are correlated to some extent with U.S. dollar crude oil prices, while most of our costs (other than debt service costs) are denominated in rubles. Therefore, the movements of ruble inflation and exchange rates significantly affect the results of our operations. In particular, our operating margins are generally adversely affected by a real appreciation of the ruble against the U.S. dollar (i.e., by an inflation rate that is higher than the rate at which the ruble is devaluing against the U.S. dollar) because this will generally cause our costs to increase in real terms relative to our revenues. Conversely, our operating margins are generally positively affected by a real depreciation of the ruble against the U.S. dollar because this will generally cause our costs to decrease in real terms relative to our revenues. The following table gives data on inflation in Russia, the nominal devaluation and the level of real appreciation.

	Year ended December 31,		
	1999	**2000**	**2001**
Inflation (CPI)	37%	20%	19%
Nominal devaluation (RUR v. U.S.$)	31%	4%	7%
Real appreciation (RUR v. U.S.$)	5%	13%	11%

Tax burden

Given the relative size of our activities in Russia, our tax profile is largely determined by the taxes payable in Russia (based on Russian accounting records – not U.S. GAAP). For 1999, 2000 and 2001 the tax charge on the Russian part of our operations was more than 95% of our total tax charge.

In addition to profits tax, we are subject to a number of other taxes in Russia, many of which are based on revenue or volumetric measures. Geological and royalty taxes, mineral extraction taxes and road taxes are calculated based on the revenue generated from exploration and production activities. Social taxes and contributions are a function of salaries and wages. Other taxes to which we are subject include:

- excise and export tariffs
- property tax
- sales tax and VAT
- minor state duties/licences

- ecological tax
- militia tax
- car owners tax
- share issue tax
- land tax
- housing tax

Our tax strategy is to structure our affairs to limit our overall tax burden, consistent with our understanding of the legal requirements in effect at the time. This has resulted in significant tax savings. Our effective income tax rates for 2001, 2000 and 1999, respectively, were 24%, 19% and 21%, while the statutory income tax rates in Russia were 35%, 30% and 30% in 2001, 2000 and 1999, respectively. The effective rate of total taxes and tariffs (total taxes, including income taxes, taxes other than on income and excise and export tariffs, divided by income before taxes and tariffs) for 2001, 2000 and 1999, respectively, were 60%, 45% and 60%.

Concessions, concessionary rates and allowances reduced our tax charge by approximately $500 million, $700 million and $700 million in 2001, 2000 and 1999, respectively. Costs related to achieving those tax efficiencies amounted to $161 million, $476 million and $235 million in 2001, 2000 and 1999, respectively and were included in selling, general and administrative expenses. In addition, tax benefits from the utilisation of investment tax credits were $325 million, $417 million and $56 million in 2001, 2000 and 1999, respectively.

Effective January 1, 2002 new taxation legislation was adopted by the Russian government. This tax legislation included a number of changes, the most significant of which were:

- a decrease in the maximum income tax rate to 24% from 35%;
- the removal of upper limits on the deductability of expenses considered to be in the normal course of business;
- the removal of investment tax credits;
- the ability to offset exploration expenditure against income tax instead of against mineral replacement taxes; and
- a change in the basis of calculating mineral based taxes to take account of average world market prices rather than the weighted average of domestic and international selling prices.

We believe that, unless mitigated, these and other legislative changes will have the effect of increasing our effective tax rate and our total tax burden. The concessionary rates and allowances we relied on, and the investment tax credits and other elements of our tax strategy, are no longer available, and it may not be possible for us to establish new strategies which facilitate similar tax efficiencies in the future.

The taxation systems in Russia and other emerging markets where we operate are relatively new and are characterised by numerous taxes and changing legislation, which may be applied retroactively and is sometimes unclear, contradictory, and subject to interpretation. Often, differing interpretations exist among different taxation authorities within the same jurisdictions and among taxing authorities in different jurisdictions. Taxes are subject to review and investigation by a number of authorities, which are enabled by law to impose severe fines, penalties and interest charges. Such factors may create taxation risks in Russia and other countries where our companies operate substantially more significant than those in other countries where taxation regimes have been subject to development and clarification over long periods.

The regional organisational structure of the tax authorities and the regional judicial system can mean that issues successfully defended in one region may be unsuccessful in another region. The tax authorities in each region may have a different interpretation of similar issues. There is however some degree of direction provided from the central authority based in Moscow on particular tax issues.

Our tax planning and management strategies were based on our understanding of tax legislation existing at the time of implementation. We are subject to tax authority audits on an ongoing basis, as is normal in the Russian environment, and, at times, the authorities have attempted to impose significant additional taxes on us. We believe that we have adequately met and provided for tax liabilities based on our interpretation of existing tax legislation.

However, the relevant authorities may have differing interpretations and the effects could be significant. See “Part 3 – Risk Factors – Risk Factors Relating to Our Business.”

Barter and non-cash settlements

Historically, in common with other Russian companies, we have entered into agreements to settle a number of transactions by the transfer of goods and services, as opposed to cash. This results principally from the following factors:

- high inflation in Russia;
- unreliable banking services; and
- oil products produced by us are required for the day-to-day operations of a number of our key suppliers.

As the economic climate in Russia has improved, these transactions have decreased significantly.

While the use of barter transactions and illiquid promissory notes to settle commercial transactions continues to be prevalent in Russia, our reliance on such non-cash transactions has decreased as a proportion of the value of transactions; a trend that we believe will continue and may positively affect our cash flows.

	Year ended December 31,		
	1999	**2000**	**2001**
Non cash transactions as a proportion of sales	11.0%	10.6%	9.6%
Non cash investing activities as a proportion of total investing activities	9.5%	8.5%	3.0%

RESULTS OF OPERATIONS

The table below details certain income and expense items from our consolidated statements of income for the periods indicated, expressed in millions of U.S. dollars except per share amounts and the items expressed as a percentage of revenues.

	Year ended December 31,					
	1999		2000		2001	
Revenues						
Sales	7,544	98.8%	13,210	98.3%	13,426	99.0%
Equity share in income of affiliates	88	1.2%	230	1.7%	136	1.0%
Total revenues	**7,632**	**100.0%**	**13,440**	**100.0%**	**13,562**	**100.0%**
Costs and other deductions						
Operating expenses	(2,622)	(34.4%)	(4,225)	(31.4%)	(4,671)	(34.4%)
Selling, general and administrative expenses	(1,623)	(21.3%)	(1,956)	(14.6%)	(2,294)	(16.9%)
Depreciation, depletion and amortisation	(598)	(7.8%)	(838)	(6.2%)	(886)	(6.5%)
Taxes other than income taxes	(527)	(6.9%)	(1,050)	(7.8%)	(1,010)	(7.4%)
Excise and export tariffs	(460)	(6.0%)	(932)	(6.9%)	(1,456)	(10.7%)
Exploration expense	(61)	(0.8%)	(130)	(1.0%)	(144)	(1.1%)
Loss on disposal and impairment of assets	(49)	(0.6%)	(247)	(1.8%)	(153)	(1.1%)
Income from operating activities	**1,692**	**22.2%**	**4,062**	**30.2%**	**2,948**	**21.7%**
Interest expense	(192)	(2.5%)	(198)	(1.5%)	(257)	(1.9%)
Interest and dividend income	73	1.0%	209	1.6%	146	1.1%
Currency translation (loss) gain	(34)	(0.4%)	1	0.0%	(33)	(0.2%)
Other non-operating (expense) income	(168)	(2.2%)	71	0.5%	31	0.2%
Minority interest	(34)	(0.4%)	(61)	(0.5%)	(52)	(0.4%)
Income before income taxes	**1,337**	**17.5%**	**4,084**	**30.4%**	**2,783**	**20.5%**
Current income taxes	(390)	(5.1%)	(790)	(5.9%)	(861)	(6.3%)
Deferred income taxes	115	1.5%	18	0.1%	187	1.4%
Net income	**1,062**	**13.9%**	**3,312**	**24.6%**	**2,109**	**15.6%**
Basic earnings per share of common stock	$1.69		$4.83		$2.68	
Diluted earnings per share of common stock	$1.69		$4.73		$2.66	

Year ended December 31, 2001 compared to year ended December 31, 2000

Sales

The following set out our sales volumes and realised prices for the years ended December 31, 2000 and 2001:

	Year ended December 31,	
Sales breakdown	**2000**	**2001**
	($ millions)	
Crude oil	$5,851	$4,943
Refined products	6,452	7,496
Other	907	987
Total sales	$13,210	$13,426
Sales volumes		
Crude oil	(mmbls)	
International sales	173.7	187.0
Domestic sales	90.5	91.6
Total crude oil sales	264.2	278.6
Refined products	(millions of tonnes)	
International sales	18.7	21.1
Domestic sales	16.9	18.3
Total refined products sales	35.6	39.4

Realised average sales prices

	Year ended December 31,			
	2000		**2001**	
	($ per barrel)	($ per tonne)	($ per barrel)	($ per tonne)
Average international sales prices – crude oil	$25.21		$21.13	
– refined products		$222.73		$232.27
Average domestic sales prices – crude oil	$16.25		$10.83	
– refined products		$135.33		$141.80

	2000		**2001**	
	(millions of barrels)	(millions of tonnes)	(millions of barrels)	(millions of tonnes)
Crude oil produced	490		515	
Crude oil purchased	73		52	
Refined products produced		32		34
Refined products purchased		4		7

Our sales increased by $216 million, or 2%, from 2000 to 2001. Our revenues from the sales of crude oil decreased by $908 million, or 16%. This was offset by an increase in our revenues from the sale of refined products of $1.0 billion, or 16%, predominantly due to our acquisition of Getty in December 2000. Other sales increased by $80 million, or 9%, as a result of an increase of sales of petrochemical products.

The proportion of our sales volumes represented by refined products increased slightly in 2001, from 49% in 2000 to 53% in 2001, reflecting our strategy of increasing the proportion of our crude oil production that is refined. The impact of this strategy is understated, however, because we sold a portion of our crude oil production to domestic customers for refining in Russia and then repurchased and resold the refined products they produced. If we had had sufficient refining capacity of our own, these crude oil sales to domestic customers may have been reduced, and, as a result, the proportion of our sales volumes represented by refined products may have been higher.

The overall increase in our sales revenue was principally due to the following:

International crude oil
Our revenues from the sale of crude oil outside Russia decreased by $429 million, or 10%. This was a result of a decrease in our average realised prices for crude oil of $4.08 per barrel, or 16%, reflecting the decrease in the price of Urals blend, partially offset by an increase in volumes sold of 13.3 million barrels, or 8%.

Domestic crude oil
Our revenues from the sale of crude oil on the domestic market decreased by $479 million, or 33%. This was a result of a decrease in our average realised price for crude oil sales in the domestic market of $5.42 per barrel, or 33%, partially offset by an increase in volumes sold in the domestic market of 1.1 million barrels, or 1%. The decrease in our realised price was due to the oversupply of oil that existed in the Russian market in the second half of the year.

International refined products
Our revenues from sales of refined products outside Russia increased by $736 million, or 18%. This was a result of a net increase in volumes sold of 2.4 million tonnes, or 13%. An increase of 2.8 million tonnes, attributable to refined product sales of Getty, was partially offset by a reduction in sales in other international markets due to the closure of Petrotel in July 2001. See "Part 5 – Business – Refining, Marketing and Distribution – International Refineries."

Our average realised prices for refined products sold outside Russia increased by $9.54 per tonne, or 4%, principally due to the Getty acquisition. The types of products sold through Getty's distribution network (principally gasoline, diesel and heating oil) had an average selling price that was approximately 60% higher than our average realised selling price in other international markets. Excluding Getty, there was a general reduction in the average selling price in other markets of $10.83 per tonne, or 5%.

Domestic refined products
Our revenues from sales of refined products on the domestic market increased by $308 million, or 13%. This was due to an increase in volumes sold of 1.4 million tonnes, or 8%. Additionally there was an increase in our average realised price for refined product sales in the domestic market of $6.47 per tonne, or 5%, primarily as a result of an increase in excise taxes on gasoline, diesel and motor oil, which was included in our sales revenues.

Equity share in income of affiliates
Our equity share in income of affiliates, which in 2001 principally included our 72% interest in LUKOIL AIK, our 38% interest in LUKOIL-Neftegazstroi and our 50% interest in Turgai Petroleum, decreased by $94 million, or 41%, from 2000 to 2001. This decrease was a result of the following:

- reduced profitability of LUKOIL AIK of $16 million due to reduced margins resulting from lower realisations on crude oil sales and inflationary effects on operating costs;
- the impact of changes in our shareholding in LUKOIL-Perm of $53 million, as a result of which LUKOIL-Perm was fully consolidated in the second half of 2000 and all of 2001; and
- the impact of changes in our shareholding in RITEK of $8 million, as a result of which RITEK was fully consolidated in the second half of 2000 and all of 2001.

Operating expenses
Operating expenses primarily include the costs of purchased crude oil and petroleum products and direct operating costs and labour costs associated with our exploration and production and refining, marketing and distribution activities. Our operating expenses increased by $446 million, or 11%, from 2000 to 2001. As a proportion of revenues, operating expenses increased from 2000 to 2001 by 3%.

The increase in our operating expenses was primarily due to changes in our structure. During 2000, we consolidated LUKOIL-Perm and RITEK for only half of the year, included Getty only from December 2000 and did not consolidate KomiArcticOil. During 2001, all of these businesses were consolidated for the full financial year. Other increases related to employment expenditures, artificial stimulation costs and costs related to energy and extraction materials.

In our Exploration and Production segment, average operating costs per barrel extracted increased to $3.14 per barrel in 2001, from $2.52 per barrel in 2000. This was primarily due to increased activity related to well repairs, artificial stimulation and other repair programmes as well as increased production costs, primarily electricity and labour costs, to extract oil within our main western Siberian and European Russia production subsidiaries. Other costs increased in line with inflation.

In our Refining, Marketing and Distribution segment, the major operating expense was the cost of purchasing crude oil and refined products. Our cost of purchasing crude oil and refined products decreased by $510 million, or 20%. This was due to a general price decrease in market prices for crude oil and refined products and changes in the volumes purchased between the years.

Our average purchase price for crude oil and refined products decreased by $36 per tonne, or 19%. This price decrease was consistent with the decreases outlined in our analysis of revenue movements.

The volumes of crude oil we purchased decreased by 21 million barrels, or 29%, notwithstanding an increase in our sales volumes of crude oil of 14 million barrels. The main reasons for the reduction in our need to make crude oil purchases were as follows:

- an increase in our production of 25 million barrels. This relates to increases in production at our main production subsidiaries of approximately 17 million barrels and the acquisition of AGD and Bitech that contributed an additional 8 million barrels of production;
- a decrease in the required feedstock for our international refineries of 10 million barrels. This decrease was principally a result of reduced production at our Petrotel refinery due to its closure; and
- a decrease in oil utilised in our own operations and a reduction of inventory balances totalling 21 million barrels; offset by
- an increase in feedstock provided to third party refineries under tolling arrangements of 22 million barrels.

The volumes of refined products we purchased increased by 3 million tonnes, or 75%. The major component of this increase in purchases of refined products was an increase of 2.8 million tonnes to meet the requirements of our Getty distribution network in the United States.

Selling, general and administrative expenses

Selling, general and administrative expenses are primarily costs relating to selling and marketing our products, as well as general business expenses, including business development and payroll costs. Our selling, general and administrative expenses increased by $338 million, or 17%, to $2.3 billion in 2001 due to a number of factors. These include:

- an increase of $154 million in transport tariffs and port costs as a result of increases in both volumes transported and tariff rates together with changes in customer and supplier terms;
- an increase of $147 million in sales commisions, advertising and charitable donations;
- increased staff and insurance costs; and
- our acquisition of Getty, contributing an additional $25 million in costs.

In addition, selling, general and administrative expenses in 2000 were reduced by $288 million due to the reversal in 2000 of a provision recorded in 1999.

Offsetting these factors was a reduction in 2001 of $315 million in costs relating to achieving certain tax efficiencies, as referred to above.

Depreciation, depletion and amortisation

Depreciation, depletion and amortisation expenses include depletion of assets fundamental to production, depreciation of other productive and non-productive assets and the amortisation of goodwill and intangible assets. Our depreciation, depletion and amortisation expenses increased by $48 million in 2001, or 6%, in 2001 compared to 2000, primarily due to an increase in the provision for abandonment and site restoration costs of $35 million during 2001. This increased provision is a result of changes in the estimated costs of the future abandonment and restoration of our productive oil and gas assets.

Taxes other than income taxes

Our taxes other than income taxes include royalty tax, mineral replacement tax, road user's tax, property tax and social taxes. The majority of our taxes other than income taxes are based on either revenue, sales volumes or the value of our assets. The expenditures decreased by $40 million, or 4%, in 2001 compared to 2000, primarily due to a reduction in the rate of road user's tax from 2.5% to 1% based on volumes transported and a decrease in other taxes, partially offset by increases in the remaining categories. We achieve certain tax advantages by utilising tax incentives created by legislation, and we may not be able to obtain comparable benefits in the future. See "– Certain Factors Affecting Our Results of Operations – Tax burden" and "Part 11 – Additional Information – Taxation."

Excise and export tariffs

Excise and export tariffs increased by $524 million, or 56%, from 2000 to 2001, and represented 10.7% of our revenues in 2001 compared to 6.9% in 2000. The main reason for this increase was a change in the basis of calculating crude oil export tariffs from a flat monetary amount per tonne in 2000 to a rate based on international crude oil prices for Urals blend in 2001.

Exploration expense

The costs we incur in our exploratory drilling efforts are capitalised to the extent that our exploration efforts are successful and otherwise are charged as an expense. Other exploratory expenditures, including geological and geophysical costs, are expensed as incurred. During 2001, we spent $1.8 billion on exploration and development activity, compared with $945 million for 2000. The increase in expenditures of $844 million arose primarily as a result of the exploration and discovery of new reserves in the Caspian Sea and Timan-Pechora province. We discovered 17 oil and/or gas fields during the year, 12 of which are located in the Volga Ural region. Of this expenditure, we capitalised $1.6 billion in 2001, as compared with $815 million in 2000, and we expensed $144 million in 2001, as compared to $130 million in 2000.

Loss on disposal and impairment of assets

Our loss on disposal and impairment of assets decreased by $94 million in 2001, to $153 million, from $247 million in 2000. Included in the 2001 amount was $28 million attributable to the write-off of goodwill relating to Petrotel. The remaining portion of the 2001 loss was a result of disposals of non-core assets in our production subsidiaries of $84 million and an impairment provision raised against investments.

Interest expense

The increase in interest expense from $198 million in 2000 to $257 million in 2001 was primarily due to the increase in short-term and long-term borrowings. The average annual interest rate (calculated as interest expense to average balance of borrowings) was 8.9% in 2001 and 8.2% in 2000.

Interest and dividend income

Our interest and dividend income decreased by $63 million, or 30%, from 2000 to 2001, primarily due to changes in cash balances and investments held.

Income taxes

Our effective income tax rate, defined as our income taxes divided by our income before income taxes, was 24% in 2001 and 19% in 2000. Fluctuations in these rates from year to year were principally due to differing levels of concessional tax rates we were able to utilise and the use of investment tax credis in Russia. Our effective income tax rate may increase in future periods. See "– Certain Factors Affecting Our Results of Operations – Tax Burden" and "Part 11 – Additional Information – Taxation."

Year ended December 31, 2000 compared to year ended December 31, 1999

Sales

The following tables set out our volumes and realised prices for the years ended December 31, 1999 and 2000.

	Year ended December 31, 1999	Year ended December 31, 2000
Sales breakdown	($ millions)	
Crude oil	4,801	5,851
Refined products	2,064	6,452
Other	679	907
Total sales	7,544	13,210
Sales volumes		
Crude oil	(mmbls)	
International sales	239.4	173.7
Domestic sales	172.3	90.5
Total crude oil sales	411.7	264.2
Refined products	(millions of tonnes)	
International sales	9.7	18.7
Domestic sales	12.6	16.9
Total refined products sales	22.3	35.6

Realised average sales prices

	Year ended December 31, 1999		2000	
	($ per barrel)	($ per tonne)	($ per barrel)	($ per tonne)
Average international sales prices – crude oil	$15.92		$25.21	
– refined products		$159.18		$222.73
Average domestic sales prices – crude oil	$5.73		$16.25	
– refined products		$41.27		$135.33

	1999		2000	
	(millions of barrels)	(millions of tonnes)	(millions of barrels)	(millions of tonnes)
Crude oil produced	446		490	
Crude oil purchased	134		73	
Refined products produced		18		32
Refined products purchased		6		4

Our sales increased by $5.7 billion, or 75%, from 1999 to 2000. Our revenues from the sale of crude oil increased by $1.05 billion, or 22%. Additionally our sales of refined products increased by $4.4 billion, or 213%. Other sales increased by $228 million, or 34%, as a result of an increase of sales of petrochemicals products in the domestic market following our purchase of two Russian petrochemicals plants in late 1999.

The proportion of our sales volumes represented by refined products increased in 2000, from 27% in 1999 to 49% in 2000, primarily as a result of our increased refining capacity following our acquisition of several oil refineries in late 1998 and in 1999. In addition, we refined more crude oil through tolling arrangements with the NORSI and Ufimsky refineries.

The overall increase in our sales revenue was principally due to the following:

International crude oil
In 2000 our revenues from the sale of crude oil outside Russia increased by $568 million, or 15%. Our realised prices for our crude oil increased by $9.29 per barrel, or 58%, consistent with the general increase in the price of Urals blend of 57%. This improvement was partially offset by a decrease in volumes sold by 65.7 million barrels, or 27%. Part of this decrease was attributable to the fact that in 1999 we purchased 27 million barrels from Iraq as part of the 'oil for food' program that we sold on international markets in comparison with approximately 2.9 million barrels in 2000. The further decrease in volumes resulted from our supplying 63.8 million barrels of our crude oil to our Neftochim, Petrotel and Odessa refineries compared to 18.6 million barrels in 1999. Excluding these two factors, our international crude oil sales volumes increased by approximately 3.6 million barrels in 2000.

Domestic crude oil
Our revenues from the sale of crude oil on the domestic market increased by $482 million, or 49%. This resulted from an increase in the average realised price for crude oil sales. This increase in realised price was due to increases in world prices and efforts by Russian oil companies to maintain margins by charging higher prices for domestic crude oil sales in the face of significant inflationary pressures on production costs. In order to maintain margins on domestic oil sales, the oil companies increased selling prices to domestic customers.

This increase in price was partially offset by a decrease in volumes sold on the domestic market of 81.8 million barrels, or 47%. The decrease in volumes resulted from our refining more of our crude oil through tolling arrangements with the NORSI and Ufimsky refineries.

International refined products
Our revenues from sales of refined products outside Russia increased by $2,621 million, or 170%. This was a result of an increase in volumes sold of 9 million tonnes, or 93%. This increase was attributable to the full impact of our purchase of the Neftochim refinery in October 1999, which produced 4.1 million tonnes of refined products in 2000, and the purchase of the Odessa refinery in May 2000, which produced 1.0 million tonnes of refined products from the time of acquisition. We also exported an additional 2.3 million tonnes from our refineries in Russia. Additionally, our average realised price increased by $63.55 per tonne, or 40%, as a result of a general increase in world prices for refined products.

Domestic refined products
Our revenues from sales of refined products on the domestic market increased by $1,767 million, or 340%. This was due to an increase in volumes sold of 4.3 million tonnes, or 34%. This increase resulted from our acquisition of the Ukhta refinery in September 1999, which produced approximately 3.4 million tonnes of refined product. Additional products were refined under tolling arrangements through the Ufimsky and NORSI refineries. Additionally there was an increase in our average realised price for refined product sales in the domestic market of $94.06 per tonne, or 228%. This increase reflects the increase in the domestic market price of crude oil.

Equity share in income of affiliates
Our equity share in income of affiliates, which principally included our 72% interest in LUKOIL AIK, our 38% interest in LUKOIL-Neftegazstroi and our 50% interest in Turgai Petroleum, increased by $142 million or 161% from 1999 to 2000. This increase was a result of the improvement in the profitability of our equity affiliates. Included in the equity share in income of affiliates is also our six month results for our 50% investment in LUKOIL-Perm (contributing $53 million for the first six months of 2000, and $40 million for the full year in 1999) and our 44% investment in RITEK (contributing $15 million for the first six months of 2000, and $11 million for the full year in 1999), as these became consolidated subsidiaries at June 30, 2000.

Operating expenses
Our operating expenses increased by $1.6 billion, or 61%, from 1999 to 2000. The increase was primarily due to increased costs of extraction and a significant increase in the cost of purchases of crude oil and oil products. As a proportion of revenues, operating expenses decreased from 1999 to 2000 by 3.0%.

In our Exploration and Production segment, average operating costs per barrel extracted increased to $2.52 per barrel in 2000 compared with $1.41 in 1999, due primarily to an approximately 90% increase in labour costs, an approximately 80% increase in the cost of drilling supplies, and an approximately 33% increase in electricity tariffs. We also increased our use of enhanced recovery techniques, including artificial stimulation of reservoirs, the cost of which increased by $34 million from 1999 to 2000.

In our Refining, Marketing and Distribution segment, the major operating expense was the cost of purchasing crude oil and refined products. Our cost of purchasing crude oil and refined products increased by $1.1 billion, or 73%. This was due to a general increase in market prices for crude oil and refined products and changes in the volumes purchased between the years.

Our average purchase price for crude oil and refined products increased by $128 per tonne, or 210%. This price increase was consistent with the increases outlined in our analysis of revenue movements.

The volume of crude oil we purchased decreased by 61 million barrels, or 46%, while sales volumes decreased by 147 million barrels. The main reasons for the reduction in our need to make crude oil purchases, in addition to lower sales volumes, were as follows:

- an increase in our production of 44 million barrels. This increase was as a result of our acquisition of KomiTEK which produced 29 million barrels in 2000, the change in status of LUKOIL-Perm and RITEK from associated companies to subsidiaries as at June 30, 2000, which added an additional 17 million barrels of production offset by small decreases at our other production subsidiaries; offset by
- an increase in the crude oil we supplied as feedstock for our refineries of 76 million barrels. This increase is attributable to an increase in the throughput of our Russian refineries of 30 million barrels, increased supply to the Neftochim refinery of 32 million barrels as a result of our supplying directly to this refinery, the acquisition of the Odessa refinery, which required 9 million barrels, and increased throughput of our Romanian refinery of 5 million barrels; and further offset by
- additional feedstock provided to other domestic third party refineries under tolling arrangements of 44 million barrels.

Although sales of refined products increased by 13 million tonnes, volumes of refined products purchased decreased by 2 million tonnes, or 33%. The main reasons for the reduction in our need to make refined product purchases were as follows:

- an increase in production of refined products through our Russian refineries of 4 million tonnes, primarily resulting from a full year of production through our Ukhta refinery;
- an increase in production of refined products through our international refineries of 5 million tonnes, primarily resulting from a full year of production from our Neftochim refinery and our acquisition of the Odessa refinery; and
- an increase in the amount of products tolled through third party Russian refineries of 5 million tonnes.

Other operating costs such as materials, wages, electricity and repairs, principally related to our refining operations, increased by $176 million, or 91%. This was due to catch up effects following the 1998 financial crisis and to the acquisition of the Ukhta refinery. During the last part of 1998 and for most of 1999 wages and electricity tariffs remained relatively unchanged, and during 2000, when the price of oil rose substantially, increases were made to these areas to compensate for this period of limited or no increase. Our acquisition of the Ukhta refinery in 1999, as part of the KomiTEK Group, added an additional $11 million to our operating expenses in 2000.

Selling, general and administrative expenses

Our selling, general and administrative expenses increased by 21% to $1.9 billion in 2000 from $1.6 billion in 1999 due to a number of factors, the most significant of which was a $239 million increase in costs relating to certain tax efficiencies as referred to previously. In addition, expenses settled on our behalf by entities that had accounts payable to us were classified as selling, general and administrative expenses in 2000. In 1999 these expenses were classified as other non-operating expenses. These increases were offset by the reversal of a $288 million provision in 2000.

Our 2000 selling, general and administrative expenses included the consolidation of costs of entities acquired during 2000, the first full year of inclusion of the selling costs associated with the Neftochim refinery, and the impact of the seven months of operations of the Odessa refinery.

Depreciation, depletion and amortisation

Our depreciation, depletion and amortisation expenses increased by $240 million, or 40% during 2000 compared to 1999 primarily due to the full year depreciation effects of the 1999 acquisition of KomiTEK and Neftochim and the 2000 acquisitions of LUKOIL-Perm and the Odessa refinery. In addition, a portion of the increase is due to the increased production in 2000 and the increase in oil and gas production assets.

Taxes other than income taxes
Our taxes other than income taxes increased by $523 million, or 99% during 2000 compared to 1999 primarily due to the increase in sales revenue and volumes.

Excise and Export Tariffs
Excise and export tariffs increased by $492 million, or 103%, from 1999 to 2000. The increase was generally in line with the increase in our revenues; excise and export tariffs represented 6.9% of our revenues in 2000 and 6.0% in 1999.

Exploration expense
During 2000 we spent $945 million on exploration and development activity, compared with $388 million in 1999. The increase in expenditures of 144% arose primarily as a result of the acquisition of KomiTEK and the increase in available cash resulting from higher oil prices, and an increase in the costs of exploration. Of this expenditure, we capitalised $815 million in 2000, as compared with $327 million in 1999, and we expensed $130 million in 2000, as compared to $61 million in 1999.

Loss on disposal and impairment of assets
Our loss on disposal and impairment of assets increased by $198 million in 2000, to $247 million, from $49 million in 1999. A significant portion of the 2000 loss was caused by an impairment provision against investments and the disposal of non-core assets.

Interest expense
The marginal increase in interest expense to $198 million in 2000 from $192 million in 1999 was due to an increase in the weighted average interest rates on long-term loans and borrowings from related parties, offset by a reduction in the weighted average interest rate for other borrowings and a reduction in the principal amounts of debt outstanding. A significant portion of our long term debt is fixed rate borrowings, which are not affected by changes in interest rates.

Interest and dividend income
Our interest and dividend income increased $136 million, or 186%, from 2000 when compared to 1999, primarily due to an increase in our cash and short-term investments, which resulted from our improved operating results. In addition, the centralisation of our treasury function led to an improvement in cash management and utilisation.

Other non-operating income/expense
Our other non-operating income was $71 million in 2000 compared to an expense of $168 million in 1999. The change is mainly due to the 1999 classification as other non-operating expenses of $134 million that were settled on our behalf by entities that had accounts payable with us. In 2000 such costs were classified as selling, general and administrative expenses.

Income taxes
Our effective corporate income tax rate, defined as our income taxes divided by our income before income taxes, was 19% in 2000 and 21% in 1999. Fluctuations in these rates from year to year were principally due to differing levels of concessional tax rates we were able to utilise and the use of investment tax credits in Russia. See "– Certain Factors Affecting Our Results of Operations – Tax Burden."

LIQUIDITY AND CAPITAL RESOURCES

The consolidated statement of cash flows excludes the effect of non-cash transactions. Non-cash transactions include barter transactions and mutual settlements.

Cash flows

	Year ended December 31,		
	1999	**2000**	**2001**
		($ millions)	
Net cash provided by operating activities	1,440	2,768	2,673
Net cash used in investing activities	(875)	(1,912)	(3,061)
Net cash (used in)/provided by financing activities	(88)	(228)	471

Cash flows provided by operating activities

Our primary source of cash flow is funds generated from our operations. Net funds generated from our operations for the year ended December 31, 2001 amounted to $2.7 billion. $2.1 billion of these funds were generated by net income from our operations. Other major items contributing to cash flows provided by operating activities were depreciation of $886 million, and a reduction in accounts and notes receivable of $931 million. A decrease in accounts payable reduced our cash flows by $1.1 billion in 2001. The reduction in accounts and notes receivable and the decrease in accounts payable were financially linked to one another to a significant extent.

Net funds generated from our operations for the year ended December 31, 2000 amounted to $2.8 billion. Of this amount, $3.3 billion was generated by net income from operations. Other major items contributing to cash flows provided by operating activities were depreciation of $838 million and an increase in accounts payable of $541 million. An increase in accounts and notes receivable reduced our cash flows by $1.1 billion in 2000. The increase in accounts and notes receivable and the increase in accounts payable were financially linked to one another to a significant extent.

Cash flows used in investing activities

In 2001 net cash flows used in investing activities amounted to $3.1 billion, as compared to $1.9 billion in 2000 and $875 million in 1999. The 60% increase from 2000 to 2001 and the 117% increase from 1999 to 2000 was primarily due to a large increase in our capital expenditures program. See "– Historical capital expenditures."

Cash flows used in/provided by financing activities

In 2001 net cash flows provided by financing activities amounted to $471 million, compared to net cash flow used in financing activities of $228 million and $88 million respectively in 2000 and 1999. The change in the cash flows provided by financing activities in 2001 was primarily due to new borrowings to finance the increased investment activities. The change in net cash flows from financing activities from 1999 to 2000 was due primarily to an increase in dividends paid of $97 million, and increases in principal payments on long-term debt of $250 million. These movements were offset by lower proceeds from issuance of long-term debt of $258 million.

Working capital and liquidity

Our working capital (current assets less current liabilities) was $1.9 billion at December 31, 2001 and $2.4 billion at December 31, 2000. We believe that, having regard to our liquidity reserves, including credit facilities available, we have sufficient working capital to meet our requirements for at least the next twelve months.

As of December 31, 2001 our short-term borrowings (including the current portion of long-term debt) was $1.5 billion and our long-term debt (excluding the current portion) was $1.9 billion. The annual maturities of our total long-term debt, including the portion classified as current, are $478 million in 2002, $799 million in 2003, $208 million in 2004, $424 million in 2005, $374 million in 2006 and $143 million in periods thereafter.

Historical capital expenditures

Set forth below are our capital expenditures and investments for the years ended December 31, 1999, 2000 and 2001:

	1999	2000	2001
		($ millions)	
Exploration and production – Russia	332	648	1,543
– International	56	297	246
Total exploration and production	388	945	1,789
Refining, marketing and distribution – Russia	385	738	645
– International	85	184	183
Total refining, marketing and distribution	470	922	828
Total cash and non-cash capital expenditures	858	1,867	2,617
Acquisitions and investments in affiliates			
Exploration and production – Russia	3	45	467
– International	–	–	–
Total exploration and production	3	45	467
Refining, marketing and distribution – Russia	–	–	35
– International	81	118	59
Total refining, marketing and distribution	81	118	94
Less cash acquired	(74)	(65)	(62)
Total	10	98	499

Capital expenditures totalled $2.6 billion in 2001 compared to $1.9 billion in 2000. The increase of $750 million, or 40%, in 2001 resulted from a significant increase in expenditures relating to the development of existing fields in western Siberia and expenditures relating to the development of reserves in newly acquired companies (AGD, LUKOIL-Perm and RITEK).

Capital expenditures totalled $1.9 billion in 2000 compared to $858 million in 1999. The increase of $1.0 billion, or 118%, was due to acquisitions and other factors. Total capital expenditures in KomiTEK, acquired in September 1999, totaled approximately $434 million in 2000 compared to $5 million in 1999. In addition, we increased our capital expenditures in our international refineries by $37 million due to the acquisition of Neftochim in October 1999. We increased our capital expenditures on the development of existing fields in western Siberia by $250 million and our international exploration projects in Kazakstan and Azerbaijan by $241 million.

Capital expenditures for acquisitions (excluding the cash of the acquired companies) totalled $499 million in 2001 compared to $98 million in 2000. The increase of $401 million, or 409%, was primarily due to acquisitions of controlling stakes in AGD for $308 million ($169 million in cash and $139 million in shares) YNGD for $104 million, Bitech for $77million, OOO Permtex for $50 million, NORSI Oil for $26 million and OOO Parma Oil for $26 million.

Capital expenditures for acquisitions (excluding the cash of the acquired companies) amounted to $98 million in 2000 compared to $10 million in 1999. The increase of $88 million, or 880%, was due to the acquisition of a 72% interest in Getty for $53 million, the purchase of an additional interest in the Neftochim refinery for $45 million and the acquisition of an additional interest in KomiArcticOil for $44 million.

Future capital expenditures

The table below sets out our current aggregate estimates for the years 2002 and 2003 (i) for contractually committed capital expenditures and other capital expenditures that are core to maintaining our production levels and (ii) for potential capital expenditures and other opportunities available to us if the requisite financing or cash flow from operations is available. **Our estimated capital expenditures and capital projects and investments under consideration could be delayed or postponed in implementation, reduced in scope or rejected. Accordingly, these figures are only estimates and our actual capital expenditures may change based on decisions by our management and our board of directors, who respond to changes in our business environment as they occur.**

	2002	**2003**	**Total**
		($ millions)	
Committed and core capital expenditures and investments:			
Exploration and production	1,300	1,150	1,450
Refining, marketing and distribution	450	50	500
Total committed and core expenditures and investments........	1,750	1,200	2,950
Potential capital expenditures and investments:			
Exploration and production– Russia	200	900	1,100
Refining, marketing and distribution	300	1,400	1,700
Total potential capital expenditures and investments	500	2,300	2,800

Committed and core capital expenditures

For the year ending December 31, 2002

Exploration and Production

Russia. We expect that our core Russian upstream capital expenditures will be made during 2002 to develop existing and explore new fields in western Siberia, the Timan–Pechora region and European Russia.

International. We are committed to making international upstream capital expenditures under existing production sharing agreements during 2002 in the Karachaganak project in Kazakstan, the Azeri-Chirag-Guneshli project in Azerbaijan and in certain other projects in which we participate.

Refining, Marketing and Distribution

Russia. We expect that we will make Russian downstream core capital expenditures to upgrade our refineries and expand our distribution network.

International. We are committed to upgrading our Bulgarian and Romanian refineries, and we expect to expand our overseas distribution network.

For the year ending December 31, 2003

Exploration and Production

Russia. We expect that our core Russian upstream capital expenditures will be made to develop existing and explore new fields in western Siberia, the Timan-Pechora region and European Russia.

International. We are committed to making international upstream expenditures for existing projects during 2003 in the Karachagnak project in Kazakstan, the Azeri-Chirag-Guneshli project in Azerbaijan, and for the development of offshore drilling facilities of LUKOIL Khazar and certain other projects.

Refining, Marketing and Distribution – International. We are committed to upgrading our Neftochim refinery in 2003.

Committed and core capital investments

2002-2003

Exploration and Production – Investments. In addition to our committed and core estimated capital expenditures, we have certain investment commitments, a substantial portion of which relate to our 50% joint venture SEVERTEK. SEVERTEK's principal activity is exploration and production in the Komi Republic in Russia.

Potential capital expenditures and investments

2002-2003

Exploration and Production – Russia. We currently estimate that the substantial portion of our potential Russian upstream capital expenditures will be allocated to exploration and development projects in European Russia, the Caspian Sea Shelf and the Timan-Pechora region.

Refining, Marketing and Distribution
Russia. We expect to focus potential Russian downstream capital expenditures on expanding and upgrading our retail distribution network in Nizhni Novgorod, Moscow, Perm and Kaliningrad, and possibly upgrading our refineries to improve their product output and utilisation.

International. We expect to focus potential international downstream capital expenditures on expanding and upgrading our retail distribution in Ukraine, Bulgaria and the United States and upgrading our refineries in Romania and Ukraine to improve their product output and utilisation.

Investments. Our potential downstream investment opportunities may include the purchase of an interest in Hellenic Petroleum and the Gdansk refinery in Poland.

Environmental

We have environmental liabilities due to past activities that have caused pollution of land, disturbance to land and generation of waste oils, sludge and drill cuttings. We also have obligations to dismantle production facilities and decommission wells once production ceases. We consider the scale of environmental liabilities carried in the 2001 financial statements is a reasonable estimate of the current liability based on the existing regulatory climate and Russian Federation cost base. It is possible that increasing regulatory enforcement in the future could lead to increases in both the extent of pollution considered unacceptable and its cost of remediation.

We allocate operating and cash expenditures in the amounts necessary to minimize risks of environmental losses and to comply with all pertinent regulations. Operating and capital expenditure on the prevention, control, abatement, or elimination of air, water and solid waste pollution is often not incurred as a separately identifiable transaction. Instead, it forms part of a larger transaction, which includes, for example, normal maintenance expenditure. In addition to operating and capital expenditures, we also create provisions for future environmental remediation. We believe our provisions are sufficient for known requirements, and we do not believe that our costs will differ significantly from those of other companies engaged in similar industries, or that our competitive position will be adversely affected as a result. See "Part 5 – Business – Health, Safety and Environment."

QUANTITATIVE AND QUALITATIVE DISCLOSURES ABOUT MARKET RISKS

Interest rate risk

We are exposed to changes in interest rates, primarily associated with our variable rate short-term and long-term borrowings. We do not utilise any interest rate swaps or other derivative instruments to hedge against the risk of changes in interest rates on our variable rate debt. Utilising the actual interest rates in effect and the balance of our variable rate debt at December 31, 2001 and assuming a 10% change in interest rates and no change in the balance of debt outstanding, the potential effect on annual interest expense would not be material to our results of operations.

Foreign currency risk

The countries in which our principal operations are located have been hyperinflationary for a substantial period and over the last 10 years the local currency has been subject to large devaluations. As a result we are subject to the risk that the local currency may suffer severe devaluation in the future that may subject us to losses, depending on our net monetary asset position. We currently do not use any formal hedging arrangements to minimise the effect of these potential losses. Additionally since we have operations in a number of other countries we are required to conduct our businesses in a variety of different foreign currencies and, as a result, we are subject to foreign currency exchange rate risk on cash flows related to sales, expenses, financing and investment transactions. The impacts of fluctuations in foreign currency exchange rates on our geographically diverse operations are varied. We currently do not utilise any foreign currency exchange contracts to reduce the risk of adverse foreign currency movements. We recognised net foreign currency translation gains (losses) of $(33) million, $1 million and $(34) million for the years ended December 31, 2001, 2000 and 1999, respectively.

Commodity instruments

We make limited use of commodity instruments, such as forwards, swaps, and futures contracts, to mitigate the risk of unfavourable price movements on crude oil, natural gas and petroleum product purchases and sales. We had no material commodity derivative instruments outstanding as of December 31, 2001.

Part 5 – BUSINESS

Unless otherwise specified, the reserves, production and other operating information in this Part 5 is presented on the basis set forth under "Part 2 – Key Information – Summary Reserves and Production Information." This basis is different from that used in "Part 4 – Management's Discussion and Analysis of Financial Condition and Results of Operations" and "Part 7 – Financial Information."

OVERVIEW

We are the largest publicly traded oil company in the world in terms of proven crude oil reserves and we are Russia's largest producer of crude oil. Between 1999 and 2001 our estimated proven crude oil reserves increased approximately 14% and our estimated probable crude oil reserves increased approximately 28%, while our crude oil production remained stable, our natural gas production increased approximately 11% and our oil refining volume increased approximately 18%.

As of January 1, 2002 our estimated proven crude oil reserves were 14,576.5 mmbls (1,996.8 million tonnes) and our estimated proven natural gas reserves were 13,215.9 bcf (374.2 bcm), an aggregate of 16,779.1 mmboe. As of the same date, our estimated probable oil reserves were 6,657.4 mmbls (912.0 million tonnes) and our estimated probable natural gas reserves were 3,523.9 bcf (99.8 bcm), an aggregate of 7,244.7 mmboe. See "– Exploration and Production – Oil and Gas Reserves."

Highlights from our 2001 operations include:

- Our total production of crude oil averaged approximately 1.6 mmbls (214,580 tonnes) per day. Our domestic crude oil production of approximately 555.5 mmbls (76.1 million tonnes) accounted for over 20% of all Russian crude oil production.
- We refined 278.1 mmbls (38.1 million tonnes) of crude oil of which 215.3 mmbls (29.5 million tonnes) were refined at our four domestic refineries and 62.8 mmbls (8.6 million tonnes) were refined at our international refineries. We also refined 79.5 mmbls (10.9 million tonnes) under contract with third-party refineries, mainly at the Moscow refinery and the Salavatnefteorgsintez refinery in the Russian Republic of Bashkortostan.
- We sold 278.6 mmbls (38.2 million tonnes) of crude oil and 39.4 million tonnes of refined products.
- As of December 31, 2001 we owned or leased approximately 3,544 retail service stations, including 1,384 in Russia, 1,277 in the United States and 883 in countries of the CIS and eastern Europe.

Domestic Upstream Operations. As of the end of 2001 97% of our proven reserves were in Russia and in 2001 97% of our crude oil production came from our reserves in Russia. As of the end of 2001 our western Siberia proven reserves accounted for approximately 57% of our domestic proven reserves. We are developing new reserves in Russia, most notably in the Timan-Pechora region and the northern Caspian Sea region. We believe that these new areas will provide us with substantial additional reserves and a reserves portfolio that is more balanced geographically.

International Upstream Operations. We have significant upstream interests in what we believe are some of the world's most promising regions for oil production outside Russia, including Azerbaijan and Kazakstan. We also have upstream assets in the Middle East, North Africa and Colombia. As of the end of 2001 our international assets accounted for 3% of our total crude oil production and 3% of our crude oil reserves.

Oil Refining. We own four oil refineries in Russia, located in Perm, Volgograd, Ukhta and Nizhni Novgorod. These refineries have a combined refining capacity of approximately 860,000 barrels per day (43.0 million tonnes per year). We also own refineries in Ukraine, Bulgaria and Romania, which have a combined refining capacity of approximately 380,000 barrels per day (19.0 million tonnes per year). Our international refineries are in need of substantial renovation. Our refinery in Romania is currently not operating. See "– Refining, Marketing and Distribution – International Refineries." We intend to invest substantial amounts to upgrade our international oil refineries to improve utilisation rates and depth of refining to produce products that meet U.S. and European environmental standards. Once the upgrades are complete, we believe that these international refineries will provide attractive integration benefits with our target southeastern European markets.

Retail Marketing. As of December 31, 2001 we had a network of 1,384 LUKOIL-branded retail service stations in Russia and 883 stations in countries of the CIS and eastern Europe. Additionally, as of December 31, 2001, 393 and 16 LUKOIL-branded service stations were operated under franchise agreements in Russia and Europe, respectively. In 2001 we sold approximately 2.0 million tonnes of our own oil products through LUKOIL-branded service stations in Russia and 730,000 tonnes through owned and franchised stations in other countries of the CIS and eastern Europe. In January 2001 we completed the acquisition of Getty Petroleum Marketing Inc., or Getty, which currently has a network of 1,277 leased retail service stations in the northeastern United States. In 2002 we acquired 16 service stations in Cyprus. We believe that our presence in Cyprus will provide us with a new market for oil products produced at our Neftochim refinery in Bulgaria.

Natural Gas Reserves. As of January 1, 2002 we had total proven natural gas reserves of 13,215.9 bcf (374.2 bcm). Our upstream natural gas assets include a 60% interest in Yamalneftegazdobycha, or YNGD, which has estimated proven natural gas reserves of 8,222.5 bcf (232.9 bcm). We also have rights under a production sharing agreement with the government of Uzbekistan giving us a 45% interest in the Bukhara-Khiva and Gissa fields which we believe contain substantial recoverable natural gas reserves.

Gas Production and Processing. In 2001 we produced 183.6 bcf (5.2 bcm) of gas, of which 144.7 bcf (4.1 bcm) was petroleum gas and 38.8 bcf (1.1 bcm) was natural gas. Our downstream gas assets include three gas processing facilities: the Korobkovsky gas processing plant in the Volgograd Region; the Permneftegazpererabotka facility in the Perm Region; and the Usinsky gas processing plant in the Republic of Komi. We intend to acquire the Lokosovski gas processing plant in western Siberia subject to certain contractual conditions.

Petrochemicals. We are currently expanding our petrochemicals business through a joint venture relating to the LUKOR plant in Ukraine and a number of smaller acquisitions of petrochemicals services companies. Currently we have three petrochemicals plants in southern Russia and some petrochemicals production at our Neftochim refinery in Bulgaria. Together our petrochemicals plants manufactured approximately 1.2 million tonnes of petrochemicals in 2001. We intend to utilise our expanding natural gas production and processing operations increasingly as a source of feedstock for our petrochemicals operations.

Transportation. As of December 31, 2001 we had a fleet of 122 vessels, including nine ice-breaking tankers. In addition, we are investing in several pipeline projects, including the Caspian Pipeline Consortium international pipeline, various domestic crude and refined product pipelines and a joint venture with Conoco to study the feasibility of constructing a pipeline to transport oil from our fields in western Siberia through the Timan-Pechora region to our temporary terminal at Varandei Bay. We are also investing to increase our rail transportation capacity. See "– Oil Transportation."

We plan to finance these operations and investments with cash from operations and, where appropriate, bank facilities and offerings of equity or debt securities.

STRATEGY

Strategic Objectives

Our strategic objectives are to increase the profitability and value of the company by increasing our sustainable production of crude oil, natural gas and refined products, replacing our reserves at low cost, and improving returns on capital to levels comparable to our international peers.

We aim to maximise profitability and shareholder value through rigorous management of capital and costs, and have recently adjusted our operating model to focus on more efficient deployment of capital resources to achieve more attractive returns on capital employed. We believe that one of the competitive advantages that allows us to achieve this strategic objective is our ability to identify and develop low-cost upstream and downstream opportunities in our core Russian and international markets.

Execution of Our Strategy

We have recently initiated a comprehensive corporate development and restructuring program that we believe will better enable us to achieve our strategic goals of sustainable growth and value creation. Our major priorities for the restructuring are: (i) steps designed to deliver immediate benefits to the company's profitability and returns on investment; and (ii) a long-term program designed to sustain our growth and profitability.

Short-Term Development Program

Our short-term development program, which we intend to implement over the next two years, is designed to take advantage of immediate opportunities to raise profitability. We believe that the following initiatives will, upon successful implementation, have a material positive impact on our profitability:

- **Increase exports of crude oil and refined products.** We are increasing the amount of oil and oil products that we sell into the international markets for hard currency at international prices. Until 2002 we placed less emphasis on exporting crude oil and refined products than some of our major Russian competitors. We are taking a number of steps to increase our exports including: (i) implementing a programme to increase oil production in regions that are oriented toward greater levels of export such as the Caspian; (ii) increased production of refined products at domestic refineries for export; and (iii) investment in new export transportation capacity, including new refined product pipelines and crude oil sea terminals.

- **Accelerate development of our most productive fields.** Some of our most productive fields in western Siberia and Timan-Pechora are capable of producing at flow rates above those we currently achieve in other areas. By focusing our planned investment on such fields and by applying more advanced recovery techniques and reservoir management strategies, we believe we can increase production, improve profitability and lower per-unit production costs.

- **Shut-in low-producing wells without sacrificing production growth**. Certain of our producing fields in western Siberia are over 20 years old, with some fields reaching depletion levels of up to approximately 80%. Wells in some of these fields have low flow rates and high water cut, or a high percentage of water in the liquids pumped to the surface from the wells, which decreases the productivity of the well. We have identified up to 5,000 such wells that we are reviewing for potential shutting-in. These wells represent approximately 24% of our producing wells, but less than 4% of our production. By improving reservoir management techniques, we believe that we can shut-in these low producing wells without sacrificing production growth.

- **Apply enhanced oil recovery technologies in partnership with international oilfield services companies.** We are working with international oilfield services companies to improve the efficiency of oil recovery in many of our fields. If these efforts prove successful and we are able to lower our cost of production through employment of these techniques, we intend to apply them to more fields as appropriate. We believe that successful application of these advanced recovery techniques will help us increase production and flow rates, lower costs and allow us to improve current production.

- **Seek competitive bids for oilfield services.** We intend to dispose of our drilling activities and fulfill our drilling and oilfield service requirements by seeking competitive bids from major international and Russian oilfield services companies for these services. We believe that disposal of our drilling activities and creation of a competitive environment for drilling and other oilfield services can lower our drilling and oilfield services costs while maintaining the necessary level of services to fulfill our requirements. We have begun the process of disposing of our own oilfield services company, LUKOIL Drilling.

- **Divest non-core businesses and reduce headcount.** We are undertaking a programme of disposal of less productive assets. We continue to review our non-core activities (activities outside the exploration for and production of hydrocarbons, and their refining, marketing and distribution) and will consider divesting such non-core businesses as appropriate. In addition to the potential disposition of LUKOIL Drilling, which, if completed, could reduce our headcount by approximately 18,000 employees, we also intend to reduce headcount where possible through natural attrition and retirements, and have established a goal of reducing our total headcount to approximately 85,000 employees by 2010 from approximately 180,000 as of January 1, 2002.

- **Strengthen performance-related pay.** We will increase the use of performance-related compensation across all levels of the Company to ensure a strong linkage between our financial results and the rewards for managers and employees.

- **Streamline our administration.** We are currently restructuring to reduce significantly the number of our subsidiaries and affiliated companies to make our corporate structure more manageable and efficient, to increase transparency for investors and to optimise the tax efficiency of our international operations. We believe that more efficient management of our business and a leaner, more focused corporate structure will save costs and improve profitability.

Long-Term Development Program

Our longer-term initiatives, which we intend to implement over the next ten years, include the following:

- **Change our reservoir management philosophy from maximising oil production over the life of the field to maximising net present value of oil production.** We are currently modifying our approach to long-term reservoir management to take into account not only the total of recoverable reserves of each field, but also the most efficient methods of recovery in order to maximise the net present value of the oil recovered from each field. Historically, we had focused on maximising the total amount of oil recovered from each field, a legacy of Soviet oil recovery techniques. Net present value management of oil recovery will allow us to manage our reserves and production to maximise return on capital.

- **Expand our upstream business in Russia.** We intend to increase the profitability of our exploration and production business by accelerating field development where appropriate, utilising improved recovery technology, developing satellite fields close to existing infrastructure to gain incremental reserves and production at a relatively low cost per barrel, and continuing to shut in less productive wells.

  We are particularly focused on increasing our reserves and production of hydrocarbons in Timan-Pechora and the northern Caspian Sea region. These two areas have significant reserves that we have acquired for a relatively low cost and that we believe will have higher flow rates than our more mature reserves in Russia for a lower per-barrel production cost. Although there are currently export transportation capacity constraints from these regions, we believe these areas have or will have access to export markets through diversified transport routes, including private sector transport links, ports and shipping companies in which we have an interest or exercise control.

- **Increase our international reserves and production through further development of our existing upstream assets and acquisitions.** We aim to increase our reserves and production from international operations to diversify our geographic and transportation risks and cost base; we intend to increase the share of international reserves and production to approximately 20% of total reserves and production by 2010. Our primary international areas of focus are currently Azerbaijan and Kazakstan, and we believe we can produce significant amounts of crude oil from our projects in these countries in the medium term. We have also identified attractive opportunities in Latin America, North Africa and the Middle East and are developing these opportunities; we recently signed a joint exploration agreement with Ecopetrol related to exploration acreage in Colombia. We are party to a production sharing agreement for the West Qurnah field in Iraq and expect to begin operations there when permitted by U.N. sanctions.

- **Develop our natural gas and petrochemicals operations.** We believe that natural gas is becoming a more important source of energy in Europe and Russia and that the anticipated deregulation of these markets will provide significant opportunities. We believe that increasing the share of natural gas operations in our business will give us more diversified sources of revenue and reduce exposure to oil price volatility. We have acquired upstream gas assets in Russia that we believe can generate profitable production growth if we are able to gain increased access to Russia's gas pipelines. As our natural gas production increases we intend to increase our gas processing capabilities through acquisitions of low-cost existing gas processing facilities in Russia. We intend to sell natural gas to domestic end users, to export natural gas into international markets and to use the natural gas as a low-cost supply of feedstock for our expanding petrochemical operations. We will seek to have a substantial portion of our domestic and international reserves consist of natural gas by 2010 and plan to increase capital expenditure on our gas related assets.

  We also intend to develop our petrochemicals business by acquiring low-cost petrochemicals production assets and abundant feedstock supplies in Russia. We believe that demand in the Russian market for petrochemicals products will grow in the coming years and intend to acquire petrochemicals production capacity to meet this demand.

- **Continue growth of our downstream business, including both refining and marketing, in our strategic target markets.** We believe that we can improve our profitability by participating in more of the hydrocarbon production chain, in our case from crude oil production to retail marketing of our own refined products; our large reserves base gives us the ability to supply our own crude oil to our own refineries, and then on to our own branded retail stations. We believe that participation in more stages of the production chain will generate synergies and allow us to improve profitability. The control of downstream assets will also help provide a reliable long-term outlet for crude oil, reducing our exposure to volatile Russian domestic crude prices. We therefore intend to increase crude oil refining capacity through acquisitions and modernisation of our existing facilities, both domestically and internationally, to improve throughput and output and the quality of our refined products.

We consider retail operations to be a key element in our integrated production and marketing strategy. We intend to expand our network of service stations to improve distribution of our own products in both Russia and Europe over the next several years. Finally, we consider the northeastern United States, where we recently acquired Getty, to be a key market for production from Timan-Pechora as North Sea deliveries to North America decline.

- **Upgrade our budgeting and forecasting procedures.** Prior to 2002, consolidated budgets were prepared for only certain of our Russian and international entities. Use of these budgets, in terms of monitoring actual performance to budgets, was limited.

  We have introduced new procedures for budgeting. Our budgeting process now starts with our strategic requirements in terms of production, investment and financial goals being defined by management at the head office. Central assumptions and parameters are set out by the key head office departments for production, refining, marketing and distribution, capital investment, financing, and the overall limits of cost budgets. Individual entities then project their detailed operating, selling and general administration costs and their detailed capital expenditure plans. These are reviewed by the head office and approved after any necessary adjustments have been made.

HISTORY

Our state-owned predecessor, International Oil Concern LangepasUraiKogalymneft (from which we derive the acronym LUK) was established on November 25, 1991. We were established as a joint stock company in accordance with Presidential Decree 1403, issued on November 17, 1992, under which the Government of the Russian Federation transferred to us 51% of the voting shares of 15 enterprises, and Government Resolution 861 issued on September 1, 1995, under which an additional nine enterprises were transferred to us. In 1994 the Government disposed of 51% of our share capital through (1) an exchange of shares for vouchers tendered by private investors in Russia, (2) sales to private investors in Russia for cash and (3) the distribution of shares to employees. The Government subsequently disposed of more of our shares, and, as of June 30, 2002, the Russian government owned 13.5% of our outstanding shares.

CORPORATE STRUCTURE

Our domestic operations are conducted through:

- five principal production subsidiaries: LUKOIL-Western Siberia, LUKOIL Permneft, LUKOIL-Perm, LUKOIL-Komi and AGD. We own 100% of each of these companies except LUKOIL-Perm and AGD in which we have 73% and 74.1% interests, respectively;
- four principal refining subsidiaries: the Perm refinery, Volgograd refinery, Ukhta refinery and NORSI refinery. We own 100% of the Perm and Volgograd refineries and approximately 99% and 60% of the Ukhta and NORSI refineries, respectively; and
- three principal marketing and distribution subsidiaries: LUKOIL Arctic Tanker (distribution), LUKOIL Nefteproduct (wholesale) and LUKOIL Holding Service/Nefteproduct (gas stations). We own 100% of each of these companies. In addition, we have 14 regional marketing and distribution subsidiaries.

Our international operations are conducted through two principal subsidiaries: LUKOIL INTERNATIONAL GmbH and LUKOIL Overseas Holding Ltd. LUKOIL INTERNATIONAL is primarily responsible for our international refining, marketing and distribution operations, while LUKOIL Overseas is responsible for our international exploration and production activities.

We divide our operations, both domestic and international, into two principal segments: Exploration and Production and Refining, Marketing and Distribution, which we discuss below.

EXPLORATION AND PRODUCTION

Domestic Exploration and Production

We are the largest oil company in Russia in terms of reserves and production. Our three core producing areas in Russia are western Siberia, European Russia and the Timan-Pechora region, where as of January 1, 2002 we have an aggregate of approximately 15,669.7 mmboe of proven and 6,787.1 mmboe of probable oil and gas reserves. Our main production subsidiary in western Siberia is LUKOIL-Western Siberia which controls four principal production units: Langepasneftegas, Uraineftegas, Kogalymneftegas and Pokachevneftegas. Our main production subsidiaries in European Russia are Permneft, LUKOIL-Perm, Nizhnevolzhskneft, Astrakhanmorneft and Kaliningradmorneft. In Timan-Pechora our main production subsidiaries are LUKOIL-Komi and AGD. In addition, we have approximately 257.8 mmboe of proven and 238.8 mmboe of probable oil and gas reserves in our northern Caspian Sea region. We also have a 60% interest in YNGD which has 8,222.5 bcf of proven and 2,005.1 bcf of probable gas reserves.

Licenses

We hold 277 exploration, production and combined licences. In accordance with federal legislation, licences are generally issued jointly by local and federal authorities. Licenses may be suspended or revoked if the licencee fails to comply with their terms. See “Part 8 – Regulation – Subsoil Production Licenses.”

Production licences are generally valid for 20 years and give us the exclusive right to exploit fields in a defined area. Production licences impose obligations on the holder of the licence to pay certain local and federal taxes and meet certain environmental requirements and generally contain an annual production quota, which may be revised in light of new discoveries for oil in the area licenced for production.

Exploration licences are generally valid for five years, do not restrict other entities from exploring the licenced area and cannot be used to produce oil, but generally provide a basis to obtain production licences with respect to any fields on which the licence holder finds oil without auction or tender.

Recent legislation, passed after the issuance of many of our licences, provides that licences are now granted for a time equal to the economic viability of the relevant field. As long as we meet certain conditions, such as compliance with approved development programs, we believe that each of our licences issued prior to this legislation can be extended, upon expiration, for the economic life of the relevant fields.

Oil and Gas Reserves

At our request, Miller and Lents, independent oil and gas consultants, have carried out an independent evaluation of our estimated reserves as of January 1, 2002. Unless otherwise specified, any information about our estimated crude oil and natural gas reserves contained herein is extracted from the Reserves Reports prepared by Miller and Lents for 1999, 2000 and 2001. These estimates are based upon various assumptions as to oil prices, drilling and operating expenses, capital expenditures, taxes and availability of funds that are set forth in greater detail in the Reserves Report that appears in Part 10 of this document.

The process of estimating oil reserves is complex and inherently uncertain. We must project production rates and timing of development and analyse available geological, geophysical, production, engineering and economic data for each reservoir, and the extent, quality and reliability of this data can vary. The accuracy of reserves data is also a function of the quality and quantity of other available data, engineering and geological interpretation and judgment. See “Part 2 – Key Information – Summary Reserves and Production Information” and “Part 2 – Key Information – Reserves Measurements.” See also “Part 3 – Risk Factors – Risks Relating to Our Business.”

	As of January 1, 2002		
	Net reserves[1]		
Reserve Category	Oil (mmbls)	Gas[2] (bcf)	Total (mmboe)
Proven	14,576.5	13,215.9	16,779.1
Probable	6,657.4	3,523.9	7,244.7
Proven and Probable	**21,233.9**	**16,739.8**	**24,023.8**

Notes:

[1] Net oil and gas reserves are exclusive of third-party working interests but include reserves that we do not beneficially own that are attributable to minority interests in our consolidated subsidiaries. For example, we include in our proven reserves for 2001, 1,510 mmbls (9.4%) that are attributable to minority interests. For disclosure which excludes reserves attributable to minority interests, see Table IV of the SFAS No. 69, "Disclosures About Oil and Gas Producing Activities," included in our U.S. GAAP financial statements which are found in Part 7 herein. No deduction for royalties was made in estimating net reserves.

[2] Estimated gas reserves were calculated on the basis of sales volumes, not reservoir volumes. In doing so, Miller and Lents assumed a constant ratio of gas sales to total gas production throughout the life of the fields.

The following tables set forth our Russian crude oil and natural gas reserves by production unit or subsidiary (including our share of affiliates) at the three years ended December 31, 1999, 2000 and 2001.

	Net Oil Reserves (mmbls)								
	1999			2000			2001		
Region	Proven	Probable	Proven plus Probable	Proven	Probable	Proven plus Probable	Proven	Probable	Proven plus Probable
Western Siberia									
Langepasneftegas	1,146.8	427.1	1,573.9	1,107.3	514.2	1,621.5	1,059.0	428.6	1,487.6
Uraineftegas	704.5	501.1	1,205.6	692.1	368.4	1,060.5	703.4	333.2	1,036.6
Kogalymneftegas	5,297.7	2,603.1	7,900.8	5,160.8	3,625.0	8,785.8	5,038.7	3,313.6	8,352.3
Pokachevneftegas	1,288.7	718.4	2,007.1	1,251.4	707.8	1,959.2	1,250.6	673.9	1,924.5
Total	**8,437.7**	**4,249.7**	**12,687.4**	**8,211.6**	**5,215.4**	**13,427.0**	**8,051.7**	**4,749.3**	**12,801.0**
European Russia									
Permneft	1,648.0	147.7	1,795.7	1,510.4	150.7	1,661.1	1,328.9	99.5	1,428.4
LUKOIL-Perm[1]	336.8	34.7	371.5	651.1	75.4	726.5	634.3	150.1	784.4
Nizhnevolzhskneft	362.3	66.0	428.3	311.1	78.6	389.7	293.8	75.5	369.3
Astrakhanmorneft	3.9	0.0	3.9	4.8	0.5	5.3	4.5	0.6	5.1
Kaliningradmorneft	100.7	19.5	120.2	90.6	23.8	114.4	88.4	11.7	100.1
Total	**2,451.7**	**267.9**	**2,719.6**	**2,568.0**	**329.0**	**2,897.0**	**2,349.9**	**337.4**	**2,687.3**
Timan-Pechora									
LUKOIL-Komi	1,340.0	441.8	1,781.8	1,643.5	240.1	1,883.6	2,079.0	321.9	2,400.9
AGD	–	–	–	–	–	–	1,215.8	781.3	1,997.1
Total	**1,340.0**	**441.8**	**1,781.8**	**1,643.5**	**240.1**	**1,883.6**	**3,294.8**	**1,103.2**	**4,398.0**
YNGD	–	–	–	–	–	–	**234.1**	**113.2**	**347.3**
North Caspian	–	–	–	–	–	–	**98.3**	**181.4**	**279.7**
Total for Russia	**12,229.4**	**4,959.4**	**17,188.8**	**12,423.1**	**5,784.5**	**18,207.6**	**14,028.8**	**6,484.5**	**20,513.3**

Notes:

[1] LUKOIL-Perm became a consolidated subsidiary in 2000. In 1999 we held a 50% interest in LUKOIL-Perm and it was accounted for using the equity method. Figures for 1999 therefore reflect our 50% share.

[2] Includes the KomiTEK group of companies.

Analysis of Net Natural Gas Reserves (bcf)

Region	1999 Proven	1999 Probable	1999 Proven plus Probable	2000 Proven	2000 Probable	2000 Proven plus Probable	2001 Proven	2001 Probable	2001 Proven plus Probable
Western Siberia									
Langepasneftegas	185.8	69.2	255.0	172.7	80.2	252.9	216.0	87.4	303.4
Uraineftegas	122.3	87.6	209.9	109.8	58.8	168.6	127.9	60.5	188.4
Kogalymneftegas	729.1	371.7	1,100.8	699.8	497.3	1197.1	692.3	468.7	1,161.0
Pokachevneftegas	230.8	130.8	361.6	208.5	118.2	326.7	200.1	107.8	307.9
Total	**1,268.0**	**659.3**	**1,927.3**	**1,190.8**	**754.5**	**1,945.3**	**1,236.3**	**724.4**	**1,960.7**
European Russia									
Permneft	108.8	9.8	118.6	67.0	0.0	67.0	240.6	12.8	253.4
LUKOIL-Perm[1]	90.8	8.6	99.4	176.9	14.9	191.8	178.9	27.4	206.3
Nizhnevolzhskneft	182.9	33.2	216.1	59.1	13.3	72.4	67.0	15.9	82.9
Astrakhanmorneft	4.7	0.0	4.7	1.5	0.0	1.5	0.0	0.0	0.0
Kaliningradmorneft	1.2	0.2	1.4	0.9	0.2	1.1	1.6	0.1	1.7
Total	**388.4**	**51.8**	**440.2**	**305.4**	**28.4**	**333.8**	**488.1**	**56.2**	**544.3**
Timan-Pechora									
LUKOIL-Komi	168.0	99.1	267.1	262.6	14.7	277.3	488.0	117.5	605.5
AGD	–	–	–	–	–	–	0.0	0.0	0.0
Total	**168.0**	**99.1**	**267.1**	**262.6**	**14.7**	**277.3**	**488.0**	**117.5**	**605.5**
YNGD	–	–	–	–	–	–	**8,222.5**	**2,005.1**	**10,227.6**
North Caspian	–	–	–	–	–	–	**956.9**	**344.2**	**1,301.1**
Total for Russia	**1,824.4**	**810.2**	**2,634.6**	**1,758.8**	**797.6**	**2,556.4**	**11,391.8**	**3,247.4**	**14,639.2**

Notes:

[1] LUKOIL-Perm became a consolidated subsidiary in 2000. In 1999 we held a 50% interest in LUKOIL-Perm and it was accounted for using the equity method. Figures for 1999 therefore reflect our 50% share.

Production

Our domestic production operations accounted for over 20% of Russia's oil production in 2001. Our total Russian crude oil production in 2001 was approximately 555.5 mmbls (76.1 million tonnes) and our total gas production in 2001 was approximately 162.4 bcf (4.6 bcm). The majority of our current production comes from our three core producing areas of western Siberia, European Russia and Timan-Pechora.

As part of our strategy of cutting costs and maximising profitability, we intend to utilise more advanced reserves management techniques to increase production at our most productive wells in western Siberia while shutting-in low producing wells. We believe that this will allow us to increase production while lowering costs in western Siberia. In addition, we believe that further production increases will come from Timan-Pechora and the north Caspian region, where relatively young reserves should provide higher flow rates. See "– Strategy."

The following table sets forth selected production data for our principal production units and consolidated subsidiaries in Russia for the three years ended December 31, 2001.

	Average Daily Crude Oil Production For the year ended December 31,		
	1999	**2000**	**2001**
		(mbls/day)	
Western Siberia			
Langepasneftegas	119	118	117
Uraineftegas	90	90	91
Kogalymneftegas	533	541	548
Pokachevneftegas	142	144	146
Other	58	121	120
Total	**942**	**1,014**	**1,022**
European Russia			
Permneft	108	107	107
LUKOIL-Perm[1]	25	54	56
Nizhnevolzhskneft	60	59	59
Astrakhanmorneft	1.4	1.5	1.5
Kaliningradmorneft	13	14	13
Other	2.6	48	48
Total	**210**	**284**	**285**
Timan-Pechora			
LUKOIL-Komi	147	175	179
AGD	–	–	36
Total	**147**	**175**	**215**
Total for Russia	**1,223**	**1,281**	**1,522**

Notes:

[2]LUKOIL-Perm became a consolidated subsidiary in 2000. In 1999 we held a 50% interest in LUKOIL-Perm and it was accounted for using the equity method. Figures for 1999 reflect our 50% share.

Western Siberia Operations

Our western Siberia production operations accounted for 71% of our domestic production for the year ended December 31, 2001. Our western Siberia production operations are conducted principally through LUKOIL-Western Siberia, a 100% owned consolidated subsidiary that has four production units: Langepasneftegas, Uraineftegas, Kogalymneftegas and Pokachevneftegas. These western Siberia production units operate under 51 production licences. In addition, LUKOIL-Western Siberia holds an 11.9% interest in RITEK, and OAO LUKOIL holds an additional 38.6%. RITEK's average daily crude oil production of approximately 22 mbls, 21 mbls and 17 mbls, for the three years ended December 31, 2001, 2000 and 1999, respectively, is included in "Other" under the heading "Western Siberia" in the table above. The western Siberia basin is located approximately 1,900 kilometers (1,180 miles) east of Moscow and extends over an area of approximately 3.1 million square kilometers (1.2 million square miles). The basin is bordered on the west by the Ural Mountains, on the south by the Kazakstan plate and on the east by the Siberian plate and is open to the north and extends under the Kara Sea.

Crude oil produced by LUKOIL-Western Siberia is transported principally via Transneft, the state-owned transportation company that controls Russia's trunk pipelines. However, LUKOIL-Western Siberia's Uraineftegas production unit transports its high quality light, low-sulphur crude oil directly from its production facilities via a dedicated Transneft pipeline network to the Black Sea port of Tuapse thus avoiding the blending that would otherwise occur. See "– Oil Transportation."

The following table sets forth selected operational data for LUKOIL-Western Siberia for the three years ended December 31, 2001.

	Year ended December 31,		
	1999	**2000**	**2001**
Langepasneftegas			
Proven reserves (mmboe)	1,178.4	1,136.7	1,095.0
Probable reserves (mmboe)	438.9	527.8	443.2
Annual oil production (mmbls)	43.4	43.0	42.6
Annual gas production (bcf)	9.3	8.9	8.8
Number of proven fields in production	9	9	9
Uraineftegas			
Proven reserves (mmboe)	725.3	718.8	724.7
Probable reserves (mmboe)	516.0	378.4	343.3
Annual oil production (mmbls)	32.9	32.8	33.2
Annual gas production (bcf)	7.3	6.8	7.3
Number of proven fields in production	16	16	16
Kogalymneftegas			
Proven reserves (mmboe)	5,421.6	5,279.8	5,154.1
Probable reserves (mmboe)	2,666.3	3,709.5	3,391.7
Annual oil production (mmbls)	194.5	198.1	200.2
Annual gas production (bcf)	42.6	43.2	43.8
Number of proven fields in production	13	12	11
Pokachevneftegas			
Proven reserves (mmboe)	1,327.9	1,286.8	1,284.0
Probable reserves (mmboe)	740.6	727.9	691.8
Annual oil production (mmbls)	51.8	52.6	53.2
Annual gas production (bcf)	12.7	12.2	11.9
Number of proven fields in production	7	5	7

In addition, as of December 31, 2001 RITEK had estimated proven crude oil reserves of 320.4 mmbls and estimated probable crude oil reserves of 209.6 mmbls. RITEK's average daily production was approximately 22 mbls, 21 mbls and 17 mbls, for the three years ended December 31, 2001, 2000 and 1999, respectively, and it currently has 15 proven fields in production.

European Russia Operations

Our European Russia oil production operations accounted for 18.4% of our domestic production for the year ended December 31, 2001. We have five production subsidiaries in the European Russia region: Permneft, LUKOIL-Perm and Nizhnevolzhskneft, in the Volga-Ural basin, Astrakhanmorneft, in the Pre-Caspian basin, and Kaliningradmorneft, in the Baltic basin. Together they currently hold 158 production licences. Substantially all of our European Russia crude oil production is transported via Transneft.

The Volga-Ural basin is located approximately 800 kilometers (500 miles) southeast of Moscow and includes an area of approximately 700,000 square kilometers (270,000 square miles) that includes the Russian cities of Volgograd, Astrakhan, Perm and Samara. The basin is a regional uplift of the east-central part of Russia and is bounded on the east by the Ural Mountains, on the south by the Pre-Caspian basin, and on the west by the Baltic basin.

The following table sets forth certain operational data for our European Russia operations for the three years ended December 31, 2001:

	Year ended December 31,		
	1999	**2000**	**2001**
Permneft			
Proven reserves (mmboe)	1,666.5	1,521.8	1,369.0
Probable reserves (mmboe)	149.3	150.7	101.7
Annual oil production (mmbls)	39.4	39.0	39.1
Annual gas production (bcf)	17.8	17.5	18.4
Number of proven fields in production	41	42	48
LUKOIL-Perm[1]			
Proven reserves (mmboe)	352.2	681.2	664.2
Probable reserves (mmboe)	36.2	77.9	154.7
Annual oil production (mmbls)	9.1	19.7	20.5
Annual gas production (bcf)	6.8	7.5	16.7
Number of proven fields in production	16	21	22
Nizhnevolzhskneft			
Proven reserves (mmboe)	393.4	321.2	305.0
Probable reserves (mmboe)	71.6	80.9	78.2
Annual oil production (mmbls)	21.9	21.6	21.5
Annual gas production (bcf)	16.0	17.3	17.9
Number of proven fields in production	36	42	42
Astrakhanmorneft			
Proven reserves (mmboe)	4.7	5.2	4.5
Probable reserves (mmboe)	0.0	0.5	0.6
Annual oil production (mmbls)	0.5	0.5	0.5
Annual gas production (bcf)	0.8	1.2	1.1
Number of proven fields in production	2	2	5
Kaliningradmorneft			
Proven reserves (mmboe)	100.9	90.8	88.6
Probable reserves (mmboe)	19.5	23.8	11.7
Annual oil production (mmbls)	4.8	4.9	4.9
Annual gas production (bcf)	0.4	0.4	0.4
Number of proven fields in production	17	18	19

Note:

[1]LUKOIL-Perm became a consolidated subsidiary in 2000. In 1999 we held a 50% interest in LUKOIL-Perm and it was accounted for using the equity method. Figures for 1999 reflect our 50% share.

Timan-Pechora Operations

Our Timan-Pechora operations include properties located in northern Russia in both the Timan-Pechora and Baltic basins. The Timan-Pechora basin is Russia’s third largest oil region in terms of reserves. We believe the northern portion of the Timan-Pechora region has significant undeveloped high quality reserves. The Timan-Pechora basin is located approximately 1,100 kilometers (684 miles) northeast of Moscow in the northwestern portion of Russia. The region covers approximately 777,000 square kilometers (300,000 square miles) and is a triangular-shaped basin bounded on the east by the Ural Mountains and on the southwest by the Timan ridge and extends beneath the Barents Sea to the north.

Since 1999 we have built a presence in Timan-Pechora through a series of acquisitions:

	Acquisition Cost ($ millions)	Current Ownership
1999 – KomiTEK	$619	99.9%
2000 – KomiArcticOil	44	67.5
2001 – AGD	308	74.1
2001 – AmKomi	26	87.9
2001 – Parma Oil	26	73.0
2001 – Permtex	50	86.5
2001 – Bitech	77	100.0

These companies have significant proven oil reserves but several will require major capital investment before full scale production can occur. Accordingly, we will seek to enter into a number of joint venture/partnership arrangements to share the investment burden and potential related risks as we have with Conoco on the Polar Lights project discussed in more detail below.

As of January 1, 2002 our Timan-Pechora fields had proven crude oil reserves of 3,294.8 mmbls (451.3 million tonnes) and proven gas reserves of 488.0 bcf (13.8 bcm), which in the aggregate represents 3,376.1 mmboe and probable crude oil reserves of 1,103.2 mmbls (151.1 million tonnes) and probable gas reserves of 117.5 bcf (3.3 bcm), which in the aggregate represents 1,122.8 mmboe. In 2001 we produced 78.8 mmbls (10.8 million tonnes) of crude oil from our fields in Timan-Pechora.

To provide for the transport of the oil we produce in Timan-Pechora, we have constructed a temporary oil terminal at Varendei Bay. Because this terminal is located on the Arctic Ocean we have acquired a fleet of nine ice-breaking tankers capable of transporting our crude production to European ports. We expect to take delivery of our tenth ice-breaking tanker in the last quarter of 2002. In addition, we are party to a memorandum of understanding with Conoco to prepare jointly a feasibility study for the construction of an independent pipeline from our fields in western Siberia through Timan-Pechora to our temporary terminal at Varandei Bay. See "– Oil Transportation"

Currently our key assets in Timan-Pechora are held through the LUKOIL-Komi group of companies and AGD. These companies together represent 19.6% of our total Russian reserves. LUKOIL-Komi's fields are generally located in the southern portion of Timan-Pechora while the AGD fields are generally located in the northern portion of Timan-Pechora and in the Arkhangelsk region.

LUKOIL-Komi. LUKOIL-Komi is a company that we have recently established in connection with a restructuring of our operations in Komi. LUKOIL-Komi manages the operations of OAO KomiTEK, OAO Komineft (of which we own 67.5%) and its 100% subsidiary OAO KomiArcticOil and ZAO Nobel Oil (of which we own 99%). LUKOIL-Komi holds the majority of our exploration and development licences in Komi. KomiTEK and KomiArcticOil together hold our remaining licences and account for the majority of our production in Komi. We acquired a controlling interest in KomiTEK, the holding company for the KomiTEK group of companies, including the Ukhta refinery, in 1999. For convenience we use the term "LUKOIL-Komi" in this document to refer to our current and historical operations in Komi, excluding AGD.

The following table sets forth certain operational data for LUKOIL-Komi for the three years ended December 31, 2001:

	Year ended December 31,		
	1999	2000	2001
LUKOIL-Komi			
Proven reserves (mmboe)	1,368.0	1,681.3	2,160.3
Probable reserves (mmboe)	458.3	242.5	341.5
Annual oil production (mmbls)	53.7	63.9	65.3
Annual gas production (bcf)	22.7	22.9	29.0
Number of proven fields in production	33	41	46

In connection with our acquisition of the KomiTEK properties in 1999 we inherited significant environmental problems. We have agreed to remediate the consequences of oil spills that took place in the Usinsky Region of the Komi Republic in 1994. We are currently working toward the reclamation of more than 745 hectares of damaged and contaminated land. We estimate that the recovery program should be completed by 2005 at a total cost of approximately 710 million rubles ($23.6 million as of December 31, 2001), although we can not be certain that this time-frame will not be extended or that this amount will not be greater than expected.

AGD. AGD was originally formed in 1995 pursuant to the privatisation of a state-owned entity known as Arkhangelskgeologiya. Following privatisation, AGD became the successor to all of the projects of the former state-owned entity. After 1997 Non-State Pension Fund LUKOIL-Garant acquired 57.8% of AGD's outstanding share capital. In January 2001 we acquired a 15.4% interest in AGD from Conoco. In April 2001 we completed a share exchange transaction with Garant through which we acquired its 57.8% interest in AGD. See "Part 11 – Additional Information – Certain Transactions and Relationships." As of December 31, 2001 we had a 74.1% interest in AGD and 25.5% was owned by OAO Rosneft, a competitor.

As of January 1, 2002 AGD had proven reserves of 1,215.8 mmbls and probable reserves of 781.3 mmbls. AGD reserves represent 8% of our total proven crude oil reserves and 12% of our total probable crude oil reserves. AGD does not possess any gas reserves.

In early 2001 a commission operating under the Ministry of Natural Resources recommended to the administration of the Nenets Autonomous Region (which has local jurisdiction over AGD), or NAO, that development licences held by AGD relating to three licence areas (four fields) be withdrawn or suspended because AGD had not met licence agreement requirements that specified oil production on those fields must begin by early 2000. The licences subject to withdrawal or suspension relate to fields that account for approximately 786 mmbls or 65% of AGD's proven crude oil reserves. After negotiations with both the Ministry of Natural Resources and local authorities of the NAO, we drafted amendments to the licence agreements that would bring us into compliance. In October 2001 the Ministry of Natural Resources agreed to the amendments. To date the NAO authorities have not signed the amendments. Although we believe that we can proceed with our operations in the licence areas on the basis of the amendment agreements signed by the Ministry of Natural Resources, in the absence of the NAO authorities' formal approval we cannot assure you that one or more of our licences will not be revoked or suspended. Any such licence revocation or suspension could have a material adverse effect on our results of operations. Additionally, certain of AGD's development programs and production sharing agreements have not yet received necessary government approvals. A failure to obtain such approvals could result in a loss of these licences and a corresponding decrease in our available reserves.

AGD's interests also include participation in a joint venture called the Polar Lights Company, which is involved in development and production of the Ardalin field in the northern Arkhangelsk region. Polar Lights was originally formed in 1992 as a joint venture between AGD's state-owned predecessor and Conoco, with each having an initial 50% ownership interest. In 1996, Rosneft acquired a 20% interest in Polar Lights. AGD currently owns a 30% interest in Polar Lights. Polar Lights began production in 1994, and in 2001 production averaged over 30,000 barrels of petroleum liquids per day (1.5 million tonnes per year). In 2001 Polar Lights committed to three Ardalin satellite fields, which we believe will start production in 2002-2003.

North Caspian

We have obtained a licence to explore and develop the Severni block of the Russian portion of the Caspian Sea. The licenced area is approximately 8,000 square kilometers. As of April 2002 we had drilled a total of six exploratory wells on the Khvalynskoye and Korchagina fields and discovered hydrocarbon deposits in both. As of January 1, 2002 we had 98.3 mmbls (13.4 million tonnes) of proven and 181.4 mmbls (24.8 million tonnes) of probable crude oil reserves and 956.9 bcf (27.1 bcm) of proven and 344.2 bcf (9.7 bcm) of probable gas reserves in the northern Caspian region, all located in the Korchagina field. We did not ask Miller and Lents to complete an independent evaluation of the Khvalynskoye field as of January 1, 2002 because the field was considered to be in the exploratory stage at the end of 2001. We intend to continue drilling exploratory wells and to begin developing our new reserves in the near term.

In October 2000 we formed the Caspian Oil Company, or COC, pursuant to a joint venture agreement with Gazprom and YUKOS for the exploration and development of oil and gas reserves in the northern region of the Caspian Sea. Each of the partners originally had an equal share in COC but following a share issuance in 2002 each of LUKOIL and YUKOS owns 49.6% of the equity interest in COC and Gazprom owns the balance. COC obtained a licence to explore and develop an area in the Russian region of the Caspian Sea adjacent to the Severni block that included the Kurmangazy field, which is believed to have substantial recoverable reserves. However, in April 2002 Russia and Kazakstan signed an agreement that divided ownership of a portion of the northern Caspian that included the COC licence area. Pursuant to that agreement, Kazakstan obtained ownership of the Kurmangazy field, which was the only known field in the COC licence area. In light of these recent developments, we are reviewing the options and future prospects of the COC together with our partners in the COC.

Exploration and Development

In 2001 we drilled 135 exploration wells in Russia which yielded 15 new oil fields, one oil/gas condensate field, one gas condensate field and 23 new oil reservoirs in known fields. Our exploration costs in Russia in 2001 totalled $382 million. We intend to drill 85 exploration wells in 2002.

Our development costs in Russia totalled $1.6 billion in 2001 and we expect to drill approximately 500 development wells in 2002.

Our 2002 exploration and development budget currently allocates approximately 45% to western Siberia, 25% to European Russia, 25% to Timan-Pechora and 5% to the northern Caspian region. We may revise these allocations to reflect the results of our exploration activities.

The following table sets forth our exploration and development wells drilled in our core areas of Russia for the three years ended December 31, 2001.

	Year ended December 31,[1]		
	1999	**2000**	**2001**
Western Siberia			
Exploration	53	55	70
Development	244	363	539
European Russia			
Exploration	23	50	52
Development	77	136	169
Timan-Pechora			
Exploration	2	4	11
Development	13	80	99
North Caspian			
Exploration	–	3	2
Development	–	–	–
Total			
Exploration	**78**	**112**	**135**
Development	**334**	**579**	**807**

Notes:

[1] This table includes data for the various subsidiaries that comprise each region for the calendar year and not from the date such subsidiaries were acquired.

In 2000 and 2001 our finding costs for proven and probable reserves were $.54 and $.24 per boe, respectively. We calculate our finding costs with reference to Table IV of the unaudited SFAS No. 69 “Disclosures About Oil and Gas Producing Activities” included in our audited financial statements. Specifically, we calculate finding costs by dividing our exploration and reserves acquisition costs by the sum of (i) purchases of hydrocarbons in place, (ii) extensions and discoveries and (iii) sales of reserves. A significant portion of our finding costs involves reclassifying probable reserves into proven reserves. We believe that our short and long-term restructuring plans, including our planned disposition of LUKOIL Drilling, will over time result in lower overall finding costs. See “– Strategy.”

International Exploration and Production

We currently have reserves in Azerbaijan, Kazakstan and Egypt through our participation in international joint ventures. In addition, we have an interest in a development project in Iraq, where we have limited our activities to comply with applicable international sanctions as interpreted by the Russian Federation, and we recently acquired interests in Colombia. For the year ended December 31, 2001 our share of the production from our international operations was 16.1 mmbls (2.2 million tonnes) of crude oil, representing 3% of our total production. We aim to increase our reserves and production from international operations to diversify our geographic and transportation risks and cost base. We have a long-term goal of increasing our share of international reserves and production to 20% of our total reserves and production by 2010. See " – Strategy."

The following table provides information relating to our international operations that are currently in production. We are also involved in several projects that are in the exploration stage, as discussed in detail below.

Area	Our Equity Interest	Our Share of Oil Reserves as of January 1, 2002 (mmbls)		Our Share of Gas Reserves as of January 1, 2002 (bcf)		Our Share of Gas production[1] year ended December 31, 2001 (mmcf per day)	Our Share of Oil production[1] year ended December 31, 2001 (mbls per day)
		Proven	Probable	Proven	Probable		
Azerbaijan							
Azeri/Chirag/ Gunashli[2]	10.0%	119.4	83.6	0.0	0.0	–	10.2
Kazakstan							
Tengiz[3]	2.7%	98.2	40.0	154.9	63.0	12.8	6.7
Karachaganak[2].	15.0%	240.4	33.3	1,669.2	213.3	51.3	11.2
Kumkol[3]	50.0%	85.3	16.0	0.0	0.0	0.7	15.0
Egypt							
Meleiha[3]	12.0%	4.2	0.0	0.0	0.0	–	1.0
Total International		**547.5**	**172.9**	**1,824.1**	**276.3**	**64.8**	**44.1**

Notes:

[1] Production figures include imputed volumes based on our share of revenues attributable to cost and profit of oil and gas volumes and the weighted average commodity prices at the point of sale.

[2] Consolidated on a proportionate basis.

[3] Accounted for using the equity method.

International Joint Ventures

LUKARCO. In early 1997, we entered into a joint venture agreement with Atlantic-Richfield Company, or ARCO, which is now a subsidiary of BP plc. The purpose of this joint venture was to enable the two companies to co-operate in various exploration and development projects and in the development of related infrastructure in certain areas of Russia (including the northern Caspian region) and in other states of the former Soviet Union.

Pursuant to the agreement, a Dutch joint venture company, LUKARCO B.V. was formed. We have a 54% interest in LUKARCO and BP owns the remaining 46%. Both parties, however, have equal voting rights in relation to all decisions taken by the joint venture.

Under the terms of the joint venture agreement, we must offer most upstream projects within the agreed areas to LUKARCO before offering them to any other non-Russian entity. Investments in projects are to be made either through LUKARCO itself or through one of LUKARCO's affiliates or an affiliate of one of LUKARCO's shareholders.

Under the joint venture agreement, BP will make available up to $4.5 billion in the form of debt financing for projects and LUKOIL and BP will make available up to a total of $500 million in the form of equity investments. Some of the loans made by BP may be guaranteed by us and we may be required to give performance guarantees in relation to certain projects.

We are currently involved, through LUKARCO, in the following projects:

- LUKARCO has a 5% interest in the Tengiz project in Kazakstan giving us a 2.7% effective interest.
- LUKARCO has a 60% interest in the Yalama (D-222) project, offshore of Azerbaijan, giving us a 32.4% effective interest.
- LUKARCO has a 12.5% interest in the Caspian Pipeline Consortium, or CPC, giving us a 6.75% effective interest. LUKARCO is obligated to fund 25% of the construction costs of the CPC pipeline; however under our agreements with BP relating to the LUKARCO joint venture, BP is obligated to fund LUKARCO's share of the CPC pipeline construction costs.

BP acquired ARCO in April 2000. ARCO owned approximately 7% of our capital stock when it was acquired by BP. In 2001 BP reduced its acquired interest in our stock through a combined placement of ADSs representing our ordinary shares and an offering of bonds exchangeable into ADSs representing 23.5 million of our ordinary shares. The terms of these bonds allow BP, until February 9, 2003, to call the bonds in exchange for the shares if LUKOIL's shares trade at or above a calculated price for 20 consecutive trading days. After February 9, 2003, BP can call the bonds at any time.

LUKAgip. In 1994, we entered into a joint venture agreement with Agip International B.V., or Agip. The purpose of the agreement is to facilitate joint participation and to expand cooperation between the parties with respect to various exploration and production projects in the former Soviet Union and other areas.

Pursuant to this agreement, we established LUKAgip N.V. in March 1995, as the joint venture entity. We have a 50% interest in LUKAgip and Agip owns the other 50%.

LUKAgip is currently involved in the following projects:

- it has a 10% interest in the Shakh-Deniz project in Azerbaijan, giving us a 5% effective interest.
- it has a 24% interest in the Meleiha project in Egypt, giving us a 12% effective interest.

Azerbaijan

Azeri-Chirag-Gunashli. The Azeri, Chirag and Gunashli fields, or the ACG fields, are located in the Azerbaijan sector of the Caspian Sea. The fields are currently operated under a production sharing agreement, or PSA, by the Azerbaijan International Operating Company, or AIOC. AIOC delegated its responsibilities to BP, which manages the operations. The PSA encompasses the southeastern portion of the Gunashli field (Deep Water Gunashli) and all of the Chirag and Azeri fields. The term of the PSA is 40 years beginning December 1994. We own a 10% interest in the PSA and a 10% partnership interest in AIOC. Our partners are BP (34.14%), Unocal (10.28%), State Oil Company of the Azerbaijan Republic, or SOCAR, (10%), Statoil (8.56%), Exxon Mobil (8%), Turkish Petroleum (6.75%), Devon Energy (5.63%), Itochu (3.92%) and Delta Hess Khazar (2.72%).

Together, the ACG fields are believed to be among the largest in the world. To produce the reserves believed to exist within the time period of the contract will require a combination of 222 additional wells and recompletions to occur in respect of the proven reserves and 266 additional wells to be drilled in respect of the probable reserves.

Shakh Deniz. LUKAgip has a 10% interest in a PSA to develop the Shakh Deniz area of Azerbaijan. The other owners of the PSA are BP (25.5%), Statoil (25.5%), TotalFinaElf (10%), Oil Industry and Engineering Company (10%), Turkish Petroleum (9%) and SOCAR (10%). BP is the operator of the field.

The PSA consortium has completed a four-year exploration phase involving a three-dimensional seismic survey and the drilling of three exploratory wells. Gas and condensate were encountered in the first exploratory well drilled in 1999. Further successful gas condensate wells were announced in early 2000.

Shakh Deniz stage 1 is anticipated to come on-stream in 2005, comprising an offshore production facility, with platform and subsea wells, separate natural gas and condensate lines to shore, a processing terminal at Sangachal and a new 42-inch diameter natural gas line through Azerbaijan and Georgia to Turkey along the Baku-Tbilisi-Ceyhan route up to the Georgian/Turkish border. The plateau production level of stage 1 is expected to be 247 bcf (7 bcm) per year and is expected to be reached after three to four years of production.

The consortium members estimate that the total capital investment for the completion of stage 1 will be approximately $3.5 billion.

Kazakstan

Tengiz. The Tengiz field was discovered in 1979 and has been operated under a project agreement by the Tengizchevroil, or TCO, joint venture since 1993. LUKARCO has a 5% interest in the project agreement which has a term of 40 years. Our TCO partners include ChevronTexaco (50%), Exxon Mobil (25%), and The Republic of Kazakstan (20%).

As of January 2002 there were 47 active wells in the field. To produce the reserves believed to exist, within the time frame of the agreement, will require a combination of 93 additional wells and recompletions to occur in respect of the proven category and 74 additional wells to be drilled in respect of the probable reserves. The export pipeline for a majority of the crude oil from the Tengiz field will be the CPC pipeline to the Black Sea port of Novorossiisk.

Karachaganak. The Karachaganak field was discovered in 1979 and has been operated under a PSA by the Karachaganak Integrated Organization joint venture, or KIO, since 1997. The term of the PSA is 40 years. We have a direct 15% interest in the joint venture. Our partners are BG Group (32.5%), Agip (32.5%) and ChevronTexaco (20%). BG Group and Agip jointly manage the operations for KIO.

As of January 2002 there were approximately 52 active wells in the field. Current plans call for a combination of approximately 174 additional wells and recompletions to occur in respect of the proven reserves and 26 additional wells to be drilled in respect of the probable reserves. The current phase of the Karachaganak development includes the building of processing and liquid export facilities to be completed by the end of 2003.

Kumkol. The Kumkol field was discovered in February 1983 and entered production in May 1990. The northern portion of the field, known as Kumkol North, is defined by a separate licence issued in 1995 for a 25-year term. We have a 50% interest in CJSC Turgai Petroleum (formerly CJSC Kumkol-LUKOIL), or Turgai, which owns a 100% interest in Kumkol North. Turgai is the operator of Kumkol North. Our partner is Hurricane Kumkol Munai (formerly owned by the government of Kazakstan and currently a subsidiary of Hurricane Hydrocarbons Ltd.), which owns the other 50% interest. The agreement relating to this project was entered into in April 1996 for a term expiring on December 20, 2020. Production at Kumkol North commenced in September 1995.

To produce the reserves believed to exist within the time frame of the agreement will require a combination of 119 additional wells and recompletions to occur in respect of the proven reserves and 99 additional wells to be drilled in respect of the probable reserves, including an aggregate of 47 wells in 2002.

Other International Projects

Egypt. The Meleiha field consists of eight oil fields located in the western desert of Egypt. LUKAgip acquired a 24% interest in the Meleiha field on September 1, 1995. Our partners in the project are ENI S.p.A. (56%), and the IFC (20%). ENI is the operator of the project.

Iraq. We have a 68.5% interest in a PSA relating to the development of the second stage of the West Qurnah oil field. Other parties involved include the Russian Foreign Economic Association Zarubezhneft, the Russian State Foreign Economic Association Machinoimport and the Iraqi Oil Ministry. The agreement terminates in 2020 and contemplates that the parties will invest a minimum of $6 billion on a *pro rata* basis. To date we have limited our activities in Iraq to comply with United Nations sanctions as implemented and followed by the Russian Federation and have delayed our performance of certain obligations under the agreement. We will continue to abide by such sanctions and do not currently anticipate any capital expenditures for such project; however, continued delay of our performance obligations under the agreement could result in the forfeiture of our rights under the PSA. Recent articles in the press have reported that Iraq has begun developing the West Qurnah field independently and that the current Minister of Oil of Iraq has threatened to assign our rights under the production sharing agreement to another party. We cannot assure you that we will retain our rights under the production sharing agreement or that we will be able to begin developing the field when sanctions are lifted or at any time after that.

Colombia. In April 2002 we signed a joint exploration agreement with Ecopetrol, Colombia's state-owned oil company, for the exploration and development of the Condor block in eastern Colombia. We believe that the Condor block has substantial recoverable reserves located in up to seven separate structures. Under the agreement, we will conduct exploration activities within three years.

Oil Transportation

Pipelines

Transneft. We transport most of our crude oil through the trunk pipeline system operated by Transneft, Russia's monopoly trunk pipeline operator. The Ministry of Energy allocates usage of the pipeline network for domestic deliveries to oil producers on a quarterly basis. The Ministry's allocation of pipeline capacity for export deliveries is supervised by a Russian government commission, the Pipeline Commission, with overall responsibility for the distribution of pipeline export capacity to producers on a *pro rata* basis based on output and delivery to the Transneft system. Some Russian companies are able to obtain excess export quota through extra allocation from Transneft or by purchasing quota from other oil companies. The Pipeline Commission includes representatives from a wide range of federal ministries and agencies.

Tariff rates for using Transneft pipelines are set by the Federal Energy Commission. The overall price to transport crude oil depends on the location of the fields in relation to the ultimate destination (i.e., the length of the transport route utilised). See "Part 8 – Regulation – Current System of Oil-related Taxes and Payments – Oil-related Export Duties."

The oil that we transport through Transneft is blended with oil produced by other oil companies transporting their oil through Transneft. The sales we and all such other oil companies make are of the oil blend that results from the combination of different types and qualities of oil in the system. Therefore, the price we get for our oil may be lower than the price we could get for oil of the same quality if we could transport our oil independently of Transneft. The composition of the blend of oil sold into the market through the Transneft pipelines may change, which could reduce the marketability of the oil we produce. Where possible we use alternative pipelines to avoid the blending that occurs in the main Transneft system. For example, we utilise a dedicated alternative Transneft pipeline to transport light oil from our production unit Uraineftegas to the Black Sea port of Tuapse. Similarly, we rely on our own pipeline network to transport the light crude oil that we produce at our LUKOIL-Perm subsidiary directly to our refinery in Perm. In 2002 we completed the construction of the 337 km Perm-Almetievsk-West oil product pipeline, which we expect will reduce our currrent dependence on rail transportation at the Perm refinery by between 1.5 million tonnes and 1.8 million tonnes per year. Finally, because our production facilities in Kaliningrad are close to a sea-port, we transport all of the production from our Kaliningradmorneft subsidiary by sea or rail and without the use of the Transneft system.

We transport a portion of our refined products through the country's state-owned refined products pipeline, Transnefteprodukt.

Caspian Pipeline Consortium. LUKARCO has a 12.5% interest in the Caspian Pipeline Consortium, or CPC, which has completed construction of a 1,500 kilometer (932 mile) oil pipeline to transport crude oil from the Tengiz field in Kazakstan to the Black Sea port of Novorossiisk in Russia. Other parties involved in the CPC are the government of Russia (24%), the government of Kazakstan (19%), ChevronTexaco (15%), Rosneft-Shell Caspian Ventures (7.5%), Exxon Mobil (7.5%), the government of Oman (7%), Agip (2%), BG Group (2%), Kazakoil – BP joint venture (1.75%) and Oryx (1.75%). The pipeline currently has an initial capacity of approximately 600,000 barrels (82,192 tonnes) per day, which is anticipated to be expandable to approximately 1.5 mmbls (0.21 million tonnes) per day through the addition of pump stations, tankage and marine loading facilities. Oil from the Tengiz field was first fed into the CPC pipeline on March 26, 2001.

Potential Domestic Pipelines. We have a memorandum of understanding with Conoco to prepare and submit to the Government of the Russian Federation a feasibility study relating to a pipeline system from western Siberia to our temporary terminal at Varandei Bay on the Barents Sea.

Potential International Pipelines. The Caspian Sea is land-locked. The export of oil is therefore dependent on onshore pipelines. Currently, hydrocarbons are exported from the Caspian Sea via the northern route through Azerbaijan and Russia to the Russian Black Sea port at Novorossiisk and via the western route through Azerbaijan and Georgia to the Black Sea port at Supsa. As the production volumes increase as a result of development of the ACG and other fields, the export capacity of the current infrastructure will be insufficient. Current pipeline projects include:

- a southern route from Baku through Tbilisi, Georgia to the Mediterranean port of Ceyhan, Turkey; and
- expansion of the capacity of the northern route to Novorossiisk.

Additional solutions that have been proposed include expansion of the capacity of the western route from Baku to Supsa and a swap arrangement with Iran. The latter option, suggested by Iran, would involve the transport of oil by barge for consumption in northern Iran, and an equal amount of oil to be shipped from Iranian oil fields further south to replace the oil shipped from the Caspian. Companies and host governments are trying to secure sufficient volumes for transportation infrastructure to ensure the commercial feasibility of the export routes. At the same time, flexibility to be able to transport oil through multiple pipelines is important for diversifying the risk involved in commercialising the land-locked upstream resources.

Terminals
During 2000 we constructed a temporary terminal at Varandei Bay on the Barents Sea for trial loading of oil extracted in the Timan-Pechora region. Based upon the success of this temporary terminal we have submitted draft plans to the administration of the Nenets Autonomous Region for construction of a permanent sea terminal at the site. A project feasibility study was recently completed. Once complete, we expect the sea terminal to have the capacity to receive and reload 240,000 barrels per day (12.0 million tonnes per year). We currently transport crude oil inbound to the temporary terminal by pipeline and outbound from this terminal with our ice-breaking tankers through the Barents Sea to the Dutch port of Rotterdam, a major European oil-trading center. An expanded Varandei Bay terminal is a key part of our strategy to increase our ability to transport oil to European markets.

In 2002 we acquired a licence to use and develop a terminal located in Vyborg's outer harbor, Vysotsk, on the Gulf of Finland. The infrastructure of the port is currently configured for petrochemicals products, and we intend to redevelop the terminal to allow for the storage and shipping of oil products. We are currently conducting technical due diligence and having discussions with port authorities regarding the development of the terminal. Our preliminary estimate of the total cost of investment is $150 million. However, such expenditure has not been committed at this stage. Our strategy for this terminal is to complete its development by 2004 and utilise it to load refined products for shipping to our retail network in the United States.

Shipping
As of December 31, 2001 we had a fleet of 122 vessels, including 55 marine vessels. Of our marine vessels, we have nine ice-breaking tankers and one on order. The aggregate freight-carrying capacity of our fleet is approximately one million dead-weight tonnes. Five of our ice-breaking tankers each have a dead-weight capacity of 16,000 tonnes and the other four each have a dead-weight capacity of 20,000 tonnes. Our ice-breaking tankers are capable of operating in the northern and Arctic seas. The addition of these tankers has allowed us to begin the implementation of a major strategic goal of providing for year-round export of oil and gas condensate products from our Timan-Pechora operations. However, because we have not completed the permanent terminal at Varandei Bay or other necessary infrastructure, we do not yet have the ability fully to utilise our tanker fleet to transport production from Timan-Pechora. Accordingly, we have leased four tankers to the Murmansk Shipping Company (a related party) under terms of eleven-year operating leases on a bare boat basis (i.e., the lessee is responsible for all operating costs). An additional four tankers are operated on a time-charter basis (i.e., short-term charters).

REFINING, MARKETING AND DISTRIBUTION

The Refining, Marketing and Distribution segment of our business is comprised of refining (including petrochemical operations), sales and other deliveries of crude oil, sales of refined products, gas processing and retail marketing of oil products.

Refining
In 2001 we refined a total of 277.4 mmbls (38.0 million tonnes) of crude oil. We currently produce more crude oil than we can refine in our own facilities. To increase our ability to refine our own crude oil into value added refined products, we intend to: (i) increase refining capacity, both domestically and internationally; (ii) improve throughput and output and the quality of our refined products; and (iii) expand our refining operations in Europe.

As part of our strategy to participate in more stages of the hydrocarbon production chain, we intend to increase our refining capacity both in Russia and internationally, upgrade our refineries to produce higher volumes of higher-value light products such as gasoline, jet fuel and diesel fuel, and expand into petrochemicals. Execution of this downstream expansion has to date involved the acquisition of two refineries in Russia and three refineries internationally, as well as three petrochemicals facilities in Russia. Our international refining and marketing expansion strategy is focused primarily on southeastern Europe. We believe this market offers low-cost acquisition opportunities and retail sales growth opportunities. We intend to acquire additional refineries in Russia and abroad, and are currently the preferred bidder (jointly with the Latsis Group) for a 23.17% stake in Hellenic Petroleum, which operates three refineries in Greece and the former Yugoslav Republic of Macedonia, a gas transportation and distribution network and a network of retail gasoline service stations in Greece. In addition, on June 17, 2002 we, together with Rotch Energy, filed a joint application to Nafta Polska to acquire 75% of the Gdansk refinery. Our bid must be approved by Polish governmental authorities as a condition to completing the transaction. Completion of these acquisitions depends on, among other things, successful negotiation with the privatisation authorities on governance and financial terms, as well as obtaining necessary financing on acceptable terms. We will continue to evaluate refinery acquisition opportunities both in Russia and internationally, and will attempt to acquire additional facilities if they meet our value creation criteria. We also intend to continue to invest in our refineries to upgrade the quality of refined products and the proportion of higher value light products to improve the profitability of these facilities and improve returns from our downstream business. See "– Strategy."

In Russia, we own four refineries located in Perm, Volgograd, Ukhta and Nizhni Novgorod, which in 2001 refined a total of 214.6 mmbls (29.4 million tonnes). Additionally, in Russia we refine crude oil at third party refineries under contract. See "– Other Refineries." Internationally, we have refining operations in Ukraine, Bulgaria and Romania, which in 2001 together refined 62.8 mmbls (8.6 million tonnes). Our refinery in Romania, Petrotel, is currently not operating . See " – International Refineries – Petrotel."

The following table provides certain operating characteristics of our refineries.

Refinery	Distillation Capacity	Year ended December 31, 1999	2000	2001
		(throughput – mmbls of oil)		
Russia				
Perm	87.6	76.7	81.0	78.2
Volgograd	71.5	58.4	62.1	60.5
Ukhta	46.0	16.1	26.3	25.6
NORSI[1]	109.5	30.7	27.7	48.9
Mini and other refineries	–	1.5	1.5	1.4
International				
Odessa[2]	27.7	12.3	9.1	16.4
Neftochim[3]	76.7	38.0	39.0	39.5
Petrotel[4]	–[4]	11.9	16.6	6.9
Total	**406.3**	**245.6**	**263.3**	**277.4**

Notes:

[1] We did not own or control this refinery until 2001. We currently own 91% of NORSI Oil, a holding company that owns a 49.75% interest in the NORSI refinery. In addition, we have recently acquired a 15% direct interest in the refinery, subject to the issuance of the shares.

[2] Information prior to our acquisition of the Odessa refinery in May 2000 was provided by the prior majority owner.

[3] Information prior to our acquisition of the Neftochim refinery in October 1999 was provided by the prior majority owner.

[4] Petrotel was closed in August 2001 and to date remains shut-down. Prior to shut down, Petrotel had a distillation capacity of 32.8 mmbls per year.

Domestic Refineries

The following table gives approximate quantities of refined products manufactured by our domestic refineries for the three years ended December 31, 2001.

	Year ended December 31,		
	1999	**2000**	**2001**
Domestic Product Volumes	(thousands of tonnes)		
Gasoline	3,074	3,327	3,885
Diesel Fuel	5,749	6,357	7,549
Jet Fuel	1,170	1,071	1,695
Fuel Oil	4,682	5,028	7,059
Lubricants	785	899	1,143
Other Petroleum Products[1]	4,002	5,375	6,665
Total[2]	19,462	22,057	27,996

Notes:

[1] Includes bitumen, heating oil, cokes and other products.

[2] Includes mini refineries.

Perm. We acquired the Perm refinery in 1993 and own 100% of its capital stock. The refinery was built in 1958 and currently has a refining capacity of 240,000 barrels per day (12.0 million tonnes per year). The refinery processes high-sulphur and low-sulphur crude oil. It produces a range of products, including gasoline, jet fuel, diesel fuel, lubricants, fuel oil and anode, fuel grade petroleum cokes and bitumen. The refinery's facilities include catalytic cracking, catalytic reforming, delayed coking, lubricants production and hydrotreating units.

Our investment program provides for the completion of a T-star hydrocracking complex in 2003.

We supply crude oil to the Perm refinery from our fields throughout Russia through a pipeline network that feeds into an on-site crude oil reservoir park. We transport products from the Perm refinery by rail, river-class tanker or truck. In addition, we have commenced the construction of an oil product pipeline from Perm to the Russian Republic of Bashkortostan, which we believe will allow us to expand the marketing area for our oil products.

Volgograd. We acquired the Volgograd refinery in 1993 and own 100% of its capital stock. The refinery was originally built in 1957 and currently has a refining capacity of 196,000 barrels per day (9.8 million tonnes per year). The refinery processes high-sulphur and low-sulphur crude oil. The refinery's facilities include catalytic reforming, thermal cracking, delayed coking and hydrotreating units, which enable it to produce gasoline, diesel fuel, electrode coke, lubricants, bitumen and other products. Additionally, in 2000 the first phase of a hydrorefining unit intended to minimise the sulphur content of diesel fuel began operating at the Volgograd refinery. In 2001 we completed the construction of gas refining facilities having a capacity of 240,000 tonnes of natural gas liquids per year.

The investment program for the Volgograd refinery provides for the construction of a new catalytic reforming plant which will allow us to upgrade the quality of gasoline produced by our Volgrograd refinery. In 2001 we invested $86 million in our Volgograd refinery.

The Volgograd refinery receives crude oil by pipeline and rail and transports products by rail, river-class tanker or truck.

Ukhta. We acquired the Ukhta refinery at the end of 1999 and own 98.71% of its capital stock. The refinery was originally built in 1933 and has a refining capacity of 126,000 barrels per day (6.3 million tonnes per year). The refinery processes heavy, high-sulphur and low-sulphur crude oil. The Ukhta refinery's production includes gasoline, diesel fuel, oil bitumen and lubricants. The refinery's facilities include primary petroleum processing, catalytic reforming, and bitumen production units. In 2000 a new tank car loading rack for light petroleum products was commissioned at the Ukhta refinery and in 2001 we completed a modernisation project on the refinery's primary refining unit.

Our investment program for 2001-2003 provides for the construction of a new diesel fuel hydrodeparafinisation unit, reconstruction of the catalytic reforming unit and conversion of the old primary processing unit to visbreaking.

The Ukhta refinery receives crude oil by pipeline and rail. Oil products are stored prior to shipment in an on-site reservoir park and are shipped by rail.

Nizhni Novgorod. In October 2001 we completed our acquisition of an 85.36% interest in NORSI Oil, a holding company with refining and marketing assets located in Nizhni Novgorod, bringing our total ownership interest in NORSI to 91%. NORSI's principal asset is a 49.75% interest in the NORSI refinery that has a refining capacity of 300,000 barrels per day (15.0 million tonnes per year). In June 2002 we acquired an additional 15% of the refinery's outstanding ordinary share capital from the Government of the Russian Federation, which will, upon issuance of the shares, bring our effective interest in the refinery to over 60%. The refinery's remaining capital stock is owned by a number of minority shareholders, including refinery employees. The refinery's facilities include primary petroleum processing, catalytic reforming, hydrodeparafinisation and lubricants production units. The catalytic reforming unit will have a capacity of 1.0 million tonnes once current construction of its uninterrupted catalyst recovery system is completed in 2003. In 2001 the NORSI refinery refined 48.9 mmbls (6.7 million tonnes).

The refinery is near both Nizhni Novgorod and Moscow, two of Russia's largest markets for petroleum products. A dedicated pipeline connects the refinery directly to the Transneft system, the state-owned refined products pipeline, which makes transportation costs comparatively less expensive than rail transport.

International Refineries
The following table gives approximate quantities of refined products manufactured by our international refineries for the three years ended December 31, 2001.

	Year ended December 31,		
International Refinery Product Volumes	**1999**	**2000**	**2001**
	(thousands of tonnes)		
Gasoline	1,801	1,944	1,759
Diesel Fuel	2,950	3,096	2,762
Jet Fuel	163	138	191
Fuel Oil	2,090	1,696	1,935
Lubricants	7	–	10
Other Petroleum Products[1]	1,088	1,655	1,554
Total	**8,099**	**8,509**	**8,211**

Notes:

[1] Includes bitumen, marine oil, cokes and other lubricants.

Odessa. We acquired the Odessa refinery, located in Ukraine, in May 2000 and own 97% of its capital stock. The refinery was built in 1937 and currently has a refining capacity of 76,000 barrels per day (3.8 million tonnes per year). Prior to our acquisition in May 2000 the Odessa refinery had stopped production due to a lack of supply of crude oil. Immediately upon acquisition, we began supplying crude oil to the facility and we refined approximately 9.1 mmbls (1.25 million tonnes) of oil in the balance of 2000. In 2001 the Odessa refinery refined approximately 16.4 mmbls (2.3 million tonnes), producing 2.1 million tonnes of refined petroleum products.

The refinery processes high-sulphur and low-sulphur crude oil. Crude oil is delivered to the refinery by pipeline. Odessa-refined products can be delivered by truck, rail or by pipeline to the port of Odessa.

Neftochim. The Neftochim refinery, located in Burgas, Bulgaria, is owned by a public company that was originally privatised and floated by the Bulgarian government. In October 1999 we acquired, together with a local partner, a 58% interest in Neftochim from the Government of Bulgaria. In July 2000 we purchased our partner's carried interest for $45 million in cash and a deferred payment of $42 million to be paid over 7 years. In January 2002 we acquired an additional 12.7% from a minority shareholder for $30 million bringing our total ownership interest to 70.7%.

The Neftochim refinery, originally built in 1963, has a refining capacity of 210,000 barrels per day (10.5 million tonnes per year). It is the only refinery in Bulgaria and has a 100% market share of the Bulgarian market for petroleum products. In 2001 Neftochim refined approximately 5.8 million tonnes of crude oil feedstock.

The Neftochim refinery produces a range of products, including gasoline, jet fuel, diesel fuel and fuel oil. The Neftochim refinery's facilities include primary refining, fluid catalytic cracking, catalytic reforming, thermocracking and hydrotreating units. The refinery's complex also includes a petrochemicals plant and a polymerisation plant that produce petrochemical products.

The Neftochim refinery is located 30 kilometers from a port terminal on the Black Sea. This allows the refinery to receive crude oil shipments by sea, and also to deliver its products by sea in addition to truck, rail and product pipelines. Seventy-five per cent of the Neftochim refinery's output is distributed into the Bulgarian market and one-fourth is exported, primarily to Turkey.

We are currently in the process of implementing an investment program for the Neftochim refinery. Under the purchase agreement for this refinery we are obligated to invest at least $268.3 million in the refinery complex prior to 2003, of which $184 million was outstanding as of December 31, 2001. This includes expenditures on upgrading the refinery including reconstruction of a catalytic reformer at an expected cost of $27 million over 2001 and 2002; reconstruction of the catalytic cracking aggregation plant at an expected cost of $37 million over 2001 and 2002; and reconstruction of the atmospheric oil processing plant at an expected cost of $16 million over 2001, 2002 and 2003. We are also obligated under the terms of the purchase agreement to contribute to the capital of the refinery rights to an oil field worth at least $140 million prior to 2003.

Petrotel. We acquired an 87.3% interest in the Petrotel refinery, located in Romania in a series of transactions from April 1998 through December 1999, and we are in the process of acquiring an additional 6% interest in 2002. The refinery was built in 1904. Under the terms of the purchase agreement for the refinery we are obligated to invest at least $200 million prior to 2003, including $11 million for environmental protection measures to be invested prior to the end of 2002, of which $114 million was outstanding as of December 31, 2001.

When we acquired Petrotel in 1998, it was operating on a profitable basis. However, a recession commenced in 1999 that caused demand for petroleum products in Romania to decline significantly so that demand was substantially lower than the country's total refinery capacity. As a result, the leading domestic producer of crude oil reacted by reducing the crude oil transfer price to its own refineries. The resulting lower oil product prices effectively forced Petrotel out of the domestic wholesale market and its market share fell from 38% in 1999 to 6% in 2001. In August 2001 we shut down the refinery and the refinery currently is not operating. We engaged Purvin & Gertz Inc, or PGI, international energy consultants, to perform a review of the Romanian downstream oil industry and Petrotel's competitive position. As a result of this study, we are considering the following two possible strategies:

- a comprehensive reconstruction plan to improve the quality of gasoline produced and bring it up to European Union standards at an estimated capital cost of US$29.6 million; or
- continued closure of the refinery.

We are continuing to review the situation at Petrotel in order to determine more precisely the conditions required to operate the refinery effectively. We also intend to hold further discussions with the Romanian government over the future of the refinery and the timing of the fulfilment of our investment obligations. We currently have no assurance that our investment obligations will be suspended or reduced as a result of the shut-down. We expect to keep the refinery closed until a suitable agreement on these issues has been reached with the Romanian government. Prior to being shut down, Petrotel represented approximately 5% of our total refined throughput.

Other Refineries

We utilise other refineries within Russia to refine under contract. This provides us with additional capacity on an as-needed basis. These refineries include the Moscow refinery and the Salavatnefteorgsintez refinery in the Russian region of Bashkortostan. In 2001 we refined approximately 79.5 mmbls (10.9 million tonnes) under contract.

Gas Processing

We currently process our gas production at three facilities: the Korbkovsky refinery, located in the Volgograd Region; Permneftegazpererabotka, located in the Perm Region; and the Usinsky refinery, located in the Republic of Komi. Collectively, these facilities processed 1.5 million tonnes of feedstock and produced 1.4 million tonnes of products in 2001. We intend to acquire the Lokosovski gas processing plant in western Siberia by the end of 2002. Completion of this acquisition depends on, among other things, successful negotiations with Sibur, a Russian petrochemicals company, on financial and other terms.

Petrochemicals Operations

We view our petrochemicals operations as an important part of our business strategy and believe that they provide us with strategic benefits, including more diversified revenues and an additional source of petrochemicals products necessary for our operations. We intend to continue to expand our petrochemicals operations with additional low-cost acquisitions to utilize our surplus of feedstock and to produce a range of high-value-added products. We believe that there are a number of high-quality, low-cost petrochemicals facilities available in Russia and Europe to allow us to execute this strategy. We have recently established a joint venture with the Government of Ukraine relating to LUKOR, a petrochemicals plant in Ukraine. We have also recently completed acquisitions of a small petrochemicals trading company in Hungary and a petrochemicals transportation company in Latvia.

Our petrochemicals operations are conducted through our subsidiary ZAO LUKOIL-Neftekhim, or Neftekhim. Through Neftekhim, we own the Stavrolen and Saratovorgsintez petrochemicals plants. We export over 30% of Neftekhim's total production. Additionally, our Neftochim and Petrotel refineries both have petrochemicals manufacturing capabilities.

The principal product we produce through our petrochemical operations is polyethylene, of which we produced 210.0, 322.8 and 367.8 thousand tonnes in 1999, 2000 and 2001, respectively. Total combined output from our petrochemicals facilities in 2001 was 1.5 million tonnes.

Crude oil sales

The information in this section is presented on a segment basis that is consistent with "Part 7 – Financial Information" and in particular Note 19 – Segment information and includes the operations of our Refining, Marketing and Distribution segment. The information in "Part 4 – Management's Discussion and Analysis of Financial Condition and Results of Operations" is presented on a basis that combines the operations of our Exploration and Production and Refining, Marketing and Distribution segments.

Overview

We sell the crude that we do not refine in the domestic market, which includes certain sales directed by the Russian government, and in the international market, which includes exports from Russia and sales outside of Russia of production from our international projects.

The table below summarises information regarding our crude oil sales from our Refinery, Marketing and Distribution segment for the three years ended December 31, 2001.

	Year ended December 31,					
	1999		2000		2001	
	(mmbls)	($ millions)	(mmbls)	($ millions)	(mmbls)	($ millions)
Russia	95.6	611	73.7	889	64.9	741
International	223.3	3,466	173.7	4,312	164.9	3,540
Total	**318.9**	**4,077**	**247.4**	**5,201**	**229.8**	**4,281**

Note: Does not include crude oil sales made by our Exploration and Production segment.

Domestic sales

In 2001 we sold 64.9 mmbls (8.9 million tonnes) of crude oil within Russia. This includes sales to government entities and other third party sales that the government directs us to make. Domestic crude oil prices have historically been lower than average international oil prices and are only weakly correlated with international oil prices. This is the result of a supply and demand imbalance that exists within the Russian crude oil market which, owing to limitations on export capacity, is generally significantly oversupplied. Although we may be able to receive higher prices for our crude oil on the international market, export pipeline constraints place limits on the total amount of crude oil that can be exported from Russia by pipeline. However, we believe we can increase our total exports as a percentage of our sales through increased pipeline allocations and other export routes. See "–Strategy."

International sales

In 2001 we sold 164.9 mmbls (22.6 million tonnes) of crude oil outside of Russia, primarily to purchasers in Europe. A large part of our international crude oil sales are through our subsidiary LUKOIL Petroleum Limited. This includes, among others, sales since 1992 of approximately 87.6 mmbls (12.0 million tonnes) per year to Western Petroleum. In 1998, as a condition of a proposed $1.5 billion syndicated loan, OAO LUKOIL entered into a long-term contract (for an initial period of 10 years to July 2008) to supply Western Petroleum a minimum of 7.3 million barrels per month, with a maximum quantity of 8.03 million barrels per month, on terms that included certain price discounts off the Brent price. The loan was never finalised due to the 1998 economic crisis in Russia but the contract remained in place, because of the benefits we gained by having a long-term buyer in place.

During 2000, this contract was renegotiated to include a profit sharing agreement to take into account the effect of the price discounts received by Western Petroleum. The renegotiated terms gave us an additional $.65 per tonne supplied for the period April 1, 2000 to August 31, 2001 and $.80 per tonne for the period September 1, 2001 to December 31, 2001 over and above the standard negotiated rate. The minimum supply condition of 7.3 million barrels per month was required for the additional profit sharing to take place.

The long term supply contract was terminated in July 2001 and the profit sharing agreement was terminated on December 31, 2001. We continue to trade with Western Petroleum under an annual supply contract with no minimum supply conditions and on terms and conditions applicable to other customers.

Refined petroleum product sales

The information in this section is presented on a segment basis that is consistent with "Part 7 – Financial Information" and in particular Note 19 – Segment information and includes the operations of our Refining, Marketing and Distribution segment. The information in "Part 4 – Management's Discussion and Analysis of Financial Condition and Results of Operations" is presented on a basis that combines the operations of our Exploration and Production and Refining, Marketing and Distribution segments.

Overview

In 2001 we sold a total of approximately 40.3 million tonnes of refined petroleum products. We sell a wide range of refined products, including gasoline, diesel fuel, fuel oil and lubricants.

We divide our refined products sales into domestic sales and international sales. In 2001 we sold approximately 18.5 million tonnes, or 45.9%, of our refined products in the domestic market (including 4.3 million tonnes sold pursuant to government programs), and 21.8 million tonnes, or 54.1%, internationally.

The table below provides information on our refined petroleum product sales from our Refinery, Marketing and Distribution segment for the three years ended December 31, 2001:

	Year ended December 31,					
	1999		2000		2001	
	(millions of tonnes)	($ millions)	(millions of tonnes)	($ millions)	(millions of tonnes)	($ millions)
Russia[1]						
Wholesale	8.9	886	10.5	1,567	12.2	1,708
Retail	1.3	213	1.6	377	2.0	514
Governmental institutions[2]	2.4	238	4.2	467	4.3	446
	12.6	**1,337**	**16.3**	**2,411**	**18.5**	**2,668**
International						
Wholesale	8.8	1,199	17.2	3,961	18.9	3,869
Retail	0.4	89	0.3	139	2.9	1,132
	9.2	**1,288**	**17.5**	**4,100**	**21.8**	**5,001**
Total	**21.8**	**2,625**	**33.8**	**6,511**	**40.3**	**7,669**

Notes:

1 Includes sales made by LUKOIL Holding Service and LUKOIL Nefteproduct through their own and franchised retail networks and excludes those of Kominefteproduct which forms part of our Exploration and Production segment.

2 Sales to government institutions exclude sales to RAO UES made by Trading House LUKOIL, an Exploration and Production consolidated subsidiary.

The tables below provide selected data for sales of refined products from our Refinery, Marketing and Distribution segment by product type and by destination for the three years ended December 31, 2001:

	Year ended December 31,					
	1999		**2000**		**2001**	
	(millions of tonnes, except percentages)					
Light products						
Gasoline	3.9	18%	6.1	18%	8.5	21%
Diesel	5.3	24%	7.3	21%	6.3	15%
Gas oil	2.8	13%	3.0	9%	4.3	11%
Jet fuel	0.9	4%	1.3	4%	1.6	4%
Heavy products						
Mazut	4.5	21%	7.5	22%	9.5	24%
Lubricants	0.7	3%	0.8	3%	0.8	2%
Others	3.7	17%	7.8	23%	9.3	23%
Total	21.8	100%	33.8	100%	40.3	100%

	Russia			**International**		
	1999	**2000**	**2001**	**1999**	**2000**	**2001**
	(millions of tonnes)			**(millions of tonnes)**		
Gasoline	3.0	4.0	3.6	0.9	2.1	4.9
Diesel	3.7	4.4	3.1	1.6	2.9	3.2
Gas oil	–	–	–	2.8	3.0	4.3
Jet fuel	0.8	1.3	1.3	0.1	–	0.3
Mazut	2.1	3.2	4.7	2.4	4.3	4.8
Lubricants	0.6	0.6	0.6	0.1	0.2	0.2
Others	2.4	2.8	5.2	1.3	5.0	4.1
Total	12.6	16.3	18.5	9.2	17.5	21.8

We transport our refined products through Transnefteprodukt's refined product pipeline, our fleet of ships and via rail and truck. During 2001 we shipped 8.7 million tonnes of petroleum products via rail and we are expanding our rail delivery capacity to increase our ability to transport our own products and to decrease our reliance on Transneft. Our principal transportation subsidiary LUKOIL-Trans has approximately 6,000 rail tank cars and operates a motor transport fleet of approximately 2,000 vehicles that in 2001 transported 1.32 million tonnes of refined products.

Our retail distribution system is divided into a central office and regional distribution centres. Sales and distribution are managed centrally from our Moscow headquarters. Using data from internal sources on refined products production and projected demand from individual regions, the central sales and distribution office directs refineries to send refined product to regional distribution centres. The refinery then ships the product via the designated transport route to the regional distribution centre for onward distribution.

The regional distribution centres receive instructions from the central selling and distribution centre on the destination of products. This centralised system helps us improve distribution efficiency by determining distribution according to regional demand, and considering a greater number of markets for receipt of our products.

Domestic refined petroleum product sales

Domestically, we sell refined products through wholesale and retail channels. In 2001 we sold a total of 14.2 million tonnes of refined products domestically, not including government-directed sales. This included 2.0 million tonnes through LUKOIL-branded service stations within Russia and 12.2 million tonnes through wholesale channels. See "– Retail Marketing."

In the past, the Russian government has directed us to sell refined petroleum products to certain parties. Deliveries of refined products pursuant to government orders amounted to 4.3 million tonnes in 2001. These government-directed sales can be mandated by the government through either formal or informal means. Government-directed sales are sales directed to government agencies, the military, agricultural producers, to remote (in particularly northern) regions or to specific refineries. Such government-directed sales take precedence over market sales and, as a result, may disrupt our relations with our other customers. Additionally, while such government-directed sales may be, at times, at prices that are above typical domestic market prices, at other times they may be at prices that are significantly less than we could otherwise obtain from other purchasers. In 2001 we supplied petroleum products pursuant to government delivery programs to RAO Unified Energy Systems (the owner of the electricity grid and of significant interests in Russia's principal electricity generating companies), or UES, the Ministry of Railways, agricultural enterprises, law-enforcement agencies, the Defense Ministry and to consumers located in the far north of Russia. Sales to UES and the Ministry of Railways accounted for more than 25% of our domestic wholesale volumes in 2000:

- We supplied 3.0 million tonnes of fuel oil to UES in 2000 at prices of $42-82, which were 10% to 12% lower than normal sales prices. In return, AO Permenergo supplied electricity and heat to the Perm Refinery during 2000 at discounts to normal rates; and
- We supplied 0.8 million tonnes of diesel fuel to entities of the Ministry of Railways in 2000 at prices that were 25% to 40% below market levels. In return, the Ministry reduced certain tariffs on rail transport for our oil products.

International refined petroleum product sales

Internationally, we sell refined petroleum products to third parties through wholesale and retail channels. In 2001 we sold a total of 21.8 million tonnes of refined products in the international market, the majority of which was exported from Russia. In 2001 2.9 million tonnes of refined products were sold through LUKOIL-branded service stations outside Russia.

Retail Marketing

As of December 31, 2001, excluding stations operated under franchising agreements, our retail distribution network consisted of 3,544 owned or leased LUKOIL-branded service stations in Russia, other countries of the CIS, eastern Europe and the United States, including one of the largest networks of stations in Russia. In addition to automotive fuels, many of these stations provide car accessories and basic vehicle service, and increasingly offer goods such as fast food, convenience products and groceries.

We intend to expand our network of service stations in Russia in geographic areas that we consider to be more promising, such as Moscow, St. Petersburg, Nizhni Novgorod, Yekaterinburg and Novosibirsk, among others, due to their relatively strong economic positions and strategic locations at intersections of various major Russian highways.

In addition to our owned and leased service stations in Russia, we have a network of 393 franchised stations that sell our products exclusively. Our franchise program includes rigid quality control requirements and requirements that station exteriors comply with LUKOIL corporate specifications and designs. In 2000 we identified 170 franchisees that failed to meet these quality standards, and in 2001 we terminated our franchise agreements with them.

In December 2000 and January 2001 we acquired Getty, a U.S. oil products retailer comprised of a fuel oil and oil products division and leases covering 1,260 service stations located in 13 states in the northeast and Mid-Atlantic regions. As of December 31, 2001, Getty had leases covering 1,277 service stations and had 2.6 million tonnes of annual gasoline sales (average daily gasoline sales volume of 7.1 tonnes). In 2002 we acquired 16 service stations in Cyprus. We believe that our presence in Cyprus will provide us with a new market for oil products produced at the Neftochim refinery.

Our strategy includes concentrating on customer service and undertaking quality control measures to ensure that our retail service stations are performing in accordance with our policies and standards. We now have a significant share of the retail lubricant market in Russia and we have launched an advertising campaign in Russia to promote the sale of LUKOIL-branded packaged lubricants through our chain of service stations.

The following table provides selected data on our retail outlets as of December 31, 2001.

	Year ended December 31, 2001			
Number of Stations that are:	**Russia**	**CIS and Eastern Europe**	**United States**	**Total**
LUKOIL owned or leased	1,384	883	1,277[1]	3,544
Franchised	393	16	–	409
Total	**1,777**	**899**	**1,277**	**3,953**

Note:

[1] Leased only.

COMPETITION

The oil and gas industry is characterised by intense competition for production licences, operatorships, capital, experienced human resources and customers. We have faced, and will continue to face, intense competition both domestically and internationally. Our competitors include all other major Russian oil companies, including YUKOS, Tyumen Oil Company, Surgutneftegaz, Sibneft and Rosneft, as well as the major international oil and gas companies. We compete with these and other oil companies, both within Russia and internationally, with respect to the exploration for and production and sale of crude oil and with respect to the wholesale and retail sale of refined oil products.

The integrated oil and gas industry is currently subject to several important influences that impact the industry's competitive landscape. These include the following:

- *Consolidation.* In the past few years, the strategic and competitive landscape of the oil and gas industry has been transformed by mergers and acquisitions, driven mainly by the need to enhance shareholder returns, to respond to the growing competitiveness of national oil companies, and to achieve greater operational scale to capture new, attractive business opportunities.

- *Deregulation.* The establishment of free, competitive and integrated markets has become an important governmental objective in many countries, including Russia. Within Russia, privatisation of the oil and gas industry has allowed Russian as well as foreign oil companies to bid for licences and to offer services, providing for new and increased competitive forces.

- *Technological Advances.* Technological innovations in the oil and gas industry have improved the industry's performance in finding and developing hydrocarbon resources. Exploration success rates have improved, field life and recovery rates from existing and marginal fields have been increased, and full project cycle costs have generally been reduced. These have been achieved by applying advanced technology more effectively. In general, there is comparable access to technology across the industry and, to achieve our strategic and financial goals, we will need to compete by applying available technology to complex projects in the most skilful manner.

- *Environmental and Social Concerns.* In the face of intense competition oil and gas companies are also facing increasing demands to conduct their operations consistent with environmental and social goals. Investors, customers and governments are more actively following companies' performance on environmental responsibility and human rights including performance with respect to the development of alternative and renewable fuel resources.

As a result of the above influences and other factors, we expect competition to intensify. A number of other Russian oil companies, as well as foreign oil companies, are permitted to compete for licences and to offer services in Russia, increasing the competition that we face domestically. Our key Russian competitors currently have lower operating and selling, general and administrative costs than us and have historically exported higher percentages of their production. We are focused on eliminating these disparities and being competitive with other Russian oil and gas companies on the basis of costs and export volumes. See "– Strategy." Additionally, internationally, we compete with the largest and most sophisticated oil and gas companies outside of Russia. In some cases, we may be at a disadvantage because foreign-domiciled companies may have access to greater financial and other resources, giving them a competitive advantage, both within Russia and internationally. We also expect competition to increase domestically due to the limited quantities of unexploited and unallocated oil reserves remaining in Russia and the effects of and financial resources provided by increasing levels of foreign investment into Russian oil projects. Full implementation of Russia's Production Sharing Law could substantially increase the interest of foreign and domestic companies in oil production in Russia and further increase the level of competition we face. Domestic competitors may also be strengthened if they acquire additional assets through the privatisation processes, or through mergers, joint ventures or other forms of business combinations.

HEALTH, SAFETY AND ENVIRONMENT

Our operations are subject to a number of environmental laws and regulations in Russia and each of the other areas in which we operate. These laws govern, among other things, air emissions, wastewater discharges and discharges to the sea, the use, handling and disposal of hazardous substances and wastes, soil and groundwater contamination and employee health and safety. As with our competitors, environmental liability risks are inherent in our operations. We have environmental liabilities due to past activities that have caused pollution of land, disturbance to land and generation of waste oils, sludge and drill cuttings. Additionally, we also have long-term obligations concerning the decommissioning of operational facilities and the remediation of soil or groundwater at certain of our facilities and liability for waste disposal or contamination on properties owned by others.

The following table provides data on our environmental and decommissioning liabilities as of December 31, 2001.

	As of December 31, 2001				
	Western Siberia	**LUKOIL-Komi**	**Other E&P**	**Drilling and Downstream**	**Total**
			($ millions)		
Environmental Liabilities					
Polluted land	9	8	–	2	19
Disturbed land	29	12	2	–	43
Waste	15	1	1	–	17
Total	**53**	**21**	**3**	**2**	**79**
Decommissioning					
Well decommissioning	640	83	358	–	1,081
Above-ground upstream decommissioning	202	28	235	–	465
Total	**842**	**111**	**593**	**–**	**1,546**

We have undertaken significant efforts and have made significant expenditures to comply with environmental regulations. However, additional financial reserves or compliance expenditures could be required in the future due to changes in law, new information on environmental conditions or other unforeseen events, and those expenditures could have a material adverse effect on our financial condition or results of operations. In addition, if Romania and Bulgaria are admitted to the European Union, then our refineries in these countries would become subject to stricter environmental laws and regulations, which could have a material adverse effect on our operations in these countries.

Russian legislation provides a basis for requiring those violating environmental regulations to remediate any environmental damage such violations have caused. However, to date there have been few attempts to enforce these requirements. Instead, environmental authorities have imposed relatively low fines for breaches of environmental and sanitation standards in what is effectively a "pay-to-pollute" scheme. Compensation also may be payable for any damage caused. Notwithstanding the relatively limited environmental enforcement in place in Russia and some other countries in which we operate, and the moderate level of any fines and fees imposed, we are committed to a long-term proactive policy to address environmental concerns and actively pursue policies that are designed to reduce pollution and its effects.

We allocate operating and cash expenditures in the amounts necessary to minimise risks of environmental loss and to comply with all pertinent environmental regulations. Although our operating and capital expenditures on the prevention, control, abatement, or elimination of air, water and solid waste pollution are often not incurred as separately identifiable transactions, they often form a part of larger transactions, such as normal maintenance expenditures. In addition, we also create provisions for future environmental remediation. We believe our provisions are sufficient, based upon known requirements, and we do not believe that our costs will differ significantly from those of other companies engaged in similar industries, or that our competitive position will be adversely affected as a result.

In connection with our acquisition of KomiTEK in 1999 we inherited significant environmental problems. We have agreed to remediate the consequences of approximately 350 oil spills that took place in the Usinsky Region of the Komi Republic. We are currently working toward the reclamation of more than 745 hectares of damaged and contaminated land. We estimate that the recovery program should be completed by 2005 at a total cost of approximately 710 million rubles ($23.6 million as of December 31, 2001), although we can not be certain that this time will not be extended or that this amount will not increase.

Our Petrotel refinery in Romania, which we purchased in 1998-1999, and our Neftochim refinery in Bulgaria, purchased in 1999, require the remediation of a substantial amount of environmental pollution that pre-dated our acquisition of these facilities. At the time of our acquisition of the Petrotel refinery, there was an understanding that the Romanian government would retain liability for existing environmental pollution at the site. In the purchase agreement, however, we agreed, as part of our investment to upgrade the facilities, to commit $11 million for environmental protection measures, which could include remediation. In connection with our acquisition of the Neftochim refinery, we understand that the Bulgarian government retains liability for remediation of existing environmental pollution at the site, estimated at approximately $80-100 million. Specifically, we understand that the Bulgarian government intends to commit $40 million in the first stage of remediation, of which we understand that $20 million is expected to be funded in 2003 pending the results of environmental surveys. There can be no assurance that the Romanian and Bulgarian governments will remediate the environmental pollution at these facilities in the way we expect. Accordingly, we could be exposed to additional remediation costs at these sites in excess of our planned expenditures.

Managed nuclear explosions were carried out within the Osinskoye oil field in 1969. This field is currently operated by LUKOIL-Permneft. Subsequent drilling allowed radioactively contaminated water to enter the oil reservoir, which eventually led to a ground-level radioactive contamination problem being identified in 1976. Between 1996 and 2001 we undertook a project at a cost of $6 million to manage and contain associated radiological risks, and we believe that no further material liability exists. Well management procedures are in place to maintain a buffer zone around the location of the nuclear explosions. We do not expect further ground water contamination of the surface soil.

In 2000 we revised our “Industrial/Occupational Safety Policy.” This policy, which applies to us and all of our subsidiaries, has the following key goals:

- efficient management of natural resources;
- protection of the health and safety of our employees and the communities in which we operate;
- maintenance of industrial and environmental safety at a level consistent with modern technology and societal expectations;
- reduction of negative environmental impacts through improvement in equipment reliability;
- further reduction of emissions and discharges while increasing productive output through the use of modern technologies, equipment, materials and process management;
- reduction of environmental impacts through pre-project documentation and assessment; and
- development of an efficient system of environmental and safety monitoring.

As a result of these and other efforts, we have received awards and recognition for our environmental, health and safety efforts. In January 2001 we became the first Russian company to receive certification for our environmental protection management system's compliance with international ISO 14001 standards. Additionally, we were the first Russian company to qualify for certification that our industrial safety and labour protection management system is in compliance with the international OHSAS 18001 standard. We have also been selected three times as the Russian company with the "Most Effective Environmental Policy" in an annual contest involving Russian companies sponsored by the Russian Union of Industrialists and Entrepreneurs and the Chamber of Commerce and Industry of the Russian Federation.

Part 6 – MANAGEMENT

MEMBERS OF THE BOARD OF DIRECTORS AND THE MANAGEMENT COMMITTEE

The current members of our Board of Directors are as follows:

Name	Position at the Company	Age
ALEKPEROV, Vagit Yusufovich	Director, President, and Chairman of the Management Committee	51
BEREZHNOY, Mikhail Pavlovich	Non-Executive Director	56
GRAIFER, Valeri Isaakovich	Non-Executive Chairman of the Board of Directors	72
KUTAFIN, Oleg Emelyanovich	Non-Executive Director	65
MAGANOV, Ravil Ulfatovich	Director, First Vice President, and member of the Management Committee	47
MALIN, Vladimir Vladimirovich	Non-Executive Director	42
MATZKE, Richard H.	Non-Executive Director	65
MEDVEDEV, Yury Mitrofanovich	Non-Executive Director	54
MOBIUS, J. Mark	Non-Executive Director	65
SHERKUNOV, Igor Vladimirovich	Non-Executive Director	38
TSVETKOV, Nikolai Aleksandrovich	Non-Executive Director	42

The current members of our Management Committee who are not directors are as follows:

Name	Position	Age
BARKOV, Anatoli Aleksandrovich	Vice President and Head of the Department for General Issues, Human Resources, Social Development, and Transport	54
BAZHENOV, Vladislav Panteleymonovich	Vice President and Head of the Department for Oil Refining and Petrochemicals	64
CHELOYANTS, Dzhevan Krikorovich	Vice President and Head of the Department for Oil and Gas Production	42
FEDOUN, Leonid Arnoldovich	Vice President and Head of the Department for Development and Securities	46
GALUSTOV, Albert Mikhailovich	Secretary of the Board of Directors and Head of the Office of the Board of Directors	67
KHISYAMETDINOVA, Lilya Yasharovna	Chief Accountant	45
KHOBA, Lubov Nikolaevna	Vice President and Head of the Department for Financial Control	45
KOZYREV, Anatoli Gavrilovich	Vice President and Head of the Department for Planning and Marketing	60
KUKURA, Sergei Petrovich	First Vice President	48
MASLYAEV, Ivan Alexeyevich	Head of the Main Legal Department	44
MATYTSYN, Alexander Kuzmich	Vice President and Head of the Department for Corporate Finance and Investment	40
NEKRASOV, Vladimir Ivanovich	Vice President	45
NOVIKOV, Anatoly Aleksandrovich	Vice President and Head of the Department for Geology and Exploration	63
RAKHMETOV, Serik Murzabekovich	Vice President and Head of the Department for Capital Construction, Engineering, and Corporate Services	53
SHARIFOV, Vagit Sadiyevich	Vice President and Head of the Department for Sales of Oil Products	56
SMIRNOV, Alexander Semyonovich	Vice President	53
STOROZHEV, Yury Filippovich	Vice President and Head of the Department for Oil and Gas Delivery and Export of Oil Products	55
TARASOV, Dmitri Nikolayevich	First Vice President	39
YASCHENKO, Anatoli Alekseevich	Chairman of the Council of Trade Unions	60

The business address of our Directors and members of our Management Committee is 11 Sretensky Boulevard, 101000, Moscow, Russia, which is our registered and head office.

DIRECTOR BIOGRAPHIES

Vagit Yusufovich Alekperov

Mr. Alekperov has served as our President since 1991 and as the chairman of our Management Committee since 1993. From 1993 to 2000 he also served as the chairman of our Board of Directors. From 1990 to 1992 he served as Deputy Minister and then First Deputy Minister of the Ministry of Oil and Gas of the Soviet Union and then Russia. In 1974 Mr. Alekperov earned a degree in Economics and Engineering from the Azerbaijani Institute of Oil and Chemistry.

Mikhail Pavlovich Berezhnoy

Mr. Berezhnoy has served as a member of our Board of Directors since 1997 and has worked for us in a number of different capacities since 1994. He also serves as the General Director of Non-State Pension Fund LUKOIL-Garant, Chairman of the Board of Directors of CJSC Radio Company Novaya Volna and as a member of the Boards of Directors of OJSC Publishing House Izvestia and CJSC Moscow Independent Broadcasting

Corporation. Prior to joining us in 1994 Mr. Berezhnoy was a Chief Lecturer of military political science and sociology at the Dzerdzhinsky Military Academy form 1981 to 1993. Mr. Berezhnoy earned a law degree in 1974 from the Saratov Law Institute.

Valeri Isaakovich Graifer
Mr. Graifer has served as the Chairman of our Board of Directors since 2000 and has been a member of our Board of Directors since 1996. In addition Mr. Graifer has served as the General Director of OAO RITEK since 1992, the chairman of the Boards of Directors of CJSC Ritek-Vnedreniye since 1997 and JSCB Medprominvestbank since 1996 and chairman of the Council of Trustees of the Russian University of Oil and Gas since 1992. He is also a member of the Boards of Directors of OJSC Kogalymnefteprogress, Zenith Bank and JSCB Nefteprombank. From 1985 to 1992, he served as Deputy Minister of the Ministry of Oil and Gas of the Soviet Union and then Russia. Mr. Graifer earned a degree in Science from the State Academy of Oil and Gas.

Oleg Emelianovich Kutafin
Mr. Kutafin has served as a member of our Board of Directors since 2001. He also served as the Legal Advisor to our President from 1996 to 2001. In addition he has taught at the Moscow State Academy of Law since 1971 and has been its head since 1987. Mr. Kutafin earned a law degree from the Lomonosov Moscow State University in 1959.

Ravil Ulfatovich Maganov
Mr. Maganov has served as a member of our Board of Directors and Management Committee and as a First Vice President since 1993. He has also served as the General Director of OJSC LUKOIL-Langepasneftegas, one of our subsidiaries, since 1993. Mr. Maganov worked in several capacities for Production Association Langepasneftegas from 1988 to 1993, including as General Director from 1991 to 1993. He served in several different capacities for Production Association Tatneft from 1977 to 1991, including as head of the Department for Oil and Gas Production for Tatneft's oil field "Uriyevneft." In 1977 he earned a degree in Engineering from the Goubkin State Academy of Oil and Gas.

Vladimir Vladimirovich Malin
Mr. Malin has served as a member of our Board of Directors since 2000. He has also served as the Chairman of the Russian Federal Property Fund since 1998, which he joined in 1996 as head of the Department of Sales of Securities. He also serves as Chairman of the Board of Directors of OJSC Murmansky Morskoy Torgovy Port and as a member of the Boards of Directors of OJSC Rosneft, OJSC TNK, OJSC Svyazinvest, OJSC Sovkomflot and State Company "Agency for Restructuring Credit Organisations." He is also a member of the Audit Commissions of OJSC Rossiysky Bank of Development and OJSC International Agro-Industrial Fund. From 1995 to 1996 he was the director of financial management and First Vice President of OJSC Federal Stock Corporation; from 1993 to 1995, he was the Director of Stock Operations at CJSC ESTA Corp. Mr. Malin earned a degree in Economics from Lomonosov Moscow State University in 1982.

Richard H. Matzke
Mr. Matzke was elected to our Board of Directors as a Non-Executive Director in 2002. He is also currently Chairman of the Board of Directors of the United States-Kazakstan Council, a member of the Board of Directors of the Business Council for International Understanding and a member of the Advisory Board of the Center for Strategic and International Studies. Prior to his election to our Board of Directors, from 1997 to 2002 Mr. Matzke was a member of the Board of Directors of ChevronTexaco Corporation (formerly Chevron Corporation), where he was responsible for Chevron's worldwide oil and gas exploration and production. He joined Chevron in 1961 and was elected Vice President in 1990, a Director in 1997, and Vice Chairman in 2000. He was also President of Chevron Overseas Petroleum Inc. from 1997 to 2000.

Yury Mitrofanovich Medvedev
Mr. Medvedev has served as a member of our Board of Directors since 2001. He was also a member of our Board of Directors from 1999 to 2000. In addition he has served as First Deputy Minister of Property Relations of the Russian Federation since 1998. From 1997 to 1998 he was the Authorised Representative of the Russian Federation in the Volgograd region; from 1992 to 1997, he was the Deputy Governor and Chairman of the Committee for State Property Management of the Volgograd region. Mr. Medvedev earned a degree in Chemical Machine Building and Equipment Construction from the Tambov Institute of Chemical Machine Building in 1971.

J. Mark Mobius

Dr. Mobius was elected to our Board of Directors as a Non-Executive Director in 2002. Since 1997, he has managed emerging market funds and currently manages the Templeton Emerging Markets Fund and numerous other funds for the Franklin/Templeton Group. The funds that he manages, with a total capitalisation of approximately $6.5 billion, focus on emerging markets, including Argentina, Brazil, Hong Kong, Japan, Poland, Singapore, South Africa, Thailand, Russia, and Vietnam. He has spent over 30 years working in Asia and other parts of the emerging markets world. As a result of his experience, in 1999 he was appointed joint chairman of the World Bank and the Organisation for Economic Cooperation and Development Global Corporate Governance Forum's Investor Responsibility Task Force. Prior to joining Templeton in 1987, from 1983 to 1986 Dr. Mobius was President of International Investment Trust Company Ltd., Taiwan's first and largest investment management firm. Dr. Mobius earned his Ph.D. in economics and political science from the Massachusetts Institute of Technology and Bachelor's and Master's degrees from Boston University.

Igor Vladimirovich Sherkunov

Mr. Sherkunov has served as a member of our Board of Directors since 2001. He has also served as the General Director of LLC LUKOIL-Reserve-Invest since 1996. From 1993 to 1996 he served as Vice President of OJSC LUKOIL Insurance Company. Mr. Sherkunov earned a degree in Finance from the Moscow Financial Institute in 1985 and a degree in International Economic Relations from the Academy of Foreign Trade in 1993.

Nikolai Aleksandrovich Tsvetkov

Mr. Tsvetkov has served as a member of our Board of Directors since 1998. He has also served in a number of different capacities at OJSC NIKoil, an investment bank, since 1997. He is currently a member of the Board of Directors and the Chairman of the Management Board of NIKoil. He also serves as Chairman of the Boards of Directors of OJSC Novorossiysky Torgovy Port, OJSC Oil and Investment Company NIKoil, CJSC Management Company NIKoil, OJSC Registrar NIKoil and OJSC Krasnogorsk Agro-Industrial Community. He is also the Chairman of the Supervisory Board of CJSC Azerbaijani Investment Company NIKoil. Prior to joining NIKoil he served as the head of our Department of Finance and Investment for two years. He served in the Russian military from 1977 to 1993. During that time he earned degrees from the Tambov State Institute for Military Engineers in 1980 and the Zhukovsky Military Air Academy in 1988. Mr. Tsvetkov earned a marketing degree in 1996 from the Plekhanov Economic Academy.

ADDITIONAL INFORMATION ABOUT OUR DIRECTORS

Interests of the Directors in our Share Capital

The interests of each director (including interests held through his connected persons and through trusts, funds and other investment vehicles) in our share capital, the existence of which is known to such director, including through the exercise of reasonable diligence, whether or not such interests are held through another party, as of July 12, 2002, which is the most recent practicable date prior to the date of this document, are as follows:

Name of Director	Percentage of Ordinary Shares Held
Vagit Yu. Alekperov	10.380%
Mikhail P. Berezhnoy	0.005%
Valeri I. Graifer	0.002%
Oleg E. Kutafin	–
Ravil U. Maganov	0.257%
Vladimir V. Malin	–
Richard H. Matzke	–
Yury M. Medvedev	–
J. Mark Mobius	–
Igor V. Sherkunov	0.056%
Nikolai A. Tsvetkov	5.260%

Mr. Fedoun, a Vice President and member of our Management Committee, has interests (including interests held through his connected persons and through trusts, funds and other investment vehicles) in 4.620% of our share capital.

None of our directors (including through their connected persons) has any interest in any options to acquire our shares. Interests held through connected persons and through trusts, funds and other investment vehicles reflect such person's economic interests therein.

Management Compensation

Our shareholders determine the compensation of our directors at each annual shareholders' meeting. Our charter does not contain any provisions directly relating to the power of directors to approve remuneration (including pension or other benefits) for themselves or any other member of our Board of Directors. In the financial year that ended on December 31, 2001, we paid aggregate compensation (including pension contributions) and granted benefits in kind to our directors in an amount equal to 52,599,453 rubles ($1,745,171 as of December 31, 2001) and to the members of our management committee who are not directors in an amount equal to 165,245,845 rubles ($5,482,603 as of December 31, 2001). On the basis of the arrangements in force on the date of this document, we estimate that we will pay aggregate compensation (including pension contributions) and grant benefits in kind to our directors for the year that will end on December 31, 2002 in an amount equal to approximately 84,000,000 rubles ($2,786,994 as of December 31, 2001). None of our directors has waived or agreed to waive future emoluments.

Interests in Transactions with the Company

None of our directors has or had any interest in any transaction effected by us during the current or immediately preceding financial year (or during an earlier financial year and remain in any respect outstanding or unperformed), which is or was unusual in its nature or conditions or significant to our business except as disclosed in "Part 11 – Additional Information – Certain Transactions and Relationships."

Director Service Contracts

We have entered into service contracts with the following directors:

- Vagit Yu. Alekperov
- Ravil U. Maganov

We entered into an employment agreement, dated June 28, 2001 and amended as of July 10, 2002, with Mr. Alekperov in his capacity as our President. His agreement expires on the date of the annual shareholders' meeting held in 2006. Under the terms of his agreement, Mr. Alekperov will receive an annual salary of $1,500,000. In addition, he is entitled to receive an annual incentive payment of an amount equal to $2,225,000, or 150% of his annual salary, if we achieve certain targets set forth in our global annual plan, including targets for income, oil production and sales and growth in oil reserves.

In addition Mr. Alekperov received 500,000 "phantom shares" in 2001. His phantom shares do not convey any actual ownership in our share capital. Rather, Mr. Alekperov will receive an additional annual bonus equal to the amount of the dividend per ordinary share declared at our annual shareholders' meeting multiplied by the number of his phantom shares. In addition, at the expiration of three years from the date Mr. Alekperov's phantom shares were granted, we will pay him a bonus of an amount equal to the increase in the value of our ordinary shares over that three-year period multiplied by the number of his phantom shares. Mr. Alekperov must use this bonus payment to purchase our ordinary shares. In addition our Board of Directors may approve additional payments to Mr. Alekperov in its discretion. The agreement provides for notice of one month prior to its early termination. If we terminate Mr. Alekperov's agreement prior to its expiration in 2006, we must pay him a severance amount equal to his annual salary.

We entered into an employment agreement with Mr. Maganov effective from July 10, 2002 in his capacity as First Vice President. His agreement will terminate on the date on which our Board of Directors elects the members of the Management Committee in 2003. Under the terms of his agreement, Mr. Maganov will receive an annual salary of $799,800 and may receive an additional annual incentive payment of up to $1,119,720, or 140% of his annual salary. In addition, he received 300,000 phantom shares in 2001. He may also receive additional payments at the discretion of the Board of Directors. In the event that we wish to terminate his agreement early, he would be entitled to one month's notice and a severance payment of an amount equal to annual salary.

In addition to the above discussion of remuneration, Mr. Alekperov and Mr. Maganov may receive additional housing, health, pension and other benefits under the terms of their respective employment agreements. Except as disclosed above there are no service contracts existing or proposed between our directors and us.

In addition, we have entered into agreements with each of Mr. Matzke and Dr. Mobius that provide that we will indemnify them for any losses that they incur as a result of any action that relates to the performance of their duties as directors, except in the case of intentional misconduct or breach of legal duties.

Part 7 – FINANCIAL INFORMATION

ACCOUNTANT'S REPORT ON THE COMPANY

OAO LUKOIL
11 Sretensky Boulevard
Moscow 101000
Russia

Morgan Stanley & Co. International Limited
25 Cabot Square
Canary Wharf
London E14 4QA
United Kingdom

July 31, 2002

Dear Sirs

OAO LUKOIL

We report on the financial information set out on pages 88 to 118. This financial information has been prepared for inclusion in the listing particulars dated July 31, 2002 of OAO LUKOIL ('the Company').

Basis of preparation

The financial information set out on pages 88 to 118 is based on the audited consolidated U.S. GAAP financial statements of the Company and of its subsidiary undertakings (collectively referred to as 'the Group') for the three years ended 31 December 2001 prepared on the basis described in note 1 after making such adjustments as we consider necessary.

Also included, on pages 119 to 125, is unaudited supplemental information provided by management of the Company to address the requirements of Statement of Financial Accounting Standards No. 69 "Disclosures about Oil and Gas Producing Activities." Accordingly, we do not report upon such supplemental information in this report.

Responsibility

Such financial statements are the responsibility of the Directors of the Company who have approved their issue.

The Directors of the Company are responsible for the contents of the listing particulars dated July 31, 2002 in which this report is included.

It is our responsibility to compile the financial information set out in our report from the financial statements, 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 the Statements of Investment Circular Reporting Standards issued by the Auditing Practices Board. Our work included an assessment of evidence relevant to the amounts and disclosures in the financial information. The evidence included that previously obtained by KPMG Limited relating to the audit of the financial statements underlying the financial information. It also included an assessment of significant estimates and judgements made by those responsible for the preparation of the financial statements underlying the 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 financial information is free from material misstatement whether caused by fraud or other irregularity or error.

Opinion

In our opinion the financial information set out on pages 88 to 118 gives, for the purposes of the listing particulars, a true and fair view of the state of affairs of the Group as at the dates stated and of its profits and cash flows for the years then ended.

OAO LUKOIL

Consolidated Balance Sheets as of December 31, 1999, 2000 and 2001
(Millions of U.S. dollars, unless otherwise noted)

	Note	1999	2000	2001
Assets				
Current assets				
Cash and cash equivalents	4	537	1,137	1,170
Short-term investments		137	253	218
Accounts and notes receivable, net	6	1,931	2,948	2,230
Inventories	7	530	719	829
Prepaid taxes and other expenses		133	675	889
Other current assets		147	362	340
Total current assets		**3,415**	**6,094**	**5,676**
Investments	8	750	423	770
Property, plant and equipment	9	8,129	9,906	12,296
Deferred income tax assets	12	79	201	291
Goodwill and intangible assets		251	278	485
Other non-current assets		212	207	424
Total assets		**12,836**	**17,109**	**19,942**
Liabilities and Stockholders' equity				
Current liabilities				
Accounts payable		1,812	2,221	1,402
Short-term borrowings and current portion of long-term debt	10	728	829	1,480
Taxes payable		569	404	522
Other current liabilities		110	238	421
Total current liabilities		**3,219**	**3,692**	**3,825**
Long-term debt	11	1,769	1,483	1,948
Deferred income tax liabilities	12	146	284	390
Other long-term liabilities		145	147	463
Minority interest in subsidiary companies		484	984	931
Total liabilities		**5,763**	**6,590**	**7,557**
Stockholders' equity				
Common stock (738 million, 757 million and 850 million shares of par value of 0.025 rubles each, authorized in 1999, 2000 and 2001, respectively; 738 million, 738 million and 850 million (including 19 million held by subsidiaries) shares issued in 1999, 2000 and 2001 respectively; 678 million, 715 million and 805 million shares outstanding in 1999, 2000 and 2001 respectively)	14	14	14	15
Preferred stock (77 million, 77 million and nil shares of par value of 0.025 rubles each authorized and issued in 1999, 2000 and 2001, respectively; 77 million, 77 million and nil shares outstanding in 1999, 2000 and 2001, respectively)	14	1	1	–
Treasury stock (common and preferred stock, at cost; 62 million, 23 million and 26 million shares in 1999, 2000 and 2001, respectively)	2	(549)	(376)	(403)
Additional paid-in capital	2	2,816	2,895	3,044
Retained earnings		4,803	7,994	9,738
Accumulated other comprehensive loss		(12)	(9)	(9)
Total stockholders' equity		**7,073**	**10,519**	**12,385**
Total liabilities and stockholders' equity		**12,836**	**17,109**	**19,942**

OAO LUKOIL

Consolidated Statements of Income for the years ended December 31, 1999, 2000 and 2001
(Millions of U.S. dollars, except share data)

	Note	1999	2000	2001
Revenues				
Sales (including excise and export tariffs)	19	7,544	13,210	13,426
Equity share in income of affiliates	8	88	230	136
Total revenues		**7,632**	**13,440**	**13,562**
Costs and other deductions				
Operating expenses	19	(2,622)	(4,225)	(4,671)
Selling, general and administrative expenses		(1,623)	(1,956)	(2,294)
Depreciation, depletion and amortization		(598)	(838)	(886)
Taxes other than income taxes		(527)	(1,050)	(1,010)
Excise and export tariffs		(460)	(932)	(1,456)
Exploratory expense		(61)	(130)	(144)
Loss on disposal and impairment of assets		(49)	(247)	(153)
Income from operating activities		**1,692**	**4,062**	**2,948**
Interest expense	19	(192)	(198)	(257)
Interest and dividend income		73	209	146
Currency translation (loss) gain		(34)	1	(33)
Other non-operating (expense) income		(168)	71	31
Minority interest		(34)	(61)	(52)
Income before income taxes		**1,337**	**4,084**	**2,783**
Current income taxes	12	(390)	(790)	(861)
Deferred income taxes	12	115	18	187
Net income		**1,062**	**3,312**	**2,109**
Dividends declared on preferred stock		(8)	(47)	(157)
Net income available for common stockholders		**1,054**	**3,265**	**1,952**
Basic earnings per share of common stock (U.S. dollars)	14	1.69	4.83	2.68
Diluted earnings per share of common stock (U.S. dollars)	14	1.69	4.73	2.66

OAO LUKOIL

Consolidated Statements of Stockholders' Equity and Comprehensive Income for the years ended December 31, 1999, 2000 and 2001 (Millions of U.S. dollars, unless otherwise noted)

	1999		2000		2001	
	Stockholders' equity	Comprehen-sive income	Stockholders' equity	Comprehen-sive income	Stockholders' equity	Comprehen-sive income
Common stock						
Balance at January 1	14		14		14	
Conversion of preferred stock into common stock	–		–		1	
Outstanding at December 31	**14**		**14**		**15**	
Preferred stock						
Balance at January 1	1		1		1	
Conversion of preferred stock into common stock	–		–		(1)	
Outstanding at December 31	**1**		**1**		**–**	
Treasury stock						
Balance at January 1	(426)		(549)		(376)	
Stock purchased	(150)		(1,021)		(185)	
Stock issued	27		1,194		158	
Balance at December 31	**(549)**		**(376)**		**(403)**	
Additional paid-in capital						
Balance at January 1	2,245		2,816		2,895	
Premium on new shares issued	–		–		147	
Premium on shares issued for KomiTEK acquisition	469		–		–	
Contributions required and received under privatization tender	102		117		–	
Proceeds from issuance of treasury stock in excess of carrying amount	–		292		2	
Put option on Company's common stock	–		(330)		–	
Balance at December 31	**2,816**		**2,895**		**3,044**	
Retained earnings						
Balance at January 1	3,756	–	4,803	–	7,994	
Net income	1,062	1,062	3,312	3,312	2,109	2,109
Dividends on preferred stock	(8)	–	(47)	–	(157)	–
Dividends on common stock	(7)	–	(74)	–	(208)	–
Balance at December 31	**4,803**		**7,994**		**9,738**	
Accumulated other comprehensive loss, net of tax						
Balance at January 1	(5)		(12)		(9)	
Foreign currency translation adjustment	(7)	(7)	3	3	14	14
Minimum pension liability adjustment	–	–	–	–	(14)	(14)
Balance at December 31	**(12)**		**(9)**		**(9)**	
Total comprehensive income for the year		1,055		3,315		2,109
Total stockholders' equity as of December 31	**7,073**		**10,519**		**12,385**	

OAO LUKOIL

Consolidated Statements of Stockholders' Equity and Comprehensive Income (continued)
for the years ended December 31, 1999, 2000 and 2001
(Millions of U.S. dollars, unless otherwise noted)

	Share activity		
	1999	**2000**	**2001**
	(millions of shares)	**(millions of shares)**	**(millions of shares)**
Common stock			
Balance at January 1	669	738	738
Issuance of common stock	–	–	35
Conversion of preferred stock into common stock (1 preference share into 6 common shares)	69	–	–
Conversion of preferred stock into common stock (1 preference share into 1 common share)	–	–	77
Balance at December 31	**738**	**738**	**850**
Preferred stock			
Balance at January 1	77	77	77
Issuance of preferred stock	12	–	–
Conversion of preferred stock into common stock	(12)	–	(77)
Balance at December 31	**77**	**77**	**–**
Treasury stock			
Balance at January 1	(48)	(62)	(23)
Purchase of treasury stock	(25)	(88)	(17)
Sales of treasury stock	11	127	14
Balance at December 31	**(62)**	**(23)**	**(26)**

OAO LUKOIL

Consolidated Statements of Cash Flows for the years ended December 31, 1999, 2000 and 2001
(Millions of U.S. dollars)

	1999	2000	2001
Cash flows from operating activities			
Net income	**1,062**	**3,312**	**2,109**
Adjustments for non-cash items			
Depreciation, depletion and amortization	598	838	886
Equity share in income of affiliates	(88)	(230)	(136)
Loss on disposal and impairment of assets	49	247	153
Deferred income taxes	(115)	(18)	(187)
Non-cash currency translation (loss) gain	(37)	(29)	24
Non-cash investing activities	(92)	(177)	(96)
Exploratory expense	61	130	144
All other items – net	(12)	25	37
Changes in operating assets and liabilities:			
Accounts and notes receivable	(139)	(1,142)	931
Short term loan receivables of a banking subsidiary	(70)	(71)	(95)
Net movements of short term borrowings of a banking subsidiary	140	102	208
Inventories	(25)	(50)	(56)
Accounts payable	147	541	(1,077)
Taxes payable	(71)	(195)	109
Other current assets and liabilities	32	(515)	(281)
Net cash provided by operating activities	**1,440**	**2,768**	**2,673**
Cash flows from investing activities			
Capital expenditures	(766)	(1,674)	(2,521)
Proceeds from sale of property, plant and equipment	41	10	45
Purchases of investments	(390)	(197)	(314)
Proceeds from sale of investments	250	47	228
Acquisitions of subsidiaries, net of cash acquired	(10)	(98)	(499)
Net cash used in investing activities	**(875)**	**(1,912)**	**(3,061)**
Cash flows from financing activities			
Net movements of short-term borrowings	(400)	11	121
Proceeds from issuance of long-term debt	549	291	938
Principal payments of long-term debt	(189)	(439)	(349)
Dividends paid	(21)	(118)	(244)
Financing received from stockholders under privatization tender	102	50	–
Purchase of treasury stock	(150)	(1,021)	(185)
Proceeds from sale of treasury stock	27	1,005	158
Other – net	(6)	(7)	32
Net cash (used in) provided by financing activities	**(88)**	**(228)**	**471**
Effect of exchange rate changes on cash and cash equivalents	(33)	(28)	(50)
Net increase in cash and cash equivalents	**444**	**600**	**33**
Cash and cash equivalents at beginning of year	93	537	1,137
Cash and cash equivalents at end of year	**537**	**1,137**	**1,170**
Supplemental disclosures of cash flow information			
Interest paid	134	170	276
Income taxes paid	302	865	833

Note 1. Organization and environment

The primary activities of OAO LUKOIL (“the company”) and its subsidiaries (together, “the Group”) are oil exploration, production, refining, marketing and distribution. The Company is the ultimate parent entity of this vertically integrated group of companies.

The Group was established in accordance with Presidential Decree 1403, issued on November 17, 1992 under which, on April 5, 1993, the Russian Federation (the “State”) transferred to the Company 51% of the voting shares of fifteen enterprises, and Government Resolution 861 issued on September 1, 1995 under which, during 1995 a further nine enterprises were transferred to the Group. Subsequently the Group carried out a share exchange program to increase its shareholding in each of the twenty-four founding subsidiaries to 100%.

From formation, the Group has expanded substantially through consolidation of its interests, acquisition of new companies and establishment of new businesses.

Basis of preparation

The consolidated financial information has been prepared in accordance with accounting principles generally accepted in the United States of America (“U.S. GAAP”).

The financial information reflects management’s assessment of the impact of the business environment in the countries in which the Group operates on the financial position of the Group. Among other things, this includes assessment of collectability of accounts receivable and provisions for taxes (including penalties and interest). The impact on the Group of the current and future business environments may differ from management’s assessment and such differences may be significant.

The financial information should be read in conjunction with the risk factors set out in note 3.

Note 2. Summary of significant accounting policies

Principles of consolidation

The financial position and results of subsidiaries of which the Company directly or indirectly owns more than 50% of the voting interest and which the Company controls are included with the financial position and results of the Company in the consolidated financial information. Other significant investments in companies of which the Company directly or indirectly owns between 20% and 50% of the voting interest and over which the Company exercises significant influence but not control, are accounted for using the equity method of accounting. Investments in other companies are included in ‘Investments’ at cost or fair value.

Use of estimates

The preparation of financial statements in conformity with U.S. GAAP requires management to make estimates and assumptions which affect reported amounts of assets, liabilities, revenues and expenses. Eventual actual amounts could differ from such estimates.

Revenue recognition

Revenues from the production and sale of crude oil and petroleum products are recognized when title passes to customers.

Revenues from non-cash sales are recognized at the fair market value of the crude oil and petroleum products sold.

Foreign currency translation

The accounting records of Group companies’ operations in the Russian Federation are maintained in Russian rubles and the Company prepares its statutory financial statements and reports in that currency to its shareholders in accordance with the laws of the Russian Federation.

As the Russian economy is considered to be hyperinflationary, the U.S. dollar is the functional currency of the Company in accordance with Statement of Financial Accounting Standards (“SFAS”) No. 52, “*Foreign Currency Translation*”.

For the purposes of presenting financial statements prepared in conformity with U.S. GAAP, the U.S. dollar is considered to be the reporting currency of the Group.

Foreign currency transaction gains and losses are included in the consolidated statement of income.

Note 2. Summary of significant accounting policies *(continued)*

For operations in the Russian Federation or other economies considered to be hyperinflationary, monetary assets and liabilities have been translated into U.S. dollars at the rate prevailing at each balance sheet date. Non-monetary assets and liabilities have been translated into U.S. dollars at historical rates. Revenues, expenses and cash flows have been translated into U.S. dollars at rates, which approximate to actual rates at the date of the transaction. Translation differences resulting from the use of these rates are included in the consolidated statements of income.

For the majority of operations outside the Russian Federation, the U.S. dollar is the functional currency. For certain other operations outside the Russian Federation, assets and liabilities are generally translated into U.S. dollars at year-end exchange rates and revenues and expenses are translated at average exchange rates for the year. Resulting translation adjustments are reflected as a separate component of stockholders' equity.

As of December 31, 1999, 2000 and 2001, exchange rates of 27.00, 28.16 and 30.14 Russian rubles, respectively to the U.S. dollar have been used for translation purposes.

A significant portion of the balances and transactions of Group companies are denominated in Russian rubles or in currencies of certain republics of the former Soviet Union. Accordingly, future movements in the exchange rate between the U.S. dollar and the Russian ruble and such other currencies may significantly affect the carrying value of the monetary assets and liabilities of the Group expressed in U.S. dollars. Such changes may also affect the Group's ability to realize non-monetary assets at the amounts stated in the consolidated financial information.

The Russian ruble and other currencies of republics of the former Soviet Union are not convertible outside of their countries. Accordingly, the translation of amounts recorded in these currencies into U.S. dollars should not be construed as a representation that such currency amounts have been, could be or will in the future be converted into U.S. dollars at the exchange rate shown or at any other exchange rate.

Cash and cash equivalents
Cash and cash equivalents include all highly liquid investments with an original maturity of three months or less.

Cash with restrictions on immediate use
Cash funds for which restrictions on immediate use exist are accounted for within other non-current assets. Interest bearing security deposits with credit institutions that do not reduce the balance on long-term loan accounts are accounted for within long-term investments.

Accounts and notes receivable
Accounts and notes receivable are recorded at their transaction amounts less provisions for doubtful debts. Provisions for doubtful debts are recorded to the extent that there is a likelihood that any of the amounts due will not be obtained. Non-current receivables are discounted to the present value of expected cash flows in future periods.

Inventories
Inventories, consisting primarily of stocks of crude oil, petroleum products and materials and supplies, are stated at the lower of cost or market value. Cost is determined using an "average cost" method.

Investments
Debt and equity securities are classified into one of three categories: trading, available-for-sale, or held-to-maturity.

Trading securities are bought and held principally for the purpose of selling in the near term. Held-to-maturity securities are those securities in which a Group company has the ability and intent to hold until maturity. All securities not included in trading or held-to-maturity are classified as available-for-sale.

Note 2. Summary of significant accounting policies *(continued)*

Trading and available-for-sale securities are recorded at fair value. Held-to-maturity securities are recorded at cost, adjusted for the amortization or accretion of premiums or discounts. Unrealized holding gains and losses on trading securities are included in the consolidated statement of income. Unrealized holding gains and losses, net of the related tax effect, on available-for-sale securities are reported as a separate component of comprehensive income until realized. Realized gains and losses from the sale of available-for-sale securities are determined on a specific identification basis. Dividends and interest income are recognized in the consolidated statement of income when earned.

A permanent decline in the market value of any available-for-sale or held-to-maturity security below cost is accounted for as a reduction in the carrying amount to fair value. The impairment is charged to the consolidated statement of income and a new cost base for the security is established. Premiums and discounts are amortized or accreted over the life of the related held-to-maturity or available-for-sale security as an adjustment to yield using the effective interest method and such amortization and accretion is recorded in the consolidated statement of income.

Property, plant and equipment

Oil and gas properties are accounted for using the successful efforts method of accounting whereby property acquisitions, successful exploratory wells, all development costs, and support equipment and facilities are capitalized. Unsuccessful exploratory wells are expensed when a well is determined to be non-productive. Other exploratory expenditures, including geological and geophysical costs are expensed as incurred.

Depreciation, depletion and amortization of capitalized costs of oil and gas properties is calculated using the unit-of-production method based upon proved reserves for the cost of property acquisitions and proved developed reserves for exploration and development costs. Estimated costs of dismantling oil and gas production facilities, including abandonment and site restoration costs are included as a component of depreciation, depletion and amortization.

Production and related overhead costs are expensed as incurred.

Depreciation of assets not directly associated with oil production is calculated on a straight-line basis over the economic lives of such assets, estimated to be in the following ranges:

Buildings and constructions	5 – 40 Years
Machinery and equipment	5 – 20 Years

In addition to production assets, certain Group companies also maintain and construct social assets for the use of local communities. Such assets are capitalized only to the extent that they are expected to result in future economic benefits to the Group. If capitalized, they are depreciated over their estimated economic lives.

Goodwill and intangible assets

Goodwill represents the excess of purchase price over the fair value of net assets acquired. In accordance with the provisions of SFAS 142, "*Goodwill and Other Intangible Assets*" goodwill acquired before June 30, 2001, has been amortized on a straight-line basis over its useful life to a maximum 20 years. Goodwill acquired after June 30, 2001, is not amortized. Identifiable intangible assets are amortized on a straight line basis over their useful or legal lives to a maximum of 20 years.

Note 2. Summary of significant accounting policies *(continued)*

Impairment of long-lived assets

Long-lived assets, including oil and gas properties and goodwill, are assessed for possible impairment in accordance with SFAS No. 121, "*Accounting for the Impairment of Long-Lived Assets and for Long-Lived Assets to Be Disposed Of.*" SFAS No. 121 requires long-lived assets with recorded values which are not expected to be recovered through future cash flows to be written down to current fair value. Fair value is generally determined by reference to discounted estimated future net cash flows. Permanent impairment of the carrying value of long-lived assets is assessed by comparing the carrying value against the undiscounted projection of net future pre-tax cash flows. Where an assessment has indicated impairment in value, the long-lived assets are written down to their fair value, as determined by the discounted projection of net future pre-tax cash flows.

Deferred income taxes

Deferred income tax assets and liabilities are recognized in respect of future tax consequences attributable to temporary differences between the carrying amounts of existing assets and liabilities for the purposes of the consolidated financial statements and their respective tax bases and in respect of operating loss and tax credit carryforwards. Deferred income tax assets and liabilities are measured using enacted tax rates expected to apply to taxable income in the years in which those temporary differences are expected to reverse and the assets be recovered and liabilities settled. The effect on deferred income tax assets and liabilities of a change in tax rates is recognized in the consolidated statement of income in the reporting period which includes the enactment date.

The ultimate realization of deferred income tax assets is dependent upon the generation of future taxable income in the reporting periods in which the originating expenditure becomes deductible. In assessing the realizability of deferred income tax assets, management considers whether it is more likely than not that the deferred income tax assets will be realized. In making this assessment, management considers the scheduled reversal of deferred income tax liabilities, projected future taxable income, and tax planning strategies.

Interest-bearing borrowings

Interest-bearing borrowings are initially recorded at the value of net proceeds received. Any difference between the net proceeds and the redemption value is amortized at a constant rate over the term of the borrowing. Amortization is included in the consolidated statement of income each year and the carrying amounts are adjusted as amortization accumulates.

If borrowings are repurchased or settled before maturity, any difference between the amount paid and the carrying amount is recognized in the consolidated statement of income in the period in which the repurchase or settlement occurs.

Pension benefits

The expected costs in respect of pension obligations of Group companies are determined by an independent actuary. Obligations in respect of each employee are accrued by the relevant Group company over the reporting periods during which the employee renders service in the Group.

Treasury stock

Purchases by Group companies of the Company's outstanding stock are recorded at cost and classified as treasury stock within Stockholders' equity. Shares shown as Authorized and Issued include treasury stock. Shares shown as Outstanding do not include treasury stock.

Additional paid in capital

Additional Paid in Capital represents all capital contributed to the Group other than that defined as par or stated value.

Note 2. Summary of significant accounting policies *(continued)*

Earnings per share
Earnings per share are computed by dividing net income available to common stockholders by the weighted-average number of shares of common stock outstanding during the reporting period. A calculation is carried out to establish if there is potential dilution in earnings per share if convertible securities were to be converted into shares of common stock or contracts to issue shares of common stock were to be exercised. If there is such dilution, diluted earnings per share is presented.

Contingencies
Certain conditions may exist as of balance sheet dates, which may result in losses to the Group but the impact of which will only be resolved when one or more future events occur or fail to occur.

If a Group company's assessment of a contingency indicates that it is probable that a material loss has been incurred and the amount of the liability can be estimated, then the estimated liability is accrued and charged to the consolidated statement of income. If the assessment indicates that a potentially material loss is not probable, but is reasonably possible, or is probable, but cannot be estimated, then the nature of the contingent liability, together with an estimate of the range of possible loss, is disclosed in the notes to the consolidated financial information. Loss contingencies considered remote are generally not disclosed unless they involve guarantees, in which case the nature of the guarantee is disclosed.

Environmental expenditures
Estimated losses from environmental remediation obligations are generally recognized no later than completion of remedial feasibility studies. Group companies accrue for losses associated with environmental remediation obligations when such losses are probable and reasonably estimable. Such accruals are adjusted as further information becomes available or circumstances change. Costs of expected future expenditures for environmental remediation obligations are not discounted to their present value.

Impact of accounting pronouncements
The accounting pronouncements which were adopted during the years ended 31 December 1999, 2000 and 2001 are set out below. In accordance with U.S. GAAP new accounting standards have been applied from their effective date, no adjustment has been made to restate figures reported in prior periods.

Effective January 1, 2001, the Group adopted SFAS No. 133, "*Accounting for Derivative Instruments and Hedging Activities*" and SFAS No. 138, "*Accounting for Certain Derivative Instruments and Certain Hedging Activities – An Amendment of FASB Statement No. 133*." SFAS No. 133 and SFAS No. 138 establish new accounting and reporting standards for derivative instruments and hedging activities and require recognition of all derivatives as assets or liabilities in the balance sheet and measurement of those instruments at fair value. The effect of the adoption of these standards on the Group's operations and consolidated financial statements was not material because of its limited use of derivative instruments.

In June 2000, the FASB issued SFAS No. 140, "*Accounting for Transfers and Servicing of Financial Assets and Extinguishments of Liabilities – a replacement of FASB Statement 125.*" SFAS No. 140 revises the standards for accounting for transfers of assets and extinguishments of liabilities and requires companies to disclose financial assets pledged as collateral separately from other assets. SFAS No. 140 is effective for transfers and extinguishments after March 3, 2001, and for disclosure of assets pledged for fiscal years ending after December 15, 2000. Information about securitized assets is disclosed in notes 10 and 11.

Note 2. Summary of significant accounting policies *(continued)*

In June 2001, the FASB issued SFAS No. 141, "*Business Combinations.*" SFAS No. 141 requires that the purchase method of accounting be used for all business combinations initiated after June 30, 2001 and specifies that certain acquired intangible assets be recognized apart from goodwill. The Group adopted SFAS No. 141 during 2001.

In June 2001, the FASB issued SFAS No. 142, "*Goodwill and Other Intangible Assets*." SFAS No. 142 revises the accounting standards for intangible assets that are acquired individually or with a group of other assets, other than those acquired in a business combination. Under SFAS No. 142, goodwill and certain intangible assets will no longer be amortized, but will be subject to annual impairment tests. The Group adopted SFAS No. 142 effective January 1, 2002. The Group is currently evaluating the impact of adopting SFAS No. 142, including whether any transitional impairment losses will be required to be recognised as a cumulative effect of a change in accounting principle. Beginning January 1, 2002, effective with the adoption of SFAS No. 142, the Group will no longer record amortization expense related to goodwill.

In July 2001, the FASB issued SFAS No. 143, "*Accounting for Asset Retirement Obligations.*" SFAS No. 143 requires entities to record the fair value of a liability for an asset retirement obligation in the period in which it is incurred and a corresponding increase in the carrying amount of the related long-lived asset. Subsequently, the asset retirement obligation should be amortized to expense using a systematic and rational method. The Group is required to adopt SFAS No. 143 in the financial year beginning January 1, 2003. The Group is currently assessing the impact of adopting SFAS No. 143.

In October 2001, the FASB issued SFAS No. 144, "*Accounting for the Impairment or Disposal of Long-Lived Assets*," which addresses financial accounting and reporting for the impairment of long-lived assets and long-lived assets to be disposed of. The standard supersedes, with exceptions, SFAS No. 121, "*Accounting for the Impairment of Long-Lived Assets and for Long-Lived Assets to be Disposed Of.*" SFAS No. 144 became effective for the Group on January 1, 2002, and as of the date of this report, the Group is evaluating the impact of adopting SFAS No. 144.

Note 3. Risk factors

Business and economic environment
The environment for business in the Russian Federation has changed rapidly over the last decade from a system where central planning and direction dominated to one in which market forces increasingly operate. As a result of the speed and continuation of this complex change, the legal and regulatory framework in place in more mature market economies for the protection and regulation of companies and investors is still being developed.

The Russian Federation and other former Soviet Union republics have also experienced periods of political change and macro-economic instability during recent years.

These factors have affected and may continue to affect the activities of enterprises doing business in these environments. Operating in the Russian Federation and other former Soviet Union republics involves risks which do not typically exist in more mature and developed market economies.

Taxation environment
The taxation systems in the Russian Federation and other emerging markets where Group companies operate are relatively new and are characterized by numerous taxes and changing legislation, which may be applied retroactively and is sometimes unclear, contradictory, and subject to interpretation. Often, differing interpretations exist among numerous taxation authorities and jurisdictions. Taxes are subject to review and investigation by a number of authorities, who are enabled by law to impose severe fines, penalties and interest charges. Such factors may create taxation risks in the Russian Federation and other countries where Group companies operate substantially more significant than those in other countries where taxation regimes have been subject to development and clarification over long periods.

The Group has implemented tax planning and management strategies based on existing legislation at the time of implementation. Management believes that it has adequately met and provided for tax liabilities based on its interpretation of such legislation. However, the relevant authorities may have differing interpretations and the effects could be significant.

Insurance
The insurance industry in the Russian Federation and certain other areas where the Group has operations is in the course of development. Many forms of insurance protection common in other parts of the world are not yet generally available. The Group does not have full coverage for its plant facilities, for business interruption, for third party liability in respect of property and for environmental damage arising from accidents on Group property or relating to Group operations. Until Group companies are able to obtain adequate insurance coverage, there is a risk that the loss or destruction of certain assets could have a material adverse effect on the Group's operations and financial position.

Note 4. Cash and cash equivalents

	As of December 31, 1999	As of December 31, 2000	As of December 31, 2001
Cash held in Russian rubles	227	142	373
Cash held in other currencies	310	995	797
Total cash and cash equivalents	**537**	**1,137**	**1,170**

Note 5. Non-cash transactions

The consolidated statement of cash flows excludes the effect of non-cash transactions. The following table shows the distribution of such non-cash transactions:

	Year ended December 31, 1999	Year ended December 31, 2000	Year ended December 31, 2001
Settlement of amounts payable through exchange of goods	740	1,224	1,194
Net non-cash investing activities	92	177	96
Total non-cash transactions	**832**	**1,401**	**1,290**

The following table shows the effect of non-cash transactions on investing activities:

	Year ended December 31, 1999	Year ended December 31, 2000	Year ended December 31, 2001
Net cash used in investing activities	875	1,912	3,061
Net non-cash investing activities	92	177	96
Net cash and non-cash investing activities	**967**	**2,089**	**3,157**

See note 16 “Business combinations” for information about acquisitions partially completed through the exchange of common stock.

Note 6. Accounts and notes receivable

	As of December 31, 1999	As of December 31, 2000	As of December 31, 2001
Trade accounts and notes receivable (net of provisions of $403 million, $98 million and $77 million as of December 31, 1999, 2000 and 2001 respectively)	1,384	2,236	1,383
Current VAT recoverable	255	378	434
Short-term loans of a banking subsidiary receivable (net of provisions of $3 million, $11 million and $14 million as of December 31, 1999, 2000 and 2001, respectively)	106	141	236
Other current accounts receivable (net of provisions of $69 million and $16 million and $21 as of December 31, 1999 and 2000 and 2001, respectively)	186	193	177
Total accounts and notes receivable	**1,931**	**2,948**	**2,230**

Note 7. Inventories

	As of December 31, 1999	As of December 31, 2000	As of December 31, 2001
Crude oil and petroleum products	322	346	389
Materials for extraction and drilling	68	155	218
Materials and supplies for refining	10	53	80
Other goods, materials and supplies	130	165	142
Total inventories	**530**	**719**	**829**

Note 8. Investments

	As of December 31, 1999	As of December 31, 2000	As of December 31, 2001
Investments in “equity method” affiliates and joint ventures	573	274	382
Cash security deposit in a bank	–	–	215
Other long-term investments	177	149	173
Total long-term investments	**750**	**423**	**770**

Investments in “equity method” affiliates and joint ventures

The summarized financial information below is in respect of corporate joint ventures, companies of which the Group owns less than a majority and companies where the Group owns a majority of voting stock, but does not possess a majority of voting rights. The companies are primarily engaged in crude oil exploration, production, marketing, refining and distribution operations in the Russian Federation and crude oil production and marketing in Kazakstan, Azerbaijan and Egypt.

	Year ended December 31, 1999		Year ended December 31, 2000		Year ended December 31, 2001	
	Total	Group’s share	Total	Group’s share	Total	Group’s share
Revenues	2,008	751	2,403	1,040	1,696	694
Income before income taxes	406	140	691	318	436	197
Less income taxes	(140)	(52)	(209)	(88)	(115)	(61)
Net income	**266**	**88**	**482**	**230**	**321**	**136**

	As of December 31, 1999		As of December 31, 2000		As of December 31, 2001	
	Total	Group’s share	Total	Group’s share	Total	Group’s share
Current assets	767	306	514	213	493	194
Property, plant and equipment, net	1,464	717	1,188	598	1,903	941
Other non-current assets	59	28	32	14	126	56
Total assets	**2,290**	**1,051**	**1,734**	**825**	**2,522**	**1,191**
Short-term debt	37	10	2	–	65	27
Other current liabilities	412	144	275	112	452	173
Long-term debt	566	270	785	418	1,214	579
Other non-current liabilities	112	54	48	21	60	30
Net assets	**1,163**	**573**	**624**	**274**	**731**	**382**

Note 9. Property, plant and equipment

	At cost			Net		
	As of December 31, 1999	As of December 31, 2000	As of December 31, 2001	As of December 31, 1999	As of December 31, 2000	As of December 31, 2001
Exploration and Production:						
Western Siberia	10,663	10,652	11,281	3,694	3,798	4,193
European Russia	5,566	7,138	8,928	1,839	2,645	4,148
International	253	657	868	203	553	727
Total	16,482	18,447	21,077	5,736	6,996	9,068
Refining, Marketing and Distribution:						
Western Siberia	–	46	82	–	24	58
European Russia	3,674	4,063	4,307	1,861	2,133	2,335
International	1,090	1,344	1,511	374	574	668
Total	4,764	5,453	5,900	2,235	2,731	3,061
Other:						
Western Siberia	160	185	134	99	123	74
European Russia	56	52	81	47	43	72
International	32	25	47	12	13	21
Total	248	262	262	158	179	167
Total property, plant and equipment	**21,494**	**24,162**	**27,239**	**8,129**	**9,906**	**12,296**

Note 10. Short-term borrowings and current portion of long-term debt

	As of December 31, 1999	As of December 31, 2000	As of December 31, 2001
Short-term borrowings	460	623	1,002
Current portion of long-term debt	268	206	478
Total short-term borrowings and current portion of long-term debt	**728**	**829**	**1,480**

Short-term borrowings are loans from various third parties and are secured by export sales, property, plant and equipment and securities. The weighted average interest rate on short term borrowings from third parties was 4.9% per annum as of December 31, 2001.

Note 11. Long-term debt

	As of December 31, 1999	As of December 31, 2000	As of December 31, 2001
Long-term loans and borrowings from third parties (including loans from banks in the amount of $529 million, $374 million, and $1,153 million as of December 31, 1999, 2000 and 2001 respectively)	917	755	1,453
Long-term loans and borrowings from related parties	233	5	1
3.5% Convertible U.S. dollar bonds, maturing 2002	270	284	298
1% Convertible U.S. dollar bonds, maturing 2003	414	445	476
Variable interest unsecured ruble bonds, maturing 2003	111	107	99
Long-term promissory notes	24	–	–
Capital lease obligation	68	93	99
Total long-term debt	2,037	1,689	2,426
Current portion of long-term debt	(268)	(206)	(478)
Total non-current portion of long-term debt	**1,769**	**1,483**	**1,948**

Long-term loans and borrowings

Long-term loans and borrowings are primarily repayable in U.S. dollars, maturing from 2001 through 2025 and are secured by export sales, property, plant and equipment and securities. The weighted-average interest rate on long-term loans and borrowings from third parties was 8.18%, 6.91% and 6.32% per annum as of December 31, 1999, 2000 and 2001, respectively.

The Company has outstanding obligations of U.S.$150 million under an agreement dated September 7, 2000 with the European Bank for Reconstruction and Development ('EBRD'). This loan is provided for financing the export supplies of oil and refined products, including their refining and transportation.The loan bears interest at LIBOR plus 3.5% and is payable in 2004. In accordance with the agreement all monies deposited in the Company's U.S. dollar account with Raiffeisen Zentralbank Oesterreich AG are assigned as security to EBRD. As at December 31, 2000 and 2001 the amount of such security included in cash and cash equivalents was nil.

The Company has a loan facility with the Russian Commercial Bank that provides borrowings up to $200 million. Borrowings under this loan facility bear interest at LIBOR plus 4%. At December 31, 1999, 2000 and 2001 the amount outstanding under this loan facility was $nil, $nil and $200 million respectively.

A Group subsidiary has a revolving credit facility with Chase Manhattan Bank that provides borrowings up to $89 million. Borrowings under this credit facility bear interest at LIBOR plus 2%. At December 31, 2001 $69 million was outstanding under this credit facility.

The Group has revolving credit facilities with a number of other banks that provide borrowings up to $261 million. The weighted average interest rate under these credit facilities was, 8.8% per annum as of December 31, 2001. At December 31, 2001 outstanding amounts under these credit facilities were $176 million.

Convertible U.S. dollar bonds

On May 6, 1997, a Group company issued 230,000 convertible bonds with a face value of $1,000 each, maturing on May 6, 2002, and convertible to 15 global depositary receipts ('GDRs') of the Company per bond. The liability on the bonds was included in the current portion of long term debt as of December 31, 2001. Subsequently, these bonds have been redeemed for cash at the stated redemption price of 130.323% of the face value and 11,185,059 shares of common stock of the company.

Note 11. Long-term debt *(continued)*

On November 3, 1997, a group company issued 350,000 high yield and premium exchangeable redeemable bonds with a face value of $1,000 each, maturing on November 3, 2003, and exchangeable for 5.625 GDRs of the Company per bond. The bonds are convertible into GDRs up to the maturity dates. The GDRs are exchangeable into four shares of common stock of the Company. Bonds not converted by the maturity date must be redeemed for cash. The redemption price at maturity will be 153.314% of the face value in respect of the bonds issued on November 3, 1997. The Company may redeem the bonds for cash prior to maturity, subject to certain restrictions and early redemption charges. The carrying amount of the bonds is being accreted to their redemption value with the accreted amount being charged to the consolidated statement of income.

Group companies held sufficient treasury stock throughout 1999, 2000 and 2001 to permit the full conversion of the bonds to GDRs.

Rouble bonds
On August 13, 1999, the Company issued three million variable interest rate ruble bonds with a face value of 1,000 rubles each, maturing on August 13, 2003. The bonds are unsecured and bear interest at 6% per annum adjusted for ruble to dollar devaluation, payable semi-annually. The principal is repayable at maturity date at face value in rubles.

Maturities of long term debt
Annual maturities of total long term debt during the next five years, including the portion classified as current, are $478 million in 2002, $799 million in 2003, $208 million in 2004, $424 million in 2005, $374 million in 2006 and $143 million thereafter.

Note 12. Taxes

The Group is taxable in a number of jurisdictions within and outside of the Russian Federation and, as a result, is subject to a variety of taxes as established under the statutory provisions of each jurisdiction.

The total cost of taxation to the Group is reported in the Consolidated Statement of Income as “Current and Deferred income taxes” for income taxes and as “Taxes other than income taxes” for other types of taxation. In each category taxation is made up of taxes levied at various rates in different jurisdictions.

The statutory income tax rates in the Russian Federation applicable to the Company were:

35% from January 1, 1999 to March 31, 1999
30% from April 1, 1999 to December 31, 2000
35% from January 1, 2001 to December 31, 2001

There are not currently, and have not been during the three years ended December 31, 2001, any provisions in the taxation legislation of the Russian Federation to permit the Group to reduce taxable profits in a Group company by offsetting tax losses in another Group company against such profits. Tax losses of a Group company in the Russian Federation may, however, be used fully or partially to offset taxable profits in the same company in any of the ten years following the year of loss, subject to the restriction that no more than 30% of the taxable profit in a given year can be reduced by loss relief.

A number of concessionary taxation rates and allowances have been available to the Group in various jurisdictions during the three years ended December 31, 2001.

Note 12. Taxes *(continued)*

Certain taxation legislation changes in the area of Mineral Extraction and Excise Taxes, Capital Investment Concessions and Concessionary Rate Regimes have recently been made in the Russian Federation, which will first have an impact on the total cost of taxation for the Group in the year ending December 31, 2002. If not mitigated, these changes are expected to increase the overall taxes borne by the Group. It may not be possible to establish other arrangements which facilitate similar tax efficiencies in future to replace the arrangements which have reduced the cost of taxation in the years ended December 31, 1999, 2000 and 2001.

These concessions, concessionary rates and allowances, which are no longer available to the Group, have reduced "Taxes other than income tax" and "Income tax" by approximately the following amounts:

Year ended December 31, 1999	Year ended December 31, 2000	Year ended December 31, 2001
756	1,117	825

Included in "Selling, general and administrative expenses" in arriving at Net income before income taxes were costs related to achieving those tax efficiencies as follows:

Year ended December 31, 1999	Year ended December 31, 2000	Year ended December 31, 2001
235	476	161

Such costs will not be incurred in future years as the concessions and allowances which required them to be incurred are no longer available to the Group. Other tax efficiency arrangements may require other related costs.

Net income before income taxes for the year ended December 31, 1999 included a provision of $288 million in respect of transactions then in progress to facilitate tax efficiency. The transactions were subsequently successfully completed and, accordingly, the provision was released in Net income before income tax for the year ended December 31, 2000.

Domestic and foreign components of income before income taxes and income taxes are shown below:

	Year ended December 31, 1999	Year ended December 31, 2000	Year ended December 31, 2001
Domestic	1,430	4,012	2,616
Foreign	(93)	72	167
Income before income taxes	**1,337**	**4,084**	**2,783**

Domestic and foreign components of income taxes were:

	Year ended December 31, 1999	Year ended December 31, 2000	Year ended December 31, 2001
Current			
Domestic	372	775	849
Foreign	18	15	12
Current income taxes	390	790	861
Deferred			
Domestic	(106)	(27)	(207)
Foreign	(9)	9	20
Deferred income taxes	(115)	(18)	(187)
Total income taxes	**275**	**772**	**674**

Note 12. Taxes *(continued)*

The following table is a reconciliation of the notional income tax at the Russian statutory tax rate applied to Income before income taxes to Total income taxes:

	Year ended December 31, 1999	Year ended December 31, 2000	Year ended December 31, 2001
Income before income taxes	1,337	4,084	2,783
Notional income tax at Russian statutory rates	401	1,225	974
Increase (reduction) in income tax due to:			
Non-deductible items	157	327	191
Domestic and foreign rate differences	(135)	(409)	(233)
Foreign currency gains (losses)	(89)	17	8
Effect of rate changes	(13)	7	19
Investment tax credits	(56)	(417)	(325)
Change in valuation allowance	10	4	39
Other	–	18	1
Total income taxes	**275**	**772**	**674**

Taxes other than income taxes are:

	Year ended December 31, 1999	Year ended December 31, 2000	Year ended December 31, 2001
Royalty tax	168	259	347
Mineral replacement tax	114	150	215
Road users' tax	87	179	100
Social taxes and contributions	78	198	201
Property tax	32	50	83
Other taxes and contributions	48	214	64
Taxes other than income taxes	**527**	**1,050**	**1,010**

Deferred income taxes are included in the consolidated balance sheets as follows:

	As of December 31, 1999	As of December 31, 2000	As of December 31, 2001
Other current assets	36	142	143
Deferred income tax assets – non-current	79	201	291
Other current liabilities	(24)	(108)	(124)
Deferred income tax liabilities – non-current	(146)	(284)	(390)
Net deferred income tax (liability)	**(55)**	**(49)**	**(80)**

Note 12. Taxes *(continued)*

The following table sets out the tax effects of the temporary differences which gave rise to deferred income tax assets and liabilities:

	As of December 31, 1999	As of December 31, 2000	As of December 31, 2001
Accounts receivable	–	87	94
Long-term liabilities	70	105	173
Inventories	10	55	42
Property, plant and equipment	11	50	92
Account payable	29	17	23
Other	15	9	28
Operating loss carry forward	22	69	48
Total gross deferred income tax assets	157	392	500
Less valuation allowance	(42)	(49)	(66)
Deferred income tax assets	**115**	**343**	**434**
Property, plant and equipment	(133)	(257)	(334)
Accounts payable	–	(54)	(45)
Accounts and notes receivable	(14)	(52)	(36)
Inventories	(10)	–	(43)
Investments	(9)	(23)	(20)
Other	(4)	(6)	(36)
Deferred income tax liabilities	**(170)**	**(392)**	**(514)**
Net deferred income tax liability	**(55)**	**(49)**	**(80)**

Retained earnings of foreign subsidiaries included $691 million for which deferred taxation has not been provided for because remittance of the earnings has been indefinitely postponed through reinvestment and as a result, such amounts are considered to be permanently invested.

In accordance with SFAS No. 52 and SFAS No. 109, "*Accounting for Income Taxes*," deferred tax assets and liabilities are not recognized for exchange rate effects resulting from the translation of transactions and balances from the Russian ruble to the U.S. dollar. Also, in accordance with SFAS No. 109, no deferred tax assets or liabilities are recognized for the effects of statutory indexation of property, plant and equipment.

Based upon the level of historical taxable income and projections for future taxable income over the periods in which the deferred income tax assets are deductible, management believes it is more likely than not that Group companies will realize the benefits of the deductible differences, net of the existing valuation allowances as of December 31, 1999, 2000 and 2001.

In August 2000, the Federal Law of the Russian Federation on Income Tax for Companies was amended, giving local authorities the right to increase the statutory income tax rate from 30 to 35%, effective from January 1, 2001. Accordingly, deferred taxes for Russian Group companies as of December 31, 2000 are calculated at 35% and the income tax expense recorded in the period ended December 31, 2000 includes a deferred tax expense of $7 million as a result of this change.

Note 12. Taxes *(continued)*

In August 2001, the Federal Law of the Russian Federation on Tax Code for Companies was amended, establishing a decrease of the statutory income tax rate from 35 to 24%, effective from January 1, 2002. Accordingly, deferred taxes for Russian Group companies as of December 31, 2001 are calculated at 24% and the income tax expense recorded in the period ended December 31, 2001 includes a deferred tax expense of $19 million as a result of this change. Also, as a result of the amendment, certain tax benefits have been eliminated, including investment tax credits.

At December 31, 2001, the Group has operating loss carry forwards of $184 million of which $75 million are attributable to Russian Group companies and expire up to 2011, and for other Group companies $51 million expire during 2006, $40 million expire during 2037, and $18 million have indefinite carry forward.

Note 13. Pension benefits

The Company sponsors a pension plan that covers the majority of Group employees. This plan, administered by a non-state pension fund, LUKOIL-GARANT, provides defined pension benefits based on years of service and final remuneration levels.

The pension related expense was as follows:

	Year ended December 31, 1999	Year ended December 31, 2000	Year ended December 31, 2001
Service cost	7	7	8
Interest cost	23	22	16
Less expected return on plan assets	(2)	(3)	(6)
Amortization of prior service cost	5	5	5
Actuarial (profit) loss	–	–	(3)
Total expense	**33**	**31**	**20**

An independent actuary has assessed the benefit obligations and plan assets for the fund as of December 31, 1999, 2000 and 2001 as summarized below:

	Year ended December 31, 1999	Year ended December 31, 2000	Year ended December 31, 2001
Benefit obligations			
Benefit obligations at January 1	121	121	110
Effect of exchange rate changes	(32)	(5)	(16)
Service cost	7	7	8
Interest cost	23	22	16
Plan amendments	–	7	144
Actuarial (gain) loss	4	(38)	108
Benefits paid	(2)	(4)	(3)
Benefit obligations at December 31	**121**	**110**	**367**
Plan assets			
Fair value of plan assets at January 1	5	12	24
Effect of exchange rate changes	(2)	(1)	(2)
Return on plan assets	4	5	6
Employer contributions	7	12	8
Benefits paid	(2)	(4)	(3)
Fair value of plan assets at December 31	**12**	**24**	**33**

Note 13. Pension benefits *(continued)*

	Year ended December 31, 1999	Year ended December 31, 2000	Year ended December 31, 2001
Funded status	(109)	(86)	(334)
Unamortized prior service cost	63	62	193
Unrecognized actuarial loss (gain)	1	(38)	72
Net amount recognized	**(45)**	**(62)**	**(69)**
Amounts recorded in the consolidated balance sheets were:			
Accrued benefit liabilities	(57)	(62)	(281)
Intangible assets	12	–	193
Additional minimum pension liability	–	–	19
Net amount recognized	**(45)**	**(62)**	**(69)**

	Year ended December 31, 1999	Year ended December 31, 2000	Year ended December 31, 2001
Assumptions as of December 31			
Discount rate	19.5%	15.3%	22.0%
Expected return on plan assets	22.0%	22.0%	22.0%

In addition to the plan assets listed above, LUKOIL–GARANT holds net assets in an operating fund. The operating fund includes an insurance reserve, the purpose of which is to satisfy pension obligations should the plan assets, including contributions due from the Group, not be sufficient to meet pension obligations. The Group's contributions to the pension plan are determined without considering the assets in the insurance reserve.

During 2000, LUKOIL–GARANT acquired a group of companies from the Group. A contingent obligation to purchase 7,876,000 shares of common stock of the Company was included in the terms of the agreement of the sale (Note 14 "Stockholders equity"). The obligation transferred to LUKOIL–GARANT will only be settled from the assets held by the group of companies acquired by LUKOIL–GARANT.

Note 14. Stockholders' equity

Common Stock
Common stock holders are the principal stock holders of the Company with rights to vote at stockholder meetings.

Preferred stock
Holders of preferred stock have the right to receive annual fixed dividends. The fixed dividend is 10% of the net income of the reporting year or the dividend paid on each share of common stock, which ever is the greater. During 2001, all outstanding preference shares were converted to common stock (see below).

Dividends and dividend limitations
Profits available for distribution to common stockholders in respect of any reporting period are determined by reference to the statutory financial statements of the Company prepared in accordance with the laws of the Russian Federation and denominated in rubles. Under Russian Law, dividends are limited to the net profits as set out in the statutory financial statements of the Company. These laws and other legislative acts governing the rights of shareholders to receive dividends are subject to various interpretations.

Note 14. Stockholders' equity *(continued)*

The net profits included in the statutory financial statements of the Company were:

	Year ended December 31, 1999	Year ended December 31, 2000	Year ended December 31, 2001
Net profits (million rubles)	13,404	45,686	20,987
Net profits translated at year end rates ($million)	496	1,622	696

At the annual stockholders' meeting on June 29, 1999, dividends were declared for 1998 in the amount of 0.25 rubles per common share and 2.67 rubles per preferred share, which at the date of the decision was equivalent to $0.01 and $0.11, respectively.

At the annual stockholders' meeting on June 8, 2000, dividends were declared for 1999 in the amount of 3.00 rubles per common share and 17.45 rubles per preferred share, which at the date of the decision was equivalent to $0.11 and $0.62, respectively.

At the annual stockholders' meeting on June 28, 2001, dividends were declared for 2000 in the amount of 8.00 rubles per common share and 59.16 rubles per preferred share, which at the date of the meeting was equivalent to $0.27 and $2.03, respectively.

Share capital

At the annual stockholders meeting on June 8, 2000 a resolution to increase the number of shares of common stock by 35,000,000 shares of par value of 0.025 Russian rubles each was approved. The Company issued and exchanged 18,431,061 of these shares for shares of OAO Arkhangelskgeoldobycha and for minority interest shareholdings of OAO LUKOIL-Ukhtaneftepererabotka and OAO LUKOIL-Kominefteproduct (note 16, "Business combinations") and sold 16,568,939 shares to LUKinter Finance B.V., a Group company. The results of these issues were registered by the Russian Federal Commission for Securities on April 27, and October 9, 2001, respectively.

At the annual stockholders meeting on June 28, 2001 a resolution to increase the number of shares of common stock by 77,211,864 shares of par value of 0.025 Russian rubles each was approved. These shares were exchanged for all of the outstanding preferred stock of the Company in the ratio of one share of common stock for one share of preferred stock. The results of this transaction were registered by the Russian Federal Commission for Securities on December 14, 2001.

During 2001, the Company issued 2,780,525 shares (included in the 18,431,061 shares disclosed above) to LUKOIL Finance Limited, a Group company, in exchange for its 15.7% of the shares in OAO Arkhangelskgeoldobycha (note 16, "Business combinations"). These shares and the 16,568,939 shares sold to LUKinter Finance B.V. were held by these subsidiaries at December 31, 2001. The shares held by subsidiaries were not considered to be outstanding shares at December 31, 2001 in the consolidated financial statements.

As noted in note 13 "Pension benefits" the Group sold a group of companies to LUKOIL-GARANT, a related party, during 2000. The assets and liabilities of the companies sold included 45,108,103 shares of common stock of the Company (accounted for as Treasury Stock of the Group prior to the sale) and a contingent obligation to purchase a further 7,876,000 shares of common stock of the Company from the Company on November 3, 2003. The contingent obligation is in the form of a put option held by the Group. The fair value of the net assets of the companies sold by the Group including the contingent obligations, was equivalent to the amount paid by LUKOIL-GARANT for the group of companies.

Note 14. Stockholders' equity *(continued)*

Earnings per share
The calculation of diluted earnings per share for these years was as follows:

	Year ended December 31, 1999	Year ended December 31, 2000	Year ended December 31, 2001
Net income	1,062	3,312	2,109
Dividends on preferred shares	(8)	(47)	(157)
Net income related to common shares	1,054	3,265	1,952
Add back convertible debt interest (net of tax at effective rate)			
3.5% Convertible U.S. dollar bonds, maturing 2002	17	17	17
1% Convertible U.S. dollar bonds, maturing 2003	23	23	23
Total diluted net income	1,094	3,305	1,992
Weighted average number of outstanding common shares (thousands of shares)	622,990	676,341	727,348
Add back treasury shares held in respect of convertible debt (thousands of shares)	21,675	21,675	21,675
Weighted average number of outstanding common shares, after dilution (thousands of shares)	644,665	698,016	749,023

Note 15. Financial instruments

Fair value
The fair values of cash and cash equivalents, current accounts and notes receivable, and liquid securities are approximately equal to their value as disclosed in the consolidated financial information.

The fair value of long-term receivables included in other non-current assets approximates the amounts disclosed in the consolidated financial information as a result of discounting using estimated market interest rates for similar financing arrangements. Long-term debt is the only category of financial instruments whose fair value differs materially from the amount disclosed in the consolidated financial information.

The estimated fair value of long-term debt as of December 31, 2000 and 2001 was $1,515 million, and $2,081 million respectively, as a result of discounting using estimated market interest rates for similar financing arrangements. These amounts include all future cash outflows associated with the long term debt repayment, including its current portion, and interest.

Note 16. Business combinations

In September 1999, the Group acquired OAO KomiTEK and minority interests held in the KomiTEK group of companies for $619 million through a share exchange. KomiTEK is an integrated oil and gas company operating primarily in the Komi Republic in the Russian Federation.

In October 1999, the Group was part of a consortium which acquired 58% of the company which owns the Neftochim Burgas AD refinery located in Bulgaria for $81 million. The Group held a 51% interest in this consortium. During 2000, the Group bought out the remaining 49% consortium interest held by other consortium parties. The consideration for this acquisition was cash of $45 million and debt of $42 million to be paid over 7 years. The Group's effective ownership in the Neftochim Burgas AD refinery as of December 31, 2001 and 2000 was 58%.

Note 16. Business combinations *(continued)*

In May 2000, the Group acquired LUK–Sintez Oil B.V. which owns 97% of the OAO Odessa Oil Refinery Plant located in Ukraine for $20 million.

In June 2000, the Group acquired 14% of ZAO LUKOIL–Perm in exchange for 54% of the Group's interest in OAO Vatoil thereby increasing the Group's ownership stake in ZAO LUKOIL Perm to 64% and reducing the Group's effective interest in OAO Vatoil from 100% to 80%. Prior to this acquisition, ZAO LUKOIL–Perm was recorded as an associated company using the equity method of accounting. During 2001 the Group increased its ownership stake in LUKOIL Perm to 73%. ZAO LUKOIL–Perm is an exploration and production company operating in European Russia.

In June 2000, the Group acquired 7% of OAO RITEK for $1 million thereby increasing the Group's ownership stake in OAO RITEK to 51%. Prior to this acquisition, OAO RITEK was recorded as an associated company using the equity method of accounting. OAO RITEK is an exploration and production company operating in Western Siberia.

In December 2000, the Group acquired 32% of ZAO KomiArcticOil for $44 million thereby increasing the Group's ownership stake in ZAO KomiArcticOil to 53%. Prior to the acquisition, ZAO KomiArcticOil was recorded as an associated company using the equity method of accounting. ZAO KomiArcticOil is an exploration and production company operating in the Komi Republic in the Russian Federation.

In December 2000, the Group acquired 72% of Getty Petroleum Marketing Inc. for $53 million. Getty Petroleum Marketing Inc. is a marketing and distribution company operating throughout the Northeast and Mid Atlantic regions of the United States of America. In January 2001, the Group acquired the remaining 28% of shares in Getty Petroleum Marketing Inc. for $20 million thereby increasing the Group's ownership stake in Getty Petroleum Marketing Inc. to 100%.

In March 2001, the Company acquired 74% of the shares in OAO Arkhangelskgeoldobycha in exchange for 17,710,697 shares of common stock and cash consideration of $130 million. The shares of OAO Arkhangelskgeoldobycha were held by third parties, LUKOIL-GARANT, a related party, and LUKOIL Finance Limited, a Group company, which had acquired its interest in OAO Arkhangelskgeoldobycha from a third party in January 2001 for $39 million. OAO Arkhangelskgeoldobycha is a Russian oil and gas exploration company operating predominantly within the Timan-Pechora region of Northern Russia.

In March 2001, the Company also exchanged 720,724 shares of common stock for 13% and 22% of the minority interest shareholding of OAO LUKOIL Ukhtaneftepererabotka and OAO LUKOIL-Kominefteproduct, respectively. OAO LUKOIL Ukhtaneftepererabotka is an oil refinery and OAO LUKOIL-Kominefteproduct is a marketing and distribution company. Both companies operate primarily in the Komi Republic of Russia.

In September 2001, the Group acquired 100% of the share capital of Bitech Petroleum Corporation ("Bitech") for $77 million. Bitech is a Canadian oil exploration company with operations predominantly within the Komi Republic of Russia.

In May and December 2001, the Group acquired 25% and 35%, respectively, of the share capital of OAO "Yamalneftegazodobycha" in total for $104 million. Prior to the December acquisition, OAO Yamalneftegazodobycha was recorded as an associated company using the equity method of accounting. OAO Yamalneftegazodobycha is a Russian oil and gas exploration company with significant proved undeveloped reserves predominantly within the Yamal Nenetsky Autonomous District of Northern Russia.

Note 17. Commitments and contingencies

Capital expenditure and investment programs
Under the terms of the purchase agreement, the Group is required to invest $268 million in the Neftochim Burgas AD refinery prior to 2005. As of December 31, 2001 the Group's commitments under these agreements were $184 million.

Under the terms of the original purchase agreement, the Group is required to invest $200 million in the Petrotel SA refinery prior to 2005. As of December 31, 2001 the Group's commitments under these agreements were $114 million ($50 million for 2002-2005 and $64 million for 2006-2008).

Group companies have commitments of $39 million in 2002 and, $6 million in 2003 for the construction of oil tankers.

Group companies have exploratory and development drilling commitments under the terms of exploration and development licence agreements in the Russian Federation of $471 million over the next five years.

Group companies have commitments for capital expenditure contributions in the amount of $1,008 million to be spent in the Caspian region over the next 29 years.

Group companies have investment commitments relating to oil deposits in Iraq of $495 million to be spent within three years from when exploitation becomes possible.

Operating lease obligations
A Group company has commitments of $864 million for the lease of petroleum distribution outlets over the next 14 years. Commitments for minimum rentals under these leases as of December 31, 2001 are as follows:

	As of December 31, 2001
2002	67
2003	62
2004	62
2005	62
2006 and beyond	611

Letters of credit and financial guarantees
As of December 31, 1999, 2000 and 2001, Group companies were contingently liable for performance under letters of credit and other financial guarantees totaling approximately $356 million, $5 million and $975 million.

Environmental liabilities
Group companies and their predecessor entities, have operated in the Russian Federation and other countries for many years and, in certain parts of the operations, environmental problems have developed. Environmental regulations are currently under consideration in both the Russian Federation and other areas where the Group has operations. Group companies routinely assess and evaluate their obligations in response to new and changing legislation.

As liabilities in respect of the Group's environmental obligations are able to be determined, they are provided for over the estimated remaining lives of the related assets or recognized immediately depending on their nature. The likelihood and amount of liabilities relating to environmental obligations under proposed or any future legislation cannot be reasonably estimated at present and could become material. Under existing legislation, however, management believes that there are no significant unrecorded liabilities or contingencies, which could have a materially adverse effect on the operating results or financial position of the Group.

Note 17. Commitments and contingencies *(continued)*

In respect of disassembling equipment, winding up production and restoring work sites, potential expenses for Group companies as of December 31, 1999, 2000 and 2001 were estimated at $1,273 million, $964 million and $1,546 million, respectively. Of these amounts, $152 million, $200 million and $267 million are included in accumulated depreciation, depletion and amortization as of December 31, 1999, 2000 and 2001, respectively.

Social assets
Certain Group companies contribute to Government sponsored schemes, the maintenance of local infrastructure and the welfare of their employees within the Russian Federation and elsewhere. Such contributions include assistance with the construction, development and maintenance of housing, hospitals and transport services, recreation and other social needs. The funding of such assistance is periodically determined by management and is appropriately capitalized or expensed as incurred.

Litigation and claims
On November 27, 2001, Archangel Diamond Corporation ("ADC"), a diamond development company filed a lawsuit in the circuit court of Denver, Colorado, against OAO "Arkhangelskgeoldobycha" ("AGD"), a Group company, and the Company (together the "Defendants") claiming compensation for damage allegedly caused by the Defendants relating to Almazny Bereg, a joint venture between AGD and ADC. ADC claims, among other things, that the Defendants interfered with the transfer of a diamond exploitation licence which was subject to an agreement between ADC and AGD. The total damages claimed by ADC is $4.8 billion, including compensatory damages of $1.2 billion and punitive damages of $3.6 billion. The claim is currently in its early stages, but the Company believes the claim to be without merit and plans a vigorous defence which includes among other defenses an objection to jurisdiction. While the claim is in its early stages and no assurance can be given about the ultimate outcome, the Company does not believe that the ultimate resolution of this matter will have a material adverse effect on its financial condition.

The Group is involved in various other claims and legal proceedings arising in the normal course of business. While these claims may seek substantial damages against the Group and are subject to uncertainty inherent in any litigation, management does not believe that the ultimate resolution of such matters will have a material adverse impact on the group's operating results or financial condition.

Other matters
During July 2001, the Group temporarily shut down operations of the Petrotel SA refinery due to the economic conditions in Romania. The refinery remains closed as of the date of this report. Management is currently assessing its plans regarding the future operations of this refinery and options in relation to the Group's Romanian operations. If management decides to sell or abandon the refinery, the Group may be exposed to losses on the carrying value of property, plant and equipment of approximately $60 million.

Additionally, a decision to abandon the refinery may result in claims against the Group's future investment commitments as described in this note under *Capital expenditure and investment programs*.

Note 18. Related party transactions

In the rapidly developing business environment in the Russian Federation, companies and individuals have frequently used nominees and other forms of intermediary companies in transactions. The senior management of the Company consider that the Group has appropriate procedures in place to identify and properly disclose transactions with related parties in this environment and has disclosed all of the relationships identified which it deemed to be significant.

	Year ended December 31, 1999 $m	Year ended December 31, 2000 $m	Year ended December 31, 2001 $m
Sales of oil and oil products	215	44	98
Other sales	10	34	46
Purchase of oil and oil products	273	441	305
Purchase of construction services	118	355	389
Purchase of insurance services	–	–	214
Other purchases	83	181	128
Amounts receivable at year end (including loans and advances)	120	121	209
Amounts payable at year end	50	83	73

LUKOIL–GARANT is a defined benefit pension fund established for the benefit of employees of the Group. Transactions and balances with the fund are disclosed in notes 13, 14 and 16.

As of December 31, 1999, 2000 and 2001 the Government of the Russian Federation owned respectively 28%, 16% and 14% of the shares of the common stock of the Company. The Russian Federation also owns, controls, or has significant influence over the operations of many other companies and enterprises in the Russian Federation and has a significant influence on the operation of the business and economic environment. A significant part of the activity of Group companies is linked to companies belonging to or controlled by the Russian Federation. The Russian Federation is a customer and supplier of the Group through numerous affiliated and other related organizations. Management consider such trading relationships as part of the normal course of conducting business in the Russian Federation and consider that such relationships will remain for the foreseeable future. Accordingly, information on these transactions is not disclosed as related party transactions.

Note 19. Segment information

Presented below is information about the Company's operating and geographical segments for the years ended December 31, 1999, 2000 and 2001 in accordance with SFAS No. 131, "*Disclosures about Segments of an Enterprise and Related Information.*"

The Company has three operating segments – exploration and production; refining, marketing and distribution; and other business segments. These segments have been determined based on the nature of their operations. Management, on a regular basis, assesses the performance of these operating segments. The exploration and production segment explores for, develops and produces primarily crude oil. The refining, marketing and distribution segment processes crude oil into refined products and purchases, sells and transports crude oil and refined petroleum products. Activities of the other businesses operating segment include the development of businesses beyond the Company's traditional operations.

The sales, operating expenses and net income figures reported by division and region below include the effects of intercompany transfer pricing and certain tax planning arrangements. As a result the reported figures are significantly affected by these arrangements. Were the figures to be prepared on any other basis the profitability of divisions and regions may be materially different.

For the years ended December 31, 1999, 2000 and 2001 the Group had one customer who accounted for 21.2%, 18.2% and 14.2% of total sales respectively.

Geographical segments have been determined based on the area of operations and include three segments. They are western Siberia, European Russia and International.

Operating segments

1999	Exploration and production	Refining, marketing and distribution	Other	Elimination	Consolidated
Sales					
Third parties	635	6,798	111	–	7,544
Inter-segment	1,491	59	2	(1,552)	–
Total sales	2,126	6,857	113	(1,552)	7,544
Operating expenses	648	3,470	56	(1,552)	2,622
Depletion, depreciation and amortization	471	127	–	–	598
Interest expense	26	167	9	(10)	192
Income taxes	54	215	6	–	275
Net income	139	851	72	–	1,062
Total assets	7,671	5,828	154	(1,150)	12,503
Capital expenditures	388	466	4	–	858

Note 19. Segment information *(continued)*

2000	Exploration and production	Refining, marketing and distribution	Other	Elimination	Consolidated
Sales					
Third parties	834	12,211	165	–	13,210
Inter-segment	2,919	681	70	(3,670)	–
Total sales	3,753	12,892	235	(3,670)	13,210
Operating expenses	1,283	6,405	154	(3,617)	4,225
Depletion, depreciation and amortization	611	221	6	–	838
Interest expense	37	169	32	(40)	198
Income taxes	154	605	13	–	772
Net income	794	2,727	(96)	(113)	3,312
Total assets	9,359	8,956	492	(1,698)	17,109
Capital expenditures	945	909	30	(17)	1,867

2001	Exploration and production	Refining, marketing and distribution	Other	Elimination	Consolidated
Sales					
Third parties	1,225	12,144	57	–	13,426
Inter-segment	4,153	347	136	(4,636)	–
Total sales	5,378	12,491	193	(4,636)	13,426
Operating expenses	2,031	7,149	130	(4,639)	4,671
Depletion, depreciation and amortization	606	278	2	–	886
Interest expense	74	190	27	(34)	257
Income taxes	52	605	17	–	674
Net income	911	1,175	11	12	2,109
Total assets	12,024	10,101	843	(3,026)	19,942
Capital expenditures	1,789	810	18	–	2,617

Geographical segments

	1999	2000	2001
Sales of crude oil within Russia	989	1,471	992
Export of crude oil and sales of oil by foreign subsidiaries	3,812	4,380	3,951
Sales of refined product within Russia	520	2,287	2,595
Export of refined product and sales of refined products by foreign subsidiaries	1,544	4,165	4,901
Other sales within Russia	576	830	594
Other export sales and other sales of foreign subsidiaries	103	77	393
Total sales	7,544	13,210	13,426

Note 19. Segment information *(continued)*

1999	Western Siberia	European Russia	International	Elimination	Consolidated
Sales					
Third parties	222	2,403	4,919	–	7,544
Inter-segment	1,139	2,710	24	(3,873)	–
Total sales	1,361	5,113	4,943	(3,873)	7,544
Operating expenses	412	1,831	4,252	(3,873)	2,622
Depletion, depreciation and amortization	338	187	73	–	598
Interest expense	4	114	74	–	192
Income taxes	23	243	9	–	275
Net income	611	553	(102)	–	1,062
Total assets	4,281	7,200	2,186	(1,164)	12,503
Capital expenditures	214	526	118	–	858

2000	Western Siberia	European Russia	International	Elimination	Consolidated
Sales					
Third parties	176	4,628	8,406	–	13,210
Inter-segment	1,831	4,754	68	(6,653)	–
Total sales	2,007	9,382	8,474	(6,653)	13,210
Operating expenses	842	2,598	7,385	(6,600)	4,225
Depletion, depreciation and amortization	332	390	116	–	838
Interest expense	1	129	96	(28)	198
Income taxes	71	677	24	–	772
Net income	232	3,151	48	(119)	3,312
Total assets	4,737	10,434	3,212	(1,274)	17,109
Capital expenditures	377	1,172	335	(17)	1,867

2001	Western Siberia	European Russia	International	Elimination	Consolidated
Sales					
Third parties	379	4,389	8,658	–	13,426
Inter-segment	2,329	5,204	73	(7,606)	–
Total sales	2,708	9,593	8,731	(7,606)	13,426
Operating expenses	1,220	3,450	7,610	(7,609)	4,671
Depletion, depreciation and amortization	325	404	157	–	886
Interest expense	19	168	73	(3)	257
Income taxes	(66)	714	26	–	674
Net income	477	1,482	141	9	2,109
Total assets	5,400	11,883	3,991	(1,332)	19,942
Capital expenditures	667	1,579	371	–	2,617

OAO LUKOIL

Supplemental Information on Oil and Gas Exploration and Production Activities (Unaudited)
(Millions of U.S. dollars, except as indicated)

This section sets out unaudited supplemental information on oil and gas exploration and production activity of Group companies provided by management of the Company to address the requirements of Statement of Financial Accounting Standards ("SFAS") No. 69 "*Disclosures about Oil and Gas Producing Activities*" in six separate tables:

I. Capitalized costs relating to oil and gas producing activities

II. Costs incurred in oil and gas property acquisition, exploration, and development activities

III. Results of operations for oil and gas producing activities

IV. Reserve quantity information

V. Standardized measure of discounted future net cash flows

VI. Principal sources of changes in the standardized measure of discounted future net cash flows

I. Capitalized costs relating to oil and gas producing activities

As of December 31, 1999	**International**	**Russia**	**Total**
Unproved oil and gas properties	–	34	34
Proved oil and gas properties	303	15,709	16,012
Accumulated depreciation, depletion, and amortization	(50)	(10,487)	(10,537)
Net capitalized costs	253	5,256	5,509
Group's share of "equity method" affiliates' net capitalized costs	189	351	540
Net capitalized costs	442	5,607	6,049

As of December 31, 2000	**International**	**Russia**	**Total**
Unproved oil and gas properties	–	246	246
Proved oil and gas properties	657	17,020	17,677
Accumulated depreciation, depletion, and amortization	(104)	(11,127)	(11,231)
Net capitalized costs	553	6,139	6,692
Group's share of "equity method" affiliates' net capitalized costs	164	104	268
Net capitalized costs	717	6,243	6,960

As of December 31, 2001	**International**	**Russia**	**Total**
Unproved oil and gas properties	–	354	354
Proved oil and gas properties	868	19,855	20,723
Accumulated depreciation, depletion, and amortization	(141)	(11,868)	(12,009)
Net capitalized costs	727	8,341	9,068
Group's share of "equity method" affiliates' net capitalized costs	157	169	326
Net capitalized costs	884	8,510	9,394

OAO LUKOIL

Supplemental Information on Oil and Gas Exploration and Production Activities (Unaudited)
(Millions of U.S. dollars, except as indicated)

II. Costs incurred in oil and gas property acquisition, exploration, and development activities

Year ended December 31, 1999	International	Russia	Total
Acquisition of properties – proved	–	943	943
Acquisition of properties – unproved	–	2	2
Exploration costs	–	61	61
Development costs	56	271	327
Group's share of "equity method" affiliates' costs of property acquisition, exploration and development	40	24	64
Total costs incurred	96	1,301	1,397

Year ended December 31, 2000	International	Russia	Total
Acquisition of properties – proved	–	631	631
Acquisition of properties – unproved	–	32	32
Exploration costs	18	112	130
Development costs	279	536	815
Group's share of "equity method" affiliates' costs of property acquisition, exploration and development	35	34	69
Total costs incurred	332	1,345	1,677

Year ended December 31, 2001	International	Russia	Total
Acquisition of properties – proved	–	445	445
Acquisition of properties – unproved	–	310	310
Exploration costs	–	144	144
Development costs	246	1,399	1,645
Group's share of "equity method" affiliates' costs of property acquisition, exploration and development	49	65	114
Total costs incurred	295	2,363	2,658

OAO LUKOIL

Supplemental Information on Oil and Gas Exploration and Production Activities (Unaudited)
(Millions of U.S. dollars, except as indicated)

III. Results of operations for oil and gas producing activities

Year ended December 31, 1999	**International**	**Russia**	**Total**
Revenue			
Sales	71	3,755	3,826
Transfers	–	528	528
	71	4,283	4,354
Production costs (excluding production taxes)	26	651	677
Exploratory expense	–	61	61
Depreciation, depletion, and amortization	51	420	471
Taxes other than income taxes	1	448	449
Related income taxes	3	980	983
Results of operations from producing activities (excluding corporate overhead and interest costs)	(10)	1,723	1,713
Group's share of "equity method" affiliates' results of operations for producing activities	3	135	138
Total results of operations for producing activities	(7)	1,858	1,851

Year ended December 31, 2000	**International**	**Russia**	**Total**
Revenue			
Sales	284	6,531	6,815
Transfers	–	2,429	2,429
	284	8,960	9,244
Production costs (excluding production taxes)	30	1,199	1,229
Exploratory expense	18	112	130
Depreciation, depletion, and amortization	48	563	611
Taxes other than income taxes	2	674	676
Related income taxes	47	1,914	1,961
Results of operations from producing activities (excluding corporate overhead and interest costs)	139	4,498	4,637
Group's share of "equity method" affiliates' results of operations for producing activities	37	43	80
Total results of operations for producing activities	176	4,541	4,717

OAO LUKOIL

Supplemental Information on Oil and Gas Exploration and Production Activities (Unaudited)
(Millions of U.S. dollars, except as indicated)

III. Results of operations for oil and gas producing activities (continued)

Year ended December 31, 2001	**International**	**Russia**	**Total**
Revenue			
Sales	142	5,149	5,291
Transfers	–	3,139	3,139
	142	8,288	8,430
Production costs (excluding production taxes)	16	1,620	1,636
Exploratory expense	–	144	144
Depreciation, depletion, and amortization	49	557	606
Taxes other than income taxes	–	1,751	1,751
Related income taxes	20	1,451	1,471
Results of operations from producing activities (excluding corporate overhead and interest costs)	57	2,765	2,822
Group's share of "equity method" affiliates' results of operations for producing activities	46	33	79
Total results of operations for producing activities	103	2,798	2,901

IV. Reserve quantity information

Proved reserves are the estimated quantities of oil and gas reserves which geological and engineering data demonstrate will be recoverable with reasonable certainty in future years from known reservoirs under existing economic and operating conditions. Proved reserves do not include additional quantities of oil and gas reserves recoverable beyond the term of the lease or concession agreement which may result from extensions of currently proved areas or from applying secondary or tertiary recovery processes not yet tested and determined to be economic.

Proved developed reserves are the quantities of reserves expected to be recovered through existing wells with existing equipment and operating methods.

Due to the inherent uncertainties and the necessarily limited nature of reservoir data, estimates of reserves are subject to change as additional information becomes available.

OAO LUKOIL

Supplemental Information on Oil and Gas Exploration and Production Activities (Unaudited)
(Millions of U.S. dollars, except as indicated)

IV. Reserve quantity information (continued)

Group companies' estimated net proved oil and gas reserves and changes thereto for the years 1999, 2000 and 2001 are shown in the table set out below.

	International		Russia		Total	
Proved Reserves	**Millions of barrels**	**Millions of tonnes**	**Millions of barrels**	**Millions of tonnes**	**Millions of barrels**	**Millions of tonnes**
Oil equivalent						
January 1, 1999	376	51	10,242	1,397	10,618	1,448
Revisions of previous estimates	–	–	1,026	140	1,026	140
Purchase of hydrocarbons in place	–	–	1,314	179	1,314	179
Extensions and discoveries	–	–	187	26	187	26
Production	(7)	(1)	(472)	(64)	(479)	(65)
Sales of reserves	–	–	(197)	(27)	(197)	(27)
December 31, 1999	369	50	12,100	1,651	12,469	1,701
Revisions of previous estimates	277	38	(671)	(92)	(394)	(54)
Purchase of hydrocarbons in place	–	–	1,167	159	1,167	159
Extensions and discoveries	26	4	302	41	328	45
Production	(14)	(2)	(515)	(70)	(529)	(72)
Sales of reserves	–	–	(21)	(3)	(21)	(3)
December 31, 2000	658	90	12,362	1,686	13,020	1,776
Revisions of previous estimates	(12)	(1)	(13)	(2)	(25)	(3)
Purchase of hydrocarbons in place	–	–	3,033	414	3,033	414
Extensions and discoveries	3	–	741	101	744	101
Production	(11)	(2)	(521)	(71)	(532)	(73)
December 31, 2001	**638**	**87**	**15,602**	**2,128**	**16,240**	**2,215**
Group's share of the reserves of affiliates, accounted for using the "equity method" as at December 31, 1999	179	24	797	109	976	133
Group's share in the reserves of affiliates, accounted for using the "equity method" as at December 31, 2000	184	25	295	40	479	65
Group's share in the reserves of affiliates, accounted for using the "equity method" as at December 31, 2001	213	29	360	49	573	78
Minority's share, included in the above proved reserves as at December 31, 1999	–	–	41	6	41	6
Minority's share, included in the above proved reserves as at December 31, 2000	–	–	568	77	568	77
Minority's share, included in the above proved reserves as at December 31, 2001	–	–	1,510	206	1,510	206

IV. *Reserve quantity information (continued)*

	International		Russia		Total	
Proved reserves, adjusted for minority interests:	Millions of barrels	Millions of tonnes	Millions of barrels	Millions of tonnes	Millions of barrels	Millions of tonnes
December 31, 1999	548	74	12,856	1,754	13,404	1,828
December 31, 2000	842	115	12,089	1,649	12,931	1,764
December 31, 2001	**851**	**116**	**14,452**	**1,971**	**15,303**	**2,087**
Proved developed reserves, adjusted for minority interests:						
December 31, 1999	79	11	7,894	1,077	7,973	1,088
December 31, 2000	196	27	8,417	1,148	8,613	1,175
December 31, 2001	**300**	**41**	**8,917**	**1,216**	**9,217**	**1,257**

V. *Standardized measure of discounted future net cash flows*

The standardized measure of discounted future net cash flows, related to the above oil and gas reserves, is calculated in accordance with the requirements of SFAS No. 69. Estimated future cash inflows from production are computed by applying year-end prices for oil and gas to year-end quantities of estimated net proved reserves. Adjustment in this calculation for future price changes is limited to those required by contractual arrangements in existence at the end of each reporting year. Future development and production costs are those estimated future expenditures necessary to develop and produce year-end estimated proved reserves based on year-end cost indices, assuming continuation of year-end economic conditions. Estimated future income taxes are calculated by applying appropriate year-end statutory tax rates. These rates reflect allowable deductions and tax credits and are applied to estimated future pre-tax net cash flows, less the tax bases of related assets. Discounted future net cash flows have been calculated using a ten percent discount factor. Discounting requires a year-by-year estimate of when future expenditures will be incurred and when reserves will be produced.

The information provided in the tables set out below does not represent management's estimate of the Group's expected future cash flows or of the value of the Group's proved oil and gas reserves. Estimates of proved reserve quantities are imprecise and change over time as new information becomes available. Moreover, probable and possible reserves, which may become proved in the future, are excluded from the calculations. The arbitrary valuation prescribed under SFAS No. 69 requires assumptions as to the timing and amount of future development and production costs. The calculations should not be relied upon as an indication of the Group's future cash flows or of the value of its oil and gas reserves.

	International	Russia	Total
As of December 31, 1999			
Future cash inflows	5,556	148,295	153,851
Future production and development costs	(3,376)	(63,950)	(67,326)
Future income tax expenses	(826)	(25,147)	(25,973)
Future net cash flows	1,354	59,198	60,552
Discount for estimated timing of cash flows (10% p.a.)	(1,046)	(37,752)	(38,798)
Discounted future net cash flows	308	21,446	21,754
Group's share of "equity method" affiliates' standardized measure of discounted future net cash flows	534	1,536	2,070
Minority share in discounted future net cash flows	–	55	55

OAO LUKOIL

Supplemental Information on Oil and Gas Exploration and Production Activities (Unaudited)
(Millions of U.S. dollars, except as indicated)

V. Standardized measure of discounted future net cash flows (continued)

	International	Russia	Total
As of December 31, 2000			
Future cash inflows	6,378	170,534	176,912
Future production and development costs	(2,276)	(90,698)	(92,974)
Future income tax expenses	(1,156)	(27,020)	(28,176)
Future net cash flows	2,946	52,816	55,762
Discount for estimated timing of cash flows (10% p.a.)	(2,064)	(33,463)	(35,527)
Discounted future net cash flows	882	19,353	20,235
Group's share of "equity method" affiliates' standardized measure of discounted future net cash flows	597	638	1,235
Minority share in discounted future net cash flows	–	921	921

	International	Russia	Total
As of December 31, 2001			
Future cash inflows	5,410	163,720	169,130
Future production and development costs	(2,180)	(97,755)	(99,935)
Future income tax expenses	(766)	(14,909)	(15,675)
Future net cash flows	2,464	51,056	53,520
Discount for estimated timing of cash flows (10% p.a.)	(1,743)	(34,337)	(36,080)
Discounted future net cash flows	721	16,719	17,440
Group's share of "equity method" affiliates' standardized measure of discounted future net cash flows	360	685	1,045
Minority share in discounted future net cash flows	–	1,362	1,362

VI. Principal sources of changes in the standardized measure of discounted future net cash flows

	1999	2000	2001
Discounted present value as at January 1	4,072	21,754	20,235
Purchase of oil and gas reserves	3,276	2,788	4,169
Sales and transfers of oil and gas produced, net of production costs	(3,185)	(7,280)	(4,872)
Net changes in prices and production costs estimates	20,649	608	(12,686)
Extensions, discoveries, and improved recovery, less related costs	467	797	1,045
Development costs incurred during the period	255	458	1,011
Revisions of previous quantity estimates	2,559	(952)	(295)
Net change in income taxes	(7,286)	(1,403)	5,334
Other changes	301	435	424
Accretion of discount	646	3,030	3,075
Discounted present value at December 31	**21,754**	**20,235**	**17,440**

Yours faithfully

KPMG Audit Plc
8 Salisbury Square
London EC4Y 8BB

KPMG Limited
11 Gogolevsky Bulvar
Moscow 119019
Russia

OAO LUKOIL
Interim Financial Statements
Three Months Ended March 31, 2002

The following are the unaudited consolidated financial statements and notes thereto of OAO LUKOIL for the three months ended March 31, 2002 and 2001, and as of March 31, 2002 and December 31, 2001.

During September 2001, the Company published interim financial information as of and for the three months ended March 31, 2001 in the form of a press release and by placing interim consolidated financial statements on its website. This financial information was not audited or reviewed by independent accountants. During the preparation and review of these interim consolidated financial statements, certain adjustments and reclassifications were made to the previously published March 31, 2001 financial information. The net effect of these adjustments and reclassifications was to decrease net income by $10 million to $680 million.

OAO LUKOIL

Consolidated Balance Sheets as of December 31, 2001 and March 31, 2002
(Millions of U.S. dollars, unless otherwise noted)

	As of December 31, 2001	As of March 31, 2002 (unaudited)
Assets		
Current assets		
Cash and cash equivalents	1,170	867
Short-term investments	218	250
Accounts and notes receivable, net	2,230	2,301
Inventories	829	848
Prepaid taxes and other expenses	889	698
Other current assets	340	451
Total current assets	**5,676**	**5,415**
Investments	770	779
Property, plant and equipment	12,296	12,485
Deferred income tax assets	291	297
Goodwill and intangible assets	485	480
Other non-current assets	424	549
Total assets	**19,942**	**20,005**
Liabilities and Stockholders' equity		
Current liabilities		
Accounts payable	1,402	1,154
Short-term borrowings and current portion of long-term debt	1,480	1,657
Taxes payable	522	550
Other current liabilities	421	333
Total current liabilities	**3,825**	**3,694**
Long-term debt	1,948	1,974
Deferred income tax liabilities	390	404
Other long-term liabilities	463	485
Minority interest in subsidiary companies	931	843
Total liabilities	**7,557**	**7,400**
Stockholders' equity		
Common stock		
(850 million shares of par value of 0.025 Russian rubles each, authorized as of March 31, 2002 and December 31, 2001; 850 million shares (including 19 million shares held by subsidiaries) issued as of March 31, 2002 and December 31, 2001; 804 million and 805 million shares outstanding as of March 31, 2002 and December 31, 2001, respectively)	15	15
Treasury stock (common stock, at cost; 27 million and 26 million shares as of March 31, 2002 and December 31, 2001, respectively)	(403)	(424)
Additional paid-in capital	3,044	3,044
Retained earnings	9,738	9,981
Accumulated other comprehensive loss	(9)	(11)
Total stockholders' equity	**12,385**	**12,605**
Total liabilities and stockholders' equity	**19,942**	**20,005**

OAO LUKOIL
Consolidated Statements of Income for the three months ended March 31, 2001 and 2002
(Millions of U.S. dollars, except share data)

	For the three months ended March 31, 2001 (unaudited)	For the three months ended March 31, 2002 (unaudited)
Revenues		
Sales (including excise and export tariffs)	3,335	2,847
Equity share in income of affiliates	31	20
Total revenues	**3,366**	**2,867**
Costs and other deductions		
Operating expenses	(1,067)	(1,053)
Selling, general and administrative expenses	(459)	(575)
Depreciation, depletion and amortization	(208)	(237)
Taxes other than income taxes	(275)	(377)
Excise and export tariffs	(446)	(212)
Exploration expense	(19)	(20)
Loss on disposal and impairment of assets	(1)	(22)
Income from operating activities	**891**	**371**
Interest expense	(62)	(67)
Interest and dividend income	53	32
Currency translation loss	(44)	(34)
Other non-operating income	84	21
Minority interest	(22)	(6)
Income before income taxes	900	317
Current income taxes	(240)	(108)
Deferred income tax benefit	20	34
Net income	**680**	**243**
Basic earnings per share of common stock (U.S. dollars)	0.95	0.30
Diluted earnings per share of common stock (U.S. dollars)	0.94	0.30

OAO LUKOIL
Consolidated Statements of Cash Flows for the three months ended March 31, 2001 and 2002
(Millions of U.S. dollars)

	For the three months ended March 31, 2001 (unaudited)	For the three months ended March 31, 2002 (unaudited)
Cash flows from operating activities		
Net income	**680**	**243**
Adjustments for non-cash items		
Depreciation, depletion and amortization	208	237
Equity share in income of affiliates	(31)	(20)
Loss on disposal and impairment of assets	1	22
Deferred income taxes	(20)	(34)
Non-cash currency translation gain	(9)	(4)
Non-cash investing activities	(12)	5
Exploration expense	19	20
All other items – net	(35)	2
Changes in operating assets and liabilities:		
Accounts and notes receivable	(52)	(65)
Short-term loans receivable of a banking subsidiary	(28)	(1)
Net movements of short-term borrowings of a banking subsidiary	31	(7)
Inventories	(95)	(21)
Accounts payable	(145)	(351)
Taxes payable	219	28
Other current assets and liabilities	(128)	154
Net cash provided by operating activities	**603**	**208**
Cash flows from investing activities		
Capital expenditures	(532)	(515)
Proceeds from sale of property, plant and equipment	9	4
Purchases of investments	(187)	(50)
Proceeds from sale of investments	22	11
Acquisition of subsidiaries, net of cash acquired	(196)	(55)
Net cash used in investing activities	**(884)**	**(605)**
Cash flows from financing activities		
Net movements of short-term borrowings	308	142
Proceeds from issuance of long-term debt	125	91
Principal payments of long-term debt	(107)	(57)
Dividends paid	(5)	(75)
Purchase of treasury stock	(53)	(114)
Proceeds from sale of treasury stock	36	93
Other – net	–	26
Net cash provided by financing activities	**304**	**106**
Effect of exchange rate changes on cash and cash equivalents	(1)	(12)
Net (decrease) increase in cash and cash equivalents	22	**(303)**
Cash and cash equivalents at beginning of the period	1,137	1,170
Cash and cash equivalents at end of the period	1,159	867
Supplemental disclosures of cash flow information		
Interest paid	53	65
Income tax paid	162	156

Note 1. Basis of Financial Statement presentation

The accompanying consolidated interim financial statements and notes thereto of OAO LUKOIL (the "Company") and its subsidiaries (the "Group") have not been audited by independent accountants, except for the balance sheet at December 31, 2001. In the opinion of the Company's management, the interim financial information includes all adjustments and disclosures necessary to present fairly the Group's financial position, results of operations and cash flows for the interim periods reported herein. These adjustments were of a normal recurring nature.

Certain notes and other information have been condensed or omitted from the interim financial statements. Therefore, these financial statements should be read in conjunction with the Group's 2001 Annual Consolidated Financial Statements.

The results for the three-month period ended March 31, 2002, are not necessarily indicative of future financial results.

Foreign currency translation

The accounting records of Group companies' operations in the Russian Federation are maintained in Russian rubles and the Company prepares its statutory financial statements and reports in that currency to its shareholders in accordance with the laws of the Russian Federation.

As the Russian economy is considered to be hyperinflationary, the U.S. dollar is the functional currency of the Company in accordance with Statement of Financial Accounting Standards ("SFAS") No. 52, "*Foreign Currency Translation.*"

For the purposes of presenting financial statements prepared in conformity with U.S. GAAP, the U.S. dollar is considered to be the reporting currency of the Group.

Foreign currency transaction gains and losses are included in the consolidated statement of income.

For operations in the Russian Federation, hyperinflationary economies or operations where the U.S. dollar is the functional currency, monetary assets and liabilities have been translated into U.S. dollars at the rate prevailing at each balance sheet date. Non-monetary assets and liabilities have been translated into U.S. dollars at historical rates. Revenues, expenses and cash flows have been translated into U.S. dollars at rates, which approximate actual rates at the date of the transaction. Translation differences resulting from the use of these rates are included in the consolidated statement of income.

For the majority of operations outside the Russian Federation, the U.S. dollar is the functional currency. For certain other operations outside the Russian Federation, where the U.S. dollar is not the functional currency and the economy is not hyperinflationary, assets and liabilities are generally translated into U.S. dollars at year-end exchange rates and revenues and expenses are translated at average exchange rates for the year. Resulting translation adjustments are reflected as a separate component of stockholders' equity.

As of March 31, 2002 and December 31, 2001, exchange rates of 31.12 and 30.14 Russian rubles to the U.S. dollar, respectively, have been used for translation purposes.

Note 1. Basis of Financial Statement presentation (continued)

A significant portion of the balances and transactions of Group companies are denominated in Russian rubles or in currencies of certain republics of the former Soviet Union. Accordingly, future movements in the exchange rate between the U.S. dollar and the Russian ruble and such other currencies may significantly affect the carrying value of the monetary assets and liabilities of the Group expressed in U.S. dollars. Such changes may also affect the Group's ability to realize non-monetary assets at the amounts stated in the consolidated financial statements.

The Russian ruble and other currencies of republics of the former Soviet Union are not convertible outside of their countries. Accordingly, the translation of amounts recorded in these currencies into U.S. dollars should not be construed as a representation that such currency amounts have been, could be or will in the future be converted into U.S. dollars at the exchange rate shown or at any other exchange rate.

Note 2. Accounting changes

Effective January 1, 2002, the Group adopted SFAS No. 142, "*Goodwill and Other Intangible Assets.*" Under SFAS No. 142, goodwill and intangible assets with indefinite useful lives are no longer amortized, but are instead tested for impairment at least annually. SFAS No. 142 requires that intangible assets with definite useful lives be amortized over their respective estimated useful lives.

Beginning January 1, 2002, effective with the adoption of SFAS No. 142, the Group discontinued the amortization of goodwill. Goodwill amortization recorded during the three months ended March 31, 2001 was $3 million.

In connection with the transitional goodwill impairment test required by SFAS No. 142, the Group is required to perform an assessment of whether there is an indication that goodwill is impaired as of the adoption date. To perform this assessment, the Group is first required to determine the fair value of its reporting units and compare such fair value to each reporting unit's carrying value by June 30, 2002. If the reporting unit's carrying value exceeds its fair value, an indication exists that the reporting unit's goodwill may be impaired and the Group must perform the second step of the transitional impairment test. In the second step, the Group must compare the implied fair value of the reporting unit's goodwill to its carrying value, both of which are to be measured as of January 1, 2002. The second step is required to be completed as soon as possible, but no later than the end of 2002. Any transitional impairment will be recognized as the cumulative effect of a change in accounting principle in the Group's 2002 statement of income. The Group is currently completing the transitional impairment test. As of January 1, 2002, the Group had unamortized goodwill of $221 million.

Effective January 1, 2002, the Group adopted SFAS No. 144, "*Accounting for the Impairment or Disposal of Long-Lived Assets.*" SFAS No. 144 addresses financial accounting and reporting for the impairment or disposal of long-lived assets. The adoption of this standard had no significant impact on the Group's financial statements.

Note 3. Recently issued statements of accounting standards

In July 2001, the FASB issued SFAS No. 143, "*Accounting for Asset Retirement Obligations.*" SFAS No. 143 requires entities to record the fair value of a liability for an asset retirement obligation in the period in which it is incurred and a corresponding increase in the carrying amount of the related long-lived asset. Subsequently, the liability will be accreted for the passage of time and the related asset will be depreciated over its estimated useful life. The Group is required to adopt SFAS No. 143 effective January 1, 2003. The Group is currently evaluating the impact of adopting SFAS No. 143.

In April 2002, the FASB issued SFAS No. 145, "Rescission of FASB Statements No. 4, 44, and 64, Amendment of FASB Statement No. 13 and Technical Corrections." SFAS No. 145 primarily addresses income statement classification of gains and losses on extinguishments of debt and accounting for certain lease modifications that have economic effects similar to sale-leaseback transactions. The Group is required to adopt SFAS No. 145 effective January 1, 2003. The Group is currently evaluating the impact of adopting SFAS No. 145.

Note 4. Income taxes

The statutory income tax rate in the Russian Federation during the period ended March 31, 2001 was 35%. Effective January 1, 2002, as a result of amendments to the Tax Code of the Russian Federation, the statutory income tax rate was changed from 35% to 24%. Also, as a result of the amendments, certain tax benefits have been eliminated, including investment tax credits.

Note 5. Cash and cash equivalents

	As of December 31, 2001	As of March 31, 2002
Cash held in Russian rubles	373	383
Cash held in other currencies	797	484
Total cash balance	**1,170**	**867**

Note 6. Non-cash transactions

The consolidated statement of cash flows excludes the effect of non-cash transactions, which are described in the following table:

	For the three months ended March 31, 2001	For the three months ended March 31, 2002
Settlement of amounts payable through exchange of goods	308	236
Net non-cash investing activities	12	(5)
Total non-cash transactions	**320**	**231**

The following table shows the effect of non-cash transactions on investing activities:

	For the three months ended March 31, 2001	For the three months ended March 31, 2002
Net cash used in investing activities	884	605
Net non-cash investing activities	12	(5)
Net cash and non-cash investing activities	**896**	**600**

Note 12 “Business combinations” sets out information about acquisitions partially completed through the exchange of common stock.

Note 7. Accounts and notes receivable

	As of December 31, 2001	As of March 31, 2002
Trade accounts and notes receivable (net of provisions of $72 million and $77 million as of March 31, 2002 and December 31, 2001, respectively)	1,383	1,309
Current VAT recoverable	434	547
Short-term loans receivable of a banking subsidiary (net of provisions of $14 million and $14 million as of March 31, 2002 and December 31, 2001, respectively)	236	237
Other current accounts receivable (net of provisions of $14 million and $21 million as of March 31, 2002 and December 31, 2001, respectively)	177	208
Total accounts and notes receivable	**2,230**	**2,301**

Note 8. Short-term borrowings and current portion of long-term debt

	As of December 31, 2001	As of March 31, 2002
Short-term borrowings	1,002	1,154
Current portion of long-term debt	478	503
Total short-term borrowings and current portion of long-term debt	**1,480**	**1,657**

The majority of short-term borrowings are loans from various third parties and are secured by export sales, property, plant and equipment and securities.

Note 9. Long-term debt

	As of December 31, 2001	As of March 31, 2002
Long-term loans and borrowings from third parties	1,453	1,511
Long-term loans and borrowings from related parties	1	1
3.5% Convertible U.S. dollar bonds, maturing 2002	298	299
1% Convertible U.S. dollar bonds, maturing 2003	476	484
Variable interest unsecured Russian ruble bonds, maturing 2003	99	96
Capital lease obligation	99	86
Total long-term debt	2,426	2,477
Current portion of long-term debt	(478)	(503)
Total non-current portion of long-term debt	**1,948**	**1,974**

Long-term loans and borrowings

Long-term loans and borrowings are primarily repayable in U.S. dollars, maturing from 2002 through 2025 and are secured by export sales, property, plant and equipment and securities.

Convertible U.S. dollar bonds

On May 6, 1997, a Group company issued 230,000 convertible bonds with a face value of $1,000 each, maturing on May 6, 2002, and convertible to fifteen global depository receipts ("GDRs") of the Company per bond. The liability on the bonds was included in the current portion of long-term debt as of March 31, 2002. Subsequently, during the second quarter of 2002, these bonds were redeemed for cash at the stated redemption price of 130.323% of the face value and 11,185,059 shares of common stock of the Company.

Note 9. Long-term debt (continued)

On November 3, 1997, a Group company issued 350,000 high yield and premium exchangeable redeemable bonds with a face value of $1,000 each, maturing on November 3, 2003, and exchangeable for 5.625 GDRs of the Company per bond. The bonds are convertible into GDRs up to the maturity dates. The GDRs are exchangeable into four shares of common stock of the Company. Bonds not converted by the maturity date must be redeemed for cash. The redemption price at maturity will be 153.314% of the face value in respect of the bonds issued on November 3, 1997. The Company may redeem the bonds for cash prior to maturity, subject to certain restrictions and early redemption charges. The carrying amount of the bonds is being accreted to their redemption value with the accreted amount being charged to the consolidated statement of income.

Group companies held sufficient treasury stock to permit the full conversion of the bonds to GDRs.

Russian ruble bonds

On August 13, 1999, the Company issued three million variable interest rate Russian ruble bonds with a face value of 1,000 Russian rubles each, maturing on August 13, 2003. The bonds are unsecured and bear interest at 6% per annum adjusted for Russian ruble to dollar devaluation, payable semi-annually. The principal is repayable at maturity date at face value in Russian rubles.

Note 10. Comprehensive income

	For the three months ended March 31, 2001	For the three months ended March 31, 2002
Net income	680	243
Other comprehensive loss:		
Foreign currency translation adjustment	(1)	(2)
Comprehensive income	**679**	**241**

Note 11. Earnings per share

	For the three months ended March 31, 2001 (unaudited)	For the three months ended March 31, 2002 (unaudited)
Net income	680	243
Add back convertible debt interest (net of tax at effective rate)		
3.5% Convertible U.S. dollar bonds, maturing 2002	4	4
1% Convertible U.S. dollar bonds, maturing 2003	6	6
Total diluted net income	690	253
Weighted average number of outstanding common shares (thousands of shares)	714,427	804,880
Add back treasury shares held in respect of convertible debt (thousands of shares)	21,675	21,675
Weighted average number of outstanding common shares, after dilution (thousands of shares)	736,102	826,555

Note 12. Business combinations

In February 2002, the Company acquired an additional 13% of OAO Komineft for $40 million, increasing the Group's ownership stake in OAO Komineft to 67%. OAO Komineft is a Russian oil and gas exploration company operating predominantly in the Komi Republic of the Russian Federation.

In March 2001, the Company acquired 74% of the shares in OAO Arkhangelskgeoldobycha in exchange for 17,710,697 shares of common stock and cash consideration of $130 million. The shares of OAO Arkhangelskgeoldobycha were held by third parties, LUKOIL - GARANT, a related party, and LUKOIL Finance Limited, a Group company, which had acquired its interest in OAO Arkhangelskgeoldobycha from a third party in January 2001 for $39 million. OAO Arkhangelskgeoldobycha is a Russian oil and gas exploration company operating predominantly within the Timan-Pechora region of Northern Russia.

In March 2001, the Company exchanged 720,364 shares of common stock for the remaining 13% and 22% minority interest shareholding of OAO LUKOIL Ukhtaneftepererabotka and OAO LUKOIL – Kominefteproduct, respectively. OAO LUKOIL Ukhtaneftepererabotka is an oil refinery and OAO LUKOIL – Kominefteproduct is a marketing and distribution company. Both companies operate primarily in the Komi Republic of the Russian Federation.

In January 2001, the Group acquired the remaining 28% of shares in Getty Petroleum Marketing Inc. for $20 million thereby increasing the Group's ownership stake in Getty Petroleum Marketing Inc. to 100%.

Note 13. Related party transactions

In the rapidly developing business environment in the Russian Federation, companies and individuals have frequently used nominees and other forms of intermediary companies in transactions. The senior management of the Company consider that the Group has appropriate procedures in place to identify and properly disclose transactions with related parties in this environment and has disclosed all of the relationships identified which it deemed to be significant.

Sales of oil and oil products to related parties were $80 million and $30 million for the three months ended March 31, 2002 and 2001, respectively.

Other sales to related parties were $13 million and $9 million for the three months ended March 31, 2002 and 2001, respectively.

Purchases of oil and oil products from related parties were $37 million and $49 million for the three months ended March 31, 2002 and 2001, respectively.

Purchases of construction services from related parties were $58 million and $124 million for the three months ended March 31, 2002 and 2001, respectively.

Purchases of insurance services from related parties were $32 million and $29 million during the three months ended March 31, 2002 and 2001, respectively.

Other purchases from related parties were $2 million and $9 million for the three months ended March 31, 2002 and 2001, respectively.

Amounts receivable from related parties, including loans and advances, were $216 million and $209 million as of March 31, 2002 and December 31, 2001, respectively. Amounts payable to related parties were $56 million and $73 million as of March 31, 2002 and December 31, 2001, respectively.

Note 13. Related party transactions (continued)

As of March 31, 2002 and December 31, 2001 the Government of the Russian Federation owned 14% of the shares of the common stock of the Company. The Russian Federation also owns, controls, or has significant influence over the operations of many other companies and enterprises in the Russian Federation and has a significant influence on the operation of business and the economic environment. A significant part of the activity of Group companies is linked to companies belonging to or controlled by the Russian Federation. The Russian Federation is a customer and supplier of the Group through numerous affiliated and other related organizations. Management consider such trading relationships as part of the normal course of conducting business in the Russian Federation and consider that such relationships will remain for the foreseeable future. Accordingly, information on these transactions is not disclosed as related party transactions.

Note 14. Segment information

Presented below is information about the Group's operating and geographical segments for the periods ended March 31, 2002 and 2001, in accordance with SFAS No. 131, "Disclosures about Segments of an *Enterprise and Related Information.*"

The Group has three operating segments - exploration and production; refining, marketing and distribution; and other business segments. These segments have been determined based on the nature of their operations. Management on a regular basis assesses the performance of these operating segments. The exploration and production segment explores for, develops and produces primarily crude oil. The refining, marketing and distribution segment processes crude oil into refined products and purchases, sells and transports crude oil and refined petroleum products. Activities of the other businesses operating segment include the development of businesses beyond the Group's traditional operations.

Geographical segments have been determined based on the area of operations and include three segments. They are Western Siberia, European Russia and International.

Operating segments

For the three months ended March 31, 2002

	Exploration and production	Refining, marketing and distribution	Other	Elimination	Consolidated
Sales					
Third parties	252	2,584	11	–	2,847
Inter-segment	828	61	33	(922)	–
Total sales	1,080	2,645	44	(922)	2,847
Operating expenses	452	1,497	26	(922)	1,053
Depletion, depreciation and amortization expense	159	77	1	–	237
Interest expense	23	40	12	(8)	67
Income tax expense	48	23	3	–	74
Net income	(11)	235	15	4	243
Total assets	11,961	10,467	861	(3,284)	20,005
Capital expenditures	404	133	1	–	538

Note 14. Segment information (continued)

For the three months ended March 31, 2001

	Exploration and production	Refining, marketing and distribution	Other	Elimination	Consolidated
Sales					
Third parties	399	2,908	28	–	3,335
Inter-segment	998	79	24	(1,101)	–
Total sales	1,397	2,987	52	(1,101)	3,335
Operating expenses	524	1,595	43	(1,095)	1,067
Depletion, depreciation and amortization expense	128	79	1	–	208
Interest expense	20	51	6	(15)	62
Income tax expense	81	136	3	–	220
Net income	209	436	28	7	680
Total assets	10,318	9,567	699	(1,622)	18,962
Capital expenditures	403	164	1	–	568

Geographical segments

	For the three months ended March 31, 2001	**For the three months ended March 31, 2002**
Sales of crude oil within Russia	221	101
Export of crude oil and sales of oil of foreign subsidiaries	873	947
Sales of refined product within Russia	672	530
Export of refined product and sales of refined products of foreign subsidiaries	1,239	1,054
Other sales within Russia	203	138
Other export sales and other sales of foreign subsidiaries	127	77
Total sales	**3,335**	**2,847**

For the three months ended March 31, 2002

	Western Siberia	European Russia	International	Elimination	Consolidated
Sales					
Third parties	65	822	1,960	–	2,847
Inter-segment	465	1,185	15	(1,665)	–
Total sales	530	2,007	1,975	(1,665)	2,847
Operating expenses	227	823	1,668	(1,665)	1,053
Depletion, depreciation and amortization expense	80	121	36	–	237
Interest expense	5	42	20	–	67
Income tax expense	20	53	1	–	74
Net income	(34)	250	23	4	243
Total assets	5,413	12,211	4,102	(1,721)	20,005
Capital expenditures	94	405	39	–	538

Note 14. Segment information (continued)

For the three months ended March 31, 2001

	Western Siberia	European Russia	International	Elimination	Consolidated
Sales					
Third parties	19	1,212	2,104	–	3,335
Inter-segment	646	1,293	10	(1,949)	–
Total sales	665	2,505	2,114	(1,949)	3,335
Operating expenses	260	904	1,848	(1,945)	1,067
Depletion, depreciation and amortization expense	75	98	35	–	208
Interest expense	1	44	18	(1)	62
Income tax expense	36	171	13	–	220
Net income	103	522	75	(20)	680
Total assets	4,972	11,981	3,195	(1,186)	18,962
Capital expenditures	173	357	38	–	568

Note 15. Dividends

At the annual stockholders' meeting on June 27, 2002, dividends were declared for 2001 in the amount of 15.00 Russian rubles per common share, which at the date of the meeting was equivalent to $0.48.

Note 16. Contingencies

Litigation and claims

On November 27, 2001, Archangel Diamond Corporation ("ADC"), a Canadian diamond development company, filed a lawsuit in the district court of Denver, Colorado, against OAO Arkhangelskgeoldobycha ("AGD"), a Group company, and the Company (together the "Defendants") claiming compensation for damage allegedly caused by the Defendants relating to Almazny Bereg, a joint venture between AGD and ADC. ADC claims, among other things, that the Defendants interfered with the transfer of a diamond exploration license which was subject to an agreement between ADC and AGD. The total damages claimed by ADC are $4.8 billion, including compensatory damages of $1.2 billion and punitive damages of $3.6 billion. The claim is currently in its early stages and to date there has been no discovery process, but the Company believes the claim to be without merit and plans a vigorous defense, which includes among other defenses an objection to jurisdiction. While the claim is in its early stages and no assurance can be given about the ultimate outcome, the Company does not believe that the ultimate resolution of this matter will have a material adverse effect on its financial condition.

The Group is involved in various other claims and legal proceedings arising in the normal course of business. While these claims may seek substantial damages against the Group and are subject to uncertainty inherent in any litigation, management does not believe that the ultimate resolution of such matters will have a material adverse impact on the Group's operating results or financial condition.

Taxation environment

The taxation systems in the Russian Federation and other emerging markets where Group companies operate are relatively new and are characterized by numerous taxes and changing legislation, which may be applied retroactively and is sometimes unclear, contradictory, and subject to interpretation. Often, differing interpretations exist among different tax authorities within the same jurisdictions and among taxing authorities in different jurisdictions. Taxes are subject to review and investigation by a number of authorities, which are enabled by law to impose severe fines, penalties and interest charges. Such factors may create taxation risks in the Russian Federation and other countries where Group companies operate substantially more significant than those in other countries where taxation regimes have been subject to development and clarification over long periods.

Note 16. Contingencies (continued)

The regional organizational structure of the tax authorities and the regional judicial system can mean that taxation issues successfully defended in one region may be unsuccessful in another region. The tax authorities in each region may have a different interpretation of similar taxation issues. There is however some degree of direction provided from the central authority based in Moscow on particular taxation issues.

The Group's tax planning and management strategies are based on its understanding of tax legislation existing at the time of implementation. The Group is subject to tax authority audits on an ongoing basis, as is normal in the Russian environment, and, at times, the authorities have attempted to impose significant taxes on the Group. Management believes that it has adequately met and provided for tax liabilities based on its interpretation of existing tax legislation. However, the relevant tax authorities may have differing interpretations and the effects could be significant.

Other matters

During July 2001, the Group temporarily shut down operations of the Petrotel SA refinery due to the economic conditions in Romania. The refinery remains closed as of the date of these interim consolidated financial statements. Management is currently assessing its plans regarding the future operations of this refinery and options in relation to the Group's Romanian operations. If management decides to sell or abandon the refinery, the Group may be exposed to losses on the carrying value of property, plant and equipment of approximately $60 million. Additionally, a decision to abandon the refinery may result in claims against the Group's future investment commitments.

These interim consolidated financial statements were prepared by OAO LUKOIL in accordance with U.S. GAAP and have not been audited by our independent auditor. If these financial statements are audited in the future, the audit could reveal differences in our consolidated financial results and we can not assure that any such differences would not be material.

Part 8 – REGULATION

RUSSIAN LEGAL SYSTEM

The legal system in Russia has experienced frequent and substantial changes in the last ten years. Several fundamental Russian laws have been adopted during these years, including:

- Parts One, Two and Three of the Civil Code of the Russian Federation (effective January 1, 1995, March 1, 1996 and March 1, 2002, respectively), as amended;
- the Russian Federal Law on Joint Stock Companies (dated December 26, 1995), as amended;
- the Russian Federal Law on Production Sharing Agreements (dated December 30, 1995), as amended;
- the Russian Federal Law on Subsoil (restated on March 3, 1995), as amended;
- the Russian Federal Law on the Securities Market (dated April 22, 1996), as amended;
- the Criminal Code of the Russian Federation (effective January 1, 1997), as amended;
- the Russian Federal Law on Insolvency (Bankruptcy) (effective March 1, 1998), as amended;
- the Russian Federal Law on Limited Liability Companies (effective March 1, 1998), as amended;
- the Russian Federal Law on Foreign Investment (dated July 9, 1999), as amended;
- Parts One and Two of the Tax Code of the Russian Federation (effective January 1, 1999 and January 1, 2001, respectively), as amended;
- the Russian Federal Law on Currency Regulation and Currency Control (dated October 9, 1992), as amended;
- the Customs Code of the Russian Federation (dated June 18, 1993), as amended;
- the Russian Federal Law on Privatisation of State and Municipal Property (dated December 21, 2001);
- the Russian Federal Law on Competition and Restriction of Monopoly Activity on Commodity Markets (dated March 22, 1991), as amended;
- the Russian Federal Law on Protection of Rights and Legitimate Interests of Investors at Securities Market (dated March 5, 1999), as amended; and
- the Land Code of the Russian Federation (dated October 25, 2001).

SOURCES OF REGULATION OF THE RUSSIAN OIL INDUSTRY

Privatisation

Presidential Decree No. 1403 issued on November 17, 1992, as amended, established the federal framework for the privatisation of Russian oil companies and the basis for the transformation of state-owned oil exploration, production, distribution and refining enterprises into vertically integrated private oil companies. Through this framework, most of Russia’s production, processing and exploration companies were privatised by 1997. The government continues its efforts towards selling its remaining interest in previously partially privatised entities.

Russian general privatisation legislation is composed of a number of legislative and governmental acts, including:

- The Civil Code of the Russian Federation, which establishes general requirements for corporate transactions (including those related to privatisation), performance of transactions and grounds for their invalidity;
- The Russian Federal Law on Privatisation of State and Municipal Property, dated December 21, 2001, which establishes legal and organisational grounds for privatisation of state and municipal property; and
- Russian Federal laws and other governmental acts on the privatisation of state property.

The privatisation laws permit challenges on the basis of a violation of applicable regulations and procedures.

Federal, Regional and Local Regulatory Authorities Governing Oil and Gas Licensing and Operations

At the federal level, regulatory authority over the oil industry is divided primarily between the Ministry of Energy and the Ministry of Natural Resources. The Ministry of Energy sets governmental policy for the industry and regulates and controls the activities of oil and gas companies. The Ministry of Natural Resources is involved in the licensing of subsoil resources and also regulates exploration and geological prospecting for the oil and gas industries. The Federal Energy Commission and the Government Commission on the Use of Systems of Oil and Gas Trunk Pipelines and Oil Products Pipelines, or the Pipelines Commission, coordinate the activities of various federal executive agencies to address issues in the oil industry, including, among others, issues related to Transneft trunk oil pipelines access and tariffs. Russian Federal legislation also provides a degree of autonomy to regional authorities to exercise rights with respect to the use of natural resources and provides that the regulation of the use of the subsoil is under the joint jurisdiction of federal and regional authorities. Generally, regional authorities with jurisdiction over the specific area in which an oil and gas project, pipeline, refinery or other enterprise is located have substantial authority. Regional authorities execute subsoil production licences together with the Ministry of Natural Resources. Regional and local authorities usually control regional and local (respectively) land-use allocations.

Subsoil Production Licenses

Under the Regulations on Licensing of Subsoil Use of July 15, 1992, or the Regulations, and the Russian Federal Law on Subsoil of March 3, 1995, or the Subsoil Law, combined subsoil exploration and production licences were previously granted for up to 25 years. Additionally, licences could be issued separately: for five years for exploration and for 20 years for production. However, as of January 2000, subsoil production licences are granted for the term of operation of the field, calculated on the basis of a feasibility study for the development of the natural resource deposits providing for the rational use and protection of the subsoil.

Generally, licences are awarded by tender or auction held jointly by the Ministry of Natural Resources and the relevant regional authority. The winning bidder in a tender is expected to submit the most technically competent, financially attractive and environmentally sound proposal that meets published tender terms and conditions. However, in accordance with the January 2000 amendments to the Subsoil Law, licences for geological exploration and production may be issued under the decision of the federal government or the joint decision of the authorised federal and regional agencies to subsoil users (without the holding of an auction or tender) that have discovered mineral resource deposits through exploration work conducted at their own expense.

Licences are nontransferable, except in certain limited circumstances specified by the Subsoil Law. A subsoil production licence gives its holder exclusive rights of mineral resources development and production to an identified licence area (including subsurface zones) for the term of the licence.

A licence holder has the right to develop and sell oil extracted from the licence area. The Russian Federation, however, retains ownership of all subsoil resources at all times, and the licence holder only has rights to the crude oil when extracted.

The licences generally require the licence holder to make various commitments, including:

- extracting annually an agreed upon target amount of reserves;
- conducting agreed upon drilling and other exploratory and development activities;
- protecting the ecology in the fields from damage;
- providing geological information and data to the relevant authorities;
- submitting on a regular basis formal progress reports to regional authorities; and
- paying certain royalty and other obligatory payments when due.

The Regulations and the Subsoil Law provide that upon the expiration of a licence, it may be renewed at the initiative of the licence holder, provided that the licence holder observes the provisions of the licence and provided that it is necessary to complete the development of the natural resources deposits or carry out liquidation measures. Since the law applies both to new licences and the renewal of licences, we believe that our licences will be renewed upon their expiration for the remainder of the productive life of each respective field.

Governmental authorities may undertake periodic reviews for ensuring compliance by subsoil licence users with the terms of their licences and applicable legislation. We have received notices from regional authorities that have alleged areas of non-compliance with the terms of our licences, such as the failure to perform scheduled drilling and geological exploration activities and violations of ecological standards established by local ordinances. In response to such notices, we have engaged the authorities in negotiations over the timing and focus of certain investments and activities in an effort to remedy any such non-compliance.

A licencee can be fined for failing to comply with the subsoil production licence and the subsoil production licence can be revoked, suspended or limited in certain circumstances, including:

- a breach or violation by the licencee of material terms and conditions of the licence;
- the repeated violation by the licencee of the subsoil regulations;
- the failure by the licencee to commence operations within a required period of time or to produce required volumes, both as specified in the licence;
- the occurrence of an emergency situation;
- upon the emergence of a direct threat to the life or health of people working or residing in the area affected by the operations under the licence;
- the liquidation of the licencee; and
- the non-submission of reporting data in accordance with the legislation or submission of untrue information.

Accordingly, we cannot assure you that one or more of our licences will not be revoked, suspended or limited, notwithstanding the remedial actions we have taken or have proposed to take in the future. Any such revocation, suspension or limitation of our rights under our licences may result in a reduction in the size of our reserves and/or have a material adverse effect on the results of our operations.

Land Use Permits

In addition to a subsoil production licence, rights to use surface land within the specified licenced area need to be obtained. Under the new Land Code dated October 25, 2001, it will only be possible (for commercial legal entities) to either own or lease land.

We hold land use permits to carry on the business currently conducted within the area of each of our licences. Our rights to use relevant land may need to be changed if necessary to comply with requirements of the Land Code by January 1, 2004.

Fees Payable by Subsoil Production Licensee

The Subsoil Law provides for the basic framework of payments applicable to licence holders, which includes the following main types of payments: (i) one-time payments in cases specified in the licence, (ii) regular payments for the subsoil use (i.e., rentals paid for the right to conduct prospecting and exploration works), (iii) payments for geological subsoil information, (iv) fees for the right to participate in auctions/tenders and (v) fees for the issuance of licences. See "– Taxation." The rate at which rentals are to be levied may be established by the executive bodies of the political subdivisions of the Russian Federation within a range of minimum and maximum rates established by the Russian government. In the event that such executive bodies do not establish such a rate, the maximum rate established by the Russian government will be applicable.

Environmental Protection

Our operations are subject to extensive Federal and regional environmental laws and regulations. These laws and regulations set various standards for health and environmental quality, provide for penalties and other liabilities for the violation of such standards, and establish, in certain circumstances, obligations to compensate for environmental damage and restore environmental conditions.

The Russian Federal Law on Environmental Protection dated January 10, 2002, establishes a "pay-to-pollute" regime administered by the Ministry of Natural Resources and regional authorities.

Natural resource development matters are subject to periodic environmental evaluation. While these evaluations have in the past generally not resulted in substantial limitations on natural resource exploration and development activities, they are expected to become increasingly strict in the future.

We have received, from time to time, and anticipate receiving in the future, notices and meeting minutes from regional authorities that allege that we have violated certain environmental regulations. We have worked and will continue to work with each of these authorities to address such allegations.

In addition, the Subsoil Law and Regulations provide that a subsoil licence must include a provision establishing the procedure for the restoration of the site and recultivation of the land plot upon termination of the subsoil licence. This procedure generally requires the licencee to submit, for the approval of regional authorities, a proposed plan detailing the timeframe and actions the licencee will undertake to restore the site and recultivate the land plot. Additional requirements in respect of restoration of the environment, recultivation of land and compensation of damage to the environment are prescribed by the Law on Environmental Protection.

Gas Flaring Operations

We are currently flaring a portion of the gas produced in our fields, for which we are subject to insignificant state-imposed charges for excess gas flared. These charges are levied in accordance with regulations of the Ministry of Natural Resources and of the Russian Government. Limitations on gas flaring may be established in our licences.

Crude Oil and Refined Product Transportation Regime

From 1995, as part of a scheme to deregulate prices and liberalise export controls, the Russian Government established equal pipeline and sea terminal access procedures for all oil companies in proportion to the actual production volume of each company. This system allowed Russian oil companies to export, on average, 30-35% of the produced oil.

Currently the allocation of pipeline and sea terminal access rights is overseen by the Pipelines Commission. This Commission approves quarterly schedules that, *inter alia*, detail the precise volumes of oil that each oil producer can pump through the Transneft system. Once the access rights are allocated, oil producers generally cannot increase their allotted capacity in the export pipeline system, although they do have limited flexibility in altering delivery routes. Oil producers are generally allowed to assign their access rights to a third party.

In August 2001, the Russian Government began implementing reforms relating to the allocation of pipeline and sea terminal access rights. As of September 11, 2001 pipeline and sea terminal access rights are distributed among oil producers and their parent companies in proportion to the volumes of oil produced and delivered to the Transneft pipeline system (and not in proportion to mere oil production volumes).

Transneft has a very limited ability to transport individual batches of crude oil with the result that crude oil of differing qualities, delivered in the pipeline system, is blended. Transneft does not currently operate a system whereby companies shipping heavy and sour crude would compensate the shippers of higher-quality crude oil for the deterioration in the crude quality arising from blending. Although the introduction of such a compensatory system is currently under discussion between Transneft and the Russian Government, these prospects cause aggressive resistance from regions with low-grade quality reserves. Thus, currently, the oil we produce enters the Transneft pipeline and is blended with oil produced by other companies. The majority of the sales we make in the export markets are sales of oil blends that results from such combination, known either as the Urals blend or Siberian Light.

The tariffs for using Transneft’s pipelines are set by the Federal Energy Commission.

Production Sharing Agreements

The Russian Federal Law on Production Sharing Agreements, dated December 30, 1995, as amended, or the PSA Law, sets forth general principles for investment in the exploration and production of minerals on a “production sharing” basis.

A production sharing agreement is a contract between the Russian government, both on the Federal and regional level, and an investor in which the investor agrees to bear the costs and risks of exploration and production of a mineral resource and the parties agree to share the output in predetermined shares. Production sharing agreements aim to reduce an investor’s risk by providing a stable legal and fiscal framework for long-term and large investments.

Since the PSA Law was enacted, the legislature has approved a number of oil fields as eligible for production sharing agreements. As of yet, few of these are subject to an effective production sharing agreement. The legislation and rules implementing production sharing agreements are still evolving.

Currency Exchange Controls and Export Proceeds Repatriation

The currency control rules govern transactions in foreign currency (including currency valuables and currency-denominated instruments) between Russian residents as well as transactions in foreign currency and in rubles between residents and nonresidents.

“Current” and “Capital” Foreign Currency Transactions
“Current” foreign currency transactions generally may be freely carried out between residents and non-residents. Current transactions include transfers in and out of Russia of foreign currency for payments on import and export of goods and services without deferral of settlement, as well as payments in connection with credits on import-export operations with a term not exceeding 90 days; receipt and extension of financial credits with a term not exceeding 180 days; and transfers in and out of Russia of interest, dividend payments and other income on deposits, investments, credits and other similar transfers in connection with “capital” transactions and certain other payments specified by law. All other currency transactions are classified as “capital” transactions, which generally require a licence from the Central Bank, subject to certain specified exceptions. Cash transactions in foreign currency are generally prohibited within Russia. Permissible payments in foreign currency must be made by means of wire transfers.

Russian currency legislation generally allows:

- foreign investors to repatriate income in rubles received from investments in Russia (including profits, dividends, and interest) (subject to the rules applicable to the accounts of non-residents and the conversion of rubles into foreign currencies); and
- legal entities to convert rubles into foreign currency for purposes of making dividend payments to foreign investors and meeting their foreign currency obligations.

Foreign currency may be freely exchanged for rubles in Russia. However, the exchange of rubles for foreign currency in Russia is limited, while the exchange of rubles abroad is restricted. Russian exporters are required to repatriate 100% and convert into rubles 50% of foreign currency export proceeds. Russian resident companies may exchange rubles for foreign currency if they can document “current” foreign currency transactions (including payments of interest and dividends), if they engage in “capital” foreign currency transactions not requiring authorisation from the Central Bank of the Russian Federation or if they have authorisation from the Central Bank of the Russian Federation to engage in “capital” foreign currency transactions. Non-resident companies may convert foreign currency into rubles, but may only do so through special ruble accounts, which are subject to strict regulations and close control by the Central Bank of the Russian Federation.

Ruble “Convertible” Accounts
Foreign investors may purchase ruble-denominated shares from Russian residents with settlement in rubles through a special ruble “convertible” account. Foreign investors may also use ruble “convertible” accounts to receive ruble proceeds from investments in ruble-denominated shares (profit, dividends and proceeds from the sale of such ruble-denominated shares). With certain limited exceptions, rubles received into ruble “convertible” accounts may be converted into foreign currency and subsequently repatriated, subject to payment of all applicable taxes and duties. Russian tax legislation currently requires a foreign investor to obtain a certificate confirming its tax registration with the tax authorities prior to opening such a ruble “convertible” account.

Bankruptcy Legislation
Pursuant to the current Russian Federal Law on Insolvency (Bankruptcy) (effective March 1, 1998), any creditor, the attorney-general or the tax authorities may commence under a court’s supervision a bankruptcy action against a debtor if the debtor owes the creditor an equivalent of, or more than, approximately $1,600 for a period of three months or longer.

TAXATION

Evolution of the Russian Tax System
From its inception in late 1991, the Russian tax system has been characterised by rapid and unpredictable changes, with numerous taxes being introduced at different levels of government. The Russian Government has historically had an acute need for revenues because of public finance deficits at all levels. Tax laws have been changed occasionally, without warning, and sometimes retroactively. The nature and amount of taxes applicable to a business’ activities could ultimately be very different from what was expected. Widespread non-compliance with tax laws and inconsistent enforcement by tax authorities contributed to the system’s inefficiency.

However, recent legislative changes have improved the Russian tax system. For the past several years, the Russian Government has been developing a comprehensive tax code to unify multiple federal, regional and local tax laws and regulations. In particular, Part One of the Tax Code, which became effective on January 1, 1999, and eight chapters of Part Two of the Tax Code, which became effective either as of January 1, 2001 or January 1, 2002, strengthened taxpayers' rights and streamlined tax laws. However, despite these positive changes, many taxpayers in Russia continue to be subject to uncertainties regarding the application of tax laws.

Part One of the Tax Code contains general taxation principles and tax administration provisions. Part Two of the Tax Code contains regulations related to specific taxes (such as profits tax and VAT) and tax regimes (such as taxation of agricultural enterprises). At present, Part Two includes eight chapters covering value-added tax, excise taxes, personal income tax, unified social tax, profits tax, mineral resources production tax, a taxation system for agricultural producers and sales tax, thus covering most major taxes. The remaining taxes are currently regulated by various federal laws, which should not be, however, in contradiction with the general taxation principles and tax administrative provisions of the Tax Code. The Russian Government has indicated that it intends to enact the remaining chapters (approximately twenty chapters) in 2002–2003 to finalise the unification of the Russian tax system.

Tax Registration

Entities carrying on activities in Russia must register with local tax authorities. They are generally required to submit monthly, quarterly and/or annual tax declarations for a number of separate taxes, quarterly and annual financial statements and statistical information.

Current Tax Regime

The following discussion describes the Russian tax regime effective as of July 1, 2002. The Russian tax regime includes federal (established by the Tax Code or by Federal Laws, which are in force until the enactment of the relevant Tax Code chapters and applied for all entities doing business in Russia), regional (established by the Tax Code and regional authorities and applied for entities doing business in particular regions) and local (established by the Tax Code and local authorities and applied to entities registered or doing business in particular municipalities) taxes.

Below we briefly describe the major federal and regional taxes applicable to our group.

Profit Tax

Provisions of the profit tax chapter of the Tax Code became effective as of January 1, 2002 and replaced the provisions of the Profits Tax Law existing since the early 1990s.

There is a single profit tax system, but payments are split between federal, regional and local budgets. The statutory profit tax rate is currently 24%, of which 7.5% will be subject to payment to the federal budget and 14.5% and 2% shall be payable to the regional and local budgets respectively. The profit tax chapter of the Tax Code introduced the following important elements into the profit tax regime:

- Profit was defined more closely to real economic profit, and many expenses that were previously non-deductible became deductible for tax purposes; however, certain limitations still exist;
- Depreciation rates increased and became more closely tied to the economic life of the assets; taxpayers are now given a choice between straight-line and declining balance methods of depreciation for tax purposes for most groups of assets; thus, the amount of depreciation in early years may be significantly increased, if a taxpayer chooses the latter method;
- The loss carry-forward rules have been amended to allow taxpayers to offset tax losses against profits in future tax periods within the next ten years (instead of the previously applicable five year period); provided, however, that the amount of such carry-forwards may not exceed 30% of the tax base in any tax period (instead of the previous limitation that loss relief, when taken in aggregate with other tax concessions, should not reduce taxable profit by more than 50%);
- Methods of profit tax calculation have been modified with the accrual method becoming the only method available for major companies.

The profit tax chapter of the Tax Code also eliminated numerous tax exemptions that were available under prior law, including the deduction of capital investments in the year when the costs are incurred. The profit tax chapter also limited the ability of the regional legislative bodies to decrease the rate of profit tax payable to the regional budget. Such rate is currently set at 14.5% and cannot be reduced below 10.5%. Thus the lowest overall profit tax rate is 20%. Prior to the introduction of the profits tax chapter of the Tax Code, certain concessions could be granted from regional and local portions of the profits tax for periods of up to three years. Where such concessions were in effect at December 31, 2001, the concessions will continue to be in effect until they expire under the original terms when granted. In such cases, the overall profits tax rate is 7.5%, being the federal profits tax element.

Value-added Tax

A value-added tax, or VAT, of 20% (10% in the case of certain foods and children's goods) is imposed on domestic sales of goods, works and services and on the customs value of goods imported into Russia inclusive of customs duties. Exports of goods are generally subject to VAT at the rate of 0% except for exports of oil, oil condensate and natural gas to other Commonwealth of Independent States, or CIS, countries, in which case a general 20% VAT rate applies. The normal domestic VAT rates also apply for sales of goods to the Republic of Belarus.

VAT paid to suppliers of the goods, works and services can be offset by the taxpayer against VAT received. With the introduction of the VAT Chapter of the Tax Code, the value-added tax on constructed fixed assets also became recoverable for construction taking place after the chapter was introduced. This amendment significantly lowered the cost of our capital investments.

A number of goods, works and services are exempt from VAT. An exemption from VAT applies to certain goods imported into Russia, e.g., technological equipment, its components and spare parts contributed to the charter capital of Russian companies.

Import Duties

Import customs duties are generally imposed at rates ranging from 5% to 25% on a wide range of imports. Imported goods that qualify as fixed assets used for production activities contributed by foreign investors to the charter capital of Russian companies are exempt from import customs duty.

Turnover Taxes

As of January 1, 2001, we pay the road user's tax at a rate of 1% of our sales revenue. As of January 1, 2003, the road user's tax will be repealed.

Social Security Contributions for Employees

Historically, social security contributions were payable by employers to four different non-budgetary funds (the Pension Fund, Social Insurance Fund, Medical Insurance Fund and Employment Fund) at the aggregate rate of 38.5% of gross payroll. In addition, employees were subject to a Pension Fund contribution equal to 1% of their wages.

Currently, we pay a unified social tax assessed on our gross payroll according to a regressive-rate schedule ranging from 35.6% to 2%, depending on the level of employees' wages.

In addition to the unified social tax, employers are liable for obligatory contributions to the Social Insurance Fund for insurance for work-related injuries and diseases at rates ranging from 0.2% to 8.5% of gross payroll, depending on the type of activity carried out by the employer.

Local And Regional Taxes

In addition to the taxes described above, each Russian region and locality may impose certain regional and local taxes, respectively, in accordance with procedures established by federal law.

Property Tax

Property tax is a regional tax that is currently levied at a rate of up to 2% of the average annual net book value of fixed assets, intangibles and inventory (including work in progress), prepaid expenses per annum and construction in progress.

Current System of Oil-Related Taxes and Payments

Mineral Production Tax

Federal Law No. 126-FZ of August 8, 2001, which became effective on January 1, 2002, amended the previously existing regime of mineral resource restoration payments, royalties and excise taxes on the production of oil and gas condensate and replaced all such taxes with a mineral production tax.

From January 1, 2002 until December 31, 2004, the mineral production tax with respect to crude oil will be based on the amount of oil produced. The tax rate applicable from January 1, 2002 until December 31, 2004, will be 340 rubles per tonne of crude oil, subject to an adjustment using a special coefficient reflecting the dynamics of world oil prices and the ruble/U.S. dollar exchange rate. This coefficient will be applicable on a quarterly basis and will represent a ratio in which (i) the numerator is the product of (x) the ruble/U.S. dollar average quarterly exchange rate and (y) the difference between quarterly average oil prices per barrel for "Urals" blend and $8.00 and (ii) the denominator equals 252.

Starting January 1, 2005, the tax base will be determined as the value of extracted minerals, which may be calculated by reference to actual sale prices of minerals or the deemed value of minerals. With respect to the production of oil and oil condensate, the minerals production tax will be levied at the rate of 16.5% of the value of extracted natural resources.

Oil-related Export Duties

In early 1999, the government reintroduced export customs duties on crude oil and oil products. Following increases in world oil prices, the export customs duties have been steadily increasing. In December 2001 the Law on Customs Tariff was amended to establish the rates of export customs duties for crude oil based on the average price of "Urals" blend for the two preceding months.

The rates of customs duties established by the Russian government in accordance with the Law on Customs Tariff are as follows:

Average Price for "Urals" Crude Oil Blend[1]	Export customs duties
Up to $109.50 per tonne ($15.00 per barrel)	0%
$109.50 to $182.50 per tonne ($15.00 to $25.00 per barrel)	35% of the difference between the actual price (per tonne) and $109.50
Greater than $182.50 per tonne ($25.00 per barrel)	$25.53 plus 40% of the difference between the actual price (per tonne) and $182.50

Note:

[1] The Urals crude oil blend price is calculated as the price for Urals blend on world markets (Mediterranean and Rotterdam) for the two months immediately preceding the current two-month period.

Payments for the use of subsoil

Starting from January 1, 2002 regular payments for the use of subsoil were introduced to replace a number of previously changed taxes. The payments relate to the size of the licence area provided to the exclusive user of the subsoil. The minimum and the maximum rates of quarterly payments are set by the Russian government as follows: (i) the rate for the right to explore and appraise oil fields ranges from 120 rubles/sq.km (50 rubles/sq.km for offshore areas) to 360 rubles/sq.km (150 rubles/sq.km for offshore areas); (ii) the rate for the right to prospect for natural resources ranges from 5,000 rubles/sq.km (4,000 rubles/sq.km for offshore areas) to 20,000 rubles/sq.km (16,000 rubles/sq.km for offshore areas).

Exact rates for specific areas are to be set by regional authorities for onshore areas and the Ministry of Natural Resources for offshore areas. Where these specific rates have not been set, the above maximum rates shall apply. Payments must be made on a quarterly basis.

Excise Tax on Oil Products

The excise tax is charged on sales of gasoline, diesel fuel and motor oils. The current rates are as follows:

Oil Product	Rate
Natural gas sold in the Russian Federation or exported to CIS countries	15% of the sale or export price
Natural gas exported to countries other than CIS countries	30% of the sale or export price
Gasoline with octane numbers not exceeding "80"	1,512 rubles per 1 tonne
Gasoline with octane numbers exceeding "80"	2,072 rubles per 1 tonne
Diesel fuel	616 rubles per 1 tonne
Motor oil	1,680 rubles per 1 tonne

Taxation regime for investors under Production Sharing Agreements (PSAs)

Part One of the Tax Code anticipates that a special chapter of the Tax Code establishing the taxation regime for investors under PSAs will be adopted. Until such a chapter is passed, the taxation of investors in PSA is regulated by those Chapters of the Tax Code and Federal Laws that relate to specific taxes. These regulatory documents contain a number of specific provisions and tax concessions for investors under PSAs:

- Sales of goods (works, services) by contractors to PSA investors are VAT exempt;
- Import of goods designated for the execution of a PSA is exempt from import VAT and excise tax;
- Profits tax is levied on the value of profit oil received by the investors, less certain unrecoverable costs. Cost oil received by investors in compensation of recoverable costs is not taxable;
- The rate of the mineral production tax is 50% lower for natural resources produced under a PSA;
- PSA investors are exempt from turnover taxes, property tax and local taxes.

For PSAs that were concluded prior to the entry into force of Federal Law No. 225-FZ of December 30, 1995, “On Production Sharing Agreements,” the taxation regime stipulated by these agreements applies, which may vary from agreement to agreement.

Part 9 – THE DEPOSITARY RECEIPTS

INTRODUCTION

Application has been made to the Financial Services Authority in its capacity as U.K. Listing Authority for a listing of the ADRs to be admitted to the official list of the U.K. Listing Authority. Application has also been made to the London Stock Exchange for such ADRs to be admitted to trading on the London Stock Exchange in accordance with the rules of the London Stock Exchange.

TERMS AND CONDITIONS OF THE LEVEL 1 ADRs

The following is a summary of certain provisions of the Deposit Agreement, as amended and restated as of March 11, 1998 (the "Level 1 Deposit Agreement"), among the Company, The Bank of New York, as depositary, and each Owner and Beneficial Owner (as defined in the Level 1 Deposit Agreement) from time to time of the Level 1 ADRs issued thereunder.

This summary does not purport to be complete and is subject to the detailed provisions of the Level 1 Deposit Agreement, including the form of Level 1 ADRs attached thereto as Exhibit A. Each Owner and Beneficial Owner by accepting a Level 1 ADR or an ADS (as defined below) agrees to become a party to the Level 1 Deposit Agreement and to become bound by all the terms and conditions thereof. Terms used in these Terms and Conditions of the Level 1 ADRs and not otherwise defined herein will have the meanings set forth elsewhere in this document and in the Level 1 Deposit Agreement. Copies of the Level 1 Deposit Agreement will be available for inspection at the Corporate Trust Office of the Depositary, currently located at 101 Barclay Street, New York, New York, 10286. The depositary's principal executive office is located at One Wall Street, New York, New York, 10286. ***Owners and Beneficial Owners are deemed to have notice of and be bound by all the provisions of the Level 1 Deposit Agreement applicable to them.***

The Level 1 ADRs are issuable pursuant to the Level 1 Deposit Agreement. Each Level 1 ADS represents 4 of our shares or evidences the right to receive 4 of our shares deposited under the Level 1 Deposit Agreement and any other securities, property and cash received by the depositary in respect of those shares and held by it under the deposit agreement (referred to together as deposited securities).

The deposited shares are deposited with ING Bank (Eurasia), the agent of the depositary acting as custodian pursuant to the Level 1 Deposit Agreement or any other custodian that may be appointed under the Level 1 Deposit Agreement.

We will not treat a Level 1 ADR holder as one of our shareholders and a Level 1 ADR holder will not have shareholders' rights. The Depositary will be the holder of the shares underlying the Level 1 ADSs. Holders of the Level 1 ADRs will only have Level 1 ADR holder rights. However, see "Risk Factors – Risks Relating to our Depositary Shares."

For a description of the shares see "Part 11 – Additional Information." The ownership of our shares is evidenced only by a record of ownership maintained in our share register. In consequence, all references in these "Terms and Conditions of the Level 1 ADRs" to the deposit, surrender and delivery of the shares refer only to book-entry transfers and do not contemplate the physical transfer of certificates representing the shares.

1. Deposit of shares

1.1 Subject to the terms and conditions of the Level 1 Deposit Agreement, shares or evidence of rights to receive shares may be deposited by delivery thereof to any custodian under the Level 1 Deposit Agreement, accompanied by any appropriate instrument or instruments of transfer (which will consist of (a) extracts from our share register and, where applicable, share certificates evidencing ownership of the shares, (b) a transfer deed or other similar document authorising registration of the shares in the name of the depositary, the custodian or their respective nominees, or endorsement, in form satisfactory to the custodian, and (c) where applicable, a purchase/sale contract or other similar document relating to the transfer of our shares, in each case together with all such certifications as may be required by the depositary or the custodian in accordance with the provisions of the Level 1 Deposit Agreement, and, if the depositary requires, together with a written order directing the depositary to execute and deliver to, or upon the written order of, the person or persons stated in such order, a Level 1 ADR or Level 1 ADRs for the number of ADSs representing such deposit).

1.2 Subject to the terms and conditions of the Level 1 Deposit Agreement, upon receipt by any custodian of any deposit and upon receipt in form satisfactory to the depositary of a proper acknowledgment or other evidence from us or the Russian Share Registrar (including extracts from the Share Register) that any Deposited Securities have been recorded on our share register maintained by the Russian Share Registrar in the name of the depositary or its nominee or such custodian or its nominee, together with the other documents described in this paragraph 1, such custodian shall notify the depositary of such deposit and the person or persons to whom or upon whose written order a Level 1 ADR or Level 1 ADRs are deliverable in respect thereof and the number of ADSs to be evidenced thereby. Such notification shall be made by letter or, at the request, risk and expense of the person making the deposit, by cable, telex or facsimile transmission. Upon receiving such notice from such custodian, the depositary, subject to the terms and conditions of the Level 1 Deposit Agreement, shall execute and deliver at its Corporate Trust Office, to or upon the order of the person or persons entitled thereto, a Level 1 ADR or Level 1 ADRs, registered in the name or names and evidencing any authorised number of ADSs requested by such person or persons, but only upon payment to the depositary of the fees and expenses of the depositary for the execution and delivery of such a Level 1 ADR or Level 1 ADRs and of all taxes and governmental charges and fees payable in connection with such deposit and the transfer of the Deposited Securities.

1.3 No share shall be accepted for deposit unless accompanied by evidence satisfactory to the depositary that (i) all conditions to such deposit have been satisfied by the person depositing such shares under Russian laws and regulations (ii) any necessary approval has been granted by any governmental body in the Russian Federation that is then performing the function of the regulation of currency exchange and (iii) all applicable taxes and governmental charges and the fees and expenses of the depositary have been paid. If required by the depositary, shares presented for deposit at any time, whether or not our share register is closed, shall also be accompanied by an agreement or assignment, or other instrument satisfactory to the depositary, which will provide for the prompt transfer to the custodian of any dividend, or right to subscribe for additional shares or to receive other property that any person in whose name the shares are or have been recorded may thereafter receive upon or in respect of such deposited shares, or in lieu thereof, such agreement of indemnity or other agreement as shall be satisfactory to the depositary.

1.4 Subject to the limitations and other provisions set forth in the Level 1 Deposit Agreement, the depositary may (but is not required to) execute and deliver Level 1 ADRs prior to the receipt of shares in respect of which such Level 1 ADRs are to be issued (a "Pre-Release") and/or deliver shares upon the receipt and cancellation of Level 1 ADRs which have been Pre-Released, whether or not such cancellation is prior to the termination of such Pre-Release or the depositary knows that such Level 1 ADR has been Pre-Released.

1.5 Upon each delivery to a custodian of a certificate or certificates for, or other documents evidencing title to (including extracts from our share register evidencing ownership of the shares by each person presenting shares for deposit under the Level 1 Deposit Agreement), shares to be deposited under the Level 1 Deposit Agreement, together with the other documents above specified, such custodian or its agents shall present such certificate or certificates or other documents as above specified to the Russian Share Registrar for transfer and recordation of the shares being deposited in the name of the depositary or its nominee or such custodian or its nominee, and we shall ensure that such transfer and recordation is promptly effected.

1.6 Records of ownership of Deposited Securities (including extracts from our share register) shall be held by the depositary or by a custodian for the account and to the order of the depositary or at such other place or places as the depositary shall determine.

2. Withdrawal of deposited securities

2.1 Upon surrender at the Corporate Trust Office of the depositary of a Level 1 ADR for the purpose of withdrawal of the Deposited Securities represented by the ADSs evidenced by such Level 1 ADR, accompanied by such documents as the depositary may require (including a purchase/sale contract relating to the transfer of the shares) and upon payment of the fees and expenses of the depositary for the surrender of Level 1 ADRs and payment of all taxes and governmental charges payable in connection with such surrender and withdrawal of the Deposited Securities, and subject to the terms and conditions of the Level 1 Deposit Agreement, the Owner of such Level 1 ADR shall be entitled to delivery, to him or upon his order, of the amount of Deposited Securities at the time represented by the Level 1 ADSs evidenced by such Level 1 ADR. Delivery of such Deposited Securities may be made by the delivery of (a) certificates or other documents evidencing title (including extracts from our share register) in the name of such Owner or as ordered by him or properly endorsed or accompanied by proper instruments of transfer to such Owner or as ordered by him and (b) any other securities, property and cash to which such Owner is then entitled in respect of such Level 1 ADR to such Owner or as ordered by him. Such delivery shall be made, as hereinafter provided, without unreasonable delay.

2.2 A Level 1 ADR surrendered for such purposes may be required by the depositary to be properly endorsed in blank or accompanied by proper instruments of transfer in blank, and if the depositary so required, the Owner thereof shall execute and deliver to the depositary a written order directing the depositary to cause the Deposited Securities being withdrawn to be delivered to or upon the written order of a person or persons designated in such order. Thereupon the depositary shall direct the custodian or its agents to cause the transfer and recordation by the Russian Share Registrar on the Share Register of the shares being withdrawn in the name of such Owner or as directed by him as above provided, and we shall ensure that such transfer and recordation is effected within 72 hours from the time it is requested to do so by the depositary or the custodian or any of their respective agents; provided that all required documents have been completed and submitted in accordance with applicable Russian law and regulations. Upon such transfer and recordation, the custodian shall deliver at the Moscow, Russian Federation, office of such custodian, subject to the terms and conditions of the Level 1 Deposit Agreement, to or upon the written order of the person or persons designated in the order delivered to the depositary as above provided, documents evidencing title (including extracts from the Share Register) for the amount of Deposited Securities represented by the Level 1 ADSs evidenced by such Level 1 ADR, except that, if and to the extent practicable, the depositary may make delivery to such person or persons at the Corporate Trust Office of the depositary of any dividends or distributions with respect to the Deposited Securities represented by the Level 1 ADSs evidenced by such Level 1 ADR, or of any proceeds of sale of any dividends, distributions or rights, which may at the time be held by the depositary.

2.3 At the request, risk and expense of any Owner so surrendering a Level 1 ADR, and for the account of such Owner, the depositary shall direct the custodian to forward any cash or other property (other than rights) comprising, and forward a certificate or certificates and other proper documents evidencing title for, the Deposited Securities represented by the Level 1 ADSs evidenced by such Level 1 ADR to the depositary for delivery at the Corporate Trust Office of the depositary. Such direction shall be given by letter or, at the request, risk and expense of such Owner, by cable, telex or facsimile transmission.

3. Ownership and transfer

3.1 Ownership

Title to a Level 1 ADR (and to the Level 1 ADSs evidenced thereby), when properly endorsed or accompanied by proper instruments of transfer, is transferable by delivery with the same effect as in the case of a negotiable instrument under the laws of New York; provided, however that the depositary, notwithstanding any notice to the contrary, may treat the Owner thereof as the absolute owner thereof for the purpose of determining the person entitled to distribution of dividends or other distributions or to any notice provided for in the Level 1 Deposit Agreement and for all other purposes, and neither the depositary nor we will have any obligation to or be subject to any liability under the Level 1 Deposit Agreement to any holder of a Level 1 ADR, unless such holder is the Owner of it.

3.2 Transfers, split-ups and combinations of Level 1 ADRs

3.2.1 The transfer of the Level 1 ADRs is registrable on the books of the depositary at its Corporate Trust Office by the Owner in person or by a duly authorised attorney, upon surrender of a Level 1 ADR properly endorsed for transfer or accompanied by proper instruments of transfer duly stamped as may be required by laws of the State of New York and of the United States and funds sufficient to pay any applicable transfer taxes and the expenses of the depositary and upon compliance with such regulations, if any, as the depositary may establish for each purpose. Level 1 ADRs may be split into other such Level 1 ADRs, or may be combined with other such Level 1 ADRs into one Level 1 ADR, evidencing the same aggregate number of Level 1 ADSs as the Level 1 ADR or Level 1 ADRs surrendered. As a condition precedent to the execution and delivery, registration of transfer, split-up, combination, or surrender of any Level 1 ADR or withdrawal of any Deposited Securities, the depositary, the custodian, or registrar may require payment from the depositor of the shares or the presenter of the Level 1 ADR of a sum sufficient to reimburse it for any tax or other governmental charge and any stock transfer or registration fee with respect thereto (including any such tax or charge and fee with respect to shares being deposited or withdrawn) and payment of any applicable fees and expenses as provided in the Level 1 ADR may require the production of proof satisfactory to it as to the identity and genuineness of any signature and may also require compliance with any regulations the depositary may establish consistent with the provisions of the Level 1 Deposit Agreement or the Level 1 ADR.

3.2.2 The delivery of Level 1 ADRs against deposits of shares generally or against deposits of particular shares may be suspended, or the transfer of Level 1 ADRs in particular instances may be refused, or the registration of transfer of outstanding Level 1 ADRs generally may be suspended, during any period when the transfer books of the depositary are closed, or if any such action is deemed necessary or advisable by the depositary or us at any time or from time to time because of any requirements of law or of any government or governmental body or commission, or under any provision of the Level 1 Deposit Agreement or the Level 1 ADR, or for any other reason, subject to the provisions of the following sentence. Notwithstanding anything to the contrary in the Level 1 Deposit Agreement, the surrender of outstanding Level 1 ADRs and withdrawal of Deposited Securities may not be suspended subject only to (i) temporary delays caused by closing the transfer books of the depositary or us or the deposit of shares in connection with voting at a shareholders' meeting, or the payment of dividends, (ii) the payment of fees, taxes and similar charges, and (iii) compliance with any U.S. or foreign laws or governmental regulations relating to the Level 1 ADRs or to the withdrawal of the Deposited Securities. Without limitation of the foregoing, the depositary shall not knowingly accept for deposit under the Deposit Agreement any Shares required to be registered under the provisions of the Securities Act of 1933, as amended (the "Securities Act"), unless a registration statement is in effect as to such shares.

3.3 Filing Proofs

Any person presenting shares for deposit or any Owner or Beneficial Owner of a Level 1 ADR may be required from time to time to file with the depositary or the custodian such proof of citizenship or residence, exchange control approval, evidence of payment of applicable taxes and other governmental charges, or such information relating to the registration on the books of the Russian Share Registrar to execute such certificates and to make such representations and warranties, as the depositary may deem necessary or proper. The depositary may withhold the delivery or registration of transfer of any Level 1 ADR or the distribution of any dividend or sale or distribution of rights or of the proceeds thereof or the delivery of any Deposited Securities until such proof, evidence or other information is filed or such certificates are executed or such representations and warranties made.

3.4 Warranties on Deposit of Shares

Every person depositing shares under the Level 1 Deposit Agreement shall be deemed thereby to represent and warrant that such shares and each certificate therefor are validly issued, fully paid, nonassessable and free of any preemptive rights of the holders of outstanding shares and that the person making such deposit is duly authorised so to do. Every such person shall also be deemed to represent and warrant that such shares and the Level 1 ADRs evidencing ADSs representing such shares would not be Restricted Securities. Such representations and warranties shall survive the deposit of shares and issuance of Level 1 ADRs.

4. Cash Distributions

Whenever the depositary receives any cash dividend or other cash distribution on any Deposited Securities, the depositary shall, subject to the provisions of the Level 1 Deposit Agreement, convert such dividend or distribution into U.S. Dollars and shall distribute the amount thus received (net of the fees and expenses of the depositary as provided in the Level 1 Deposit Agreement) to the Owners entitled thereto, in proportion to the number of ADSs representing such Deposited Securities held by them respectively; provided, however, that in the event that we or the depositary shall be required to withhold and does withhold from such cash dividend or such other cash distribution an amount on account of taxes, the amount distributed to the Owner of the Level 1 ADRs evidencing ADSs representing such Deposited Securities shall be reduced accordingly. The depositary shall distribute only such amount, however, as can be distributed without attributing to any Owner a fraction of one cent. Any fractional amounts shall be rounded to the nearest whole cent and so distributed to Owners entitled thereto. We or our agent will remit to the appropriate governmental agency in the Russian Federation all amounts withheld and owing to such agency. The depositary will forward to us or our agent such information from its records as we may reasonably request to enable us or our agent to file necessary reports with governmental agencies, and the depositary or we or our agent may file any such reports necessary to obtain benefits under the applicable tax treaties for the Owners of Level 1 ADRs.

5. Distribution of Shares

If any distribution upon any Deposited Securities consists of a dividend in, or free distribution of, shares, the depositary may distribute to the Owners of outstanding Level 1 ADRs entitled thereto, in proportion to the number of Level 1 ADSs representing such Deposited Securities held by them respectively, additional Level 1 ADRs evidencing an aggregate number of Level 1 ADSs representing the amount of shares received as such dividend or free distribution, subject to the terms and conditions of the Level 1 Deposit Agreement with respect to the deposit of shares and the issuance of Level 1 ADSs evidenced by Level 1 ADRs, including the withholding of any tax or other governmental charge and the payment of the fees and expenses of the depositary as provided in the Level 1 Deposit Agreement. The depositary may withhold any such distribution of Level 1 ADRs if it has not received satisfactory assurances from us that such distribution does not require registration under the Securities Act or is exempt from registration under the provisions of such Act. In lieu of delivering Level 1 ADRs for fractional Level 1 ADSs in any such case, the depositary will sell the amount of shares represented by the aggregate of such fractions and distribute the net proceeds, all in the manner and subject to the conditions described in paragraph 4 above. If additional Level 1 ADRs are not so distributed, each Level 1 ADS shall thenceforth also represent the additional shares distributed upon the Deposited Securities represented thereby.

6. Distributions other than cash or Shares

Subject to the provisions of paragraphs 9 and 16, whenever the depositary receives any distribution other than a distribution for cash, distribution of shares or a rights issue pursuant to the terms and conditions of the Level 1 Deposit Agreement, the depositary shall cause the securities or property received by it to be distributed to the Owners entitled thereto, after deduction or upon payment of any fees and expenses of the depositary or any taxes or other governmental charges, in proportion to the number of ADSs representing such Deposited Securities held by them respectively, in any manner that the depositary may deem equitable and practicable for accomplishing such distribution; provided, however, that if in the opinion of the depositary such distribution cannot be made proportionately among the Owners entitled thereto, or if for any other reason (including, but not limited to, any requirement that we or the depositary withhold an amount on account of taxes or other governmental charges or that such securities must be registered under the Securities Act in order to be distributed to Owners or Beneficial Owners) the depositary deems such distribution not to be feasible, the depositary may adopt such method as it may deem equitable and practicable for the purpose of effecting such distribution, including, but not limited to, the public or private sale of the securities or property thus received, or any part thereof, and the net proceeds of any such sale (net of the fees and expenses of the depositary as provided in paragraph 16) shall be distributed by the depositary to the Owners entitled thereto, all in the manner and subject to the conditions described in paragraph 4 above.

7. Rights issues

7.1 In the event that we offer or cause to be offered to the holders of any Deposited Securities any rights to subscribe for additional shares or any rights of any other nature, the depositary has discretion as to the procedure to be followed in making such rights available to any Owners or in disposing of such rights on behalf of any Owners and making the net proceeds available to such Owners or, if by the terms of such rights offering or for any other reason, the depositary may neither make such rights available to any Owners nor dispose of such rights and make the net proceeds available to such Owners, then the depositary shall allow the rights to lapse. If at the time of the offering of any rights the depositary determines in its discretion that it is lawful and feasible to make such rights available to all or certain Owners but not to other Owners, the depositary may distribute to any Owner to whom it determines the distribution to be lawful and feasible, in proportion to the number of Level 1 ADSs held by such Owner, warrants or other, instruments therefor in such form as it deems appropriate.

7.2 In circumstances in which rights would otherwise not be distributed, if an Owner of Level 1 ADRs requests the distribution of warrants or other instruments in order to exercise the rights allocable to the Level 1 ADSs of such Owner, the depositary will make such rights available to such Owner upon written notice from us to the depositary that (a) we have elected in our sole discretion to permit such rights to be exercised and (b) such Owner has executed such documents as we have determined in our sole discretion are reasonably required under applicable law.

7.3 If the depositary has distributed warrants or other instruments for rights to all or certain Owners, then upon instruction from such an Owner pursuant to such warrants or other instruments to the depositary from such Owner to exercise such rights, upon payment by such Owner to the depositary for the account of such Owner of an amount equal to the purchase price of the shares to be received upon the exercise of the rights, and upon payment of the fees and expenses of the depositary and any other charges as set forth in such warrants or other instruments, the depositary shall, on behalf of such Owner, exercise the rights and purchase the shares, and we shall cause the shares so purchased to be delivered to the depositary on behalf of such Owner. As agent for such Owner, the depositary will cause the shares so purchased to be deposited pursuant to the Level 1 Deposit Agreement and will execute and deliver Level 1 ADRs to such Owner. In the case of a distribution pursuant to the paragraph 7.2, such Level 1 ADRs shall be legended in accordance with applicable U.S. laws, and shall be subject to the appropriate restrictions on sale, deposit, cancellation and transfer under such laws.

7.4 If the depositary determines in its discretion that it is not lawful and feasible to make such rights available to all or certain Owners, it may sell the rights, warrants or other instruments in proportion to the number of Level 1 ADSs held by the Owners to whom it has determined it may not lawfully or feasibly make such rights available, and allocate the net proceeds of such sales (net of the fees and expenses of the depositary and all taxes and governmental charges payable in connection with such rights and subject to the terms and conditions of the Level 1 Deposit Agreement) for the account of such Owners otherwise entitled to such rights, warrants or other instruments, upon an averaged or other practical basis without regard to any distinctions among such Owners because of exchange restrictions or the date of delivery of any Level 1 ADR or otherwise.

7.5 The depositary will not offer rights to Owners unless both the rights and the securities to which such rights relate are either exempt from registration under the Securities Act with respect to a distribution to all Owners or are registered under the provisions of such Act; provided, that nothing in the Level 1 Deposit Agreement shall create any obligation on our part to file a registration statement with respect to such rights or underlying securities or to endeavour to have such a registration statement declared effective. If an Owner of Level 1 ADRs requests the distribution of warrants or other instruments, notwithstanding that there has been no such registration under the Securities Act, the depositary shall not effect such distribution unless it has received an opinion from recognised counsel in the United States for us upon which the depositary may rely that such distribution to such Owner is exempt from such registration.

7.6 The depositary is not responsible for any failure to determine that it may be lawful or feasible to make such rights available to Owners in general or any Owner in particular.

8. Conversion of foreign currency

8.1 Whenever the depositary shall receive foreign currency, by way of dividends or other distributions or the net proceeds from the sale of securities, property or rights, into the depositary's foreign investment account in the Russian Federation, and if at the time of the receipt thereof the foreign currency so received can in the judgment of the depositary be converted on a reasonable basis into U.S. dollars and the resulting U.S. dollars transferred to the United States, the depositary shall convert or cause to be converted, by sale or in any other manner that it may determine, such foreign currency into U.S. dollars, and such U.S. dollars shall be distributed to the Owners entitled thereto or, if the depositary shall, have distributed any warrants or other instruments that entitle the holders thereof to such U.S. dollars, then to the holders of such warrants and/or instruments upon surrender thereof for cancellation. Such distribution may be made upon an averaged or other practicable basis without regard to any distinctions among Owners on account of exchange restrictions, the date of delivery of any Level 1 ADR or otherwise and shall be net of any expenses of conversion into U.S. dollars incurred by the depositary.

8.2 If such conversion or distribution can be effected only with the approval or licence of any government or agency thereof, the depositary shall file such application for approval or licence, if any, as it may, in its sole discretion, deem desirable.

8.3 If at any time the depositary shall determine that in its judgment any foreign currency received by the depositary or the custodian is not convertible on a reasonable basis into U.S. dollars transferable to the

United States, or if any approval or licence of any government or agency thereof that is required for such conversion is denied or in the opinion of the depositary is not obtainable, or if any such approval or licence is not obtained within a reasonable period as determined by the depositary, the depositary may distribute the foreign currency (or an appropriate document evidencing the right to receive such foreign currency) received by the depositary to, or in its discretion may hold such foreign currency uninvested and without liability for interest thereon for the respective accounts of, the Owners entitled to receive the same.

8.4 If any such conversion of foreign currency, in whole or in part, cannot be effected for distribution to some of the Owners entitled thereto, the depositary may in its discretion make such conversion and distribution in U.S. dollars to the extent permissible to the Owners entitled thereto and may distribute the balance of the foreign currency received by the depositary to, or hold such balance uninvested and without liability for interest thereon for the respective accounts of, the Owners entitled thereto.

9. Fixing of record dates

Whenever any cash dividend or other cash distribution shall become payable or any distribution other than cash shall be made, or whenever rights shall be issued with respect to the Deposited Securities, or whenever the depositary shall receive notice of any meeting of holders of shares or other Deposited Securities, or whenever for any reason the depositary causes a change in the number of shares that are represented by each Level 1 ADS, or whenever the depositary shall find it necessary or convenient, the depositary shall fix a record date (a) for the determination of the Owners who shall be (i) entitled to receive such dividend, distribution or rights or the net proceeds of the sale thereof or (ii) entitled to give instructions for the exercise of voting rights at any such meeting, (b) on or after which each Level 1 ADS will represent the changed number of shares or (c) for the determination of the Owners who shall be responsible for the fee assessed by the depositary for inspection of our share register maintained by the Russian Share Registrar. Subject to the terms and conditions of the Level 1 Deposit Agreement, the Owners on such record date shall be entitled, as the case may be, to receive the amount distributable by the depositary with respect to such dividend or other distribution or such rights or the net proceeds of sale thereof in proportion to the number of ADSs held by them respectively and to give voting instructions and to act in respect of any such other matter.

10. Capital reorganisation

In circumstances where the provisions in relation to distributions of shares in the Level 1 Deposit Agreement do not apply, upon any change in nominal value, change in par value, split-up, consolidation or any other reclassification of Deposited Securities, or upon any recapitalisation, reorganisation, merger or consolidation or sale of assets affecting us or to which we are a party, any securities that shall be received by the depositary or a custodian in exchange for or in conversion of or in respect of Deposited Securities, shall be treated as new Deposited Securities under the Level 1 Deposit Agreement, and Level 1 ADSs shall then represent, in addition to the existing Deposited Securities, the right to receive the new Deposited Securities so received in exchange or conversion, unless additional Level 1 ADRs are delivered pursuant to the following sentence. In any such case the depositary may execute and deliver additional Level 1 ADRs as in the case of a dividend in shares, or call for the surrender of outstanding Level 1 ADRs to be exchanged for new Level 1 ADRs specifically describing such new Deposited Securities.

11. Withholding taxes and applicable laws

In the event that the depositary determines that any distribution in property including shares and rights to subscribe therefor) or any deposit of shares, transfer of Level 1 ADRs or withdrawal of Deposited Securities hereunder is subject to any tax or other governmental charge that the depositary determines, in its absolute discretion, it is, or may be, obligated to withhold, the depositary may by public or private sale dispose of all or a portion of such property (including shares and rights to subscribe therefor) in such amounts and in such manner as the depositary deems necessary and practicable to pay any such taxes or charges and the depositary shall distribute the net proceeds of any such sale after deduction of such taxes or charges to the Owners entitled thereto in proportion to the number of ADSs held by them respectively.

12. Voting rights

Upon receipt of notice of any meeting of shareholders or holders of other Deposited Securities, if requested in writing by us, the depositary shall, as soon as practicable thereafter, mail to the Owners of Level 1 ADRs a notice, the form of which notice shall be in the sole discretion of the depositary, which shall contain (a) such information as is contained in such notice of meeting received by the depositary from us, (b) a statement that the Owners of Level 1 ADRs as of the close of business on a specified record date will be entitled, subject to any applicable provision of law and of our Charter, to instruct the depositary as to the exercise of the voting rights, if any, pertaining to the amount of shares or other Deposited Securities represented by their respective Level 1 ADSs and (c) a statement as to the manner in which such instructions may be given, including an express indication that such instructions may be given, or deemed given in accordance with the last sentence of this paragraph if no instruction is received, to the depositary to give a discretionary proxy in conformity with Russian law to us or to a person designated by us. Upon the written request of an Owner of a Level 1 ADR on such record date, received on or before the date established by the Depositary for such purpose, the Depositary shall endeavour insofar as practicable to vote or cause to be voted the amount of shares or other Deposited Securities represented by such Level 1 ADSs evidenced by such Level 1 ADR in accordance with the instructions set forth in such request. The depositary shall not vote or attempt to exercise the right to vote that attaches to the shares or other Deposited Securities, other than in accordance with such instructions or deemed instructions. If no instructions are received by the depositary from any Owner with respect to any of the Deposited Securities represented by the Level 1 ADSs evidenced by such Owner's Level 1 ADRs on or before the date established by the depositary for such purpose, the depositary shall deem such Owner to have instructed the depositary to give a discretionary proxy in conformity with Russian law to us or to a person designated by us with respect to such Deposited Securities and the depositary will give a discretionary proxy in conformity with Russian law to us or to a person designated by us to vote such Deposited Securities; provided that no such instruction will be deemed given and no such discretionary proxy will be given with respect to any matter as to which we inform the depositary (and, we agree to provide such information as promptly as practicable in writing) that (x) we do not wish such proxy given, (y) substantial opposition exists or (z) such matter materially and adversely affects the rights of holders of shares.

13. Documents to be furnished, recovery of taxes, duties and other charges

If any tax or other governmental charge shall become payable by the custodian or the depositary with respect to any Level 1 ADR or any Deposited Securities represented by any Level 1 ADR, such tax or other governmental charge shall be payable by the Owner or Beneficial Owner of such Level 1 ADR to the depositary, and such Owner or Beneficial Owner shall be deemed liable therefor. In addition to any other remedies available to it, the depositary may refuse to effect any transfer of such Level 1 ADR or any withdrawal of Deposited Securities represented by the Level 1 ADSs evidenced by such Level 1 ADR until such payment is made, and may withhold any dividends or other distributions, or may sell for the account of the Owner or Beneficial Owner thereof any part or all of the Deposited Securities represented by the Level 1 ADSs evidenced by such Level 1 ADR, and may apply such dividends or other distributions or the proceeds of any such sale in payment of such tax or other governmental charge and the Owner or Beneficial Owner of such Level 1 ADR shall remain liable for any deficiency. The obligations of Owners and Beneficial Owners shall survive any transfer of Level 1 ADRs, any surrender of Level 1 ADRs and withdrawal of Deposited Securities, or the termination of the Level 1 Deposit Agreement.

14. Liability

14.1 Neither the depositary nor we nor any of their or our respective directors, employees, agents or affiliates shall incur any liability to any Owner or Beneficial Owner of any Level 1 ADR, if by reason of (a) any provision of any present or future law or regulation of the United States, the Russian Federation or any other country, or of any other governmental or regulatory authority or stock exchange, or by reason of any act of God or war or other circumstances beyond its control, or (b) in the case of the depositary only, (i) any act or failure to act by us or our agents, including the Russian Share Registrar, or their or our respective directors, employees, agents or affiliates, (ii) any provision, present or future, of our Charter or any other instrument of us governing the Deposited Securities or (iii) any provision of any securities issued or distributed by us, or any offering or distribution thereof, the depositary or we shall be prevented, delayed or forbidden from or be subject to any civil or criminal penalty on account of doing or performing any act or thing that by the terms of the Level 1 Deposit Agreement or Deposited Securities it is provided shall be done or performed (including, in the case of the depositary, delivery of any Deposited Securities or distribution of cash or property in respect thereof pursuant to paragraphs 4 through 7); nor shall the depositary or we or their or our respective directors, employees, agents or affiliates incur any liability to any Owner or Beneficial Owner of a Level 1 ADR by reason of any non-performance or delay, caused as aforesaid, in the performance of any act or thing which by the terms of the Level 1 Deposit Agreement it is provided shall or may be done or performed, or by reason of any exercise of, or failure to exercise, any discretion provided for in the Level 1 Deposit Agreement. Where, by the terms of a distribution pursuant to the terms and conditions of the Level 1 Deposit Agreement, or an offering or distribution pursuant to the Level 1 Deposit Agreement, such distribution or offering may not be made available to Owners of Level 1 ADRs, and the depositary may not dispose of such distribution or offering on behalf of such Owners and make the net proceeds available to such Owners, then the depositary shall not make such distribution or offering, and shall allow any rights, if applicable, to lapse.

14.2 Neither we nor the depositary assumes any obligation or shall be subject to any liability under the Level 1 Deposit Agreement to Owners or Beneficial Owners of Level 1 ADRs, except that (i) we agree to perform our obligations specifically set forth in the Level 1 Deposit Agreement and (ii) the depositary agrees to perform its obligations specifically set forth in the Level 1 Deposit Agreement without negligence or bad faith. The depositary will not be subject to any liability with respect to the validity or worth of the Deposited Securities. Neither the depositary nor we will be under any obligation to appear in, prosecute or defend any action, suit, or other proceeding in respect of any Deposited Securities or in respect of the Level 1 ADRs, which in its or our opinion may involve it in expense or liability, unless indemnity satisfactory to it against all expense and liability shall be furnished as often as may be required, and the custodian shall not be under any obligation whatsoever with respect to such proceedings, the responsibility of the custodian being solely to the depositary.

14.3 Neither the depositary nor we will be liable for any action or inaction by it in reliance upon the advice of or information from legal counsel, accountants, any person presenting shares for deposit, any Owner or Beneficial Owner of a Level 1 ADR, or any other person believed by it in good faith to be competent to give such advice or information; provided, however, that in the case of us, advice of, or information from legal counsel is from recognised U.S. legal counsel for U.S. legal issues, recognised Russian counsel for Russian legal issues and recognised counsel of any other jurisdiction for legal issues with respect to that jurisdiction.

14.4 The depositary will not be responsible for any failure to carry out any instructions to vote any of the Deposited Securities, or for the manner in which any such vote is cast or the effect of any such vote, provided that any such action or inaction is in good faith.

14.5 The depositary will not be liable for any acts or omissions made by a successor depositary whether in connection with a previous act or omission of the depositary or in connection with a matter arising wholly after the removal or resignation of the depositary, provided that in connection with the issue out of which such potential liability arises, the depositary performed its obligations without negligence or bad faith while it acted as depositary.

14.6 The depositary shall not be liable to us, any Owner or Beneficial Owner or any other person for the unavailability of Deposited Securities or for the failure to make any distribution of cash or property with respect thereto as a result of (i) any act or failure to act by us or our agents including the Russian Share Registrar, or our or their respective directors, employees, agents or affiliates, (ii) any provision of any present or future law or regulation of the United States, the Russian Federation or any other country, (iii) any provision of any present or future regulation of any governmental or regulatory authority or stock exchange, (iv) any provision of any present or future Charter of us or any other instrument of us governing the Deposited Securities, (v) any provision of any securities issued or distributed by us or any offering or distribution thereof, or (vi) any act of God or war or other circumstance beyond its control.

14.7 We have agreed in the Level 1 Deposit Agreement to indemnify the depositary, any custodian, and their respective directors, employees, agents and affiliates and any custodian, against and hold each of them harmless from, any liability or expense (including but not limited to, the expenses of counsel) that may arise out of (a) any registration with the U.S. Securities and Exchange Commission, or the SEC, of Level 1 ADRs, Level 1 ADSs or Deposited Securities or the offer or sale thereof, or out of acts performed or omitted, in accordance with the provisions of the Level 1 Deposit Agreement and of the Level 1 ADRs, as the same may be amended, modified or supplemented from time to time, (i) by either the depositary or a custodian or their respective directors, employees, agents and affiliates, except for any liability or expense arising out of the negligence or bad faith of either of them, or (ii) by us or any of our directors, employees, agents and affiliates or (b) the unavailability of Deposited Securities or the failure to make any distribution of cash or property with respect thereto as a result of (i) any act or failure to act by us or our agents, including the Russian Share Registrar, or our or their respective directors, employees, agents or affiliates, (ii) any provision of any present or future Charter of us or any other instrument of us governing Deposited Securities or (iii) any provision of any securities issued or distributed by us, or any offering or distribution thereof or (c) any assessment (or purported assessment) against shares or other Deposited Securities of the sort contemplated by paragraph 10. No disclaimer of liability under the Securities Act is intended by any provision of the Level 1 Deposit Agreement.

15. Issue and delivery of replacement Level 1 ADRs and exchange of Level 1 ADRs

If any Level 1 ADR is mutilated, destroyed, lost or stolen, the depositary will execute and deliver a new Level 1 ADR of like tenor in exchange and substitution for such mutilated Level 1 ADR upon cancellation thereof, or in lieu of and in substitution for such destroyed, lost or stolen Level 1 ADR. Before the depositary will execute and deliver a new Level 1 ADR in substitution for a destroyed lost or stolen Level 1 ADR, the Owner thereof shall (a) file with the depositary (i) a request for such execution and delivery before the depositary has notice that the Level 1 ADR has been acquired by a bona fide purchaser and (ii) a sufficient indemnity bond and (b) satisfy any other reasonable requirements imposed by the depositary.

16. Depositary's fees, costs and expenses

16.1 We have agreed in the Level 1 Deposit Agreement to pay the fees, reasonable expenses and out-of-pocket charges of the depositary and those of any registrar only in accordance with agreements in writing entered into between the depositary and us from time to time. The depositary will present its statement for such charges and expenses to us once every three months. The charges and expenses of the custodian are for the sole account of the depositary.

16.2 The following charges will be incurred by any party depositing or withdrawing shares or by any Owner of Level 1 ADRs or by any party surrendering Level 1 ADRs or to whom Level 1 ADRs are issued (including, without limitation, issuance pursuant to a stock dividend or stock split declared by us or an exchange of stock regarding the Level 1 ADRs or Deposited Securities or a distribution of Level 1 ADRs paragraph 5), whichever applicable: (1) taxes and other governmental charges, (2) such registration fees as may from time to time be in effect for the registration of transfers of shares generally on our share register maintained by the Russian Share Registrar and applicable to transfers of shares to the name of the depositary or its nominee or the custodian or its nominee on the making of deposits or withdrawals hereunder, (3) such cable, telex and facsimile transmission expenses as are expressly provided in the Level 1 Deposit Agreement, (4) such expenses are incurred by the depositary in the conversion of foreign currency pursuant to paragraph 8, (5) a fee of $5.00 or less per 100 Level 1 ADSs (or portion thereof) for the execution and delivery of Level 1 ADRs pursuant to paragraphs 5, 7 or 12 and the surrender of Level 1 ADRs pursuant to paragraphs 2 or 21, (6) a fee of $.02 or less per ADS (or portion thereof) for any cash distribution made pursuant to paragraphs 4-9 and 12, (7) a fee: of $.01 or less per Level 1 ADS (or portion thereof) per year to cover such expenses as are incurred for inspections by the depositary, the custodian or their respective agents of our share register maintained by the Russian Share Registrar (which fee shall be assessed against Owners of record as of the date or dates set by the depositary in accordance with paragraph 9 and shall be collected at the sole discretion of the depositary by billing such Owners for such fee or by deducting such fee from one or more cash dividends or other cash distributions), (8) a fee for the distribution of securities pursuant to paragraph 6, such fee being in an amount equal to the fee for the execution and delivery of Level 1 ADSs referred to above that would have been charged as a result of the deposit of such securities (for purpose of this sub-clause 8 treating all such securities as if they were shares) but which securities are instead distributed by the depositary to Owners and (9) a fee not in excess of $1.50 per certificate for a Level 1 ADR or Level 1 ADRs for transfers made pursuant to terms of the Level 1 Deposit Agreement.

17. Maintenance of Office and Transfer Books by Depositary

17.1 Until termination of the Level 1 Deposit Agreement in accordance with its terms, the depositary will maintain in the Borough of Manhattan, The City of New York, facilities for the execution and delivery, registration, registration of transfers and surrender of Level 1 ADRs in accordance with the provisions of Level 1 Deposit Agreement.

17.2 The depositary shall keep books, at its Corporate Trust Office, for the registration of Level 1 ADRs and transfers of Level 1 ADRs which at all reasonable times shall be open for inspection by the Owners, provided that such inspection shall not be for the purpose of communicating with Owners in the interest of a business or object other than our business or a matter related to the Level 1 Deposit Agreement or the Level 1 ADRs.

17.3 The depositary may close the transfer books, at any time or from time to time, when deemed expedient by it in connection with the performance of its duties under the Level 1 Deposit Agreement.

17.4 If any Level 1 ADRs or the ADSs evidenced thereby are listed on one or more stock exchanges in the United States, the depositary shall act as registrar or appoint a registrar or one or more co-registrars for registry of such Level 1 ADRs in accordance with any requirements of such exchange or exchanges.

18. The Custodian

18.1 The custodian is subject at all times and in all respects to the directions of the depositary and shall be responsible solely to it. The custodian may resign and be discharged from its duties under the terms and conditions of the Level 1 Deposit Agreement by notice of such resignation delivered to the depositary at least 30 days prior to the date on which such resignation is to become effective. If upon such resignation there shall be no custodian acting, the depositary shall, promptly after receiving such notice, appoint a substitute custodian or custodians, each of which shall thereafter be a custodian. Whenever the depositary in its discretion determines that it is in the best interest of the Owners to do so, it may appoint a substitute or additional custodian or custodians, each of which shall thereafter be one of the custodians. Upon demand of the depositary the custodian will deliver such of the Deposited Securities held by it as are requested of it to any other custodian or such substitute or additional custodian or custodians. Each such substitute or additional custodian shall deliver to the depositary, forthwith upon its appointment, an acceptance of such appointment satisfactory in form and substance to the depositary.

18.2 Upon the appointment of any successor depositary, each custodian then acting will forthwith become, without any further act or writing, the agent of such successor depositary and the appointment of such successor depositary shall in no way impair the authority of each custodian; but the successor depositary so appointed shall, nevertheless, on the written request of any custodian, execute and deliver to such custodian all such instruments as may be proper to give to such custodian full and complete power and authority as agent of such successor depositary.

19. The Russian Share Registrar

19.1 We have agreed to designate and appoint the JSC Registration Company NIKoil, in the Russian Federation, as our Russian Share Registrar in respect of the shares and Deposited Securities. We further agree to take any and all action, including the filing of any and all such documents and instruments, as may be necessary to continue the designation and appointment of a Russian Share Registrar in full force and effect for so long as any ADSs or Level 1 ADRs remain outstanding under the Level 1 Deposit Agreement or the Level 1 Deposit Agreement remains in force.

19.2 We have agreed that we shall, at any time and from time to time:

(i) take any and all action as may be necessary to assure the accuracy and completeness of all information set forth in the share register maintained by the Russian Share Registrar in respect of the shares or Deposited Securities;

(ii) provide or cause the Russian Share Registrar to provide to the depositary, the custodian or their respective agents unrestricted access to the share register during ordinary business hours in Moscow, Russian Federation, in such manner and upon such terms and conditions as the depositary may, in its sole discretion, deem appropriate, to permit the depositary, the custodian or their respective agents to regularly (and in any event not less than monthly) confirm the number of Deposited Securities registered in the name of the depositary, the custodian or their respective nominees, as applicable, pursuant to the terms of the Level 1 Deposit Agreement and, in connection therewith, to provide the depositary, the custodian or their respective agents, upon request, with a duplicative extract from the share register duly certified by the Russian Share Registrar (or some other evidence of verification which the depositary, in its sole discretion, deems sufficient);

(iii) cause the Russian Share Registrar promptly (and, in any event, within 72 hours from the time it is requested to do so by the depositary or the custodian or any of their respective agents) to effect the re-registration of ownership of Deposited Securities in the share register in connection with any deposit or withdrawal of shares or Deposited Securities under the Level 1 Deposit Agreement;

(iv) permit and cause the Russian Share Registrar to permit the depositary or the custodian to register any shares or other Deposited Securities held hereunder in the name of the depositary, the custodian or their respective nominees (which may, but need not be, a non-resident of the Russian Federation); and

(v) cause the Russian Share Registrar promptly to notify the depositary in writing at any time that the Russian Share Registrar (A) eliminates the name of a shareholder from the Share Register or otherwise alters a shareholder's interest in our shares and such shareholder alleges to us or the Russian Share Registrar or publicly that such elimination or alteration is unlawful; (B) no longer will be able materially to comply with, or has engaged in conduct that indicates it will not materially comply with, the provisions of the Level 1 Deposit Agreement relating to it (including, without limitation, this paragraph 19); (C) refuses to re-register our shares in the name of a particular purchaser and such purchaser (or its respective seller) alleges that such refusal is unlawful; (D) holds our shares for its own account; or (E) has materially breached the provisions of the Level 1 Deposit Agreement relating to it (including, without limitation, this paragraph 19) and has failed to cure such breach within a reasonable time.

19.3 We agree that we shall be solely liable for any act or failure to act on the part of the Russian Share Registrar and that we shall be solely liable for the unavailability of Deposited Securities or for the failure of the depositary to make any distribution of cash or property with respect thereto as a result of (i) any act or failure to act of us or our agents, including the Russian Share Registrar, or our respective directors, employees, agents or affiliates, (ii) any provision of any present or future Charter of ours or any other instrument of ours governing the Deposited Securities, or (iii) any provision of any securities issued or distributed by us, or any offering or distribution thereof.

19.4 The depositary has agreed for the benefit of Owners and Beneficial Owners that the depositary or the custodian shall regularly (and in any event not less than monthly) confirm the number of Deposited Securities registered in the name of the depositary, the custodian or their respective nominees, as applicable, pursuant to the terms of the Level 1 Deposit Agreement. We and the depositary agree that, for purposes of the rights and obligations under the Level 1 Deposit Agreement of the parties thereto, the records of the depositary and the custodian shall be controlling for all purposes with respect to the number of shares or other Deposited Securities which should be registered in the name of the depositary, the custodian or their respective nominees, as applicable, pursuant to the terms of the Level 1 Deposit Agreement. The depositary agrees that it will instruct the custodian to maintain custody of all duplicative share extracts (or other evidence of verification) provided to the depositary, the custodian or their respective agents pursuant to paragraph 19.2. In the event of any material discrepancy between the records of the depositary or the custodian and the share register, then, if an officer of the ADR Department of the depositary has actual knowledge of such discrepancy, the depositary shall promptly notify us. In the event of any discrepancy between the records of the depositary or the custodian and the share register, we agree that (whether or not we have received any notification from the depositary) we will (i) use our best efforts to cause the Russian Share Registrar to reconcile its records to the records of the depositary or the custodian and to make such corrections or revisions in the share register as may be necessary in connection therewith, and (ii) to the extent we are unable to so reconcile such records, promptly instruct the depositary to notify the Owners of the existence of such discrepancy. Upon receipt of such instruction, the depositary shall promptly give such notification to the Owners pursuant to paragraph 23 (it being understood that the depositary may at any time give such notification to the Owners, whether or not it has received instructions from us), and the depositary shall promptly cease issuing Level 1 ADRs pursuant to paragraph 1 until such time as, in the opinion of the depositary, such records have been appropriately reconciled.

20. Resignation and termination of appointment of the Depositary

20.1 The depositary may at any time resign as depositary by written notice of its election so to do delivered to us, such resignation to take effect upon the appointment of a successor depositary and its acceptance of such appointment.

20.2 The depositary may at any time be removed by us by written notice of such removal effective upon the appointment of a successor depositary and its acceptance of such appointment.

20.3 In case at any time the depositary shall resign or be removed, we shall use our best efforts to appoint a successor depositary, which will be a bank or trust company having an office in the Borough of Manhattan, The City of New York. Every successor depositary shall execute and deliver to its predecessor and to us an instrument in writing accepting its appointment and thereupon such successor depositary, without any further act or deed, shall become fully vested with all the rights, powers, duties and obligations of its predecessor; but such predecessor, nevertheless, upon payment of all sums due it and on the written request of us will execute and deliver an instrument transferring to such successor all rights and powers of such predecessor, shall duly assign, transfer and deliver all right, title and interest in the Deposited Securities to such successor, and shall deliver to such successor a list of the Owners of all outstanding Level 1 ADRs. Any such depositary shall promptly mail notice of its appointment to the Owners.

20.4 Any corporation into or with which the depositary may be merged or consolidated shall be the successor of the depositary without the execution or filing of any document or any further act.

21. Termination of the Deposit Agreement

The depositary will, at any time at our direction, terminate the Level 1 Deposit Agreement by mailing notice of such termination to the Owners of all Level 1 ADRs then outstanding at least 90 days prior to the date fixed in such notice for such termination. The depositary may likewise terminate the Level 1 Deposit Agreement by mailing notice of such termination to us and the Owners of all Level 1 ADRs then outstanding, if at any time 90 days shall have expired after the Depositary shall have delivered to us a written notice of its election to resign and a successor depositary shall not have been appointed and accepted its appointment. On and after the date of termination, the Owner of a Level 1 ADR will, upon (a) surrender of such Level 1 ADR to the Corporate Trust Office of the depositary and (b) payment of any applicable taxes or governmental charges and the fees and expenses of the depositary, including the fees of the depositary for the surrender of Level 1 ADRs referred to in the Level 1 Deposit Agreement be entitled to delivery, to him or upon his order, of the amount of Deposited Securities represented by the ADSs evidenced by such Level 1 ADR. If any Level 1 ADRs remain outstanding after the date of termination, the depositary thereafter shall suspend the registration of transfers of Level 1 ADRs, shall suspend the distribution of dividends to the Owners thereof, and shall not give any further notices or perform any further acts under the Level 1 Deposit Agreement, except that the depositary will continue to collect dividends and other distributions pertaining to Deposited Securities, will sell rights and other property as provided in the Level 1 Deposit Agreement, and will continue to deliver Deposited Securities, together with any dividends or other distributions received with respect thereto and the net proceeds of the sale of any rights or other property, in exchange for Level 1 ADRs surrendered to the depositary (after deducting, in each case, the fees of the depositary for the surrender of a Level 1 ADR, any expenses for the account of the Owner of such Level 1 ADR in accordance with the terms and conditions of the Level 1 Deposit Agreement and any applicable taxes or governmental charges). At any time after the expiration of one year from the date of termination, the depositary may sell the Deposited Securities then held and may thereafter hold uninvested the net proceeds of any such sale, together with any other cash then held by it, unsegregated and without liability for interest, for the pro rata benefit of the Owners of Level 1 ADRs that have not theretofore been surrendered, such Owners thereupon becoming general creditors of the depositary with respect to such net proceeds. After making such sale, the depositary will be discharged from all obligations under the Level 1 Deposit Agreement, except to account for such net proceeds and other cash (after deducting, in each case, the fee of the depositary for the surrender of a Level 1 ADR, any expenses for the account of the Owner of such Level 1 ADR in accordance with the terms and conditions of the Level 1 Deposit Agreement, and any applicable taxes or governmental charges). Upon the termination of the Level 1 Deposit Agreement, we will be discharged from all obligations under the Level 1 Deposit Agreement except for our continuing obligations to the depositary under the Level 1 Deposit Agreement.

22. Amendment of Level 1 Deposit Agreement and Conditions

Except for amendments to paragraph 21, the form of the Level 1 ADRs and any provisions of the Level 1 Deposit Agreement may at any time and from time to time be amended by agreement between us and the depositary without the consent of Owners or Beneficial Owners of Level 1 ADRs in any respect that we may deem necessary or desirable. Paragraph 20 may be amended by us without the consent of the depositary upon 30 days' prior written notice to Owners of outstanding Level 1 ADRs as specified in the next sentence. Any amendment that shall impose or increase any fees or (other than taxes and other governmental charges, registration fees, cable, telex or facsimile transmission costs, delivery costs or other such expenses), or that shall otherwise prejudice any substantial existing right of Owners, shall, however, not become effective as to outstanding Level 1 ADRs until the expiration of 30 days after notice of such amendment shall have been given to the Owners of outstanding Level 1 ADRs. Every Owner, at the time any amendment so becomes effective, shall be deemed, by continuing to hold such Level 1 ADR, to consent and agree to such amendment and to be bound by the Deposit Agreement as amended thereby. In no event shall any amendment impair the right of the Owner of any Level 1 ADR to surrender such Level 1 ADR and receive therefor the Deposited Securities represented thereby, except in order to comply with mandatory provisions of applicable law.

23. Notices

23.1 Any and all notices to be given to us will be deemed to have been duly given if personally delivered or sent by mail or cable, telex or facsimile transmission confirmed by letter, addressed to Leonid A. Fedoun, Vice President, Open Joint Stock Company Oil Company LUKOIL, 11 Sretensky Boulevard, 101000, Moscow, Russian Federation, or any other place to which we may have transferred our principal office.

23.2 Any and all notices to be given to the depositary are deemed to have been duly given if in English and personally delivered or sent by mail or cable, telex or facsimile transmission confirmed by letter, addressed to The Bank of New York; 101 Barclay Street, New York, New York 10286, Attention: American Depositary Receipt Administration, or any other place to which the depositary may have transferred its Corporate Trust Office.

23.3 Any and all notices to be given to any Owner are deemed to have been duly given if personally delivered or sent by mail or cable, telex or facsimile transmission confirmed by letter, addressed to such Owner at the address of such Owner as it appears on the transfer books for Level 1 ADRs of the depositary, or, if such Owner shall have filed with the depositary a written request that notices intended for such Owner be mailed to some other address, at the address designated in such request.

23.4 Delivery of a notice sent by mail or cable, telex or facsimile transmission is deemed to be effective at the time when a duly addressed letter containing the same (or a confirmation thereof in the case of a cable, telex or facsimile transmission) is deposited, postage prepaid, in a post-office letter box. The depositary or we may, however, act upon any cable, telex or facsimile transmission received by it or us, notwithstanding that such cable, telex or facsimile transmission shall not subsequently be confirmed by letter as aforesaid.

24. Reports and information on the Company

The depositary will make available for inspection by Owners at its Corporate Trust Office any reports and communications, including any proxy soliciting material, received from us that are both (a) received by the Depositary as the holder of the Deposited Securities and (b) made generally available to the holders of such Deposited Securities by us. The depositary will also send to the Owners (i) copies of such reports when furnished by us, (ii) copies of any written communications provided to the depositary by the Russian Share Registrar and (iii) copies of any notices given or required to be given by the depositary. Any such reports, including any such proxy soliciting material, furnished to the depositary by us will be furnished in English, to the extent such materials are required to be translated into English pursuant to any regulations of the SEC. Any such communications furnished to the depositary by the Russian Share Registrar will be furnished in English.

25. Copies of Company notices

On or before the first date on which we give notice, by publication or otherwise, of any meeting of holders of shares or other Deposited Securities or of any adjourned meeting of such holders, or of the taking of any action in respect of any cash or other distributions or the offering of any rights, we have agreed to transmit to the depositary and the custodian a copy of the notice thereof in the form given or to be given to holders of shares or other Deposited Securities.

We will arrange for the translation into English. if not already in English, to the extent required pursuant to any regulations of the SEC, and the prompt transmittal by us to the depositary and the custodian of such notices and any other reports and communications that are made generally available by us to holders of our shares. If requested in writing by us, the depositary will arrange for the mailing, at our expense, of copies of such notices, reports and communications to all Owners. We will timely provide the depositary with the quantity of such notices, reports, and communications, as requested by the depositary from time to time in order for the depositary to effect such mailings.

26. Severability

If any one or more of the provisions contained in the Level 1 Deposit Agreement or in the Level 1 ADRs shall be or become invalid, illegal or unenforceable in any respect, the validity, legality and enforceability of the remaining provisions contained therein shall in no way be affected, prejudiced or otherwise disturbed thereby.

27. Governing law

27.1 The Level 1 Deposit Agreement and the Level 1 ADRs will be interpreted and all rights thereunder and provisions thereof will be governed by the laws of the State of New York, except with respect to its authorisation and execution by us, which will be governed by the laws of the Russian Federation.

27.2 Any controversy, claim or cause of action brought by any party hereto against us arising out of or relating to the shares or other Deposited Securities, the Level 1 ADSs, the Level 1 ADRs or the Deposit Agreement, or the breach of the Level 1 Deposit Agreement or of any obligation related to the shares or other Deposited Securities, the Level 1 ADSs or the Level 1 ADRs, shall be settled by arbitration in accordance with the Commercial Arbitration Rules of the American Arbitration Association, and judgment upon the award rendered by the arbitrators may be entered in any court having jurisdiction thereof; provided, that in the event of any third-party litigation to which the depositary is a party and to which we may properly be joined, we may be so joined in any court in which such litigation is proceeding; and provided further that any such controversy, claim or cause of action relating to or based upon the provisions of the Federal securities laws of the United States or the rules and regulations promulgated thereunder may, but need not, be submitted to arbitration as provided in the Level 1 Deposit Agreement.

The place of the arbitration will be The City of New York, State of New York, United States of America, and the language of the arbitration will be English.

The number of arbitrators will be three, each of whom will be disinterested in the dispute or controversy, shall have no connection with any party thereto and shall be an attorney experienced in international securities transactions. If a dispute, controversy or cause of action shall involve more than two parties, the parties will attempt to align themselves in two sides (i.e., claimant and respondent), each of which will appoint one arbitrator as if there were only two parties to such dispute, controversy or cause of action. If such alignment and appointment has not occurred within 20 calendar days after the initiating party serves the arbitration demand, the American Arbitration Association will appoint the 3 arbitrators. The parties and the American Arbitration Association may appoint from among the nationals of any country, whether or not a party is a national of that country.

The arbitrators will have no authority to award punitive or other damages not measured by the prevailing party’s actual damages and may not, in any event, make any ruling, finding or award that does not conform to the terms and conditions of the Level 1 Deposit Agreement.

Any controversy, claim or cause of action arising out of or relating to the shares or other Deposited Securities, Level 1 ADSs, Level 1 ADRs or the Level 1 Deposit Agreement not subject to arbitration will be litigated in the Federal and state courts in the Borough of Manhattan.

TERMS AND CONDITIONS OF THE REG S ADRs

The Terms and Conditions of the Reg S ADRs are the same in all material respects as those that apply to the Level 1 ADRs, as summarised above, except as described below.

"Reg S Deposit Agreement" means the Regulation S Deposit Agreement dated on or about August 5, 2002 among us, The Bank of New York, as depositary, and each Owner and Beneficial Owner (as defined in the Reg S Deposit Agreement) from time to time of the Reg S ADRs issued under it.

References to the Level 1 ADRs should be read as referring to the Reg S ADRs, references to Level 1 ADSs to Reg S ADSs and references to Level 1 Deposit Agreement to the Reg S Deposit Agreement.

Deposit of shares and other securities

The following sentence should be added to the end of paragraph 1.3:

> Except in the case of the initial deposit of shares under the Reg S Deposit Agreement, no share shall be accepted for deposit under the Reg S Deposit Agreement unless the depositary has received a duly executed and completed certification and agreement in substantially the form appearing as Annex I to the Reg S Deposit Agreement by or on behalf of the person acquiring beneficial ownership of any ADSs to be issued in respect of that deposit.

The following sentence should be added to the end of paragraph 1.4:

> The person to whom any Pre-Release is to be made under the Reg S Deposit Agreement must deliver to the depositary a duly executed and completed certificate and agreement substantially in the form attached as Annex I to the Reg S Deposit Agreement.

Withdrawal of deposited property

The following paragraphs should be added to the end of paragraph 2.1:

> Notwithstanding the foregoing, no Deposited Securities may be withdrawn upon surrender of a Reg S ADR unless at or prior to the time of surrender the depositary has received a duly executed and completed written certificate and agreement, in substantially the form attached as Annex II to the Reg S Deposit Agreement, by or on behalf of the person surrendering such Reg S ADR who after such withdrawal will be the beneficial owner of such Deposited Securities.
>
> No Owner may transfer ADSs or shares represented thereby to, or for the account of, a qualified institutional buyer as defined in Rule 144A ("QIB") unless such Owner (i) withdraws such shares in accordance with the relevant provisions of the Reg S Deposit Agreement and (ii) instructs the depositary to deliver the shares so withdrawn to the account of the custodian under the Rule 144A Deposit Agreement (as defined in the Reg S Deposit Agreement) for issuance thereunder of Rule 144A American depositary shares to or for the account of such QIB. Issuance of such Rule 144A American depositary shares shall be subject to the terms and conditions of the Rule 144A Deposit Agreement including with respect to the deposit of shares and the issuance of Rule 144A American depositary shares, including delivery of the duly executed and completed written certificate and agreement required under the Rule 144A Deposit Agreement, by or on behalf of the person who will be the beneficial owner of such Rule 144A American depositary shares, representing that such person is a QIB and agreeing that it will comply with the restrictions on transfer set forth in the Rule 144A Deposit Agreement and to payment of the fees, charges and taxes provided therein. Please see "– Terms and Conditions of the New 144A ADRs" for a summary of the terms and conditions of the Rule 144A American depositary shares discussed above.

Paragraph 2.6 should be read as follows:

> Shares that the depositary believes have been withdrawn from a restricted depositary receipt facility established or maintained by a depositary bank (including any such other facility maintained by the depositary) may be accepted for deposit hereunder only if such shares are not, and will not, as a result of the transaction in connection with which the deposit is being made, be, "restricted securities" within the meaning of Rule 144(a)(3) under the Securities Act, and the depositary may, as a condition to accepting the deposit of such shares hereunder, require the person depositing such shares to provide the depositary with a certificate in writing to the foregoing effect.

Ownership and transfer

Item 3.2.2 of paragraph 3.2 should be read as follows:

> The delivery of Reg S ADRs against deposits of shares generally or against deposits of particular shares may be suspended, or the transfer of Reg S ADRs in particular instances may be refused, or the registration of transfer of outstanding Reg S ADRs generally may be suspended, during any period when the transfer books of the depositary are closed, or if any such action is deemed necessary or advisable by the depositary or us at any time or from time to time because of any requirements of law or of any government or governmental body or commission, or under any provision of the Reg S Deposit Agreement or the Reg S ADR, or for any other reason. Shares that the depositary believes have been withdrawn from a restricted depositary facility established or maintained by a depositary bank (including any such other facility maintained by the depositary) may be accepted for deposit under the Deposit Agreement only if such shares are not, and will not, as a result of the transaction in connection with which the deposit is being made, be "restricted securities" within the meaning of Rule 144(a)(3) under the Securities Act of 1933 and the depositary may, as a condition to accepting the deposit of such shares under the Reg S Deposit Agreement, require the person depositing such shares to provide the depositary with a certificate in writing to the foregoing effect.

Paragraph 3.4 should be read as follows:

> Every person depositing shares under the Reg S Deposit Agreement shall be deemed thereby to represent and warrant that such shares and each certificate therefor are validly issued, fully paid, nonassessable and free of any preemptive rights of the holders of outstanding shares and that the person making such deposit is duly authorised so to do. Such representations and warranties shall survive the deposit of shares and issuance of Reg S ADRs.

Offering conditions and transfer restrictions

The Reg S ADRs are currently subject to restrictions on transfer. Each purchaser of a Reg S ADR will be deemed to have made the following representations and warranties:

1. It acknowledges (or if it is acting for the account of another person, such person acknowledges) that the Reg S ADRs, the ADSs evidenced thereby and the shares represented thereby have not been and will not be registered under the Securities Act.
2. It certifies that either: (a) it is, or at the time the shares are deposited and at the time the Reg S ADRs are issued will be, the beneficial owner of the shares and of the ADSs evidenced by such Reg S ADR or Reg S ADRs, and (i) it is not a U.S. person (as defined in Regulation S under the Securities Act) and it is located outside the United States (within the meaning of Regulation S) and acquired, or have agreed to acquire and will have acquired, the shares to be deposited outside the United States, (ii) it is not an affiliate of ours or a person acting on behalf of such an affiliate, and (iii) it is not in the business of buying and selling securities or, if it is in such business, it did not acquire the securities to be deposited from us or any affiliate thereof in the initial distribution of the ADSs and shares; or (b) it is a broker-dealer acting on behalf of its customer; its customer has confirmed to it that it is, or at the time the shares are deposited and at the time the Reg S ADR or Reg S ADRs are issued will be, the beneficial owner of the shares and of the ADSs evidenced by such Reg S ADR or Reg S ADRs, and (i) its customer is not a U.S. person (as defined in Regulation S under the Act) and is located outside the United States (within the meaning of Regulation S, and acquired, or has agreed to acquire and will have acquired, the shares to be deposited outside the United States, (ii) its customer is not an affiliate of us or a person acting on behalf of such an affiliate, and (iii) its customer is not in the business of buying and selling securities or, if it is in such business, it did not acquire the securities to be deposited from us or any affiliate thereof in the initial distribution of ADSs and shares.
3. It agrees (or if it is a broker-dealer, its customer has confirmed to it that it agrees) that it (or its customer) will not offer, sell, pledge or otherwise transfer such Reg S ADRs, the ADSs evidenced thereby or the shares represented thereby except (a) to a person whom it reasonably believes (or its customer and anyone acting on its customer's behalf reasonably believes) is a qualified institutional buyer within the meaning of Rule 144A under the Act in a transaction meeting the requirements of Rule 144A, or (b) in accordance with Regulation S under the Act, in either case in accordance with any applicable securities laws of any state of the United States. It further agrees (or if it is a broker-dealer, its customer has confirmed to it that it agrees) that if it sells or otherwise transfers (or its customer sells or otherwise transfers) the ADSs evidenced by

the Reg S ADR or Reg S ADRs referred to above or the shares represented thereby in accordance with clause (a) above, it (or its customer) will, prior to settlement of such sale, cause such shares to be withdrawn in accordance with the terms and conditions of the Reg S Deposit Agreement and it (or its customer) will cause instructions to be given to the depositary to deliver such shares to the custodian under the Rule 144A Deposit Agreement for deposit thereunder and issuance of a Rule 144A American Depositary Receipt evidencing Rule 144A American Depositary Shares upon receipt of the proper certification on behalf of the purchaser and otherwise in accordance with the terms and conditions of such Rule 144A Deposit Agreement.

4. It understands that the Reg S ADRs will contain legends to the following effect with such modifications not inconsistent with the provisions of the Reg S Deposit Agreement as may be required by the depositary or required to comply with any applicable law or regulations thereunder or as otherwise permitted by the Reg S Deposit Agreement:

IT IS EXPECTED THAT COMMON SHARES DEPOSITED HEREUNDER WILL BE REGISTERED ON THE SHARE REGISTER MAINTAINED BY THE RUSSIAN SHARE REGISTRAR IN THE NAME OF THE DEPOSITARY OR ITS NOMINEE OR OF THE CUSTODIAN OR ITS NOMINEE. OWNERS AND BENEFICIAL OWNERS SHOULD BE AWARE, HOWEVER, THAT RUSSIA'S SYSTEM OF SHARE REGISTRATION AND CUSTODY CREATES CERTAIN RISKS OF LOSS THAT ARE NOT NORMALLY ASSOCIATED WITH INVESTMENTS IN OTHER SECURITIES MARKETS. THE DEPOSITARY WILL NOT BE LIABLE FOR THE UNAVAILABILITY OF COMMON SHARES OR FOR THE FAILURE TO MAKE ANY DISTRIBUTION OF CASH OR PROPERTY WITH RESPECT THERETO AS A RESULT OF SUCH UNAVAILABILITY.

THE DEPOSITARY HAS BEEN ADVISED BY RUSSIAN COUNSEL THAT COURTS IN THE RUSSIAN FEDERATION WILL NOT RECOGNISE OR ENFORCE JUDGEMENTS OBTAINED IN THE NEW YORK COURTS.

THIS AMERICAN DEPOSITARY RECEIPT, THE AMERICAN DEPOSITARY SHARES (“ADSs”) EVIDENCED HEREBY AND THE COMMON SHARES, PAR VALUE 0.025 RUBLES EACH, OF OPEN JOINT STOCK COMPANY OIL COMPANY LUKOIL (“COMMON SHARES”) REPRESENTED THEREBY HAVE NOT BEEN AND WILL NOT BE REGISTERED UNDER THE U.S. SECURITIES ACT OF 1933, AS AMENDED (THE “SECURITIES ACT”), AND MAY NOT BE OFFERED, SOLD, PLEDGED OR OTHERWISE TRANSFERRED EXCEPT (1) TO A PERSON WHOM THE BENEFICIAL OWNER AND ANY PERSON ACTING ON ITS BEHALF REASONABLY BELIEVE IS A QUALIFIED INSTITUTIONAL BUYER WITHIN THE MEANING OF RULE 144A UNDER THE SECURITIES ACT (A “QIB”) IN A TRANSACTION MEETING THE REQUIREMENTS OF RULE 144A OR (2) IN AN OFFSHORE TRANSACTION IN ACCORDANCE WITH RULE 903 OR RULE 904 OF REGULATION S UNDER THE SECURITIES ACT, IN EACH CASE IN ACCORDANCE WITH ANY APPLICABLE SECURITIES LAWS OF ANY STATE OF THE UNITED STATES; PROVIDED THAT IN CONNECTION WITH ANY TRANSFER UNDER (1) ABOVE, THE TRANSFEROR SHALL, PRIOR TO THE SETTLEMENT OF SUCH SALE, WITHDRAW THE COMMON SHARES IN ACCORDANCE WITH THE TERMS AND CONDITIONS OF THE REG S DEPOSIT AGREEMENT AND INSTRUCT THAT SUCH SHARES BE DELIVERED TO THE CUSTODIAN UNDER THE TEMPORARY RULE 144A DEPOSIT AGREEMENT FOR ISSUANCE, IN ACCORDANCE WITH THE TERMS AND CONDITIONS THEREOF, OF RULE 144A AMERICAN DEPOSITARY SHARES TO OR FOR THE ACCOUNT OF SUCH QIB. THE BENEFICIAL OWNER OF COMMON SHARES RECEIVED UPON CANCELLATION OF ANY RULE 144A AMERICAN DEPOSITARY RECEIPTS MAY NOT DEPOSIT OR CAUSE TO BE DEPOSITED SUCH COMMON SHARES INTO ANY GLOBAL DEPOSITARY RECEIPT FACILITY ESTABLISHED OR MAINTAINED BY A DEPOSITARY BANK (INCLUDING ANY SUCH FACILITY MAINTAINED BY THE DEPOSITARY FOR THE RULE 144A AMERICAN DEPOSITARY RECEIPTS), OTHER THAN A RESTRICTED DEPOSITARY RECEIPT FACILITY.

Voting rights

Paragraph 12, "Voting Rights" should be read as follows:

> Upon receipt of notice of any meeting of holders of shares or other Deposited Securities, if requested in writing by us, the depositary will, as soon as practicable thereafter, mail to the Owners of Reg S ADRs a notice, the form of which notice will be in the sole discretion of the depositary, which will contain (a) such information as is contained in such notice of meeting received by the depositary from us, (b) a statement that the Owners of Reg S ADRs as of the close of business on a specified record date will be entitled, subject to any applicable provision of law and of our Charter, to instruct the depositary as to the exercise of the voting rights, if any, pertaining to the amount of shares or other Deposited Securities represented by their respective ADSs and (c) a statement as to the manner in which such instructions may be given. Upon the written request of an Owner of a Reg S ADR on such record date, received on or before the date established by the depositary for such purpose, the depositary will endeavour insofar as practicable to vote or cause to be voted the amount of shares or other Deposited Securities represented by such ADSs evidenced by such Reg S ADR in accordance with the instructions set forth in such request. The depositary will not vote or attempt to exercise the right to vote that attaches to the shares or other Deposited Securities, other than in accordance with such instructions or deemed instructions.

Liability

Paragraph 14.7 should be read as follows:

> We agree to indemnify the depositary, any custodian, and their respective directors, employees, agents and affiliates against, and hold each of them harmless from, any liability or expense (including, but not limited to, the fees and expenses of counsel) that may arise out of (a) any registration with the SEC or the Russian Federal Commission for the Securities Market of Reg S ADRs, ADSs evidenced thereby or Deposited Securities or any application filed or submitted therefor, (b) any offer or sale of ADSs represented by Reg S ADRs or Deposited Securities, (c) acts performed or omitted, in accordance with the provisions of the Reg S Deposit Agreement and the Reg S ADR, as the same may be amended, modified or supplemented from time to time, (i) by either the depositary or a custodian or their respective directors, employees, agents and affiliates, except for any liability or expense arising out of the negligence or bad faith of either of them, or (ii) by us or any of our directors, employees, agents and affiliates, (d) the unavailability of Deposited Securities or the failure to make any distribution of cash or property with respect thereto as a result of (i) any act or failure to act by us or our agents, including the Russian Share Registrar, or their respective directors, employees, agents or affiliates, (ii) any provision of any present or future Charter of ours or any other instrument of ours governing the Deposited Securities or (iii) any provision of any securities issued or distributed by us, or any offering or distribution thereof, or (e) any assessment (or purported assessment) against shares or other Deposited Securities of the sort contemplated by the Reg S Deposit Agreement. No disclaimer of liability under the Securities Act is intended by any provision of the Reg S Deposit Agreement.

Reports and information on us

The following paragraphs should be added to the end of paragraph 24:

> If at any time prior to the termination of the Reg S Deposit Agreement, we are neither a reporting company under Sections 13 or 15(d) of the Securities Exchange Act of 1934 nor exempt from the reporting requirements of the Securities Exchange Act of 1934, as amended (the "Exchange Act") by reason of Rule 12g3-2(b) thereunder, we will provide, at our expense, to any Owner or Beneficial Owner or any holder of shares, and to provide any prospective purchaser of ADSs evidenced by Reg S ADRs or shares designated by such person, upon request of such Owner, Beneficial Owner, holder or prospective purchaser, the information required by Rule 144A(d)(4)(i) and otherwise comply with Rule 144A(d)(4). If at any time we are neither subject to Sections 13 or 15(d) of the Securities Exchange Act of 1934 nor exempt pursuant to Rule 12g3-2(b) under the Securities Exchange Act of 1934 (as determined by the Office of International Corporate Finance of the Commission), we have agreed to immediately so notify the depositary, and the depositary may so notify the Owners in writing at our expense.
>
> The depositary is authorized to deliver such information as furnished by us to the depositary during any period in which we inform the depositary we are subject to the information delivery requirements of Rule 144A(d)(4) to any such Owner, Beneficial Owner, holder of shares or prospective purchaser at the request

of such person. We will reimburse the depositary for its reasonable expenses in connection with such deliveries and will provide the depositary with such information in such quantities as the depositary may from time to time reasonably request.

Exchange of Reg S ADRs

Forty days after the first date of issuance of ADSs evidenced by Reg S ADRs, all such outstanding ADSs shall be exchanged into ADSs evidenced by Level 1 ADRs. At that time, the depositary shall effect the exchange of those ADSs evidenced by Reg S ADRs into ADSs evidenced by Level 1 ADRs and all outstanding ADSs evidenced by Reg S ADRs shall be cancelled upon such exchange. The depositary shall call for the surrender of all outstanding Reg S ADRs. Upon surrender of a Reg S ADR, the depositary shall execute and deliver to the Owner of that Reg S ADR a Level 1 ADR evidencing the number of ADSs into which the ADSs formerly represented by that Reg S ADRs have been exchanged and shall cancel that Reg S ADR. It is understood that no consent or other action of Owners or Beneficial Owners of Reg S ADRs shall be required for this exchange to take effect. The holders of the Reg S ADSs will be deemed to have made certain representations and warranties on the date of exchange.

TERMS AND CONDITIONS OF THE NEW 144A ADRs

The Terms and Conditions of the New 144A ADRs are the same in all material respects as those that apply to the Level 1 ADRs, as summarised above, except as described below.

"New 144A Deposit Agreement" means the Rule 144A Deposit Agreement dated on or about August 5, 2002 among us, The Bank of New York, as depositary, and each Owner and Beneficial Owner (as defined in the New 144A Deposit Agreement) from time to time of the 144A ADRs issued under it.

References to the Level 1 ADRs should be read as referring to the 144A ADRs, references to Level 1 ADSs to New 144A ADSs and references to Level 1 Deposit Agreement to the New 144A Deposit Agreement.

Deposit of shares and other securities
Paragraph 1.1 should be read as follows:

> Subject to the terms and conditions of the New 144A Deposit Agreement, shares or evidence of rights to receive shares may be deposited by delivery thereof to any custodian under the New 144A Deposit Agreement, accompanied by any appropriate instrument or instruments of transfer (which will consist of (a) extracts from our share register and, where applicable, share certificates evidencing ownership of the shares, (b) a transfer deed or other similar document authorising registration of the shares in the name of the depositary, the custodian or their respective nominees, or endorsement, in form satisfactory to the custodian, and (c) where applicable, a purchase/sale contract or other similar document relating to the transfer of the shares, in each case (except in the case of the initial deposit of shares under the New 144A Deposit Agreement) together with a duly executed and completed written certification and agreement ("Depositor Certificate"), in substantially the form attached as Annex I to the New 144A Deposit Agreement, by or on behalf of the person who will be the beneficial owner of the New 144A ADSs to be issued upon deposit of such shares, and all such certifications as may be required by the depositary or the custodian in accordance with the provisions of the New 144A Deposit Agreement, and, if the depositary requires, together with a written order directing the depositary to execute and deliver to, or upon the written order of, the person or persons stated in such order, a New 144A ADR or New 144A ADRs for the number of New 144A ADSs representing such deposit.

The following sentence should be added to the end of paragraph 1.4:

> The depositary will require that the person to whom any Pre-Release is to be made pursuant to the New 144A Deposit Agreement deliver to the depositary a duly completed and executed Depositor Certificate in substantially the form attached as Annex I to the New 144A Deposit Agreement.

The following sentence should be added to the end of paragraph 1.6:

> The depositary agrees to instruct the custodian to place all shares accepted for deposit under the New 144A Deposit Agreement into segregated accounts separate from any of our Shares that may be held by such custodian under any other depositary receipt facility relating to the shares.

Withdrawal of deposited property
The following paragraph should be added to the end of paragraph 2.1:

> Notwithstanding anything to the contrary in the New 144A Deposit Agreement, no Deposited Securities may be withdrawn upon surrender of a New 144A ADR unless the depositary has received a duly executed and completed written certificate and agreement, in substantially the form attached as Annex II to the New 144A Deposit Agreement, by or on behalf of the person surrendering such New 144A ADR who after such withdrawal will be the beneficial owner of such Deposited Securities.

Ownership and transfer
Item 3.2.2 of paragraph 3.2 should be read as follows:

> The delivery of New 144A ADRs against deposits of shares generally or against deposits of particular shares may be suspended, or the transfer of New 144A ADRs in particular instances may be refused, or the registration of transfer of outstanding New 144A ADRs generally may be suspended, during any period when the transfer books of the depositary are closed, or if any such action is deemed necessary or advisable by the depositary or us at any time or from time to time because of any requirements of law or of any

government or governmental body or commission, or under any provision of the New 144A Deposit Agreement or the New 144A ADRs, or for any other reason. The depositary will in no event be required to accept shares for deposit or issue New 144A ADRs against such delivery if the depositary believes that at the time of issuance such New 144A ADRs would not be eligible under paragraph (d)(3) of Rule 144A.

Paragraph 3.4 should be read as follows:

Every person depositing shares under the New 144A Deposit Agreement shall be deemed thereby to represent and warrant, in addition to such representations and warranties as are set forth in the Depositor Certificate, that such shares and each certificate therefor are validly issued, fully paid, nonassessable and free of any preemptive rights of the holders of outstanding shares and that the person making such deposit is duly authorised so to do. Such representations and warranties shall survive the deposit of shares and issuance of New 144A ADRs.

Offering conditions and transfer restrictions

The New 144A ADRs are currently subject to restrictions on transfer. Each purchaser will be deemed to have made the following representations and warranties:

1. It acknowledges (or if it is acting for the account of another person, such person acknowledges) that the New 144A ADRs, the New 144A ADSs evidenced thereby and the Shares represented thereby have not been and will not be registered under the Securities Act.

2. It certifies that either: (a) it is a qualified institutional buyer (as defined in Rule 144A), and at the time of issuance of the New 144A ADR or New 144A ADRs referred to above, it (or one or more qualified institutional buyers for whose account it is acting) will be the beneficial owner of the New 144A ADSs evidenced thereby, (b) it is a broker-dealer acting for the account of its customer; its customer has confirmed to it that such person is a qualified institutional buyer and either (i) at the time of issuance of the New 144A ADR or New 144A ADRs referred to above, it will be the beneficial owner of the New 144A ADRs evidenced thereby, or (ii) it is acting for the account of a qualified institutional buyer that, at the time of issuance of the New 144A ADR or New 144A ADRs referred to above, will be the beneficial owner of the New 144A ADSs evidenced thereby or (c) it is obtaining the New 144A ADR or New 144A ADRs referred to above in an offshore transaction in accordance with Rule 903 or 904 of Regulation S.

3. It agrees (or if it is acting for the account of another person, such person has confirmed to it that such person agrees) that it will not offer, sell, pledge or otherwise transfer the New 144A ADRs, the New 144A ADSs evidenced thereby or the shares represented thereby except (a) to a person whom it reasonably believes (or it and anyone acting on its behalf reasonably believes) is a qualified institutional buyer within the meaning of Rule 144A in a transaction meeting the requirements of Rule 144A, (b) in accordance with Regulation S, or (c) in accordance with Rule 144 under the Securities Act (if available), in each case in accordance with any applicable securities laws of any State of the United States.

4. It understands that the New 144A ADRs will contain legends to the following effect unless we and the depositary determine otherwise consistent with applicable law:

   IT IS EXPECTED THAT ORDINARY SHARES DEPOSITED HEREUNDER WILL BE REGISTERED ON THE SHARE REGISTER MAINTAINED BY THE RUSSIAN SHARE REGISTRAR IN THE NAME OF THE DEPOSITARY OR ITS NOMINEE OR OF THE CUSTODIAN OR ITS NOMINEE. OWNERS AND BENEFICIAL OWNERS SHOULD BE AWARE, HOWEVER, THAT RUSSIA'S SYSTEM OF SHARE REGISTRATION AND CUSTODY CREATES CERTAIN RISKS OF LOSS THAT ARE NOT NORMALLY ASSOCIATED WITH INVESTMENTS IN OTHER SECURITIES MARKETS. THE DEPOSITARY WILL NOT BE LIABLE FOR THE UNAVAILABILITY OF COMMON SHARES OR FOR THE FAILURE TO MAKE ANY DISTRIBUTION OF CASH OR PROPERTY WITH RESPECT THERETO AS A RESULT OF SUCH UNAVAILABILITY.

   THE DEPOSITARY HAS BEEN ADVISED BY RUSSIAN COUNSEL THAT COURTS IN THE RUSSIAN FEDERATION WILL NOT RECOGNISE OR ENFORCE JUDGEMENTS OBTAINED IN THE NEW YORK COURTS.

   THIS NEW 144A ADR, THE NEW 144A ADSs EVIDENCED HEREBY AND THE ORDINARY SHARES, NOMINAL VALUE 0.025 ROUBLES EACH, OF OPEN JOINT STOCK COMPANY OIL COMPANY LUKOIL REPRESENTED THEREBY HAVE NOT BEEN AND WILL NOT BE

REGISTERED UNDER THE SECURITIES ACT AND MAY NOT BE OFFERED, SOLD, PLEDGED OR OTHERWISE TRANSFERRED EXCEPT (1) TO A PERSON WHOM THE BENEFICIAL OWNERS AND ANY PERSON ACTING ON ITS BEHALF REASONABLY BELIEVE IS A QUALIFIED INSTITUTIONAL BUYER WITHIN THE MEANING OF RULE 144A IN A TRANSACTION MEETING THE REQUIREMENTS OF RULE 144A, (2) IN AN OFFSHORE TRANSACTION IN ACCORDANCE WITH RULE 903 OR RULE 904 OF REGULATION S; OR (3) PURSUANT TO AN EXEMPTION FROM REGISTRATION PROVIDED BY RULE 144 UNDER THE SECURITIES ACT (IF AVAILABLE), IN EACH CASE IN ACCORDANCE WITH ANY APPLICABLE SECURITIES LAWS OF ANY STATE OF THE UNITED STATES. THE BENEFICIAL OWNER OF SHARES RECEIVED UPON CANCELLATION OF ANY NEW 144A ADRs MAY NOT DEPOSIT OR CAUSE TO BE DEPOSITED SUCH SHARES INTO ANY GLOBAL DEPOSITARY RECEIPT FACILITY ESTABLISHED OR MAINTAINED BY A DEPOSITARY BANK (INCLUDING ANY SUCH FACILITY MAINTAINED BY THE DEPOSITARY FOR THE NEW 144A ADRs), OTHER THAN A RESTRICTED DEPOSITARY RECEIPT FACILITY, SO LONG AS SUCH SHARES ARE “RESTRICTED SECURITIES” WITHIN THE MEANING OF RULE 144(a)(3) UNDER THE SECURITIES ACT. NO REPRESENTATION CAN BE MADE AS TO THE AVAILABILITY OF THE EXEMPTION PROVIDED BY RULE 144 UNDER THE SECURITIES ACT FOR RESALE OF THE NEW 144A SHARES OR ADSs.

In addition, the New 144A ADRs may be endorsed with or have incorporated in the text of them such legends or recitals or changes not inconsistent with the provisions of the New 144A Deposit Agreement as may be required by the National Association of Securities Dealers, Inc. (the “NASD”) in order for the New 144A ADRs to be tradeable in the NASD's PORTAL market or by another self-regulatory organisation in order for the New 144A ADRs to be tradeable in another closed market open only to qualified institutional buyers (as defined in Rule 144A) (“QIBs”) and to securities eligible for resale under Rule 144A, the rules of which have been approved by the SEC.

Distribution of Shares

The following sentence should be added to the end of paragraphs 5 and 6:

Each beneficial owner of New 144A ADRs or shares so distributed will be deemed to have acknowledged that the New 144A ADRs have not been registered under the Securities Act and to have agreed to comply with the restrictions on transfer described in the form of legend set forth in the New 144A Deposit Agreement and as set forth on the face of the New 144A ADR attached as Exhibit A to the New 144A Deposit Agreement.

Voting rights

Paragraph 12, “Voting rights” should be read as follows:

Upon receipt of notice of any meeting of holders of shares or other Deposited Securities, if requested in writing by us, the depositary will, as soon as practicable thereafter, mail to the Owners of New 144A ADRs a notice, the form of which notice shall be in the sole discretion of the depositary, which will contain (a) such information as is contained in such notice of meeting received by the depositary from us, (b) a statement that the Owners of New 144A ADRs as of the close of business on a specified record date will be entitled, subject to any applicable provision of law and of our Charter, to instruct the depositary as to the exercise of the voting rights, if any, pertaining to the amount of shares or other Deposited Securities represented by their respective New 144A ADSs and (c) a statement as to the manner in which such instructions may be given. Upon the written request of an Owner of a New 144A ADR on such record date, received on or before the date established by the depositary for such purpose, the depositary will endeavour insofar as practicable to vote or cause to be voted the amount of shares or other Deposited Securities represented by such New 144A ADSs evidenced by such New 144A ADR in accordance with the instructions set forth in such request. The depositary shall not vote or attempt to exercise the right to vote that attaches to the shares or other Deposited Securities, other than in accordance with such instructions or deemed instructions.

Liability

Paragraph 14.7 should be read as follows:

> We have agreed to indemnify the depositary, any custodian, and their respective directors, employees, agents and affiliates and any custodian against, and hold each of them harmless from, any liability or expense (including, but not limited to, the expenses of counsel) that may arise out of (a) any registration with the Russian Federal Commission for Securities Market of New 144A ADRs, New 144A ADSs evidenced thereby, or Deposited Securities or any application filed or submitted therefor; (b) any offer or sale of New 144A ADSs or Deposited Securities; (c) acts performed or omitted, in accordance with the provisions of the New 144A represented by New 144A ADRs Deposit Agreement and of the New 144A ADRs, as the same may be amended, modified, or supplemented from time to time, (i) by either the depositary or a custodian or their respective directors, employees, agents and affiliates, except for any liability or expense arising out of the negligence or bad faith of either of them, or (ii) by us or any of our directors, employees, agents and affiliates; (d) the unavailability of Deposited Securities or the failure to make any distribution of cash or property with respect thereto as a result of (i) any act or failure to act by us or our agents, including the Russian Share Registrar, or our or their respective directors, employees, agents or affiliates, (ii) any provision of any present or future Charter of us or any other instrument of us governing Deposited Securities or (iii) any provision of any securities issued or distributed by us, or any offering or distribution thereof or (e) any assessment (or purported assessment) against shares or other Deposited Securities of the sort contemplated by the New 144A Deposit Agreement. No disclaimer of liability under the Securities Act is intended by any provision of the New 144A Deposit Agreement.

Reports and information on the Company

The following paragraphs should be added at the end of paragraph 24:

> If at any time prior to the termination of the New 144A Deposit Agreement we are neither a reporting company under Sections 13 or 15(d) of the Securities Exchange Act of 1934, as amended (the "Exchange Act") nor exempt from the reporting requirements thereunder by reason of Rule 12g3-2(b) thereunder, we will provide, at our expense, to any Owner or Beneficial Owner or any holder of shares, and to any prospective purchaser of New 144A ADSs or shares designated by such person, upon request of such Owner, Beneficial Owner, holder or prospective purchaser, the information required by Rule 144A(d)(4)(i) and otherwise comply with Rule 144A(d)(4). If at any time we are neither subject to Sections 13 or 15(d) of the Exchange Act nor exempt pursuant to Rule 12g3-2(b) thereunder (as determined by the Office of International Corporate Finance of the SEC), we have agreed to immediately so notify the depositary, and the depositary may so notify the Owners in writing at our expense.
>
> We have authorised the depositary to deliver such information as furnished by us to the depositary during any period in which we inform the depositary it is subject to the information delivery requirements of Rule 144A(d)(4) to any such Owner, Beneficial Owner, holder of shares or prospective purchaser at the request of such person. We have agreed to reimburse the depositary for its reasonable expenses in connection with such deliveries and to provide the depositary with such information in such quantities as the depositary may from time to time reasonably request.
>
> The depositary will make available for inspection by Owners at its Corporate Trust Office any reports and communications, including any proxy soliciting material, received from us that are both (a) received by the depositary as the holder of the Deposited Securities and (b) made generally available to the holders of such Deposited Securities by us. The depositary will also send to the Owners (i) copies of such reports when furnished by us, (ii) copies of written communications provided to the depositary by the Russian Share Registrar and (iii) copies of any notices given or required to be given by the depositary. Any such reports, including any such proxy soliciting material, furnished to the depositary by us will be furnished in English to the extent such materials are required to be translated into English pursuant to any regulations of the SEC. Any such communications furnished to the depositary by the Russian Share Registrar will be furnished in English.

Exchange of New 144A ADRs

We will notify the depositary no earlier than 30 days after the closing date of the date the existing 144A ADRs have been approved for admission to the Official List of the UK Listing Authority and admission to trading on the London Stock Exchange subject only to their issuance. Upon receipt of this notification, the depositary will exchange all outstanding New 144A ADSs into Existing 144A ADSs. All outstanding New 144A ADSs represented will be cancelled upon such exchange. The depositary will call for the surrender of all outstanding New 144A ADRs. Upon surrender of a New 144A ADR, the depositary will execute and deliver an Existing 144A ADR evidencing the number of Existing 144A ADSs into which the New 144 ADSs formerly evidenced by the New 144A ADRs have been exchanged and shall cancel the New 144A ADR. It is understood that no consent or other action of Owners or Beneficial Owners of New 144A ADRs will be required for this exchange to take effect. The holders of the New 144A ADSs will be deemed to have made certain representations and warranties on the date of exchange. We have agreed to use our best efforts to procure that the admission of the Existing 144A ADRs to the Official List of the UK Listing Authority and admission to trading on the London Stock Exchange occurs within thirty days after the closing date or, failing that, as soon as possible thereafter. Please see "– Terms and Conditions of the Existing 144A ADRs" for a summary of the terms and conditions of the Existing 144A ADRs.

TERMS AND CONDITIONS OF THE EXISTING 144A ADRs

The Terms and Conditions of the Existing 144A ADRs are the same in all material respects as those that apply to the Level 1 ADRs, as summarised above, except as described below.

"Existing 144A Deposit Agreement" means the Rule 144A Deposit Agreement, amended and restated as of March 11, 1998, among us, The Bank of New York, as depositary and each Owner and Beneficial Owner (as defined in the Existing 144A Deposit Agreement) from time to time of the Rule 144A ADRs issued under it.

References to the Level 1 ADRs should be read as referring to the Existing 144A ADRs, references to Level 1 ADSs to Existing 144A ADSs and references to Level 1 Deposit Agreement to the Existing 144A Deposit Agreement.

Deposit of Shares and other securities
Paragraph 1.1 should be read as follows:

> Subject to the terms and conditions of the Existing 144A Deposit Agreement, shares or evidence of rights to receive shares may be deposited by delivery thereof to any custodian under the Existing 144A Deposit Agreement, accompanied by any appropriate instrument or instruments of transfer (which will consist of (a) extracts from the share register and, where applicable, share certificates evidencing ownership of the shares, (b) a transfer deed or other similar document authorising registration of the shares in the name of the depositary, the custodian or their respective nominees, or endorsement, in form satisfactory to the custodian, and (c) where applicable, a purchase/sale contract or other similar document relating to the transfer of the shares, in each case together with a duly executed and completed written certification and agreement ("Depositor Certificate"), in substantially the form attached as Annex I to the Existing 144A Deposit Agreement, by or on behalf of the person who will be the beneficial owner of the ADSs to be issued upon deposit of such shares, and all such certifications as may be required by the depositary or the custodian in accordance with the provisions of this Existing 144A Deposit Agreement, and, if the depositary requires, together with a written order directing the depositary to execute and deliver to, or upon the written order of, the person or persons stated in such order, an Existing 144A ADR or Existing 144A ADRs for the number of Existing 144A ADSs representing such deposit.

The following sentence should be added to the end of paragraph 1.4:

> The depositary will require that the person to whom any Pre-Release is to be made pursuant to the Existing 144A Deposit Agreement deliver to the depositary a duly completed and executed Depositor Certificate in substantially the form attached as Annex I to the Existing 144A Deposit Agreement.

The following sentence should be added to the end of paragraph 1.6:

> The depositary agrees to instruct the custodian to place all shares accepted for deposit under the Existing 144A Deposit Agreement into segregated accounts separate from any of our shares that may be held by such custodian under any other depositary receipt facility relating to the shares.

Withdrawal of deposited property
The following paragraph should be added to the end of paragraph 2.1:

> Notwithstanding anything to the contrary in the Existing 144A Deposit Agreement, no Deposited Securities may be withdrawn upon surrender of a Existing 144A ADR unless the depositary shall have received a duly executed and completed written certificate and agreement, in substantially the form attached as Annex II to the Existing 144A Deposit Agreement, by or on behalf of the person surrendering such Existing 144A ADR who after such withdrawal will be the beneficial owner of such Deposited Securities.

Ownership and transfer

Item 3.2.2 of paragraph 3.2 should be read as follows:

> The delivery of Existing 144A ADRs against deposits of shares generally or against deposits of particular shares may be suspended, or the transfer of Existing 144A ADRs in particular instances may be refused, or the registration of transfer of outstanding Existing 144A ADRs generally may be suspended, during any period when the transfer books of the depositary are closed, or if any such action is deemed necessary or advisable by the depositary or us at any time or from time to time because of any requirements of law or of any government or governmental body or commission, or under any provision of the Existing 144A Deposit Agreement or the Existing 144A ADRs, or for any other reason. The depositary will in no event be required to accept shares for deposit or issue Existing 144A ADRs against such delivery if the depositary believes that at the time of issuance such Existing 144A ADRs would not be eligible under paragraph (d)(3) of Rule 144A.

Paragraph 3.4 should be read as follows:

> Every person depositing shares under the Existing 144A Deposit Agreement shall be deemed thereby to represent and warrant, in addition to such representations and warranties as are set forth in the Depositor Certificate, that such shares and each certificate therefor are validly issued, fully paid, nonassessable and free of any preemptive rights of the holders of outstanding shares and that the person making such deposit is duly authorised so to do. Such representations and warranties shall survive the deposit of shares and issuance of Existing 144A ADRs.

Offering conditions and transfer restrictions

The Existing 144A ADRs are currently subject to restrictions on transfer.

The Existing 144A ADRs will contain legends to the following effect unless we and the depositary determine otherwise consistent with applicable law:

> IT IS EXPECTED THAT SHARES DEPOSITED UNDER THE EXISTING 144A DEPOSIT AGREEMENT WILL BE REGISTERED ON THE SHARE REGISTER MAINTAINED BY THE RUSSIAN SHARE REGISTRAR IN THE NAME OF THE DEPOSITARY OR ITS NOMINEE OR OF THE CUSTODIAN OR ITS NOMINEE. OWNERS AND BENEFICIAL OWNERS SHOULD BE AWARE, HOWEVER, THAT RUSSIA'S SYSTEM OF SHARE REGISTRATION AND CUSTODY CREATES CERTAIN RISKS OF LOSS THAT ARE NOT NORMALLY ASSOCIATED WITH INVESTMENTS IN OTHER SECURITIES MARKETS. THE DEPOSITARY WILL NOT BE LIABLE FOR THE UNAVAILABILITY OF SHARES OR FOR THE FAILURE TO MAKE ANY DISTRIBUTION OF CASH OR PROPERTY WITH RESPECT THERETO AS A RESULT OF SUCH UNAVAILABILITY.
>
> THE DEPOSITARY HAS BEEN ADVISED BY RUSSIAN COUNSEL THAT COURTS IN THE RUSSIAN FEDERATION WILL NOT RECOGNISE OR ENFORCE JUDGEMENTS OBTAINED IN THE NEW YORK COURTS.
>
> THE EXISTING 144A ADR, THE RULE 144A ADSs EVIDENCED HEREBY AND THE SHARES, NOMINAL VALUE 0.025 ROUBLES EACH, OF OPEN JOINT STOCK COMPANY OIL COMPANY LUKOIL RESPRESENTED THEREBY HAVE NOT BEEN AND WILL NOT BE REGISTERED UNDER THE SECURITIES ACT AND MAY NOT BE OFFERED, SOLD, PLEDGED OR OTHERWISE TRANSFERRED EXCEPT (1) TO A PERSON WHOM THE BENEFICIAL OWNERS AND ANY PERSON ACTING ON ITS BEHALF REASONABLY BELIEVE IS A QUALIFIED INSTITUTIONAL BUYER WITHIN THE MEANING OF RULE 144A IN A TRANSACTION MEETING THE REQUIREMENTS OF RULE 144A, (2) IN AN OFFSHORE TRANSACTION IN ACCORDANCE WITH RULE 903 OR RULE 904 OF REGULATION S; OR (3) PURSUANT TO AN EXEMPTION FROM REGISTRATION PROVIDED BY RULE 144 UNDER THE SECURITIES ACT (IF AVAILABLE), IN EACH CASE IN ACCORDANCE WITH ANY APPLICABLE SECURITIES LAWS OF ANY STATE OF THE UNITED STATES. THE BENEFICIAL OWNER OF SHARES RECEIVED UPON CANCELLATION OF ANY EXISTING 144A ADRs MAY NOT DEPOSIT OR CAUSE TO BE DEPOSITED SUCH SHARES INTO ANY GLOBAL DEPOSITARY RECEIPT FACILITY ESTABLISHED OR MAINTAINED BY A DEPOSITARY BANK (INCLUDING ANY SUCH FACILITY

MAINTAINED BY THE DEPOSITARY FOR THE EXISTING 144A ADRs), OTHER THAN A RESTRICTED DEPOSITARY RECEIPT FACILITY, SO LONG AS SUCH SHARES ARE "RESTRICTED SECURITIES" WITHIN THE MEANING OF RULE 144(a)(3) UNDER THE SECURITIES ACT. NO REPRESENTATION CAN BE MADE AS TO THE AVAILABILITY OF THE EXEMPTION PROVIDED BY RULE 144 UNDER THE SECURITIES ACT FOR RESALE OF THE SHARES OR ADSs.

In addition, the Existing 144A ADRs may be endorsed with or have incorporated in the text thereof such legends or recitals or changes not inconsistent with the provisions of the Existing 144A Deposit Agreement as may be required by the National Association of Securities Dealers, Inc. (the "NASD") in order for the Existing 144A ADRs to be tradeable in the NASD's PORTAL market or by another self-regulatory organisation in order for the Existing 144A ADRs to be tradeable in another closed market open only to QIBs and to securities eligible for resale under Rule 144A, the rules of which have been approved by the SEC.

Distribution of shares

The following sentence should be added to the end of paragraphs 5 and 6:

Each beneficial owner of Existing 144A ADRs or shares so distributed shall be deemed to have acknowledged that the Existing 144A ADRs have not been registered under the Securities Act and to have agreed to comply with the restrictions on transfer described in the form of legend set forth in the Existing 144A Deposit Agreement and as set forth on the face of the Existing 144A ADR attached as Exhibit A to the Existing 144A Deposit Agreement.

Liability

Paragraph 14.7 should be read as follows:

We agree to indemnify the depositary, any custodian, and their respective directors, employees, agents and affiliates against, and hold each of them harmless from, any liability or expense (including, but not limited to, the fees and expenses of counsel) that may arise out of (a) any offer or sale of Existing 144A ADRs, ADSs evidenced thereby or Deposited Securities or acts performed or omitted, in accordance with the provisions of the Existing 144A Deposit Agreement and of the Existing 144A ADRs, as the same may be amended, modified or supplemented from time to time, (i) by either the depositary or a custodian or their respective directors, employees, agents and affiliates, except for any liability or expense arising out of the negligence or bad faith of either of them, or (ii) by us or any of our directors, employees, agents and affiliates, or (b) the unavailability of Deposited Securities or the failure to make any distribution of cash or property with respect thereto as a result of (i) any act or failure to act by us or our agents, including the Russian Share Registrar, or their respective directors, employees, agents or affiliates, (ii) any provision of any present or future Charter of ours or any other instrument of ours governing Deposited Securities or (iii) any provision of any securities issued or distributed by us, or any offering or distribution thereof or (c) any assessment (or purported assessment) against shares or other Deposited Securities of the sort contemplated by paragraph 10. No disclaimer of liability under the Securities Act is intended by any provision of the Existing 144A Deposit Agreement.

Reports and information on the Company

The following paragraphs should be added at the end of paragraph 24:

If at any time prior to the termination of the Existing 144A Deposit Agreement we are neither a reporting company under Sections 13 or 15(d) of the Securities Exchange Act of 1934, as amended (the "Exchange Act") nor exempt from the reporting requirements thereunder by reason of Rule 12g3-2(b) thereunder, we will provide, at our expense, to any Owner or Beneficial Owner or any holder of shares, and to any prospective purchaser of ADSs or shares designated by such person, upon request of such Owner, Beneficial Owner, holder or prospective purchaser, the information required by Rule 144A(d)(4)(i) and otherwise comply with Rule 144A(d)(4). If at any time we are neither subject to Sections 13 or 15(d) of the Exchange Act nor exempt pursuant to Rule 12g3-2(b) thereunder (as determined by the Office of International Corporate Finance of the SEC), we have agreed to immediately so notify the depositary, and the depositary may so notify the Owners in writing at our expense.

We have authorised the depositary to deliver such information as furnished by us to the depositary during any period in which we inform the depositary it is subject to the information delivery requirements of Rule 144A(d)(4) to any such Owner, Beneficial Owner, holder of shares or prospective purchaser at the request of such person. We have agreed to reimburse the depositary for its reasonable expenses in connection with such deliveries and to provide the depositary with such information in such quantities as the depositary may from time to time reasonably request.

SETTLEMENT PROVISIONS IN RELATION TO THE ADRs,

Terms used in these "Settlement Provisions in relation to the ADRs" will have the meanings set forth elsewhere in this document and in the relevant Deposit Agreement.

DTC is a limited-purpose trust company organised under the laws of the State of New York, a "banking organisation" within the meaning of New York Banking Law, a member of the Federal Reserve System, a "clearing corporation" within the meaning of the New York Uniform Commercial Code and a "clearing agency" registered pursuant to the provisions of Section 17A of the Exchange Act. DTC holds securities for DTC participants and facilitates the clearance and settlement of securities transactions between DTC participants through electronic book-entry changes in accounts of DTC participants. DTC participants include securities brokers and dealers, banks, trust companies and clearing corporations and may include certain other organisations. Indirect access to DTC is also available to others, such as banks, brokers, dealers and trust companies which clear through or maintain a custodial relationship with a DTC participant, either directly or indirectly.

We and the depositary have arranged for the ADRs to be accepted in the DTC's book-entry settlement system. A Master Reg S ADR and Master New 144A ADR certificate will be issued to DTC and registered in the name of Cede & Co., as nominee of DTC, and will be held by the depositary, as custodian for DTC. Cede & Co, initially will be the registered holder of all Reg S ADRs and New 144A ADRs for all purposes under the relevant Deposit Agreement. Accordingly, each beneficial owner of an interest in the Reg S ADR or New 144A ADR must rely upon the procedures of the institutions having accounts with DTC to exercise or be entitled to any rights of a Reg S ADR or New 144A ADR holder. ADRs that are not traded through DTC's book-entry settlement system are administered by the depositary which issues definitive certificates to the relevant holders of such ADRs.

It is expected that admission to the Official List will become effective and unconditional dealings will commence in the Reg S ADRs and the New 144A ADRs on August 6, 2002. It is expected that admission to the Official List will become effective and that unconditional dealings will commence in the Existing 144A ADRs on September 6, 2002.

It is a condition of the Listing Rules of the U.K. Listing Authority that, in summary, save as otherwise agreed with the U.K. Listing Authority, the proportion of any class of listed security in the hands of the public must be at least 25% of the total number of issued securities of that class. Securities are not regarded as being held in public hands if they are held, directly or indirectly, by: (a) a director of the issuer or any of its subsidiary undertakings; (b) a person connected with a director of the issuer or any of its undertakings; (c) the trustees of any employees' share scheme or pension fund established for the benefit of any directors and employees of the issuer and its subsidiary undertakings; (d) any person who by virtue of any agreement has a right to nominate a person to the board of directors of the issuer; or (e) any person who is interested in 5% or more of the shares of the relevant class unless, in the case of (e), the U.K. Listing Authority determines that, in all the circumstances, such person can be included in the public for these purposes. The ordinary shares, the Level 1 ADRs, the Reg S ADRs, the New 144A ADRs and the Existing 144A ADRs will each be treated as a separate class of security for the purposes of the Listing Rules of the U.K. Listing Authority. Any failure by a class of securities to comply with the condition referred to above may lead to such class of security not being admitted to listing on the Official List or such listing being suspended or cancelled by the U.K. Listing Authority.

TRANSFER OF SHARES BETWEEN OUR ADR FACILITIES

Terms used in these "Transfer of Shares between our ADR facilities" will have the meanings set forth elsewhere in this document and in the relevant Deposit Agreement.

Certain securities issued by us from time to time may be, or be deemed to be, "restricted securities" within the meaning of Rule 144 and subject to restrictions on resale. With limited exceptions, for so long as any shares are, or, as the case may be, shall be deemed to be "restricted securities" within the meaning of Rule 144 the holder of such shares may not deposit such shares in any depositary receipt facility established in respect of shares that is not so restricted.

We and the depositary will agree, subject to applicable law and the restrictions specified above, to permit and facilitate the deposit of shares into our ADR facilities.

INFORMATION REGARDING THE DEPOSITARY

The depositary is The Bank of New York, a New York banking corporation established in 1784.

It does not have a limited life. It does not have a registration number or a registered office. Its principal executive offices are located at One Wall Street, New York, New York 10286. The depositary is:

- a New York state chartered bank regulated by the New York State Banking Department and a state member bank of the Federal Reserve System regulated by the Board of Governors of the Federal Reserve System; and
- wholly owned by The Bank of New York Company Inc., a bank holding company, which is publicly held.

Copies of the most recent financial statements and annual report of The Bank of New York Company Inc., will be available for inspection at the Corporate Trust Office of the depositary located at 101 Barclay Street, New York, New York 10286 and at the office of the depositary located at One Canada Square, London, E14 5AL. Such information will be updated by The Bank of New York as long as the ADRs are listed on the London Stock Exchange and The Bank of New York is the depositary.

Part 10 – COMPETENT PERSON'S RESERVES REPORT

MILLER AND LENTS, LTD.
INTERNATIONAL OIL AND GAS CONSULTANTS
TWENTY-SEVENTH FLOOR
1100 LOUISIANA
HOUSTON, TEXAS 77002-5216
TELEPHONE 713 651-9455
TELEFAX 713 654-9914
e-mail: mail@millerandlents.com

May 20, 2002

The Directors
LUKoil OJSC
11 Sretensky Boulevard
Moscow 101000, Russia

Morgan Stanley & Co. International Limited
25 Cabot Square
London E14 4QA
United Kingdom

Re: LUKoil OJSC
Reserves and Future Net Revenues
Forecast
As of January 1, 2002

Dear Sirs:

At your request, we estimated the net oil and gas reserves and future net revenues as of January 1, 2002, attributable to LUKoil OJSC (LUKoil) in certain oil and gas properties. This report has been prepared in accordance with the provisions set out in Chapter 19 of the Listing Rules of the United Kingdom Listing Authority. Exhibit 1 is a location map that shows the properties, including associated Joint Ventures, grouped as five regions that include the Western Siberian, European, Timan-Pechora, and Caspian Sea regions of Russia, plus an international group of properties in Azerbaijan, Kazakhstan, and Egypt.

We performed our evaluations, which are designated as the Constant Price Case, using the prices and expenses provided by LUKoil. The Constant Price Case assumes no future escalations of oil or gas prices, operating expenses, capital, or taxes above those in effect on the as-of date.

Results of this evaluation are organized according to the reserve reporting status of each LUKoil subsidiary and Joint Venture, as supplied by LUKoil and as shown in Exhibit 2. As instructed by LUKoil, net reserves and future net revenues of Consolidated Subsidiaries are reported herein at 100 percent interest. This includes two Proportionally Consolidated Subsidiaries (in Kazakhstan and Azerbaijan) that are reported at 100 percent of their respective share in Production Sharing Agreements. Reserves and future net revenues of Affiliated Companies are reported herein at LUKoil's effective interests as provided by LUKoil on Exhibit 2. Note on Exhibit 2 that LUKoil's effective interest in Consolidated Subsidiaries may be less than 100 percent.

The aggregate results of our evaluations for the total LUKoil Consolidated Subsidiaries and Affiliated Companies as of January 1, 2002 are summarized below. Barrels of Oil Equivalent (BOE) shown on tables in this report are calculated with the conversion of 6,000 cubic feet of gas to one barrel of oil.

TOTAL LUKOIL CONSOLIDATED SUBSIDIARIES AND AFFILIATED COMPANIES AS OF JANUARY 1, 2002

	Net Reserves			Future Net Revenues	
Reserve Category	**Oil, MMBbls.**	**Gas, Bcf**	**BOE, MMBbls.**	**Undiscounted MM$**	**Discounted at 10% Per Year MM$**
Proven	14,576.5	13,215.9	16,779.1	72,128.4	24,785.5
Probable	6,657.4	3,523.9	7,244.7	27,743.6	4,092.8
Proven + Probable	**21,233.8**	**16,739.7**	**24,023.8**	**99,872.0**	**28,878.2**

The aggregate results of our evaluations for the LUKoil Consolidated Subsidiaries as of January 1, 2002, are summarized below.

LUKOIL CONSOLIDATED SUBSIDIARIES AS OF JANUARY 1, 2002

	Net Reserves			Future Net Revenues	
Reserve Category	**Oil, MMBbls.**	**Gas, Bcf**	**BOE, MMBbls.**	**Undiscounted MM$**	**Discounted at 10% Per Year MM$**
Proven	14,007.3	12,930.1	16,162.3	68,889.4	23,380.7
Probable	6,359.4	3,395.1	6,925.2	26,411.9	3,890.7
Proven + Probable	**20,366.6**	**16,325.1**	**23,087.5**	**95,301.3**	**27,271.4**

The aggregate results of our evaluations for the LUKoil Affiliated Companies as of January 1, 2002, are summarized below.

LUKOIL AFFILIATED COMPANIES AS OF JANUARY 1, 2002

	Net Reserves			Future Net Revenues	
Reserve Category	**Oil, MMBbls.**	**Gas, Bcf**	**BOE, MMBbls.**	**Undiscounted MM$**	**Discounted at 10% Per Year MM$**
Proven	569.2	285.8	616.8	3,239.0	1,404.8
Probable	298.0	128.8	319.5	1,331.7	202.0
Proven + Probable	**867.2**	**414.6**	**936.3**	**4,570.7**	**1,606.8**

The regions and major LUKoil subsidiaries located within the regions are summarized as follows:

Region	Subsidiary or Country
Western Siberian	Langepasneftegas; Uraineftegas; Kogalymneftegas; Pokachevneftegas; Yamalneftegazdobycha
European Region	Permneft; ZAO LUKoil-Perm; Nizhnevolzhskneft; Astrakhanneft; Kaliningradmorneft
Timan-Pechora – Russia	KomiTEK; Arkhangelskgeoldobycha
Russian Caspian Sea	Korchagina Field
International	Azerbaijan; Kazakhstan; Egypt

Definitions

Proven reserves are those reserves that, on the available evidence and taking into account technical and economic factors, have a better than 90 percent chance of being produced. *Probable reserves* are those reserves that, on the available evidence and taking into account technical and economic factors, have a better than 50 percent chance of being produced.

Volumes of oil reported herein were converted from tonnes to barrels using the surface density of each crude oil being evaluated on a reservoir basis. Therefore the total volumes reported on a fieldwide or company wide basis represent the aggregation of these individual conversions. Volumes of gas reported herein were converted from cubic meters to cubic feet using the standard conversion factor, thereby maintaining the original reporting conditions for temperature and pressure (typically 68 degrees Fahrenheit and 14.5 psia).

Net oil and gas reserves are attributed to the LUKoil working interest, shown as Reporting Interest on Exhibit 2. No deduction was made for royalty in estimating net reserves. Royalty was a deduction from gross revenues in determining net revenues but was not a deduction from gross reserves in determining net reserves.

Future net revenues as used herein are defined as the total gross revenues less royalties and unrefunded mineral replacement fees, operating expenses, property taxes, and capital investments. The total gross revenues are the total revenues received by the subsidiaries after deduction of transportation costs, export and customs duties, port expenses, excise tax, value added tax, and special taxes. Future net revenues do not include deductions for either federal or local taxes on net profit.

Reserves for all categories are considered economic for development for the time period in which undiscounted future net revenues are positive.

Estimates of future net revenues and discounted future net revenues are not intended and should not be interpreted to represent fair market values for the estimated reserves. Future costs of abandoning facilities and wells and of the restoration of producing properties to satisfy environmental standards were not deducted from total revenues as such estimates are beyond the scope of this assignment.

Economic Considerations

The oil and gas prices employed in the computations of gross revenues were provided by LUKoil and represent the pricing for December 31, 2001 and are shown on Exhibits 3 through 16.

The operating expenses employed in estimating future net revenues are the average monthly operating expenses for the year preceding the evaluated as-of date and were provided by LUKoil. These monthly operating expenses were adjusted to year-end operating expenses employing inflation factors estimated by LUKoil. For the subsidiaries of Permneft, ZAO LUKoil-Perm, Nizhnevolzhskneft, and Kogalym, LUKoil provided operating expense data on an NGDU (local district) basis. The NGDUs and their associated oil fields are identified on Exhibit 17. For all other LUKoil subsidiaries, operating expense data were provided as subsidiary-wide averages. We deducted from the operating expenses total depreciation; well restoration, recompletion, and hydraulic fracturing costs; royalty; commercial costs; and the mineral replacement fee. Restoration, recompletion, and hydraulic fracturing costs were included as capital for the portion of the proven nonproducing reserves attributed to the restoration of shut-in wells and the recompletion and the hydraulic fracturing of existing wells. Royalty and the portion of the mineral replacement fee not refunded to the production subsidiary were included as deductions to gross revenues.

Operating expenses are allocated to the number of active wells (producers and injectors) on a per-well basis and to the oil production rates on a per-barrel basis. The number of active wells for the large waterfloods are assumed to decline to approximately one-half the currently fully developed count as the field declined in production and approached the economic limit. The operating expenses are summarized in Exhibits 18 through 27 for all subsidiaries, except Arkhangelskgeoldobycha, KomiTEK, and the International Properties, which are summarized in Exhibits 14 through 16, respectively.

Future capital investments for drilling and completing new wells and for the recompletion, restoration, and hydraulic fracturing of existing wells are based on annual costs provided by LUKoil. These are summarized in Exhibit 28 for all subsidiaries, except Arkhangelskgeoldobycha, KomiTEK, and the International Properties, which are summarized in Exhibits 14 through 16, respectively. Other capital investments, such as surface facilities and pipelines, were calculated using procedures provided by LUKoil and are included in the estimates of future net revenues. Property taxes for each subsidiary or region were also calculated using procedures provided by LUKoil and are included in the estimated future net revenues.

The economic data used in this report were provided by LUKoil in United States Dollars. The conversion from Russian Rubles to US Dollars was performed by LUKoil. The conversion is summarized on a quarterly basis for the year 2001 as follows:

Year 2001	Rubles/US$
1st Quarter	28.54
2nd Quarter	28.99
3rd Quarter	29.33
4th Quarter	29.80

Estimates of future net revenues do not include any adjustments for potential fluctuations in the currency exchange rates. No escalations of prices, operating expenses, or capital costs are assumed in this report.

Plant and Equipment Considerations

We performed site visits in August 2001 to three major areas of LUKoil's Russian production: (1) Western Siberia, (2) the Volga Ural area, and (3) Timan-Pechora (Komi Republic). We visited the largest subsidiary from each area (Kogalym, Permneft, and KomiTEK, respectively) and inspected three representative large fields with associated production equipment in each subsidiary. These nine fields contain 43 percent of the proven producing reserves within the three subsidiaries. We made inspections to review the type, extent, and condition of the plant and equipment that are of material significance to LUKoil's operations and currently in use on LUKoil's major properties or fields. We also examined maintenance, operations, and safety practices during the visits.

The site visit included inspection of the facilities and equipment for artificial lift, wellhead measurement, separation of gas and water, water injection, pumping, storage, oil gathering and delivery pipelines, and final oil measurement at the sales delivery points. Some of the equipment was installed under Soviet Central Planning and was up to 35 years old. However, the majority of the equipment was installed by Western contractors to Western standards, and LUKoil has a program to modernize most of its equipment in the next few years. The older equipment was located principally at KomiTEK, with some older equipment in use at Permneft and very little in use at Kogalym. The older equipment was well maintained in good operating condition.

The offices and enclosures for the equipment are sometimes old but have been renovated and updated recently to Western standards. In most instances, sufficient separation of the various pieces of equipment and the use of multiple trains of equipment ensure continued operations in the event of a fire or other damage. Almost all the equipment is powered by electric motors for increased reliability. Automatic foam fire suppression systems are used on all new equipment and have been added to most of the older equipment. Employee housing and services for the fields have been upgraded, or soon will be upgraded, to Western standards.

The equipment used is appropriate and comparable to the equipment employed in similar circumstances in the international arena. Some operating and safety practices, such as the use of hard hats, do not meet Western standards but are similar to the operating and safety practices used by other Russian operators. LUKoil recognizes these problems and is striving to improve these practices.

The infrastructure and support facilities for the existing fields generally have spare capacity as the produced volumes have declined from peak rates occurring in the 1980s when most of the drilling occurred. Oil and gas production resulting from future drilling in new fields may require additional production facilities but, in some instances, may use spare capacity in the existing fields. The cost of maintaining the existing equipment is a significant part of the historical operating costs used in our reserve evaluations. LUKoil supplies all maintenance support in Western Siberia and KomiTEK but utilizes contractors in the Perm region where the industry is more mature. No significant factors affect the commercial viability of LUKoil's operations other than the obvious oil price and government taxes.

The value of the plant and equipment has been included in our estimates of net present value of the reserves because these items are required to produce our estimates of reserves. No salvage value for this equipment was included in our projections because we consider these values as negligible. LUKoil provided us with the costs for future facilities and equipment that we employed in estimating future net revenues.

Our visual inspection of environmental conditions was simplified because the major pipelines are laid along the major roads in the Komi Republic and in Western Siberia. Our inspection supported LUKoil's assurance that there are no major oil spills except in the Komi Republic. LUKoil has environmental teams at each of its subsidiaries for both active prevention of oil spills and prompt cleanup of any minor ones that may occur. We observed a few small spills and one large oil spill at KomiTEK, all of which were under remediation at the time. LUKoil has plans to gradually replace most older pipelines with fiberglass pipe or plastic-coated steel pipe to eliminate corrosion problems that are the cause of most oil spills.

Sensitivity Cases for the Total Evaluated Properties

The sensitivity of reserve value to the discount rate applied to the future net revenues is shown in the following table for the total of all properties. Only the annual discount rate varies; all other parameters remain as previously discussed.

Category	Total LUKoil Properties Present Worth (Million U.S. Dollars)			
	At 5 Percent	**At 15 Percent**	**At 20 Percent**	**At 25 Percent**
Proven	38,780.4	17,509.1	13,202.6	10,424.0
Probable	9,024.7	2,183.4	1,273.7	784.1
Proven + Probable	**47,805.0**	**19,692.5**	**14,476.3**	**11,208.1**

The sensitivity of reserves and reserve value to oil and gas prices is shown in the following tables for the total of all properties. For these cases, oil and gas prices are varied upward and downward by 10 percent and 20 percent from the levels discussed previously.

Category	Total LUKoil Properties Present Worth Discounted at 10 Percent (Million U.S. Dollars)			
	Change to Base Case Prices			
	-20 Percent	**-10 Percent**	**+10 Percent**	**+20 Percent**
Proven	16,609.7	20,582.3	29,046.0	33,374.7
Probable	2,350.5	3,045.2	5,205.3	6,369.4
Proven + Probable	**18,960.1**	**23,627.5**	**34,251.3**	**39,744.1**

Category	Total LUKoil Properties Oil Reserves to the LUKoil Interest (Million Barrels) — *Change to Base Case Prices* -20 Percent	-10 Percent	+10 Percent	+20 Percent
Proven	13,788.4	14,228.0	14,792.3	14,924.6
Probable	5,959.8	6,361.3	6,642.6	6,748.3
Proven + Probable	**19,748.2**	**20,589.3**	**21,434.9**	**21,672.9**

The sensitivity of reserves and reserve value to operating expenses is shown in the following tables for the total of all properties. For these cases, only the operating costs were changed. Both the fixed per-completion operating costs and the variable per-barrel operating costs are varied upward and downward by 10 and 20 percent.

Category	Total LUKoil Properties Present Worth Discounted at 10 Percent (Million U.S. Dollars) — *Change to Base Case Operating Expenses* -20 Percent	-10 Percent	+10 Percent	+20 Percent
Proven	27,249.1	26,016.1	23,602.5	21,734.5
Probable	4,608.5	4,360.8	3,937.5	3,484.1
Proven + Probable	**31,857.7**	**30,376.9**	**27,540.0**	**25,218.6**

Category	Total LUKoil Properties Oil Reserves to the LUKoil Interest (Million Barrels) — *Change to Base Case Operating Expenses* -20 Percent	-10 Percent	+10 Percent	+20 Percent
Proven	14,996.8	14,799.2	14,307.2	14,024.6
Probable	6,738.6	6,634.0	6,383.0	6,258.4
Proven + Probable	**21,735.5**	**21,433.3**	**20,690.2**	**20,283.0**

Reserve Considerations

The estimates of proven and probable reserves were made using standard geological and engineering methods accepted by the petroleum industry. These methods included analysis of production decline curves and water-oil ratio trends for producing reservoirs and of volumetric methods for nonproducing reservoirs. Recovery factors for nonproducing reservoirs were estimated from analogy to similar producing reservoirs.

Reserve estimates from volumetric calculations and from analogies are often less certain than reserve estimates based on well performance obtained over a period during which a substantial portion of the reserves were produced.

Reserves were forecast for the economic life of the reservoir or field unless (a) the projected economic life exceeded 75 years, in which case the forecast was truncated at 75 years, or (b) in the case of proven reserves, the projected life exceeded the anticipated production license expiration date, in which case the forecast was truncated at the expiration date. Exhibit 29 shows the anticipated license expiration dates as provided by LUKoil. The terms of production licenses are subject to legislation by the Russian government. We made no investigation of the terms of production and exploration licenses or of any Production Sharing Agreements, as such was beyond the scope of this assignment.

Estimated net gas reserves are based upon the ratio of gas sales volume to oil sales volume during the year 2001 for the various subsidiaries. These ratios are assumed to continue unchanged in the future. Net gas reserves do not represent the total volumes of gas expected to be produced with the net oil reserves.

Of the total net proven oil reserves attributable to the LUKoil Consolidated Subsidiaries and Affiliated Companies, approximately 39 percent are attributable to future production from currently producing wells; 24 percent are attributable to recompletions, fracture stimulations, and restorations of existing well bores; and 37 percent are attributable to future drilling.

Reserves reported herein were calculated using conventional deterministic methods as described above. To illustrate the potential relationship between reserves and confidence level, Monte Carlo statistical methods were used to create probabilistic distributions of our estimated oil reserves, as shown on Exhibits 30 and 31. The plots are intended to illustrate general trends of the statistically aggregated properties and do not represent the arithmetic summation of specific fields and reservoirs.

Exhibit 32 shows the recent production history and the future production forecasts for the evaluated LUKoil properties. These forecasts display the total proven and the proven plus probable categories for gross (total) oil production employing the economic parameters described above.

The majority of LUKoil's reserves are currently produced using artificial lift techniques. In Western Siberia, directional wells are typically drilled from a pattern of drill pads. Oil is produced primarily using electric submersible pumps, although some surface pumping units are used.

Occasionally, wells initially flow naturally. In the Volga-Ural region, wells typically are vertical holes, and oil is produced utilizing surface pumping units.

The proven developed producing reserves and production forecasts were estimated by production decline extrapolations or water-oil ratio trends, or, in a few cases, by volumetric calculations. For some reservoirs with insufficient performance history to establish trends, we estimated future production by analogy with other reservoirs having similar characteristics. Production declines were extrapolated to economic limits based on operating expense and oil price data. The past performance trends of many reservoirs were influenced by production curtailments, workovers, waterfloods, and/or infill drilling; extrapolations of past performance are based, whenever possible, upon the average performance trend of active producing wells during periods of stable field activity.

The estimated proven developed nonproducing reserves can be produced from existing well bores but require capital investments for workovers, recompletions, or restoration of shut-in wells. For wells shut in awaiting mechanical repair, we assumed that the wells producing at rates greater than the economic limit at the time of shut in will be returned to production at pre-shut-in levels and will decline in production at the average reservoir decline rate. For wells requiring recompletion, the estimates of reserves and producing rates are based on volumetric calculations and analogies with other wells that commercially produce from the same formation in the same field. Proven developed nonproducing reserves attributable to hydraulic fracturing are based upon analogy to results demonstrated by hydraulic fracturing in the same or in similar reservoirs.

The estimated proven undeveloped reserves require significant capital investments, such as costs for future development drilling and surface facilities. The proven undeveloped reserves are expected to be produced (1) from undeveloped portions of known reservoirs that have been adequately defined by wells and (2) from infill drilling currently planned by LUKoil in areas containing proven producing category reserves. Reserve estimates are based upon volumetric calculations that employ recovery factors based on the performance of analogous reservoirs. Producing rate estimates are based upon analogy.

The estimated probable and possible reserves are mainly undeveloped and require significant capital investments. The estimated probable reserves are expected to be produced from undeveloped portions of known reservoirs not adequately defined to be classified as proven. An additional component of probable reserves was included for currently producing reservoirs as follows: For some reservoirs that are currently producing at noncommercial rates, we assumed that these reservoirs could be made commercial by shutting in high water-cut wells. These reserves are classified as probable rather than proven because of the uncertainty of results from shutting in the high water-cut wells.

Langepasneftegas Subsidiary Summary

Oil production from the Langepasneftegas (Langepas) subsidiary began in 1976. Currently, nine oil fields are under production, two of which are partially operated by the Pokachev subsidiary. Through the end of 2001, cumulative production from both subsidiaries was approximately 3.112 billion gross barrels of oil, including 1.749 billion barrels from the Langepas operations. In 2001, the Langepas subsidiary produced approximately 42.2 million gross barrels of oil.

For the total evaluated properties in the Langepas subsidiary, the estimated gross proven original oil in place is 8.874 billion barrels, and at the proven plus probable confidence level, the estimated gross original oil in place is 10.151 billion barrels. Gross ultimate oil recovery, after economic considerations, is estimated to be 2.808 billion barrels at the proven level and 3.236 billion barrels at the proven plus probable confidence level. This reflects economic recovery factors of 31.6 percent at the proven level and 31.9 percent at the proven plus probable confidence level. These estimates include all reservoirs currently producing or expected to produce in the future. They do not include oil in place or ultimate oil recovery from depleted reservoirs or from nonproducing reservoirs with no future economic production. There are currently approximately 3,290 active producing wells and 860 active injection wells.

The total net reserves and future net revenues for the Langepas subsidiary are estimated to be as follows:

Langepas Subsidiary

	Net Reserves to LUKoil As of January 1, 2002			**Future Net Revenues As of January 1, 2002**	
Category	**Oil, MMBbls.**	**Gas, Bcf**	**BOE, MMBbls.**	**Undiscounted MM$**	**Discounted at 10% Per Year MM$**
Proven	1,059.0	216.0	1,095.0	2,408.7	691.9
Probable	428.6	87.4	443.2	1,214.6	192.8
Proven + Probable	**1,487.6**	**303.5**	**1,538.2**	**3,623.3**	**884.7**

To produce the reserves stated above, approximately 2,570 additional wells and associated recompletions in the proven category and 2,110 wells and associated recompletions in the probable category are required. Economic life of the subsidiary under the proven base case economic and development assumptions is 60 years.

Uraineftegas Subsidiary Summary

The Uraineftegas (Urai) producing region in Western Siberia was discovered in 1960. Production commenced in 1964. Through the end of 2001, cumulative production from the currently producing fields was approximately 1.478 billion barrels of oil. In 2001, the subsidiary produced approximately 34 million gross barrels of oil.

For the total Urai subsidiary, the estimated gross proven original oil in place is 5.872 billion barrels, and at the proven plus probable confidence level, the estimated gross original oil in place is 6.920 billion barrels. Gross ultimate oil recovery, after economic considerations, is estimated to be 2.190 billion barrels at the proven level and 2.523 at the proven plus probable confidence level. This reflects economic recovery factors of 37.3 percent at the proven level and 36.5 percent at the proven plus probable confidence level. These estimates include all reservoirs currently producing or expected to produce in the future. They do not include oil in place or ultimate oil recovery from depleted reservoirs or from nonproducing reservoirs with no future economic production. There are currently approximately 2,030 active producing wells and 550 active injection wells.

A Joint Venture is operating at the Kulturskaya and Slavenskoye fields. It is structured such that the effective net ownership of the Joint Venture portion of the field is 95 percent to LUKoil. LUKoil's share of future production is included in the estimates shown below.

The total net reserves and future net revenues for the Urai subsidiary are estimated to be as follows:

Urai Subsidiary
Including Joint Venture

	Net Reserves to LUKoil As of January 1, 2002			Future Net Revenues As of January 1, 2002	
Category	**Oil, MMBbls.**	**Gas, Bcf**	**BOE, MMBbls.**	**Undiscounted MM$**	**Discounted at 10% Per Year MM$**
Proven	703.4	127.9	724.7	1,526.4	825.8
Probable	333.2	60.5	343.3	746.9	96.7
Proven + Probable	**1,036.6**	**188.4**	**1,068.0**	**2,273.4**	**922.4**

To produce the reserves stated above, approximately 1,340 additional wells and associated recompletions in the proven category and 1,880 wells and associated recompletions in the probable category are required. Economic life of the subsidiary under the base case economic and development assumptions is 30 years.

Kogalymneftegas Subsidiary Summary

Oil production from the Kogalymneftegas (Kogalym) subsidiary began in 1976. Currently, 11 oil fields are under production, and eight additional fields are under development. Through the end of 2001, cumulative production from the subsidiary and its Joint Ventures combined was approximately 3.694 billion gross barrels of oil. In 2001, the subsidiary produced approximately 240 million gross barrels of oil, which is essentially unchanged over 2000 production levels. At the end of 2001, approximately 8,300 oil producers and 1,985 water injectors were active in Kogalym.

The estimated gross proven original oil in place, including all Joint Ventures, is 23.448 billion barrels, and at the proven plus probable confidence level, the estimated gross original oil in place is 33.565 billion barrels. Gross ultimate oil recovery, after economic considerations, is estimated to be 8.780 billion barrels at the proven level and 12.148 billion barrels at the proven plus probable confidence level. This reflects economic recovery factors of 37.4 percent at the proven level and 36.2 percent at the proven plus probable confidence level. These estimates include all reservoirs currently producing or expected to produce in the future. They do not include oil in place or ultimate oil recovery from depleted reservoirs or from nonproducing reservoirs with no future economic production.

Net oil and gas reserves are attributed to the LUKoil working interest, shown as Reporting Interest on Exhibit 2. In Kogalym, LUKoil has interests in three Joint Ventures: Vatoil, RITEK, and AIK. Vatoil is a Joint Venture in the Vat Eganskoye and Kochevskoye fields. AIK is a Joint Venture in the Kogalymskoye Field. The RITEK Joint Venture evaluation includes ten fields in Western Siberia and seven fields in the Republic of Tatarstan.

The total net reserves and future net revenues for the total Kogalym subsidiary are estimated to be as follows:

Kogalym Subsidiary
Including Joint Venture

	Net Reserves to LUKoil As of January 1, 2002			Future Net Revenues As of January 1, 2002	
Category	**Oil, MMBbls.**	**Gas, Bcf**	**BOE, MMBbls.**	**Undiscounted MM$**	**Discounted at 10% Per Year MM$**
Proven	5,038.7	692.3	5,154.1	22,765.0	9,096.4
Probable	3,313.6	468.7	3,391.7	12,073.9	1,159.9
Proven + Probable	**8,352.3**	**1,161.0**	**8,545.8**	**34,838.9**	**10,256.3**

To produce the reserves stated above, approximately 6,430 additional wells and associated recompletions in the proven category and 19,370 wells and associated recompletions in the probable category are required. Economic life of the subsidiary under the proven base case economic and development assumptions is 75 years.

Pokachevneftegas Subsidiary Summary

The Pokachevneftegas (Pokachev) subsidiary was created in December 1998 from the existing Langepas subsidiary. In the Pokachev subsidiary, there are currently seven producing oil fields, with production having commenced in 1977. Two of the producing fields are jointly operated by the Langepas and Pokachev subsidiaries, from land areas separated by the Agan River. In 2001, the Pokachev subsidiary produced approximately 53.6 million gross barrels of oil, or about 56 percent of the combined total production from the two subsidiaries. Through the end of 2001, cumulative production from both subsidiaries was approximately 3.112 billion gross barrels of oil, including 1.363 billion barrels from the Pokachev operations.

The Goloil Joint Venture is an affiliated company located in the Pokachev operating area in which LUKoil owns a 10 percent working interest. Net oil reserves to LUKoil in this Joint Venture are all undeveloped and total less than 2.5 million barrels at the proven plus probable confidence level.

For the total Pokachev subsidiary, the estimated gross proven original oil in place is 6.265 billion barrels, and at the proven plus probable confidence level, the estimated gross original oil in place is

8.926 billion barrels. Gross ultimate oil recovery, after economic considerations, is estimated to be 2.618 billion barrels at the proven level and 3.292 billion barrels at the proven plus probable confidence level. This reflects economic recovery factors of 41.8 percent at the proven level and 36.9 percent at the proven plus probable confidence level. These estimates include all reservoirs currently producing or expected to produce in the future. They do not include oil in place or ultimate oil recovery from depleted reservoirs or from nonproducing reservoirs with no future economic production. At the end of 2001, there were approximately 2,270 active producing wells and 500 active water injection wells.

The total net reserves and future net revenues for the Pokachev subsidiary are estimated to be as follows:

Pokachev Subsidiary
Including Joint Venture

	Net Reserves to LUKoil As of January 1, 2002			Future Net Revenues As of January 1, 2002	
Category	**Oil, MMBbls.**	**Gas, Bcf**	**BOE, MMBbls.**	**Undiscounted MM$**	**Discounted at 10% Per Year MM$**
Proven	1,250.6	200.1	1,284.0	5,288.6	1,894.0
Probable	673.9	107.8	691.8	1,935.7	5.8
Proven + Probable	**1,924.5**	**307.9**	**1,975.8**	**7,224.2**	**1,899.7**

To produce the reserves stated above, approximately 2,870 additional wells and associated recompletions in the proven category and 4,600 wells and associated recompletions in the probable category are required. Economic life of the subsidiary under the proven base case economic and development assumptions is 51 years.

Yamalneftegazdobycha Subsidiary Summary

Yamalneftegazdobycha includes three large gas-condensate fields that have been discovered and delineated but not yet developed. The field names are Khalmepayutinskoye, Pyakyakhinskoye, and Yuzhno-Messayakhskoye. In addition to gas and condensate, the Pyakyakhinskoye Field also includes oil rims.

LUKoil plans to drill 474 development wells in the three fields beginning 2006. We designated 228 of these wells as proven because they offset discovery or delineation wells.

The aggregate results of our evaluations as of January 1, 2002, are as follows:

Yamalneftegazdobycha Subsidiary

Category	Net Reserves to LUKoil As of January 1, 2002			Future Net Revenues As of January 1, 2002	
	Oil, MMBbls.	Gas, Bcf	BOE, MMBbls.	Undiscounted MM$	Discounted at 10% Per Year MM$
Proven	234.1	8,222.5	1,604.5	5,870.8	658.2
Probable	113.2	2,005.1	447.4	2,208.1	288.4
Proven + Probable	**347.3**	**10,227.6**	**2,051.9**	**8,078.8**	**946.7**

Economic life under the proven base case economic and development assumptions is 41 years.

Nizhnevolzhskneft Subsidiary Summary

The first oil production from the Nizhnevolzhskneft subsidiary was in the 1950s. Currently, 41 oil fields are under production, and five additional fields are under development. Through the end of 2001, cumulative production from the active fields was approximately 1.454 billion gross barrels of oil. In 2001, the subsidiary produced approximately 26 million gross barrels of oil.

For the total Nizhnevolzhskneft subsidiary, the estimated gross proven original oil in place is 3.670 billion barrels, and at the proven plus probable confidence level, the estimated gross original oil in place is 3.770 billion barrels. Gross ultimate oil recovery, after economic considerations, is estimated to be 1.772 billion barrels at the proven level and 1.851 at the proven plus probable confidence level. This reflects economic recovery factors of 48.3 percent at the proven level and 49.1 percent at the proven plus probable confidence level. For proven reserves, production forecasts were terminated at the lease dates provided by LUKoil. These estimates include all reservoirs currently producing or expected to produce in the future. They do not include oil in place or ultimate oil recovery from depleted reservoirs or from nonproducing reservoirs with no future economic production. There are currently approximately 1,230 active wells.

Included in the Nizhnevolzhskneft subsidiary is the Volgodeminoil Joint Venture which includes a portion of the Pamyatnoye-Sasovskoye Field and the Priboftovskoye Field. The net ownership of the Joint Venture is 50 percent to LUKoil. LUKoil's share of future production is included in the estimates shown below.

The total net reserves and future net revenues for the Nizhnevolzhskneft subsidiary are estimated to be as follows:

Nizhnevolzhskneft Subsidiary
Including Joint Venture

	Net Reserves to LUKoil As of January 1, 2002			Future Net Revenues As of January 1, 2002	
Category	**Oil, MMBbls.**	**Gas, Bcf**	**BOE, MMBbls.**	**Undiscounted MM$**	**Discounted at 10% Per Year MM$**
Proven	293.8	67.0	305.0	2,012.2	1,078.1
Probable	75.5	15.9	78.2	467.4	117.0
Proven + Probable	**369.4**	**82.9**	**383.2**	**2,479.7**	**1,195.0**

To produce the reserves stated above, approximately 140 additional wells and associated recompletions in the proven category and 310 wells and associated recompletions in the probable category are required. Economic life of the subsidiary under the base case economic and development assumptions is 63 years.

Permneft Subsidiary Summary

Our evaluation of the Permneft subsidiary includes 45 producing oil fields and 9 fields that are under development, one producing oil field in the AksaitovNeft Joint Venture, and three producing oil fields in the CHURS Joint Venture. The Permneft subsidiary includes one commercial gas field that accounts for approximately 60 percent of the subsidiary’s proved developed producing gas reserves. Production from the Permneft subsidiary began in 1958. Through December 2001, the fields in the Permneft subsidiary, including Joint Ventures, had a gross cumulative production volume of approximately 2,090 million barrels of oil. In 2001, the Permneft subsidiary produced approximately 38 million gross barrels of oil, which was approximately the same volume produced in 2000. At the end of 2001, there were approximately 4,920 active producers and 1,180 active water injectors in the Permneft subsidiary.

The Permneft subsidiary includes 100 percent ownerships in the AksaitovNeft and CHURS Joint Ventures. The Joint Ventures account for approximately 8 million barrels of net proven reserves.

The total estimated gross original oil in place for the Permneft subsidiary is 12.178 billion barrels at the proven confidence level and 12.750 billion barrels at the proven plus probable confidence level.

Gross ultimate oil recovery, after economic considerations, is estimated to be 3.419 billion barrels at the proven level and 3.519 billion barrels at the proven plus probable confidence level. This reflects economic recovery factors of 28.1 percent at the proven level and 27.6 percent at the proven plus probable confidence level. These estimates include all reservoirs currently producing or expected to produce in the future. They do not include oil in place or ultimate oil recovery from depleted reservoirs or from nonproducing reservoirs with no future economic production. There are currently approximately 6,110 active wells in the Permneft subsidiary.

The total net reserves and future net revenues for the Permneft subsidiary are estimated to be as follows:

Permneft Subsidiary
Including Joint Venture

	Net Reserves to LUKoil As of January 1, 2002			Future Net Revenues As of January 1, 2002	
Category	**Oil, MMBbls.**	**Gas, Bcf**	**BOE, MMBbls.**	**Undiscounted MM$**	**Discounted at 10% Per Year MM$**
Proven	1,328.9	240.6	1,369.0	3,817.4	534.3
Probable	99.5	12.8	101.7	254.1	19.4
Proven + Probable	**1,428.5**	**253.5**	**1,470.7**	**4,071.5**	**553.7**

To produce the reserves stated above, approximately 1,570 additional wells and associated recompletions in the proven category and 750 wells and associated recompletions in the probable category are required. The economic life of the subsidiary may exceed 75 years; our reserve estimates truncate the production forecast at 75 years.

ZAO LUKoil-Perm Subsidiary Summary

ZAO LUKoil-Perm includes 100 percent interest in 22 producing oil fields and three fields under development, plus various interests in seven Joint Ventures in the Volga-Ural province. The initial production for the fields in the subsidiary began in 1938 from the Severokamskoye Field in the Russian Fuel Company (RTK) Joint Venture. In 2001, the total gross production for the ZAO LUKoil-Perm subsidiary was approximately 30 million barrels of oil. Through the end of 2001, the gross cumulative production for the producing oil fields in the ZAO LUKoil-Perm subsidiary was approximately 1.70 billion barrels of oil.

The ZAO LUKoil-Perm subsidiary includes various interests in seven Volga-Ural Joint Ventures, as shown on Exhibit 2. The seven Joint Ventures are the Kamaneft Joint Venture, the Maykorskoye Joint Venture, the PermTOTIneft Joint Venture, the Permtex Joint Venture, the Russian Fuel Company (RTK) Joint Venture, the Visheraneftegas Joint Venture and the VNGK Joint Venture. The net reserves to LUKoil from the Joint Ventures are 220 million barrels at the proven confidence level and 312 million barrels at the proven plus probable confidence level.

The total estimated gross original oil in place for the ZAO LUKoil-Perm subsidiary is 5.913 billion barrels at the proven confidence level, and 6.342 billion barrels at the proven plus probable confidence level. Gross ultimate oil recovery, after economic considerations, is estimated to be 2.398 billion barrels at the proven level and 2.576 billion barrels at the proven plus probable confidence level. This reflects economic recovery factors of 40.6 percent at the proven level and 40.6 percent at the proven plus probable confidence level. Through the end of 2001, the gross cumulative production for the ZAO LUKoil-Perm subsidiary was approximately 1.70 billion barrels of oil, or 28.8 percent of the proven original oil in place volume. The estimates include all reservoirs currently producing or expected to produce in the future from ZAO LUKoil-Perm and the seven Joint Ventures. They do not include oil in place or ultimate oil recovery from depleted reservoirs or from nonproducing reservoirs with no future economic production.

There are approximately 1,916 wells currently active in the ZAO LUKoil-Perm subsidiary.

LUKoil's total net reserves and future net revenues for the ZAO LUKoil-Perm subsidiary are estimated to be as follows:

ZAO LUKoil-Perm Subsidiary
Including Joint Venture

	Net Reserves to LUKoil As of January 1, 2002			Future Net Revenues As of January 1, 2002	
Category	**Oil, MMBbls.**	**Gas, Bcf**	**BOE, MMBbls.**	**Undiscounted MM$**	**Discounted at 10% Per Year MM$**
Proven	634.3	178.9	664.2	3,241.7	1,228.2
Probable	150.1	27.4	154.7	494.8	86.5
Proven + Probable	**784.4**	**206.3**	**818.8**	**3,736.5**	**1,314.7**

To produce the reserves stated above, approximately 520 additional wells and associated recompletions in the proven category and 920 wells and associated recompletions in the probable category are required. The economic life of the subsidiary may exceed 75 years; our reserve estimates truncate the production forecast at 75 years.

Astrakhanneft Subsidiary Summary

The first oil production from the Astrakhanneft subsidiary was in 1962. Oil production from three fields included in this report are the Beshkulskoye, an oil field producing from a thin Jurassic sand; the Oleinikovskoye, a gas field with an oil rim that is being produced; and the Dolbanskoye, a new field. The reservoir is a Cretaceous sand. Through the end of 2001, cumulative oil production from the three fields evaluated for this report was approximately 45 million gross barrels. In 2001, the subsidiary produced approximately 0.5 million gross barrels of oil.

For the total oil fields in the Astrakhanneft subsidiary, the estimated gross original oil in place is 112.9 million barrels at both the proven and at the proven plus probable confidence levels. Gross ultimate oil recovery, after economic considerations, is estimated to be 48.7 million barrels. This reflects an economic recovery factor of 43.1 percent. For proven reserves, production forecasts were terminated at the lease dates provided by LUKoil. These estimates include all reservoirs currently producing or expected to produce in the future. They do not include oil in place or ultimate oil recovery from depleted reservoirs or from nonproducing reservoirs with no future economic production. There are currently approximately 47 active oil-producing wells.

The total net reserves and future net revenues for the Astrakhanneft subsidiary are estimated to be as follows:

Astrakhanneft Subsidiary

	Net Reserves to LUKoil As of January 1, 2002			Future Net Revenues As of January 1, 2002	
Category	**Oil, MMBbls.**	**Gas, Bcf**	**BOE, MMBbls.**	**Undiscounted MM$**	**Discounted at 10% Per Year MM$**
Proven	4.5	0.0	4.5	20.2	13.6
Probable	0.6	0.0	0.6	1.3	0.1
Proven + Probable	**5.1**	**0.0**	**5.1**	**21.6**	**13.7**

Economic life of the subsidiary under the base case economic and development assumptions is 20 years.

Kaliningradmorneft Subsidiary Summary

First production in the Kaliningradmorneft subsidiary, located in Russia's western region between Poland and Lithuania bordering the Baltic Sea, occurred prior to 1975. There are currently 19 producing fields. In 2001, the subsidiary produced approximately 5 million gross barrels of oil. Through the end of 2001, the gross cumulative production from the currently producing fields was approximately 214 million barrels of oil.

For the total Kaliningradmorneft subsidiary, the estimated gross proven original oil in place is 0.561 billion barrels, and at the proven plus probable confidence level, the estimated gross original oil in place is 0.594 billion barrels. Gross ultimate oil recovery, after economic considerations, is estimated to be 0.302 billion barrels at the proven level and 0.314 at the proven plus probable confidence level. This reflects economic recovery factors of 53.8 percent at the proven level and 52.9 percent at the proven plus probable confidence level. These estimates include all reservoirs currently producing or expected to produce in the future. They do not include oil in place or ultimate oil recovery from depleted reservoirs or from nonproducing reservoirs with no future economic production. There are currently approximately 266 active producing wells.

The total net reserves and future net revenues for the Kaliningradmorneft subsidiary are estimated to be as follows:

Kaliningradmorneft Subsidiary

	Net Reserves to LUKoil As of January 1, 2002			Future Net Revenues As of January 1, 2002	
Category	**Oil, MMBbls.**	**Gas, Bcf**	**BOE, MMBbls.**	**Undiscounted MM$**	**Discounted at 10% Per Year MM$**
Proven	88.4	1.6	88.6	560.1	278.3
Probable	11.7	0.1	11.7	21.5	-1.5
Proven + Probable	**100.0**	**1.7**	**100.3**	**581.6**	**276.8**

To produce the reserves stated above, approximately 14 additional wells and associated recompletions in the proven category and 12 wells and associated recompletions in the probable category are required. Economic life of the subsidiary under the base case economic and development assumptions is 35 years.

KomiTEK Properties

LUKoil ownership in the KomiTEK properties includes eight Consolidated Subsidiaries: ZAO Bitran, OOO Karayaganeft, OAO KomiArctic Oil, OAO KomiTEK, ZAO Nobel Oil, OAO Komineft, ZAO Bitech Silur, ZAO Parmaneft; and seven Affiliated Companies: OOO Amkomi, AO Investnafta, TOO KomiQuest, ZAO SeverTEK, OAO Tebukneft, OAO Ukhtaneft, and OAO YaNTK. These properties are summarized under Komi Republic in Exhibit 2. Reporting ownership in the Consolidated Subsidiaries is 100 percent, while ownership in the seven Affiliated Companies is less than 50 percent. Fifty-eight fields were evaluated, with 46 fields being classified as developed producing. Production from a number of these fields commenced prior to 1950. There are currently approximately 3,395 active producing wells in the fields. Production from these wells for the year 2001 was 64.51 million barrels.

For the total KomiTEK properties, the estimated gross proven original oil in place is 14.27 billion barrels, and at the proven plus probable confidence level, the estimated gross original oil in place is 16 billion barrels. Gross ultimate oil recovery, after economic considerations, is estimated to be 4.74 billion barrels at the proven level and 5.16 at the proven plus probable confidence level. This reflects economic recovery factors of 33.2 percent at the proven level and 32.3 percent at the proven plus probable confidence level. These estimates include all reservoirs currently producing or expected to produce in the future. They do not include oil in place or ultimate oil recovery from depleted reservoirs or from nonproducing reservoirs with no future economic production.

The total net reserves and future net revenues for the KomiTEK properties are estimated to be as follows:

KomiTEK Properties
Including All Consolidated Subsidiaries and Affiliated Companies

	Net Reserves to LUKoil As of January 1, 2002			**Future Net Revenues As of January 1, 2002**	
Category	**Oil, MMBbls.**	**Gas, Bcf**	**BOE, MMBbls.**	**Undiscounted MM$**	**Discounted at 10% Per Year MM$**
Proven	2,079.0	488.0	2,160.3	10,011.1	3,811.9
Probable	321.9	117.5	341.5	1,354.3	286.5
Proven + Probable	**2,400.9**	**605.5**	**2,501.9**	**11,365.5**	**4,098.4**

To produce the reserves stated above, approximately 3,041 additional wells and associated recompletions in the proven category and 1,020 wells and associated recompletions in the probable category are required. Economic life of the KomiTEK properties under the base case economic and development assumptions may exceed 75 years; our reserve estimates truncate the production forecast at 75 years.

Arkhangelskgeoldobycha

LUKoil's Arkhangelskgeoldobycha (Arkhangel) properties include four producing oil fields in the Baltic Basin and 24 largely undeveloped oil fields in the northern portion of the Timan-Pechora Basin.

The estimated gross proven original oil in place for the Arkhangel fields is 3.919 billion barrels and at the proven plus probable confidence level, the estimated gross original oil in place is 6.205 billion barrels. Gross ultimate oil recovery, after economic considerations, is estimated to be 1.339 billion barrels at the proven level and 2.120 billion barrels at the proven plus probable confidence level. This reflects economic recovery factors of 34.2 percent at the proven level and 34.2 percent at the proven plus probable confidence level.

The total net reserves and future net revenues for LUKoil's Arkhangel fields are estimated to be as follows:

LUKoil Arkhangel Fields
Including Joint Ventures

	Net Reserves to LUKoil As of January 1, 2002			Future Net Revenues As of January 1, 2002	
Category	Oil, MMBbls.	Gas, Bcf	BOE, MMBbls.	Undiscounted MM$	Discounted at 10% Per Year MM$
Proven	1,215.8	0.0	1,215.8	9,099.4	3,149.9
Probable	781.3	0.0	781.3	3,584.5	759.5
Proven + Probable	**1,997.1**	**0.0**	**1,997.1**	**12,683.9**	**3,909.5**

Initial sales started in 1992 from the first of nine fields that have begun production. The ninth of these fields initiated oil sales in 2001. Combined total gross production from the fields averaged approximately 37,300 barrels of oil per day for the year 2001. Cumulative oil production through year-end 2001 is approximately 94.9 million barrels. Currently, there are approximately 74 active wells. To produce the reserves stated above, approximately 1,169 new wells and associated recompletions in the proven category and approximately 1,775 new wells and recompletions in the probable category are required.

Development programs for many of the Arkhangel fields were not yet submitted or approved as of January 1, 2002. Economic viability of some fields is uncertain and may depend on approval of Production Sharing Agreements (PSAs) and/or shared field facilities and transportation systems. LUKoil's ownership in the subject fields may change, and other fields may be added to its development inventory as a result of future proposals and negotiations concerning PSAs and development of the Northern Timan-Pechora Basin fields. For purposes of this report, each field is considered as a stand-alone development. No gas sales are projected at this time for the Arkhangel fields.

Exhibit 33 shows the Arkhangel entities, field groupings, reporting interests used for this report, and reserve categories included herein for each field. Note that some fields have no reserves assigned at this time due to economic viability. The reporting interests assume full ownership of the Consolidated Subsidiaries in which LUKoil has the controlling working interest. LUKoil's interest in the Polar Lights Joint Venture operated by Conoco is 22.2 percent. Economic life of future production under base case economics is projected to be 75 years.

Korchagina Field (Russian Caspian Sea)

Korchagina Field (Korchagina) is located in the Russian sector of the Caspian Sea, 175 kilometers from the city of Astrakhan, Russia. This is a new field development without infrastructure for the field to produce continuously at this time. The field was discovered in 2000 in wildcat Shirotnaya Well No. 1. Hydrocarbon accumulation was confirmed in this well using both log and test data. A second well, Shirotnaya No. 2, was drilled and confirmed the presence of hydrocarbons and delineated the boundaries of the field.

Net oil and gas reserves and future net revenues attributed to the LUKoil working interest for the Korchagina Field as of January 1, 2002 are summarized as follows:

Korchagina Field (Russian Caspian Sea)

	Net Reserves to LUKoil As of January 1, 2002			Future Net Revenues As of January 1, 2002	
Category	**Oil, MMBbls.**	**Gas, Bcf**	**BOE, MMBbls.**	**Undiscounted MM$**	**Discounted at 10% Per Year MM$**
Proven	98.3	956.9	257.8	1,066.3	58.5
Probable	181.4	344.2	238.8	1,917.5	716.6
Proven + Probable	**279.7**	**1,301.1**	**496.6**	**2,983.7**	**775.1**

To produce the reserves stated above, approximately 29 additional wells and associated recompletions in the proven category and 50 wells and associated recompletions in the probable category are required. Economic life under the proven base case economic and development assumptions is 56 years.

INTERNATIONAL PROPERTIES

LUKoil owns interests in a number of international properties. These are the Tengiz, Korolev, Karachaganak, and Kumkol fields in Kazakhstan; the Gunashli, Chirag, and Azeri fields in Azerbaijan; and the Meleiha Field in Egypt.

Tengiz and Korolev Fields

The Tengiz Field was discovered in 1979 with production beginning in 1991. It has been operated by the Joint Venture partnership Tengizchevroil (TCO) since 1993. The term of the contract is 40 years. The satellite Korolev Field is located northeast of Tengiz, and production to the Tengiz facilities began in November 2001. Current ownership of TCO is ChevronTexaco (50 percent), ExxonMobil (25 percent), LUKArco (5 percent) and the Republic of Kazakhstan (20 percent). LUKoil owns 54 percent of LUKArco’s 5 percent interest, for a total of 2.7 percent.

At the proven confidence level, the estimated gross original oil in place for the Tengiz and Korolev fields is 16.0 billion barrels and 2.1 billion barrels, respectively. At the proven plus probable confidence level, the estimated gross original oil in place for the Tengiz and Korolev fields is 21 billion barrels and 2.7 billion barrels, respectively. Gross ultimate oil recoveries of 3.6 billion barrels and 4.9 billion barrels are estimated for the proven and proven plus probable confidence levels, respectively, for the Tengiz Field and 0.5 billion barrels and 0.8 billion barrels for the proven and proven plus probable confidence levels, respectively, for the Korolev Field. This reflects recovery factors of 22.6 percent for the proven and 23.1 percent for the proven plus probable confidence levels in Tengiz and 25 percent for the proven and 28.5 percent for the proven plus probable confidence level in the Korolev Field. In 2001, average crude oil production at Tengiz was approximately 272,900 barrels per day and 2,740 barrels per day at Korolev. Cumulative oil production as of January 1, 2002 is reported to be 502 million barrels at Tengiz and 1.0 million barrels at Korolev. As of January 2002, there were 47 active wells in Tengiz and two active wells at Korolev.

The combined total net reserves and future net revenues for the Tengiz and Korolev fields are estimated to be as follows:

Tengiz and Korolev Fields

Category	Net Reserves to LUKoil As of January 1, 2002			Future Net Revenues As of January 1, 2002	
	Oil, MMBbls.	**Gas, Bcf**	**BOE, MMBbls.**	**Undiscounted MM$**	**Discounted at 10% Per Year MM$**
Proven	98.2	154.9	124.0	787.0	235.0
Probable	40.0	63.0	50.5	338.7	46.4
Proven + Probable	**138.2**	**217.9**	**174.5**	**1,125.7**	**281.5**

To produce the reserves stated above within the time limit of the contract, approximately 93 additional wells and recompletions in the proven category and 78 additional wells and recompletions in the probable category are required.

Karachaganak Field

The Karachaganak Field was discovered in 1979 with production beginning in 1984. It has been operated under a Production Sharing Agreement (PSA) by the Joint Venture partnership Karachaganak Integrated Organization (KIO) since 1997. The term of the contract is 40 years. Current partner ownership in the PSA is British Gas (32.5 percent), AGIP (32.5 percent), ChevronTexaco (20 percent) and LUKoil (15 percent).

At the proven confidence level, the estimated gross original hydrocarbons in place include 38.6 trillion cubic feet of gas and 7.6 billion barrels of crude and condensate. At the proven plus probable confidence level, the estimated gross original gas in place is 43.4 trillion cubic feet, along with 8.5 billion barrels of crude and condensate. Based on KIO's Phase III full-field development plan, we estimate gross ultimate gas recoveries of 15.4 trillion cubic feet and 2.2 billion barrels of crude and condensate are estimated for the proven confidence level. Under Phase III, gross ultimate gas recoveries of 17.0 trillion cubic feet and 2.5 billion barrels of crude and condensate are estimated for the proven plus probable confidence level. This reflects gas recovery factors of 39.9 percent for the proven and 39.2 percent for the proven plus probable confidence levels. Crude and condensate recovery factors are 29.2 percent for the proven and 29.0 percent for the proven plus probable confidence levels. During the year 2001, hydrocarbon production at Karachaganak was 131.4 billion cubic feet of gas and 31.4 million barrels of crude and condensate. Cumulative production as of January 1, 2002 is reported to be approximately 1.89 trillion cubic feet of gas and 385 million barrels of crude and condensate. As of January 2002, there were approximately 52 active wells in the field.

The total net reserves and future net revenues for the Karachaganak Field are estimated to be as follows:

Karachaganak Field

	Net Reserves to LUKoil As of January 1, 2002			Future Net Revenues As of January 1, 2002	
Category	**Oil, MMBbls.**	**Gas, Bcf**	**BOE, MMBbls.**	**Undiscounted MM$**	**Discounted at 10% Per Year MM$**
Proven	240.4	1,669.2	518.6	1,981.9	418.6
Probable	33.3	213.3	68.9	291.2	54.8
Proven + Probable	**273.7**	**1,882.5**	**587.5**	**2,273.1**	**473.4**

To produce the reserves stated above within the time limit of the contract, approximately 149 additional wells and associated recompletions in the proven category and 22 additional wells and associated recompletions in the probable category are required.

Kumkol Field

The Kumkol Field was discovered in 1983. The northern portion of the field is known as “Kumkol-LUKoil,” defined by a separate license issued in 1995. LUKoil owns 50 percent of the contract area known as “Kumkol-LUKoil.” Production from the Kumkol-LUKoil portion of the field began in September 1995.

The estimated gross original oil in place is 511 million barrels and 581 million barrels for the proven and proven plus probable confidence levels, respectively. Gross ultimate oil recoveries of 216 million barrels and 248 million barrels are estimated for the proven and proven plus probable confidence levels, respectively. This reflects recovery factors of 42 percent for the proven and 43 percent for the proven plus probable confidence levels, respectively. As of January 2002, there were 151 active wells in the field. No value is given for the gas in Kumkol. During the year 2001, reported crude oil production at Kumkol was approximately 11 million barrels. Cumulative oil production as of January 1, 2002 is approximately 46 million barrels.

The total net reserves and future net revenues for the Kumkol Field are estimated to be as follows:

Kumkol Field

Category	Net Reserves to LUKoil As of January 1, 2002			Future Net Revenues As of January 1, 2002	
	Oil, MMBbls.	**Gas, Bcf**	**BOE, MMBbls.**	**Undiscounted MM$**	**Discounted at 10% Per Year MM$**
Proven	85.3	0.0	85.3	377.9	201.1
Probable	16.0	0.0	16.0	37.7	11.6
Proven + Probable	**101.2**	**0.0**	**101.2**	**415.6**	**212.7**

To produce the reserves stated above within the time limit of the contract, approximately 119 additional wells and associated recompletions in the proven category and 99 additional wells and associated recompletions in the probable category are required.

Gunashli, Chirag, and Azeri Fields

The Gunashli, Chirag, and Azeri fields (GCA) are located in the Azerbaijan sector of the Caspian Sea. The fields are currently operated under a PSA by the Azerbaijan International Operating Company (AIOC). The PSA encompasses the southeastern portion of the Gunashli Field (Deep Water Gunashli) and all the Chirag and Azeri fields. The term of the contract is 40 years. BP manages the operations for AIOC. LUKoil owns 10 percent interest in AIOC. AIOC commenced production from the Chirag-A platform in November 1999.

The estimated gross original oil in place is 4.6 billion barrels and 7.8 billion barrels for the proven and proven plus probable confidence levels, respectively. Gross ultimate oil recoveries of 1.7 billion barrels and 3.1 billion barrels are estimated for the proven and proven plus probable confidence levels, respectively. This reflects recovery factors of 37.0 percent for the proven and 39.7 percent for the proven plus probable confidence levels, respectively. No gas reserves are assigned to LUKoil since all gas produced not used in operations is the property of the State Oil Company of Azerbaijan (SOCAR). Only the Chirag Field has produced under the AIOC PSA. As of January 1, 2002, 12 wells were producing from the Chirag-A platform. During the year 2001, the crude oil production at Chirag was approximately 45.6 million barrels. Cumulative oil production as of January 1, 2002 is approximately 137 million barrels.

The total net reserves and future net revenues for the AIOC GCA fields are estimated to be as follows:

AIOC GCA Fields

	Net Reserves to LUKoil As of January 1, 2002			Future Net Revenues As of January 1, 2002	
Category	**Oil, MMBbls.**	**Gas, Bcf**	**BOE, MMBbls.**	**Undiscounted MM$**	**Discounted at 10% Per Year MM$**
Proven	119.4	0.0	119.4	1,248.7	579.8
Probable	83.6	0.0	83.6	801.3	252.2
Proven + Probable	**203.0**	**0.0**	**203.0**	**2,050.0**	**831.9**

To produce the reserves stated above within the time limit of the contract, approximately 222 additional wells and associated recompletions in the proven category and 266 additional wells and associated recompletions in the probable category are required.

Meleiha Field

The term “Meleiha Field” refers to eight oil fields contained within the Meleiha Development Lease located in the western desert of Egypt. LUKoil owns 50 percent of LUKAgip’s 24 percent interest in the Meleiha Field. Records indicate production from Meleiha began prior to 1995.

As of January 2002, the cumulative oil produced from the Meleiha Field was approximately 99.4 million gross barrels. Additional data proved as of January 1, 2002 were the actual 2000 and 2001 oil production volumes.

The total net reserves and future net revenues for the Meleiha Field are estimated to be as follows:

Meleiha Field

	Net Reserves to LUKoil As of January 1, 2002			Future Net Revenues As of January 1, 2002	
Category	**Oil, MMBbls.**	**Gas, Bcf**	**BOE, MMBbls.**	**Undiscounted MM$**	**Discounted at 10% Per Year MM$**
Proven	4.2	0.0	4.2	45.0	32.1
Probable	0.0	0.0	0.0	0.0	0.0
Proven + Probable	**4.2**	**0.0**	**4.2**	**45.0**	**32.1**

Information that would be required to assess the proven behind pipe, proven undeveloped, and probable reserve categories was not available, although the field is believed to be currently under waterflood.

Geologic Discussion

LUKoil's reserves are distributed primarily in the Western Siberian, Volga-Ural, and Timan-Pechora petroleum basins located in the western portion of the Russian Federation. Additionally, LUKoil's international reserves are located in Kazakhstan, Azerbaijan, and Egypt.

Exhibit 34 is a location map showing the Western Siberian Basin that is located approximately 1,200 miles east of Moscow and extends over an area of approximately 1.2 million square miles. The basin is bounded on the west by the Ural Mountains, on the south by the Kazakhstan plate, and on the east by the Siberian plate and is open to the north under the Kara Sea. The basement exhibits regional dip to the north and reaches a maximum depth of more than 30,000 feet under the Kara Sea. The basin is a cratonic rift basin formed during the Paleozoic Era. During the late Paleozoic and early Mesozoic eras, the basin was filled with Permian and Triassic clastics and volcanics. The basin continued to fill during the Jurassic and Cretaceous Periods with alternating cycles of marine sands and shales that provide the hydrocarbon source and prolific oil and gas reservoirs found in the basin, as shown in the stratigraphic column, included as Exhibit 47.

The *Langepas*, *Kogalym*, and *Pokachev* subsidiaries, in Exhibit 34, are located in the south-central portion of the basin where post-Triassic sediments range in thickness from 10,000 to 12,000 feet. Fields in this portion of the basin generally occur as large anticlinal structures formed by differential compaction, faulting, and small-scale tectonic movements associated with large basement blocks. These large anticlinal structures, combined with the widespread marine shales, provide the primary trapping mechanism for the prolific Jurassic and Cretaceous clastic oil reservoirs. Faulting does not appear to be an important controlling element of hydrocarbon accumulation.

Fields usually have multiple reservoirs that are found vertically stacked between the average depths of 6,000 feet and 10,000 feet. Average reservoir thickness is variable and ranges up to 50 feet. The lateral limits of oil accumulation are usually controlled by an oil-water contact, although occasional stratigraphic boundaries are noted.

The *Urai* subsidiary, in Exhibit 34, is located along the western edge of the basin near the Ural Mountains. Production is mainly from Cretaceous and Jurassic clastic reservoirs, as shown in Exhibit 47, although the depth and volume of the productive section is typically less due to thinning along the edge of the basin.

LUKoil typically provided a structure map, a net hydrocarbon isopach, a current reservoir development map, relevant logs, and supporting geologic cross sections for each reservoir in each field included in this report. When required, we made reservoir maps using reservoir data provided by LUKoil.

A typical set of LUKoil maps for a productive reservoir from a Western Siberian subsidiary is shown in Exhibits 35 through 37. The maps are a structure map, Exhibit 35; a net oil isopach map, Exhibit 36; and a current reservoir development map, Exhibit 37, for the BV3 reservoir from the Nong-Eganskoye Field. The field is located in the Western Siberian Basin in the Russian Federation and is operated by LUKoil's Pokachev subsidiary.

The bB3-1 reservoir is a Lower Cretaceous sandstone reservoir found in the field at an average depth of 7,200 feet. The reservoir has a vertical oil column of approximately 130 feet with no primary gas cap. The net thickness of the reservoir averages 24 feet over a productive area of 25.1 square miles above a reservoir-wide oil-water contact. The reservoir is unfaulted and appears to have a high degree of lateral reservoir continuity. Average reservoir parameters are 21 percent for porosity and 50 percent for oil saturation. The reservoir has been penetrated by approximately 223 wells and is one of six productive reservoirs found vertically stacked in the field. Approximately 95 percent of the proven reserves in the reservoir are currently developed.

The oil and gas fields of the *Yamalneftegazdobycha* subsidiary lie within the Bolshekhetskaya depression of the Western Siberian Basin. The fields produce from Cretaceous sandstone reservoirs ranging in depth from -1200 to – 3500 meters subsea. The sandstone reservoirs were deposited in non-marine to shelf marine environments. Hydrocarbon entrapment occurs as the reservoirs are stacked vertically on anticlinal structures. Faulting does not appear to be a significant factor controlling hydrocarbon accumulation.

LUKoil's European reserves are controlled by the *Permneft*, *ZAO LUKoil-Perm*, and *Nizhnevolzhskneft* subsidiaries in the Volga-Ural Basin, *Astrakhanneft* in the Pre-Caspian Basin, and

Kaliningradmorneft in the Baltic Basin, as shown on the location map included as Exhibit 38. The Volga-Ural Basin is located approximately 500 miles southeast of Moscow and includes a 270,000 square mile area that includes the Russian cities of Perm and Samara. The basin is a regional uplift of the east-central part of the Russian Platform and is bounded on the east by the Ural Mountains, on the south by the Pre-Caspian Basin, and on the west by the Baltic Basin. Sediments in the basin range in thickness from approximately 5,000 feet over the arches to more than 25,000 feet to the east in the Ural foredeep. The primary reservoirs in the basin are the sandstones and carbonates of Middle Devonian to Early Carboniferous age, as shown in Exhibit 47. Carbonate mounds and reefs are also found on some of the arches.

Individual oil fields are anticlinal structures that result from deep-seated tectonics and the differential compaction of sediments overlying deeper reefs. It is common for the oil fields in the basin to produce from multiple clastic and carbonate reservoirs that are vertically stacked.

The oil fields of *Permneft* and *ZAO LUKoil-Perm*, shown in Exhibit 38, are located on the Perm-Bashkir Arch in the northern part of the Volga-Ural Basin. The 6,500-foot sedimentary column is composed almost entirely of Paleozoic age clastics and carbonates, and oil-producing reservoirs are Devonian and Carboniferous sandstones and carbonates, shown in Exhibit 47. The sediments are only mildly deformed, and individual oil fields are localized on anticlinal structures.

The oil fields of *Nizhnevolzhskneft*, in Exhibit 38, are located in the southeastern portion of the Volga-Ural Basin near the city of Volgograd. Several linear trends of fields are apparent that are nearly perpendicular to regional dip into the basin. These fields were formed when oil and gas were trapped in vertically stacked clastic and carbonate reservoirs of Devonian and Carboniferous age, shown in Exhibit 47, on structural highs that were created by basement faulting. The discovery of Upper Devonian age reefs has significantly increased oil production in recent years.

The oil and gas fields of *Astrakhanneft*, in Exhibit 38, are located in the Pre-Cambrian Basin in southern Russia, near the Russian city of Astrakhan. Cretaceous and Jurassic sandstone reservoirs, in Exhibit 47, produce hydrocarbons from depths of 4,000 to 7,500 feet from gentle anticlinal structures.

The oil fields of *Kaliningradmorneft*, in Exhibit 38, are located in the eastern portion of the Baltic Basin near the city of Kaliningrad in the Russian Federation between Lithuania and Poland. The Baltic Basin is an inter-cratonic basin located in the western part of the Russian Platform. The oil is produced from early Cambrian sandstones at depths averaging 6,500 feet, as shown in Exhibit 47. The overlying Silurian deep-water shales probably provide the source for oil accumulation in the area. An offshore discovery, the D6 structure, is not currently producing, but development is expected in the near future.

A typical set of LUKoil maps for a productive reservoir from a European subsidiary is shown in Exhibits 39 through 41. The maps are a structure map, Exhibit 39; a net oil isopach map, Exhibit 40; and a current reservoir development map, Exhibit 41, for the Lower Carboniferous Turneisky reservoir from Pavlovskoye Field. The field is located in the Volga-Ural Basin in the Russian Federation and is operated by LUKoil's Permneft subsidiary.

The Turneisky reservoir is a Lower Carboniferous carbonate sandstone reservoir found in the field at an average depth of 5,000 feet. The reservoir has a vertical oil column of 154 feet with no primary gas cap. The net thickness of the reservoir averages 16 feet over a productive area of approximately 36.6 square miles above a reservoir-wide oil-water contact. The reservoir is unfaulted and has a fair degree of lateral reservoir continuity. Average reservoir parameters are 12 percent for porosity and 70 percent for oil saturation. The reservoir has been penetrated by approximately 212 wells and is one of seven productive reservoirs found vertically stacked in the field. Approximately 90 percent of the proven reserves in the reservoir are currently developed.

LUKoil's *Arkhangel* and *KomiTEK* subsidiaries, shown on the location map included as Exhibit 42, own reserves primarily in the Timan-Pechora Basin located approximately 700 miles northeast of Moscow in the northeastern portion of the Russian Federation. The triangular shaped basin covers approximately 300,000 square miles and is bounded on the east by the Ural Mountains and on the southwest by the Timan ridge and extends beneath the Barents Sea to the north.

The Timan-Pechora Basin was formed by subsidence and rifting that began during the Ordovician age. Sediments outcrop near the Timan ridge and the Ural Mountains and reach a thickness of nearly seven miles in the center of the basin. The primary oil-producing reservoirs are Middle Devonian clastics that are overlain and sourced by Domanik marine shales, shown in Exhibit 47. Additional hydrocarbon reservoirs are found in Devonian reefs and the carbonates of Carboniferous, Permian, and Triassic age.

The major oil fields in the Timan-Pechora Basin are associated with inverted structures. Uplift converted the thick sediments in the Devonian grabens into structural ridges. Most fields have been delineated by seismic.

The *Arkhangel* subsidiary, in Exhibit 42, also includes four fields located in the Baltic Basin in the subsidiary Closed Joint Stock Company Kaliningradskaya GDNGE.

Exhibits 43 through 45 are the reservoir structure map, net oil isopach map, and current reservoir development map for the P1 a+s reservoir at South Khylchuyuskoye Field. The field is owned by LUKoil's Timan-Pechora subsidiary, Arkhangelskgeoldobycha, and is located in the Timan-Pechora Basin in the northwestern part of the Russian Federation. LUKoil provided the reservoir structure map. We made the net isopach map and current reservoir development map in order to combine two reservoir net isopach maps provided by LUKoil and to create a pre-development map for the field showing the delineating exploratory wells.

The productive reservoir is a Lower Permian carbonate reef found at an average depth of 7,000 feet. The reservoir has a vertical oil column of 187 feet with no primary gas cap. The reservoir averages 89 feet of net oil thickness over a productive area of approximately 28.3 square miles above the field-wide oil-water contact. The reservoir is unfaulted but has a permeability barrier that limits the productive area on the southwest side of the field. Conventional core analysis shows the reservoir has an average porosity of 18 percent and an average oil saturation of 87 percent. The reservoir has been delineated by approximately 23 exploratory wells, 18 of which have tested oil at rates from 40 to over 5,000 barrels of oil per day. None of the proven reserves in the field are currently developed.

The Yu. Korchagina gas-condensate and oil field is located about 120 kilometers southeast of the city of Kaspiysky in the Russian sector of the *Caspian Sea*. The field, an unfaulted anticline that lies beneath 20-30 meters of water, has been delineated by two wells that were both flow tested and numerous 2-D seismic lines. The productive reservoirs, the Necomian sandstone reservoir and the upper Jurassic Volzhsky carbonate reservoir, were encountered at depths ranging from -1400 to -1550 meters subsea and cover a productive area of 28.2 square miles above the oil water contact. The field has not yet been developed, and LUKoil is currently formulating a feasibility study and development for the field and the north *Caspian Sea* area.

LUKoil has interests outside the Russian Federation in Kazakhstan, Azerbaijan, and Egypt, shown on the location map included as Exhibit 46. In Kazakhstan, LUKoil has interests in Tengiz, Karachaganak, and Kumkol Fields.

The Tengiz and Karachaganak fields are located in western Kazakhstan in the Pre-Caspian Basin. In the Tengiz Field, LUKoil participates in the *Tengizchevroil* Joint Venture where ChevronTexaco is the operator, shown in Exhibit 47. The oil reservoirs in the Tengiz Field are members of an Upper Devonian – Carboniferous reefal bioherm complex, shown in Exhibit 47. The top of the reservoir is found at a depth of approximately 12,600 feet and is unconformably capped by approximately 350 feet of Artinskian shale overlain by a thick (upwards of 3,500 feet) section of Kungurian salt. The lowest known oil currently extends approximately 5,200 feet below the top of the reservoir. The reservoir has a generally oval shape that covers approximately 155 square miles with structural highs along the eastern and northern edges. It is bounded by faults or lithological breaks moving outward from the central platform area to the flank and rim areas of the field.

LUKoil is a partner in a PSA operated by KIO (British Gas and AGIP) that controls the development and production from the Karachaganak oil and gas condensate field. The field lies within the northern edge of the Pre-Caspian Basin and is located in western Kazakhstan approximately 70 miles southwest of the Russian city of Orenburg, shown in Exhibit 46. In the area of the Karachaganak Field, the Pre-Caspian Basin is characterized with a thick sedimentary cover, salt tectonics, and approximately 23,000 feet of sedimentary fill. The reservoirs in the field are Late Carboniferous-Early Permian age reefal carbonates found at an average depth of approximately 13,000 feet, as seen in Exhibit 47. The field structure has approximately 180 square miles under closure and is broad to the east and narrow to the west with a saddle due to erosion. The gas column is approximately 4,650 feet with a condensate column of approximately 650 feet.

Kumkol Field is located in the South Turgay Basin in central Kazakhstan approximately 600 miles northwest of the city of Almaty, as shown in Exhibit 46. LUKoil is the operator of the *Kumkol-LUKoil* Contract Area located on the northern portion of the field. The field is a northwest-trending elongated anticline, bounded on the east by a fault, and contains two productive Upper Jurassic and Lower Cretaceous age clastic reservoirs at depths of approximately 3,700 feet, as seen in Exhibit 47.

LUKoil has interests in the *AIOC*-operated PSA that controls the development and production of Chirag, Azeri, and the southeast portion of Gunashli fields located offshore in the Azeri sector of the Caspian Sea, shown in Exhibit 46. The fields are located in the South Caspian Basin approximately 80 miles southeast of Baku, under water depths of approximately 300 to 650 feet. The fields occur over the Apsheron Sill, an elongated, northwest/southeast-trending anticline approximately 25 miles long and 2 to 3 miles wide. Production from the fields is from Pliocene age sands that are comprised of proximal and distal delta plain facies that exhibit very good to excellent reservoir parameters, as shown in Exhibit 47.

LUKoil has interests in eight fields in the Meleiha Development Lease operated by *LUKAgip* located in the western desert in northern Egypt, as seen in Exhibit 46. The fields produce from the Jurassic Khatatba and Cretaceous Bahariya reservoirs, as shown in Exhibit 47.

Reservoir Parameters

Exhibits 48 through 60 summarize the reservoir parameters employed in the evaluation. Each exhibit contains information for a single subsidiary, organized by field and by reservoir. The total proven and probable geologic areas, volumes, and average net pay thicknesses are listed for each reservoir. Also shown are the average porosity, oil saturation, permeability, and original reservoir pressure. Properties of the oil, including specific gravity, viscosity, formation volume factor, and solution gas-oil ratio, are included for each reservoir.

Other Considerations

Our reserve estimates and economic forecasts are based on audits of data and other work provided by LUKoil or its partners. We used independent interpretations, analyses, judgments, and sampling techniques considered appropriate to make any adjustments, as needed. For some fields, particularly the international properties, investigations were limited by the available technical or economic information or by the uncertainty of future development plans. Otherwise, we are not aware of any special factors that would materially affect this evaluation.

Future costs of restoration of producing properties to satisfy environmental standards were not deducted from total revenues as such estimates are beyond the scope of this assignment. Future costs of abandoning facilities and wells, except as provided by LUKoil, were not deducted from total revenues.

The existence of these oil and gas reserves is substantiated by evidence obtained from our site visits and is supported by a very large body of engineering, geologic, and economic data. In conducting this evaluation, we relied upon oil, gas, and water production histories; accounting and cost data; license ownership information; geological and geophysical interpretations, drilling results and other engineering data; and future drilling, recompletion, and workover schedules supplied by LUKoil. These data were accepted as represented, as verification of such data and information was beyond the scope of this assignment. In our judgment, the LUKoil technical staffs in Moscow and in the subsidiaries are well-trained, experienced, and competent professionals.

The evaluations presented in this report, with the exceptions of those parameters specified by others, reflect our informed judgments based on accepted standards of professional investigation but are subject to those generally recognized uncertainties associated with interpretation of geological, geophysical, and engineering information. Government policies and market conditions different from those employed in this study may cause the total quantity of oil or gas to be recovered, actual production rates, prices received, or operating and capital costs to vary from those presented in this report.

Miller and Lents, Ltd. is an independent oil and gas consulting firm. No director, officer, or key employee of Miller and Lents, Ltd. has any financial ownership in LUKoil or any affiliate of LUKoil. Our compensation for the required investigations and preparation of this report is not contingent on the results obtained and reported, and we have not performed other work that would affect our objectivity.

Miller and Lents, Ltd. was established in 1948, and maintains an ongoing practice of international oil and gas consulting with business offices currently located at 1100 Louisiana Street, 27th Floor, Houston, Texas, 77002-5216. Production of this report was supervised by the below-signed officers of the firm, each of whom holds a degree in engineering or geology, is professionally licensed to practice his respective profession, and has more than 20 years of relevant experience in the estimation, assessment, and evaluation of oil and gas reserves.

Yours very truly,

MILLER AND LENTS, LTD.

By James C. Pearson

James C. Pearson, Chairman
Registered Professional Engineer
State of Texas No. 63933

By William P. Koza

William P. Koza, Vice President
Registered Professional Engineer
State of Texas No. 58894

By Gregory W. Armes

Gregory W. Armes, President
Registered Professional Engineer
State of Texas No. 79622

By Michael S. Young

Michael S. Young, Senior Vice President
Certified Petroleum Geologist
American Association
of Petroleum Geologists No. 5436

LIST OF EXHIBITS


LUKOIL
Arkhangel
KomiTEK
Permneft
ZAO Perm
Langepas
Urai
Kogalym
Pokachev
KAZAKHSTAN
KYRGYZSTAN
Nizhnevolzhsk
Astrakhan
AZERBAIJAN
IRAN
IRAQ
KUWAIT
GEORGIA
ARMENIA
TURKEY
SYRIA
JORDAN
ISRAEL
LEBANON
CYPRUS
EGYPT
FINLAND
SWEDEN
NORWAY
ESTONIA
LATVIA
LITHUANIA
Kaliningrad
UKRAINE
MOLDOVA
ROMANIA
BULGARIA
MACEDONIA
GREECE
POLAND
GERMANY
CZECH REP.
SLOVAKIA
HUNGARY
AUSTRIA
YUGO.
B-H
CROATIA
SLOVENIA
ITALY
ALBANIA
MALTA
Mediterranean Sea
TUNISIA
LIBYA
DENMARK
NETH.
LUX.
LIECH.
SWITZ.
MONACO
SAN MARINO
VATICAN CITY

Exhibit 2

List of Consolidated Subsidiaries and Affiliated Companies for the Purpose of Reserve Evaluation as of December 31, 2001

Region/Company	Status under US GAAP reporting	Combined interest in consolidation, %	Reporting Interest, % [1]
West Siberia (Tyumen region)			
OOO LUKOIL-Western Siberia	Subsidiary	100.0	100.0
Including:			
TPP Kogalymneftegas	Subsidiary	100.0	100.0
TPP Uraineftegas	Subsidiary	100.0	100.0
TPP Langepasneftegas	Subsidiary	100.0	100.0
TPP Pokachevneftegas	Subsidiary	100.0	100.0
ZAO LUKOIL-AIK	Affiliate	72.4	72.4
OOO VATOIL	Subsidiary	73.0	100.0
ZAO Tursunt	Affiliate	95.0	95.0
OOO Shaimgeoneft	Subsidiary	70.0	100.0
OAO RITEK	Subsidiary	50.6	100.0
OAO Yamalneftegazdobycha	Subsidiary	60.0	100.0
OOO Goloil	Affiliate	10.0	10.0
ZAO Eranoil	Affiliate	17.5	17.5
Urals (Perm region, Republics of Tatarstan and Bashkortostan)			
OOO LUKOIL-Permneft	Subsidiary	100.0	100.0
ZAO Aksaitovneft	Subsidiary	100.0	100.0
OAO CHURS	Subsidiary	100.0	100.0
ZAO LUKOIL-Perm	Subsidiary	73.0	100.0
OOO Permtex	Affiliate	36.5	36.5
ZAO RTK (Russian fuel company)	Subsidiary	73.0	100.0
OOO Kamaneft	Subsidiary	86.3	100.0
OOO PermTOTIneft	Affiliate	36.5	36.5
OOO Visheraneftegaz	Subsidiary	73.0	100.0
OOO VNGK	Subsidiary	73.0	100.0
ZAO Maikorskoye	Subsidiary	73.0	100.0
OAO RITEK	Subsidiary	50.6	100.0
Lower Volga (Volgograd and Astrakhan regions)			
OOO LUKOIL-Nizhnevolzhskneft	Subsidiary	100.0	100.0
OOO Volgodeminoil	Affiliate	50.0	50.0
OOO LUKOIL-Astrakhanmorneft	Subsidiary	100.0	100.0
North West (Kaliningrad region)			
OOO LUKOIL-Kaliningradmorneft	Subsidiary	100.0	100.0
Northern Russia (Republic of Komi, Arkhangelsk region)			
OAO KomiTEK/Komineft	Subsidiary	99.9	100.0
ZAO Nobel Oil	Subsidiary	99.9	100.0
ZAO Bitran	Subsidiary	84.8	100.0
ZAO KomiArcticOil	Subsidiary	54.0	100.0
OAO Tebukneft	Affiliate	36.6	36.6
OOO AmKomi	Subsidiary	60.4	100.0
OAO Ukhtaneft	Affiliate	30.2	30.2
ZAO Investnaphta	Affiliate	27.0	27.0
OOO KomiQuest	Affiliate	27.0	27.0
OOO ParmaOil	Subsidiary	55.5	100.0
ZAO Bitech-Silur	Subsidiary	100.0	100.0
ZAO SeverTEK	Affiliate	49.9	49.9
OAO YANTK	Affiliate	15.2	15.2
OAO Yaregaruda	Affiliate	3.5	3.5
OAO Arkhangelskgeoldobycha (AGD)	Subsidiary	74.1	100.0
Including:			
ZAO Varandeineftegas	Subsidiary	74.1	100.0
ZAO Kaliningradskaya GDNGE	Subsidiary	74.1	100.0
ZAO Kolvageoldobycha	Subsidiary	74.1	100.0
ZAO Arcticneft	Subsidiary	74.1	100.0
OOO Bovel	Subsidiary	37.8	100.0
OOO Polar Lights	Affiliate	22.2	22.2
International (by projects)			
Tengiz (Kazakhstan)	Affiliated company (equity accounting)		2.7
Kumkol (Kazakhstan)	Affiliated company (equity accounting)		50.0
Karachaganak (Kazakhstan)	Proportionally consolidated subsidary - PSA		15.0
Azeri-Chirag (Azerbaijan)	Proportionally consolidated subsidary - PSA		10.0
Meleiha (Egypt)	Affiliated company (equity accounting) - PSA		12.0

Notes:

(1) Working interest employed for this report as instructed by Lukoil.

Exhibit 3

Oil and Gas Prices
LUKoil - Western Siberia
Langepas Subsidiary
December 2001

A. Export Oil Price (Non-CIS Countries)		**$US/Tonne**	**RR/Tonne**
Contract Price		**128.50**	**3873.00**
Less:	Transportation, Port and Customs Duties	17.92	540.00
	Export Tariffs	8.49	256.00
	Excise Tax	0.00	0.00
Total Deductions		**26.41**	**796.00**
Net Export Oil Price		**102.09**	**3077.00**
Percent Oil Exported (Yearly Average)		**38.0%**	
B. Export Oil Price (CIS Countries)		**$US/Tonne**	**RR/Tonne**
Contract Price		**115.00**	**3466.00**
Less:	Transportation, Port and Customs Duties	11.61	350.00
	Export Tariffs	8.49	256.00
	VAT	22.99	693.00
	Excise Tax	0.00	0.00
Total Deductions		**43.10**	**1299.00**
Net Export Oil Price		**71.90**	**2167.00**
Percent Oil Exported (Yearly Average)		**4.0%**	
C. Domestic Oil Price		**$US/Tonne**	**RR/Tonne**
Contract Price		**74.65**	**2250.00**
Less:	VAT	12.44	375.00
	Excise Tax	0.00	0.00
Total Deductions		**12.44**	**375.00**
Net Domestic Oil Price		**62.21**	**1875.00**
AVERAGE NET OIL PRICE		**$77.75**	**/Tonne**
		$10.56	**/Bbl**

D. Domestic Gas Price		**$US/1000m^3**	**RR/1000m^3**
Contract Price		**11.61**	**350.00**
Less:	VAT	1.92	58.00
	Excise Tax	0.00	0.00
Total Deductions		**1.92**	**58.00**
Net Domestic Gas Price		**9.69**	**292.00**
AVERAGE NET GAS PRICE		**$9.69**	**/1000m^3**
		$0.27	**/MCF**

2001 Gas Sales Volume	248,006	1000m^3
2001 Oil Sales Volume	5,841,765	Tonnes
RATIO OF GAS SALES TO OIL SALES	**0.204**	**MCF/Bbl**

Conversion Factors:

Bbl per Tonne	7.360
RR per U.S. $ (December 2001)	30.14

Oil and Gas Prices
LUKoil - Western Siberia
Urai Subsidiary
December 2001

		$US/Tonne	RR/Tonne
A. Export Oil Price (Non-CIS Countries)		**$US/Tonne**	**RR/Tonne**
Contract Price		**128.50**	**3873.00**
Less:	Transportation, Port and Customs Duties	17.92	540.00
	Export Tariffs	8.49	256.00
	Excise Tax	0.00	0.00
Total Deductions		**26.41**	**796.00**
Net Export Oil Price		**102.09**	**3077.00**
Percent Oil Exported (Yearly Average)		**38.0%**	
B. Export Oil Price (CIS Countries)		**$US/Tonne**	**RR/Tonne**
Contract Price		**115.00**	**3466.00**
Less:	Transportation, Port and Customs Duties	11.61	350.00
	Export Tariffs	8.49	256.00
	VAT	22.99	693.00
	Excise Tax	0.00	0.00
Total Deductions		**43.10**	**1299.00**
Net Export Oil Price		**71.90**	**2167.00**
Percent Oil Exported (Yearly Average)		**4.0%**	
C. Domestic Oil Price		**$US/Tonne**	**RR/Tonne**
Contract Price		**74.65**	**2250.00**
Less:	VAT	12.44	375.00
	Excise Tax	0.00	0.00
Total Deductions		**12.44**	**375.00**
Net Domestic Oil Price		**62.21**	**1875.00**
AVERAGE NET OIL PRICE		**$77.75**	**/Tonne**
		$10.40	**/Bbl**

D. Domestic Gas Price		**$US/1000m^3**	**RR/1000m^3**
Contract Price		**11.61**	**350.00**
Less:	VAT	1.92	58.00
	Excise Tax	0.00	0.00
Total Deductions		**1.92**	**58.00**
Net Domestic Gas Price		**9.69**	**292.00**
AVERAGE NET GAS PRICE		**$9.69**	**/1000m^3**
		$0.27	**/MCF**

2001 Gas Sales Volume	177,785	1000m^3
2001 Oil Sales Volume	4,538,763	Tonnes
RATIO OF GAS SALES TO OIL SALES	**0.185**	**MCF/Bbl**

Conversion Factors:

Bbl per Tonne	7.474
RR per U.S. $ (December 2001)	30.14

Oil and Gas Prices
LUKoil - Western Siberia
Urai Subsidiary
Tursunt JV
December 2001

A. Export Oil Price (Non-CIS Countries)		$US/Tonne	RR/Tonne
Contract Price		**128.00**	**3858.00**
Less:	Transportation, Port and Customs Duties	19.58	590.00
	Export Tariffs	8.49	256.00
	Excise Tax	0.00	0.00
Total Deductions		**28.07**	**846.00**
Net Export Oil Price		**99.93**	**3012.00**
Percent Oil Exported (Yearly Average)		**63.8%**	

B. Export Oil Price (CIS Countries)		$US/Tonne	RR/Tonne
Contract Price		**108.99**	**3285.00**
Less:	Transportation, Port and Customs Duties	6.64	200.00
	Export Tariffs	8.49	256.00
	VAT	18.61	561.00
	Excise Tax	0.00	0.00
Total Deductions		**33.74**	**1017.00**
Net Export Oil Price		**75.25**	**2268.00**
Percent Oil Exported (Yearly Average)		**23.3%**	

C. Domestic Oil Price		$US/Tonne	RR/Tonne
Contract Price		**75.65**	**2280.00**
Less:	VAT	12.61	380.00
	Excise Tax	0.00	0.00
Total Deductions		**12.61**	**380.00**
Net Domestic Oil Price		**63.04**	**1900.00**
AVERAGE NET OIL PRICE		**$89.42**	**/Tonne**
		$12.13	**/Bbl**

D. Domestic Gas Price		$US/1000m^3	RR/1000m^3
Contract Price		**0.00**	**0.00**
Less:	VAT	0.00	0.00
	Excise Tax	0.00	0.00
Total Deductions		**0.00**	**0.00**
Net Domestic Gas Price		**0.00**	**0.00**
AVERAGE NET GAS PRICE		**$0.00**	**/1000m^3**
		$0.00	**/MCF**

2001 Gas Sales Volume	0	1000m^3
2001 Oil Sales Volume	324,500	Tonnes
RATIO OF GAS SALES TO OIL SALES	**0.000**	**MCF/Bbl**

Conversion Factors:

Bbl per Tonne	7.375
RR per U.S. $ (December 2001)	30.14

Oil and Gas Prices
LUKoil - Western Siberia
Kogalym Subsidiary
December 2001

A. Export Oil Price (Non-CIS Countries)		**\$US/Tonne**	**RR/Tonne**
Contract Price		**128.00**	**3858.00**
Less:	Transportation, Port and Customs Duties	17.92	540.00
	Export Tariffs	8.49	256.00
	Excise Tax	0.00	0.00
Total Deductions		**26.41**	**796.00**
Net Export Oil Price		**101.59**	**3062.00**
Percent Oil Exported (Yearly Average)		**38.0%**	
B. Export Oil Price (CIS Countries)		**\$US/Tonne**	**RR/Tonne**
Contract Price		**115.00**	**3466.00**
Less:	Transportation, Port and Customs Duties	11.61	350.00
	Export Tariffs	8.49	256.00
	VAT	22.99	693.00
	Excise Tax	0.00	0.00
Total Deductions		**43.10**	**1299.00**
Net Export Oil Price		**71.90**	**2167.00**
Percent Oil Exported (Yearly Average)		**4.0%**	
C. Domestic Oil Price		**\$US/Tonne**	**RR/Tonne**
Contract Price		**74.65**	**2250.00**
Less:	VAT	12.44	375.00
	Excise Tax	0.00	0.00
Total Deductions		**12.44**	**375.00**
Net Domestic Oil Price		**62.21**	**1875.00**
AVERAGE NET OIL PRICE		**\$77.56**	**/Tonne**
		\$10.52	**/Bbl**

D. Domestic Gas Price		**\$US/1000m^3**	**RR/1000m^3**
Contract Price		**11.61**	**350.00**
Less:	VAT	1.92	58.00
	Excise Tax	0.00	0.00
Total Deductions		**1.92**	**58.00**
Net Domestic Gas Price		**9.69**	**292.00**
AVERAGE NET GAS PRICE		**\$9.69**	**/1000m^3**
		\$0.27	**/MCF**

2001 Gas Sales Volume	826,818	1000m^3
2001 Oil Sales Volume	27,289,146	Tonnes
RATIO OF GAS SALES TO OIL SALES	**0.145**	**MCF/Bbl**

Conversion Factors:

Bbl per Tonne	7.370
RR per U.S. \$ (December 2001)	30.14

Oil and Gas Prices
LUKoil - Western Siberia
Kogalym Subsidiary
AIK JV
December 2001

A. Export Oil Price (Non-CIS Countries)		**$US/Tonne**	**RR/Tonne**
Contract Price		**125.02**	**3768.00**
Less:	Transportation, Port and Customs Duties	18.94	571.00
	Export Tariffs	8.49	256.00
	Excise Tax	0.00	0.00
Total Deductions		**27.44**	**827.00**
Net Export Oil Price		**97.58**	**2941.00**
Percent Oil Exported (Yearly Average)		**40.6%**	
B. Export Oil Price (CIS Countries)		**$US/Tonne**	**RR/Tonne**
Contract Price		**115.00**	**3466.00**
Less:	Transportation, Port and Customs Duties	12.57	379.00
	Export Tariffs	8.49	256.00
	VAT	22.99	693.00
	Excise Tax	0.00	0.00
Total Deductions		**44.06**	**1328.00**
Net Export Oil Price		**70.94**	**2138.00**
Percent Oil Exported (Yearly Average)		**16.3%**	
C. Domestic Oil Price		**$US/Tonne**	**RR/Tonne**
Contract Price		**72.99**	**2200.00**
Less:	VAT	12.18	367.00
	Excise Tax	0.00	0.00
Total Deductions		**12.18**	**367.00**
Net Domestic Oil Price		**60.82**	**1833.00**
AVERAGE NET OIL PRICE		**$77.39**	**/Tonne**
		$10.21	**/Bbl**

D. Domestic Gas Price		**$US/1000m^3**	**RR/1000m^3**
Contract Price		**12.41**	**374.00**
Less:	VAT	2.06	62.00
	Excise Tax	0.00	0.00
Total Deductions		**2.06**	**62.00**
Net Domestic Gas Price		**10.35**	**312.00**
AVERAGE NET GAS PRICE		**$10.35**	**/1000m^3**
		$0.29	**/MCF**

2001 Gas Sales Volume	118,000	1000m^3
2001 Oil Sales Volume	1,908,000	Tonnes
RATIO OF GAS SALES TO OIL SALES	**0.288**	**MCF/Bbl**

Conversion Factors:

Bbl per Tonne	7.578
RR per U.S. $ (December 2001)	30.14

Oil and Gas Prices
LUKoil - Western Siberia
Kogalym Subsidiary
VATOIL JV
December 2001

		$US/Tonne	RR/Tonne
A. Export Oil Price (Non-CIS Countries)		**$US/Tonne**	**RR/Tonne**
Contract Price		**123.99**	**3737.00**
Less:	Transportation, Port and Customs Duties	17.72	534.00
	Export Tariffs	8.49	256.00
	Excise Tax	0.00	0.00
Total Deductions		**26.21**	**790.00**
Net Export Oil Price		**97.78**	**2947.00**
Percent Oil Exported (Yearly Average)		**36.6%**	
B. Export Oil Price (CIS Countries)		**$US/Tonne**	**RR/Tonne**
Contract Price		**115.00**	**3466.00**
Less:	Transportation, Port and Customs Duties	4.58	138.00
	Export Tariffs	8.49	256.00
	VAT	22.99	693.00
	Excise Tax	0.00	0.00
Total Deductions		**36.07**	**1087.00**
Net Export Oil Price		**78.93**	**2379.00**
Percent Oil Exported (Yearly Average)		**3.1%**	
C. Domestic Oil Price		**$US/Tonne**	**RR/Tonne**
Contract Price		**72.99**	**2200.00**
Less:	VAT	12.18	367.00
	Excise Tax	0.00	0.00
Total Deductions		**12.18**	**367.00**
Net Domestic Oil Price		**60.82**	**1833.00**
AVERAGE NET OIL PRICE		**$74.91**	**/Tonne**
		$10.20	**/Bbl**

D. Domestic Gas Price		**$US/1000m^3**	**RR/1000m^3**
Contract Price		**12.41**	**374.00**
Less:	VAT	2.06	62.00
	Excise Tax	0.00	0.00
Total Deductions		**2.06**	**62.00**
Net Domestic Gas Price		**10.35**	**312.00**
AVERAGE NET GAS PRICE		**$10.35**	**/1000m^3**
		$0.29	**/MCF**

2001 Gas Sales Volume	75,000	1000m^3
2001 Oil Sales Volume	2,873,924	Tonnes
RATIO OF GAS SALES TO OIL SALES	**0.126**	**MCF/Bbl**

Conversion Factors:

Bbl per Tonne	7.341
RR per U.S. $ (December 2001)	30.14

Oil and Gas Prices
Lukoil - Western Siberia
Ritek Subsidiary
Beloyarskneft NGDU
December 2001

		$US/Tonne	RR/Tonne
A. Export Oil Price (Non-CIS Countries)		**$US/Tonne**	**RR/Tonne**
Contract Price		**130.00**	**3918.20**
Less:	Transportation, Port and Customs Duties	13.04	393.00
	Export Tariffs	8.50	256.19
	Excise Tax	0.00	0.00
Total Deductions		**21.54**	**649.19**
Net Export Oil Price		**108.46**	**3269.01**
Percent Oil Exported (Yearly Average)		**40.0%**	
B. Export Oil Price (CIS Countries)		**$US/Tonne**	**RR/Tonne**
Contract Price		**115.00**	**3466.10**
Less:	Transportation, Port and Customs Duties	9.62	290.00
	Export Tariffs	8.50	256.19
	VAT	19.17	577.68
	Excise Tax	0.00	0.00
Total Deductions		**37.29**	**1123.87**
Net Export Oil Price		**77.71**	**2342.23**
Percent Oil Exported (Yearly Average)		**5.0%**	
C. Domestic Oil Price		**$US/Tonne**	**RR/Tonne**
Contract Price		**76.31**	**2300.00**
Less:	VAT	12.72	383.33
	Excise Tax	0.00	0.00
Total Deductions		**12.72**	**383.33**
Net Domestic Oil Price		**63.59**	**1916.67**
AVERAGE NET OIL PRICE		**$82.25**	**/Tonne**
		$11.04	**/Bbl**

D. Domestic Gas Price		**$US/1000m^3**	**RR/1000m^3**
Contract Price		**0.00**	**0.00**
Less:	VAT	0.00	0.00
	Excise Tax	0.00	0.00
Total Deductions		**0.00**	**0.00**
Net Domestic Gas Price		**0.00**	**0.00**
AVERAGE NET GAS PRICE		**$0.00**	**/1000m^3**
		$0.00	**/MCF**

2001 Gas Sales Volume	0	1000m^3
2001 Oil Sales Volume	0	Tonnes
RATIO OF GAS SALES TO OIL SALES	**0.000**	**MCF/Bbl**

Conversion Factors:

Bbl per Tonne	7.448
RR per U.S. $ (December 2001)	30.14

Oil and Gas Prices
Lukoil - Western Siberia
Ritek Subsidiary
Chenylneft NGDU
December 2001

		$US/Tonne	RR/Tonne
A. Export Oil Price (Non-CIS Countries)		**$US/Tonne**	**RR/Tonne**
Contract Price		**126.00**	**3797.64**
Less:	Transportation, Port and Customs Duties	13.93	420.00
	Export Tariffs	8.50	256.19
	Excise Tax	0.00	0.00
Total Deductions		**22.43**	**676.19**
Net Export Oil Price		**103.57**	**3121.45**
Percent Oil Exported (Yearly Average)		**91.9%**	
B. Export Oil Price (CIS Countries)		**$US/Tonne**	**RR/Tonne**
Contract Price		**0.00**	**0.00**
Less:	Transportation, Port and Customs Duties	0.00	0.00
	Export Tariffs	0.00	0.00
	VAT	0.00	0.00
	Excise Tax	0.00	0.00
Total Deductions		**0.00**	**0.00**
Net Export Oil Price		**0.00**	**0.00**
Percent Oil Exported (Yearly Average)		**0.0%**	
C. Domestic Oil Price		**$US/Tonne**	**RR/Tonne**
Contract Price		**74.65**	**2250.00**
Less:	VAT	12.44	375.00
	Excise Tax	0.00	0.00
Total Deductions		**12.44**	**375.00**
Net Domestic Oil Price		**62.21**	**1875.00**
AVERAGE NET OIL PRICE		**$100.22**	**/Tonne**
		$14.22	**/Bbl**

D. Domestic Gas Price		**$US/1000m^3**	**RR/1000m^3**
Contract Price		**0.00**	**0.00**
Less:	VAT	0.00	0.00
	Excise Tax	0.00	0.00
Total Deductions		**0.00**	**0.00**
Net Domestic Gas Price		**0.00**	**0.00**
AVERAGE NET GAS PRICE		**$0.00**	**/1000m^3**
		$0.00	**/MCF**

2001 Gas Sales Volume	0	1000m^3
2001 Oil Sales Volume	0	Tonnes
RATIO OF GAS SALES TO OIL SALES	**0.000**	**MCF/Bbl**

Conversion Factors:

Bbl per Tonne	7.048
RR per U.S. $ (December 2001)	30.14

Oil and Gas Prices
Lukoil - Western Siberia
Ritek Subsidiary
Ritekneft NGDU
December 2001

		$US/Tonne	RR/Tonne
A. Export Oil Price (Non-CIS Countries)		**$US/Tonne**	**RR/Tonne**
Contract Price		**126.00**	**3797.64**
Less:	Transportation, Port and Customs Duties	14.93	450.00
	Export Tariffs	8.50	256.19
	Excise Tax	0.00	0.00
Total Deductions		**23.43**	**706.19**
Net Export Oil Price		**102.57**	**3091.45**
Percent Oil Exported (Yearly Average)		**40.0%**	
B. Export Oil Price (CIS Countries)		**$US/Tonne**	**RR/Tonne**
Contract Price		**0.00**	**0.00**
Less:	Transportation, Port and Customs Duties	0.00	0.00
	Export Tariffs	0.00	0.00
	VAT	0.00	0.00
	Excise Tax	0.00	0.00
Total Deductions		**0.00**	**0.00**
Net Export Oil Price		**0.00**	**0.00**
Percent Oil Exported (Yearly Average)		**0.0%**	
C. Domestic Oil Price		**$US/Tonne**	**RR/Tonne**
Contract Price		**72.99**	**2200.00**
Less:	VAT	12.17	366.67
	Excise Tax	0.00	0.00
Total Deductions		**12.17**	**366.67**
Net Domestic Oil Price		**60.83**	**1833.33**
AVERAGE NET OIL PRICE		**$77.52**	**/Tonne**
		$10.82	**/Bbl**

		$US/1000m³	RR/1000m³
D. Domestic Gas Price		**$US/1000m^3**	**RR/1000m^3**
Contract Price		**0.00**	**0.00**
Less:	VAT	0.00	0.00
	Excise Tax	0.00	0.00
Total Deductions		**0.00**	**0.00**
Net Domestic Gas Price		**0.00**	**0.00**
AVERAGE NET GAS PRICE		**$0.00**	**/1000m^3**
		$0.00	**/MCF**

2001 Gas Sales Volume	0	1000m^3
2001 Oil Sales Volume	0	Tonnes
RATIO OF GAS SALES TO OIL SALES	**0.000**	**MCF/Bbl**

Conversion Factors:

Bbl per Tonne	7.168
RR per U.S. $ (December 2001)	30.14

Oil and Gas Prices
Lukoil - Western Siberia
Ritek Subsidiary
Tatritekneft NGDU
December 2001

A. Export Oil Price (Non-CIS Countries)		**$US/Tonne**	**RR/Tonne**
Contract Price		**125.00**	**3767.50**
Less:	Transportation, Port and Customs Duties	13.93	420.00
	Export Tariffs	8.50	256.19
	Excise Tax	0.00	0.00
Total Deductions		**22.43**	**676.19**
Net Export Oil Price		**102.57**	**3091.31**
Percent Oil Exported (Yearly Average)		**60.0%**	
B. Export Oil Price (CIS Countries)		**$US/Tonne**	**RR/Tonne**
Contract Price		**115.00**	**3466.10**
Less:	Transportation, Port and Customs Duties	3.98	120.00
	Export Tariffs	8.50	256.19
	VAT	19.17	577.68
	Excise Tax	0.00	0.00
Total Deductions		**31.65**	**953.87**
Net Export Oil Price		**83.35**	**2512.23**
Percent Oil Exported (Yearly Average)		**10.0%**	
C. Domestic Oil Price		**$US/Tonne**	**RR/Tonne**
Contract Price		**76.31**	**2300.00**
Less:	VAT	12.72	383.33
	Excise Tax	0.00	0.00
Total Deductions		**12.72**	**383.33**
Net Domestic Oil Price		**63.59**	**1916.67**
AVERAGE NET OIL PRICE		**$88.95**	**/Tonne**
		$13.05	**/Bbl**

D. Domestic Gas Price		**$US/1000m^3**	**RR/1000m^3**
Contract Price		**0.00**	**0.00**
Less:	VAT	0.00	0.00
	Excise Tax	0.00	0.00
Total Deductions		**0.00**	**0.00**
Net Domestic Gas Price		**0.00**	**0.00**
AVERAGE NET GAS PRICE		**$0.00**	**/1000m^3**
		$0.00	**/MCF**

2001 Gas Sales Volume	0	1000m^3
2001 Oil Sales Volume	0	Tonnes
RATIO OF GAS SALES TO OIL SALES	**0.000**	**MCF/Bbl**

Conversion Factors:

Bbl per Tonne	6.816
RR per U.S. $ (December 2001)	30.14

Exhibit 6

Oil and Gas Prices
LUKoil - Western Siberia
Pokachev Subsidiary
December 2001

A. Export Oil Price (Non-CIS Countries)		**$US/Tonne**	**RR/Tonne**
Contract Price		**128.50**	**3873.00**
Less:	Transportation, Port and Customs Duties	17.92	540.00
	Export Tariffs	8.49	256.00
	Excise Tax	0.00	0.00
Total Deductions		**26.41**	**796.00**
Net Export Oil Price		**102.09**	**3077.00**
Percent Oil Exported (Yearly Average)		**38.0%**	
B. Export Oil Price (CIS Countries)		**$US/Tonne**	**RR/Tonne**
Contract Price		**115.00**	**3466.00**
Less:	Transportation, Port and Customs Duties	11.61	350.00
	Export Tariffs	8.49	256.00
	VAT	22.99	693.00
	Excise Tax	0.00	0.00
Total Deductions		**43.10**	**1299.00**
Net Export Oil Price		**71.90**	**2167.00**
Percent Oil Exported (Yearly Average)		**4.0%**	
C. Domestic Oil Price		**$US/Tonne**	**RR/Tonne**
Contract Price		**74.65**	**2250.00**
Less:	VAT	12.44	375.00
	Excise Tax	0.00	0.00
Total Deductions		**12.44**	**375.00**
Net Domestic Oil Price		**62.21**	**1875.00**
AVERAGE NET OIL PRICE		**$77.75**	**/Tonne**
		$10.51	**/Bbl**

D. Domestic Gas Price		**$US/1000m^3**	**RR/1000m^3**
Contract Price		**11.61**	**350.00**
Less:	VAT	1.92	58.00
	Excise Tax	0.00	0.00
Total Deductions		**1.92**	**58.00**
Net Domestic Gas Price		**9.69**	**292.00**
AVERAGE NET GAS PRICE		**$9.69**	**/1000m^3**
		$0.27	**/MCF**

2001 Gas Sales Volume	243,410	1000m^3
2001 Oil Sales Volume	7,283,450	Tonnes
RATIO OF GAS SALES TO OIL SALES	**0.160**	**MCF/Bbl**

Conversion Factors:

Bbl per Tonne	7.395
RR per U.S. $ (December 2001)	30.14

Oil and Gas Prices
LUKoil - European Region
Nizhnevolzhskneft Subsidiary
Excluding Volgodeminoil Joint Venture
December 2001

A. Export Oil Price		**\$US/Tonne**	**RR/Tonne**
Contract Price		**129.00**	**3888.00**
Less:	Transportation, Port and Customs Duties	3.85	116.00
	Export Tariffs	8.49	256.00
	Excise Tax	0.00	0.00
Total Deductions		**12.34**	**372.00**
Net Export Oil Price		**116.66**	**3516.00**
Percent Oil Exported (Yearly Average)		**44.3%**	
B. Domestic Oil Price		**\$US/Tonne**	**RR/Tonne**
Contract Price		**74.65**	**2250.00**
Less:	VAT	12.44	375.00
	Excise Tax	0.00	0.00
Total Deductions		**12.44**	**375.00**
Net Domestic Oil Price		**62.21**	**1875.00**
AVERAGE NET OIL PRICE		**\$86.33**	**/Tonne**
		\$11.39	**/Bbl**

C. Domestic Gas Price		**\$US/1000m^3**	**RR/1000m^3**
Contract Price		**13.93**	**420.00**
Less:	VAT	2.32	70.00
	Excise Tax	0.00	0.00
Total Deductions		**2.32**	**70.00**
Net Domestic Gas Price		**11.61**	**350.00**
AVERAGE NET GAS PRICE		**\$11.61**	**/1000m^3**
		\$0.33	**/MCF**

Gas Sales Volume	113,226	1000m^3
Oil Sales Volume	2,827,136	Tonnes
RATIO OF GAS SALES TO OIL SALES	**0.187**	**MCF/Bbl**

Conversion Factors:

Bbl per Tonne	7.578
RR per U.S. \$ (December 2000)	30.14

Oil and Gas Prices
LUKoil - European Region
Nizhnevolzhskneft Subsidiary
Volgodeminoil JV
December 2001

A. Export Oil Price	**$US/Tonne**	**RR/Tonne**
Contract Price	**128.00**	**3858.00**
Less: Transportation, Port and Customs Duties	6.64	200.00
Export Tariffs	8.49	256.00
Excise Tax	0.00	0.00
Total Deductions	**15.13**	**456.00**
Net Export Oil Price	**112.87**	**3402.00**
Percent Oil Exported (Yearly Average)	**41.0%**	
B. Domestic Oil Price	**$US/Tonne**	**RR/Tonne**
Contract Price	**74.65**	**2250.00**
Less: VAT	12.44	375.00
Excise Tax	0.00	0.00
Total Deductions	**12.44**	**375.00**
Net Domestic Oil Price	**62.21**	**1875.00**
AVERAGE NET OIL PRICE	**$82.98**	**/Tonne**
	$10.90	**/Bbl**

C. Domestic Gas Price	**$US/1000m^3**	**RR/1000m^3**
Contract Price	**10.95**	**330.00**
Less: VAT	1.82	55.00
Excise Tax	0.00	0.00
Total Deductions	**1.82**	**55.00**
Net Domestic Gas Price	**9.12**	**275.00**
AVERAGE NET GAS PRICE	**$9.12**	**/1000m^3**
	$0.26	**/MCF**

Gas Sales Volume	65,000	1000m^3
Oil Sales Volume	436,000	Tonnes
RATIO OF GAS SALES TO OIL SALES	**0.692**	**MCF/Bbl**

Conversion Factors:

Bbl per Tonne	7.612
RR per U.S. $ (December 2000)	30.14

Oil and Gas Prices
LUKoil - European Region
LUKoil-Permneft
December 2001

A. Export Oil Price (non-CIS Countries)		$US/Tonne	RR/Tonne
Contract Price		**124.00**	**3737.36**
Less:	Transportation, Port and Customs Duties	14.27	430.00
	Export Tariffs	8.50	256.19
	Excise Tax	0.00	0.00
Total Deductions		**22.77**	**686.19**
Net Export Oil Price		**101.23**	**3051.17**
Percent Oil Exported (Yearly Average)		**31.3%**	

B. Export Oil Price (CIS Countries)		$US/Tonne	RR/Tonne
Contract Price		**0.00**	**0.00**
Less:	Transportation, Port and Customs Duties	0.00	0.00
	Export Tariffs	0.00	0.00
	VAT	0.00	0.00
	Excise Tax	0.00	0.00
Total Deductions		**0.00**	**0.00**
Net Export Oil Price		**0.00**	**0.00**
Percent Oil Exported (Yearly Average)		**0.0%**	

C. Domestic Oil Price		$US/Tonne	RR/Tonne
Contract Price		**72.99**	**2200.00**
Less:	VAT	12.17	366.67
	Excise Tax	0.00	0.00
Total Deductions		**12.17**	**366.67**
Net Domestic Oil Price		**60.83**	**1833.33**
AVERAGE NET OIL PRICE		**$73.47**	**/Tonne**
		$10.30	**/Bbl**

D. Domestic Gas Price - Oil Related Gas		$US/1000m^3	RR/1000m^3
Contract Price		**13.79**	**415.77**
Less:	VAT	2.30	69.30
	Excise Tax	0.00	0.00
Total Deductions		**2.30**	**69.30**
Net Domestic Gas Price		**11.50**	**346.48**
AVERAGE OIL-RELATED GAS NET GAS PRICE		**$11.50**	**/1000m^3**
		$0.33	**/MCF**

E. Domestic Gas Price - Free Natural Gas		$US/1000m^3	RR/1000m^3
Contract Price		**16.36**	**492.98**
Less:	VAT	2.73	82.16
	Excise Tax	0.00	0.00
Total Deductions		**2.73**	**82.16**
Net Domestic Gas Price		**13.63**	**410.82**
AVERAGE FREE NATURAL GAS NET GAS PRICE		**$13.63**	**/1000m^3**
		$0.39	**/MCF**

Gas Sales Volume	139,150	1000m^3
Oil Sales Volume	5,336,000	Tonnes
RATIO OF GAS SALES TO OIL SALES	**0.129**	**MCF/Bbl**

Conversion Factors:

Oil and Gas Prices
LUKoil - European Region
LUKoil-Permneft
Aksaitovneft JV
December 2001

		$US/Tonne	RR/Tonne
A. Export Oil Price (non-CIS Countries)		**$US/Tonne**	**RR/Tonne**
Contract Price		**124.00**	**3737.36**
Less:	Transportation, Port and Customs Duties	14.07	424.00
	Export Tariffs	8.50	256.19
	Excise Tax	0.00	0.00
Total Deductions		**22.57**	**680.19**
Net Export Oil Price		**101.43**	**3057.17**
Percent Oil Exported (Yearly Average)		**34.4%**	
B. Export Oil Price (CIS Countries)		**$US/Tonne**	**RR/Tonne**
Contract Price		**0.00**	**0.00**
Less:	Transportation, Port and Customs Duties	0.00	0.00
	Export Tariffs	0.00	0.00
	VAT	0.00	0.00
	Excise Tax	0.00	0.00
Total Deductions		**0.00**	**0.00**
Net Export Oil Price		**0.00**	**0.00**
Percent Oil Exported (Yearly Average)		**0.0%**	
C. Domestic Oil Price		**$US/Tonne**	**RR/Tonne**
Contract Price		**72.99**	**2200.00**
Less:	VAT	12.17	366.67
	Excise Tax	0.00	0.00
Total Deductions		**12.17**	**366.67**
Net Domestic Oil Price		**60.83**	**1833.33**
AVERAGE NET OIL PRICE		**$74.80**	**/Tonne**
		$10.51	**/Bbl**

		$US/1000m^3	RR/1000m^3
D. Domestic Gas Price		**$US/1000m^3**	**RR/1000m^3**
Contract Price		**14.47**	**436.10**
Less:	VAT	2.41	72.68
	Excise Tax	0.00	0.00
Total Deductions		**2.41**	**72.68**
Net Domestic Gas Price		**12.06**	**363.42**
AVERAGE NET GAS PRICE		**$12.06**	**/1000m^3**
		$0.34	**/MCF**

Gas Sales Volume	2,748	1000m^3
Oil Sales Volume	101,431	Tonnes
RATIO OF GAS SALES TO OIL SALES	**0.134**	**MCF/Bbl**

Conversion Factors:

Bbl per Tonne	7.116
RR per U.S. $ (December 2001)	30.14

Oil and Gas Prices
LUKoil - European Region
LUKoil-Permneft
Churs JV
December 2001

A. Export Oil Price (non-CIS Countries)		$US/Tonne	RR/Tonne
Contract Price		**124.00**	**3737.36**
Less:	Transportation, Port and Customs Duties	14.10	425.00
	Export Tariffs	8.50	256.19
	Excise Tax	0.00	0.00
Total Deductions		**22.60**	**681.19**
Net Export Oil Price		**101.40**	**3056.17**
Percent Oil Exported (Yearly Average)		**36.8%**	
B. Export Oil Price (CIS Countries)		**$US/Tonne**	**RR/Tonne**
Contract Price		**0.00**	**0.00**
Less:	Transportation, Port and Customs Duties	0.00	0.00
	Export Tariffs	0.00	0.00
	VAT	0.00	0.00
	Excise Tax	0.00	0.00
Total Deductions		**0.00**	**0.00**
Net Export Oil Price		**0.00**	**0.00**
Percent Oil Exported (Yearly Average)		**0.0%**	
C. Domestic Oil Price		**$US/Tonne**	**RR/Tonne**
Contract Price		**72.99**	**2200.00**
Less:	VAT	12.17	366.67
	Excise Tax	0.00	0.00
Total Deductions		**12.17**	**366.67**
Net Domestic Oil Price		**60.83**	**1833.33**
AVERAGE NET OIL PRICE		**$75.76**	**/Tonne**
		$10.96	**/Bbl**

D. Domestic Gas Price		$US/1000m³	RR/1000m³
Contract Price		**0.00**	**0.00**
Less:	VAT	0.00	0.00
	Excise Tax	0.00	0.00
Total Deductions		**0.00**	**0.00**
Net Domestic Gas Price		**0.00**	**0.00**
AVERAGE NET GAS PRICE		**$0.00**	**/1000m³**
		$0.00	**/MCF**

Gas Sales Volume	0	1000m³
Oil Sales Volume	10,533	Tonnes
RATIO OF GAS SALES TO OIL SALES	**0.000**	**MCF/Bbl**

Conversion Factors:

Bbl per Tonne	6.914
RR per U.S. $ (December 2001)	30.14

Oil and Gas Prices
LUKoil - European Region
ZAO LUKoil-Perm
December 2001

		$US/Tonne	RR/Tonne
A. Export Oil Price		**$US/Tonne**	**RR/Tonne**
Contract Price		**127.70**	**3848.88**
Less:	Transportation, Port and Customs Duties	15.23	459.00
	Export Tariffs	8.50	256.19
	Excise Tax	0.00	0.00
Total Deductions		**23.73**	**715.19**
Net Export Oil Price		**103.97**	**3133.69**
Percent Oil Exported (Yearly Average)		**34.8%**	
B. Export Oil Price (CIS Countries)		**$US/Tonne**	**RR/Tonne**
Contract Price		**115.00**	**3466.10**
Less:	Transportation, Port and Customs Duties	2.16	65.00
	Export Tariffs	8.50	256.19
	VAT	23.00	693.22
	Excise Tax	0.00	0.00
Total Deductions		**33.66**	**1014.41**
Net Export Oil Price		**81.34**	**2451.69**
Percent Oil Exported (Yearly Average)		**17.2%**	
C. Domestic Oil Price		**$US/Tonne**	**RR/Tonne**
Contract Price		**72.99**	**2200.00**
Less:	VAT	12.17	366.67
	Excise Tax	0.00	0.00
Total Deductions		**12.17**	**366.67**
Net Domestic Oil Price		**60.83**	**1833.33**
AVERAGE NET OIL PRICE		**$79.37**	**/Tonne**
		$10.73	**/Bbl**

D. Domestic Gas Price		**$US/1000m^3**	**RR/1000m^3**
Contract Price		**13.93**	**420.00**
Less:	VAT	2.32	70.00
	Excise Tax	0.00	0.00
Total Deductions		**2.32**	**70.00**
Net Domestic Gas Price		**11.61**	**350.00**
AVERAGE NET GAS PRICE		**$11.61**	**/1000m^3**
		$0.33	**/MCF**

Gas Sales Volume	215,500	1000m^3
Oil Sales Volume	2,796,308	Tonnes
RATIO OF GAS SALES TO OIL SALES	**0.368**	**MCF/Bbl**

Conversion Factors:

Bbl per Tonne	7.397
RR per U.S. $ (December 2001)	30.14

Oil and Gas Prices
LUKoil - European Region
ZAO LUKoil-Perm
Kamaneft JV
December 2001

A. Export Oil Price		**$US/Tonne**	**RR/Tonne**
Contract Price		**125.00**	**3767.50**
Less:	Transportation, Port and Customs Duties	15.23	459.00
	Export Tariffs	8.50	256.19
	Excise Tax	0.00	0.00
Total Deductions		**23.73**	**715.19**
Net Export Oil Price		**101.27**	**3052.31**
Percent Oil Exported (Yearly Average)		**44.9%**	
B. Export Oil Price (CIS Countries)		**$US/Tonne**	**RR/Tonne**
Contract Price		**114.60**	**3454.04**
Less:	Transportation, Port and Customs Duties	2.16	65.00
	Export Tariffs	8.50	256.19
	VAT	22.92	690.81
	Excise Tax	0.00	0.00
Total Deductions		**33.58**	**1012.00**
Net Export Oil Price		**81.02**	**2442.05**
Percent Oil Exported (Yearly Average)		**2.3%**	
C. Domestic Oil Price		**$US/Tonne**	**RR/Tonne**
Contract Price		**72.99**	**2200.00**
Less:	VAT	12.17	366.67
	Excise Tax	0.00	0.00
Total Deductions		**12.17**	**366.67**
Net Domestic Oil Price		**60.83**	**1833.33**
AVERAGE NET OIL PRICE		**$79.45**	**/Tonne**
		$10.49	**/Bbl**

D. Domestic Gas Price		**$US/1000m^3**	**RR/1000m^3**
Contract Price		**13.93**	**420.00**
Less:	VAT	2.32	70.00
	Excise Tax	0.00	0.00
Total Deductions		**2.32**	**70.00**
Net Domestic Gas Price		**11.61**	**350.00**
AVERAGE NET GAS PRICE		**$11.61**	**/1000m^3**
		$0.33	**/MCF**

Gas Sales Volume	50,300	1000m^3
Oil Sales Volume	432,200	Tonnes
RATIO OF GAS SALES TO OIL SALES	**0.543**	**MCF/Bbl**

Conversion Factors:

Bbl per Tonne	7.572
RR per U.S. $ (December 2001)	30.14

Oil and Gas Prices
LUKoil - European Region
ZAO LUKoil-Perm
PermTex JV
December 2001

		$US/Tonne	RR/Tonne
A. Export Oil Price		**$US/Tonne**	**RR/Tonne**
Contract Price		**126.20**	**3803.67**
Less:	Transportation, Port and Customs Duties	13.50	407.00
	Export Tariffs	8.50	256.19
	Excise Tax	0.00	0.00
Total Deductions		**22.00**	**663.19**
Net Export Oil Price		**104.20**	**3140.48**
Percent Oil Exported (Yearly Average)		**82.8%**	
B. Export Oil Price (CIS Countries)		**$US/Tonne**	**RR/Tonne**
Contract Price		**120.00**	**3616.80**
Less:	Transportation, Port and Customs Duties	6.93	209.00
	Export Tariffs	8.50	256.19
	VAT	24.00	723.36
	Excise Tax	0.00	0.00
Total Deductions		**39.43**	**1188.55**
Net Export Oil Price		**80.57**	**2428.25**
Percent Oil Exported (Yearly Average)		**8.2%**	
C. Domestic Oil Price		**$US/Tonne**	**RR/Tonne**
Contract Price		**72.99**	**2200.00**
Less:	VAT	12.17	366.67
	Excise Tax	0.00	0.00
Total Deductions		**12.17**	**366.67**
Net Domestic Oil Price		**60.83**	**1833.33**
AVERAGE NET OIL PRICE		**$98.36**	**/Tonne**
		$12.97	**/Bbl**

D. Domestic Gas Price		**$US/1000m³**	**RR/1000m³**
Contract Price		**0.00**	**0.00**
Less:	VAT	0.00	0.00
	Excise Tax	0.00	0.00
Total Deductions		**0.00**	**0.00**
Net Domestic Gas Price		**0.00**	**0.00**
AVERAGE NET GAS PRICE		**$0.00**	**/1000m³**
		$0.00	**/MCF**

Gas Sales Volume	0	1000m³
Oil Sales Volume	335,000	Tonnes
RATIO OF GAS SALES TO OIL SALES	**0.000**	**MCF/Bbl**

Conversion Factors:

Bbl per Tonne	7.583
RR per U.S. $ (December 2001)	30.14

Oil and Gas Prices
LUKoil - European Region
ZAO LUKoil-Perm
Russian Fuel Company JV
December 2001

		$US/Tonne	RR/Tonne
A. Export Oil Price		**$US/Tonne**	**RR/Tonne**
Contract Price		**125.00**	**3767.50**
Less:	Transportation, Port and Customs Duties	11.61	350.00
	Export Tariffs	8.50	256.19
	Excise Tax	0.00	0.00
Total Deductions		**20.11**	**606.19**
Net Export Oil Price		**104.89**	**3161.31**
Percent Oil Exported (Yearly Average)		**39.0%**	
B. Export Oil Price (CIS Countries)		**$US/Tonne**	**RR/Tonne**
Contract Price		**116.60**	**3514.32**
Less:	Transportation, Port and Customs Duties	6.04	182.00
	Export Tariffs	8.50	256.19
	VAT	23.32	702.86
	Excise Tax	0.00	0.00
Total Deductions		**37.86**	**1141.05**
Net Export Oil Price		**78.74**	**2373.27**
Percent Oil Exported (Yearly Average)		**3.5%**	
C. Domestic Oil Price		**$US/Tonne**	**RR/Tonne**
Contract Price		**72.99**	**2200.00**
Less:	VAT	12.17	366.67
	Excise Tax	0.00	0.00
Total Deductions		**12.17**	**366.67**
Net Domestic Oil Price		**60.83**	**1833.33**
AVERAGE NET OIL PRICE		**$78.64**	**/Tonne**
		$10.77	**/Bbl**

D. Domestic Gas Price		**$US/1000m^3**	**RR/1000m^3**
Contract Price		**13.93**	**420.00**
Less:	VAT	2.32	70.00
	Excise Tax	0.00	0.00
Total Deductions		**2.32**	**70.00**
Net Domestic Gas Price		**11.61**	**350.00**
AVERAGE NET GAS PRICE		**$11.61**	**/1000m^3**
		$0.33	**/MCF**

Gas Sales Volume	4,142	1000m^3
Oil Sales Volume	285,000	Tonnes
RATIO OF GAS SALES TO OIL SALES	**0.070**	**MCF/Bbl**

Conversion Factors:

Bbl per Tonne	7.298
RR per U.S. $ (December 2001)	30.14

Oil and Gas Prices
LUKoil - European Region
ZAO LUKoil-Perm
PermTOTIneft JV
December 2001

		$US/Tonne	RR/Tonne
A. Export Oil Price (non-CIS Countries)		**$US/Tonne**	**RR/Tonne**
Contract Price		**123.00**	**3707.22**
Less:	Transportation, Port and Customs Duties	14.83	447.00
	Export Tariffs	8.50	256.19
	Excise Tax	0.00	0.00
Total Deductions		**23.33**	**703.19**
Net Export Oil Price		**99.67**	**3004.03**
Percent Oil Exported (Yearly Average)		**37.2%**	
B. Export Oil Price (CIS Countries)		**$US/Tonne**	**RR/Tonne**
Contract Price		**97.90**	**2950.71**
Less:	Transportation, Port and Customs Duties	0.00	0.00
	Export Tariffs	8.50	256.19
	VAT	19.58	590.14
	Excise Tax	0.00	0.00
Total Deductions		**28.08**	**846.33**
Net Export Oil Price		**69.82**	**2104.37**
Percent Oil Exported (Yearly Average)		**22.9%**	
C. Domestic Oil Price		**$US/Tonne**	**RR/Tonne**
Contract Price		**69.67**	**2100.00**
Less:	VAT	11.61	350.00
	Excise Tax	0.00	0.00
Total Deductions		**11.61**	**350.00**
Net Domestic Oil Price		**58.06**	**1750.00**
AVERAGE NET OIL PRICE		**$76.23**	**/Tonne**
		$10.53	**/Bbl**

D. Domestic Gas Price		**$US/1000m^3**	**RR/1000m^3**
Contract Price		**0.00**	**0.00**
Less:	VAT	0.00	0.00
	Excise Tax	0.00	0.00
Total Deductions		**0.00**	**0.00**
Net Domestic Gas Price		**0.00**	**0.00**
AVERAGE NET GAS PRICE		**$0.00**	**/1000m^3**
		$0.00	**/MCF**

Gas Sales Volume	0	1000m^3
Oil Sales Volume	134,500	Tonnes
RATIO OF GAS SALES TO OIL SALES	**0.000**	**MCF/Bbl**

Conversion Factors:

Bbl per Tonne	7.240
RR per U.S. $ (December 2001)	30.14

Oil and Gas Prices
LUKoil - European Region
ZAO LUKoil-Perm
Maykorskoye JV
December 2001

A. Export Oil Price		**\$US/Tonne**	**RR/Tonne**
Contract Price		**129.00**	**3888.06**
Less:	Transportation, Port and Customs Duties	15.86	478.00
	Export Tariffs	8.50	256.19
	Excise Tax	0.00	0.00
Total Deductions		**24.36**	**734.19**
Net Export Oil Price		**104.64**	**3153.87**
Percent Oil Exported (Yearly Average)		**34.9%**	
B. Export Oil Price (CIS Countries)		**\$US/Tonne**	**RR/Tonne**
Contract Price		**118.00**	**3556.52**
Less:	Transportation, Port and Customs Duties	15.00	452.00
	Export Tariffs	8.50	256.19
	VAT	23.60	711.30
	Excise Tax	0.00	0.00
Total Deductions		**47.10**	**1419.49**
Net Export Oil Price		**70.90**	**2137.03**
Percent Oil Exported (Yearly Average)		**5.0%**	
C. Domestic Oil Price		**\$US/Tonne**	**RR/Tonne**
Contract Price		**77.97**	**2350.00**
Less:	VAT	12.99	391.67
	Excise Tax	0.00	0.00
Total Deductions		**12.99**	**391.67**
Net Domestic Oil Price		**64.97**	**1958.33**
AVERAGE NET OIL PRICE		**\$79.11**	**/Tonne**
		\$10.97	**/Bbl**

D. Domestic Gas Price		**\$US/1000m³**	**RR/1000m³**
Contract Price		**0.00**	**0.00**
Less:	VAT	0.00	0.00
	Excise Tax	0.00	0.00
Total Deductions		**0.00**	**0.00**
Net Domestic Gas Price		**0.00**	**0.00**
AVERAGE NET GAS PRICE		**\$0.00**	**/1000m³**
		\$0.00	**/MCF**

Gas Sales Volume	0	1000m³
Oil Sales Volume	24,440	Tonnes
RATIO OF GAS SALES TO OIL SALES	**0.000**	**MCF/Bbl**

Conversion Factors:

Bbl per Tonne	7.213
RR per U.S. \$ (December 2001)	30.14

Oil and Gas Prices
LUKoil - European Region
ZAO LUKoil-Perm
VNGK JV
December 2001

		$US/Tonne	RR/Tonne
A. Export Oil Price		**$US/Tonne**	**RR/Tonne**
Contract Price		**126.00**	**3797.64**
Less:	Transportation, Port and Customs Duties	11.38	343.00
	Export Tariffs	8.50	256.19
	Excise Tax	0.00	0.00
Total Deductions		**19.88**	**599.19**
Net Export Oil Price		**106.12**	**3198.45**
Percent Oil Exported (Yearly Average)		**45.5%**	
B. Export Oil Price (CIS Countries)		**$US/Tonne**	**RR/Tonne**
Contract Price		**0.00**	**0.00**
Less:	Transportation, Port and Customs Duties	0.00	0.00
	Export Tariffs	0.00	0.00
	VAT	0.00	0.00
	Excise Tax	0.00	0.00
Total Deductions		**0.00**	**0.00**
Net Export Oil Price		**0.00**	**0.00**
Percent Oil Exported (Yearly Average)		**0.0%**	
C. Domestic Oil Price		**$US/Tonne**	**RR/Tonne**
Contract Price		**79.63**	**2400.00**
Less:	VAT	13.27	400.00
	Excise Tax	0.00	0.00
Total Deductions		**13.27**	**400.00**
Net Domestic Oil Price		**66.36**	**2000.00**
AVERAGE NET OIL PRICE		**$84.45**	**/Tonne**
		$10.87	**/Bbl**

D. Domestic Gas Price		**$US/1000m^3**	**RR/1000m^3**
Contract Price		**16.19**	**488.00**
Less:	VAT	2.70	81.33
	Excise Tax	0.00	0.00
Total Deductions		**2.70**	**81.33**
Net Domestic Gas Price		**13.49**	**406.67**
AVERAGE NET GAS PRICE		**$13.49**	**/1000m^3**
		$0.38	**/MCF**

Gas Sales Volume	0	1000m^3
Oil Sales Volume	47,211	Tonnes
RATIO OF GAS SALES TO OIL SALES	**0.000**	**MCF/Bbl**

Conversion Factors:

Bbl per Tonne	7.767
RR per U.S. $ (December 2001)	30.14

Oil and Gas Prices
LUKoil - European Region
ZAO LUKoil-Perm
Visheraneftegas JV
December 2001

		$US/Tonne	RR/Tonne
A. Export Oil Price		**$US/Tonne**	**RR/Tonne**
Contract Price		**127.00**	**3827.78**
Less:	Transportation, Port and Customs Duties	18.61	561.00
	Export Tariffs	8.50	256.19
	Excise Tax	0.00	0.00
Total Deductions		**27.11**	**817.19**
Net Export Oil Price		**99.89**	**3010.59**
Percent Oil Exported (Yearly Average)		**50.0%**	
B. Export Oil Price (CIS Countries)		**$US/Tonne**	**RR/Tonne**
Contract Price		**0.00**	**0.00**
Less:	Transportation, Port and Customs Duties	0.00	0.00
	Export Tariffs	0.00	0.00
	VAT	0.00	0.00
	Excise Tax	0.00	0.00
Total Deductions		**0.00**	**0.00**
Net Export Oil Price		**0.00**	**0.00**
Percent Oil Exported (Yearly Average)		**0.0%**	
C. Domestic Oil Price		**$US/Tonne**	**RR/Tonne**
Contract Price		**76.31**	**2300.00**
Less:	VAT	12.72	383.33
	Excise Tax	0.00	0.00
Total Deductions		**12.72**	**383.33**
Net Domestic Oil Price		**63.59**	**1916.67**
AVERAGE NET OIL PRICE		**$81.74**	**/Tonne**
		$10.60	**/Bbl**

D. Domestic Gas Price		**$US/1000m^3**	**RR/1000m^3**
Contract Price		**13.93**	**420.00**
Less:	VAT	2.32	70.00
	Excise Tax	0.00	0.00
Total Deductions		**2.32**	**70.00**
Net Domestic Gas Price		**11.61**	**350.00**
AVERAGE NET GAS PRICE		**$11.61**	**/1000m^3**
		$0.33	**/MCF**

Gas Sales Volume	0	1000m^3
Oil Sales Volume	30,797	Tonnes
RATIO OF GAS SALES TO OIL SALES	**0.000**	**MCF/Bbl**

Conversion Factors:

Bbl per Tonne	7.713
RR per U.S. $ (December 2001)	30.14

Exhibit 10

Oil and Gas Prices
LUKoil - European Region
Astrakhanneft Subsidiary
December 2001

A. Export Oil Price		**\$US/Tonne**	**RR/Tonne**
Contract Price		**0.00**	**0.00**
Less:	Transportation, Port and Customs Duties	0.00	0.00
	Export Tariffs	0.00	0.00
	Excise Tax	0.00	0.00
Total Deductions		**0.00**	**0.00**
Net Export Oil Price		**0.00**	**0.00**
Percent Oil Exported (Yearly Average)		**0.0%**	

B. Domestic Oil Price		**\$US/Tonne**	**RR/Tonne**
Contract Price		**109.49**	**3300.00**
Less:	VAT	18.25	550.00
	Excise Tax	0.00	0.00
Total Deductions		**18.25**	**550.00**
Net Domestic Oil Price		**91.24**	**2750.00**
AVERAGE NET OIL PRICE		**\$91.24**	**/Tonne**
		\$11.92	**/Bbl**

C. Domestic Gas Price		**\$US/1000m³**	**RR/1000m³**
Contract Price		**12.65**	**381.31**
Less:	VAT	2.11	63.55
	Excise Tax	0.00	0.00
Total Deductions		**2.11**	**63.55**
Net Domestic Gas Price		**10.54**	**317.76**
AVERAGE NET GAS PRICE		**\$10.54**	**/1000m³**
		\$0.30	**/MCF**

Gas Sales Volume	0	$1000m^3$
Oil Sales Volume	71,714	Tonnes
RATIO OF GAS SALES TO OIL SALES	**0.000**	**MCF/Bbl**

Conversion Factors:

Bbl per Tonne	7.657
RR per U.S. \$ (December 2001)	30.14

Exhibit 11

Oil and Gas Prices
LUKoil - European Region
Kaliningradmorneft Subsidiary
December 2001

A. Export Oil Price		**$US/Tonne**	**RR/Tonne**
Contract Price		**129.99**	**3918.00**
Less:	Transportation, Port and Customs Duties	7.07	213.00
	Export Tariffs	8.49	256.00
	Excise Tax	0.00	0.00
Total Deductions		**15.56**	**469.00**
Net Export Oil Price		**114.43**	**3449.00**
Percent Oil Exported (Yearly Average)		**100.0%**	
B. Domestic Oil Price		**$US/Tonne**	**RR/Tonne**
Contract Price		**0.00**	**0.00**
Less:	VAT	0.00	0.00
	Excise Tax	0.00	0.00
Total Deductions		**0.00**	**0.00**
Net Domestic Oil Price		**0.00**	**0.00**
AVERAGE NET OIL PRICE		**$114.43**	**/Tonne**
		$15.44	**/Bbl**

C. Domestic Gas Price		**$US/1000m^3**	**RR/1000m^3**
Contract Price		**18.41**	**555.00**
Less:	VAT	3.09	93.00
	Excise Tax	0.00	0.00
Total Deductions		**3.09**	**93.00**
Net Domestic Gas Price		**15.33**	**462.00**
AVERAGE NET GAS PRICE		**$15.33**	**/1000m^3**
		$0.43	**/MCF**

Gas Sales Volume	4,104	1000m^3
Oil Sales Volume	652,000	Tonnes
RATIO OF GAS SALES TO OIL SALES	**0.030**	**MCF/Bbl**

Conversion Factors:

Bbl per Tonne	7.410
RR per U.S. $ (December 2000)	30.14

Exhibit 12

Oil and Gas Prices
Lukoil - Russian Caspian Sea
Korchagina Field
December 2001

		$US/Tonne	RR/Tonne
A. Export Oil Price (CIS Countries)		**$US/Tonne**	**RR/Tonne**
Contract Price		**129.00**	**941.70**
Less:	Transportation, Port and Customs Duties	18.00	131.40
	Export Tariffs	8.50	62.05
Total Deductions		**26.50**	**193.45**
Net Export Oil Price		**102.50**	**748.25**
Percent Oil Exported (Yearly Average)		**100.0%**	
B. Domestic Oil Price		**$US/Tonne**	**RR/Tonne**
Contract Price		**75.00**	**547.50**
Less:	VAT	12.50	91.25
	Excise Tax	0.00	0.00
Total Deductions		**12.50**	**91.25**
Net Domestic Oil Price		**62.50**	**456.25**
AVERAGE NET OIL PRICE		**$102.50**	**/Tonne**
		$14.04	**/Bbl**

		$US/1000m³	RR/1000m³
C. Export Gas Price		**$US/1000m^3**	**RR/1000m^3**
Contract Price		**92.00**	**671.60**
Less:	Transportation, Port and Customs Duties	22.00	160.60
	Export Tariffs	10.00	73.00
	Excise Tax	4.60	33.58
Total Deductions		**36.60**	**267.18**
Net Export Oil Price		**55.40**	**404.42**
Percent Oil Exported (Yearly Average)		**75.0%**	
D. Domestic Gas Price		**$US/1000m^3**	**RR/1000m^3**
Contract Price		**20.00**	**146.00**
Less:	VAT	3.30	24.09
	Excise Tax	0.00	0.00
Total Deductions		**3.30**	**24.09**
Net Domestic Gas Price		**16.70**	**121.91**
Percent Oil Exported (Yearly Average)		**25.0%**	
AVERAGE NET GAS PRICE		**$45.73**	**/1000m^3**
		$1.29	**/MCF**

Conversion Factors:

Bbl per Tonne	7.300
RR per U.S. $ (December 2001)	30.14

Exhibit 13

Oil and Gas Prices
Lukoil - Western Siberia
Yamalneftegazdobycha
December 2001

A. Export Oil Price		**$US/Tonne**	**RR/Tonne**
Contract Price		**136.00**	**992.80**
Less:	Transportation, Port and Customs Duties	36.00	262.80
	Export Tariffs	8.50	62.05
Total Deductions		**44.50**	**324.85**
Net Export Oil Price		**91.50**	**667.95**
Percent Oil Exported (Yearly Average)		**90.0%**	
B. Domestic Oil Price		**$US/Tonne**	**RR/Tonne**
Contract Price		**75.00**	**547.50**
Less:	VAT	12.50	91.25
	Excise Tax	0.00	0.00
Total Deductions		**12.50**	**91.25**
Net Domestic Oil Price		**62.50**	**456.25**
Percent Domestic Sales (Yearly Average)		**10.0%**	
AVERAGE NET OIL PRICE		**$88.60**	**/Tonne**
		$12.13	**/Bbl**

C. Export Gas Price		**$US/1000m^3**	**RR/1000m^3**
Contract Price		**92.00**	**671.60**
Less:	Transportation, Port and Customs Duties	22.00	160.60
	Export Tariffs	10.00	73.00
	Excise Tax	4.90	35.77
Total Deductions		**36.90**	**269.37**
Net Export Oil Price		**55.10**	**402.23**
Percent Oil Exported (Yearly Average)		**75.0%**	
D. Domestic Gas Price		**$US/1000m^3**	**RR/1000m^3**
Contract Price		**20.00**	**146.00**
Less:	VAT	3.30	24.09
	Excise Tax	0.00	0.00
Total Deductions		**3.30**	**24.09**
Net Domestic Gas Price		**16.70**	**121.91**
Percent Oil Exported (Yearly Average)		**25.0%**	
AVERAGE NET GAS PRICE		**$45.50**	**/1000m^3**
		$1.28	**/MCF**

Conversion Factors:

Bbl per Tonne	7.300
RR per U.S. $ (December 2001)	30.14

LUKoil - Arkhangel Fields
Economic Parameters

COMPANY / Code Field	Net Oil Price ($/Bbl)	Royalty Rate (%)	Operating Expenses Fixed ($/W/mo)	Operating Expenses Variable ($/BO)	Economic Limit (BOPD/W)	Drilling Cost (M$/W)	Recompl. Cost (M$/W)	Restor. Cost (M$/W)
OAO ARKHANGELSKGEOLDOBYCHA Licensed Fields								
Northern Territories								
A-01 Khylchuyuskoye	13.88	16.50	6,487	0.960	20.3	1,200	50	35
A-02 Yuzhno-Khylchuyuskoye	13.85	16.50	6,487	0.960	20.4	1,600	50	35
A-03 Yareiyuskoye	13.80	16.50	6,487	0.960	20.5	1,600	50	35
A-12 Inzyreiskoye	11.29	16.50	6,487	0.960	25.5	2,200	50	35
Other Fields								
A-13 Tabrovoyakhinskoye	13.64	16.50	6,487	0.960	20.7	2,500	50	35
A-11 named after Yuri Rossikhin	10.56	16.50	6,487	0.960	27.5	2,500	50	35
A-17 Medynskoye	13.53	16.50	6,487	0.960	20.9	2,500	50	35
A-07 Toboiskoye	13.80	16.50	6,487	0.960	20.5	2,200	50	35
A-06 Myadseiskoye	13.80	16.50	6,487	0.960	20.5	2,200	50	35
A-08 Severo-Saremboiskoye	14.05	16.50	6,487	0.960	20.1	2,000	50	35
A-16 Zapadno-Lekeiyaginskoye	14.71	16.50	6,487	0.960	19.1	1,800	50	35
A-14 Sediyaginskoye	14.71	16.50	6,487	0.960	19.1	1,600	50	35
A-15 Mezhdurechenskoye	14.88	16.50	6,487	0.960	18.9	1,200	50	35
A-18 Ust-Tolotinskoye	14.22	16.50	6,487	0.960	19.8	2,000	50	35
A-31 Perevoznaya	13.80	16.50	6,487	0.960	20.5	2,500	50	35
ZAO ARKTICNEFT								
A-09 Peschanoozerskoye	12.78	16.50	3,896	0.868	13.2	795	50	35
OOO BOVEL								
A-10 Tedinskoye	11.30	16.50	6,487	0.960	25.5	2,000	50	35
ZAO KOLVAGEOLDOBYCHA								
A-19 Vostochno-Khariyaginskoye	11.81	16.50	11,900	2.274	38.3	1,600	50	35
ZAO VARANDEINEFTEGAS								
A-04 Varandeiskoye	14.70	16.50	11,336	0.663	35.7	1,200	55	35
A-05 Toraveiskoye	14.70	16.50	11,336	0.663	28.8	1,200	55	35
ZAO KALININGRADSKAYA GDNGE								
A-20 Vostochno-Gorinskoye	13.72	16.50	10,639	1.295	34.9	1,000	55	35
A-21 Vostochno-Gorinskoye-II	13.76	16.50	10,639	1.295	34.8	1,000	55	35
A-22 Novo-Iskrinskoye	13.76	16.50	10,639	1.295	34.8	1,000	55	35
A-30 Zapadno-Rakitinskoye	13.69	16.50	1,500	1.295	4.9	1,000	55	35
OOO POLAR LIGHTS								
A-23 Oshkotynskoye	11.11	16.50	111,962	0.826	441.6	2,000	55	35
A-24 Dyusushevskoye	11.24	16.50	111,962	0.826	436.0	2,000	55	35
A-25 Vostochno-Klvinskoye	10.98	16.50	111,962	0.826	447.4	2,000	55	35
A-26 Ardalinskoye	10.89	16.50	149,282	1.101	622.6	2,000	55	35

Exhibit 14

Exhibit 15

LUKoil - Komi Republic
Economic Parameters
As of January 1, 2002

Production Association	Reporting	GOR	Conversion	Prices, $		Operating Costs, $		Royalty	Economic Limit		Capital Costs, M$		
Field Name	Interest	B/MM	Bbl/Tonne	OIL	GAS	Per Well	Per Bbl	%	Bbl/Mo	Bbl/day	Drill	Recomp	SI
AMKOMI	**100.00**	**0.000**	**7.469**	**9.82**	**0.00**	**19,100**	**2.709**	**16.50**	**3,478.6**	**116.0**	**2,230.0**	**28.2**	**0.0**
ARESSKOYE													
ARESKOYE SEVERO													
ARESSKOYE ZAPADNO													
ISAKOVSKOYE													
KYRTAYELSKOYE													
VERKHNE KOSEWSKOYE													
TYRYSHEVSKOYE													
BITECH SILUR	**100.00**	**0.000**	**7.790**	**11.80**	**0.00**	**5,844**	**1.094**	**16.50**	**667.2**	**22.2**	**1,568.0**	**66.0**	**71.7**
LEKKERSKOYE													
SUBORSKOYE													
VERKHNEAMDERMAELSKOYE													
YUZHNO KIRTAELSKOYE													
BITRAN	**100.00**	**0.000**	**6.656**	**11.11**	**0.00**	**1,550,420**	**2.446**	**16.50**	**226,973.2**	**7,565.8**	**0.0**	**0.0**	**68.8**
YAREGA													
INVESTNAPHTA	**27.00**	**0.000**	**7.417**	**12.83**	**0.00**	**7,429**	**1.272**	**16.50**	**786.9**	**26.2**	**0.0**	**0.0**	**151.6**
USINSKOYE (INVESTNAFTA)													
KHARYAGANEFT	**100.00**	**0.246**		**11.02**	**0.29**	**5,844**	**1.094**	**16.50**	**715.5**	**23.9**	**1,568.0**	**66.0**	**71.7**
KOMANDIRSKOYE													
KOMANDIRSKOYE SEVERO													
KOMANDIRSKOYE ZAPADNO													
KOMANDIRSKOYE VOSTOCHNO													
KOMIARCTIC	**100.00**	**0.747**	**7.718**	**11.92**	**0.40**	**13,623**	**0.833**	**16.50**	**1,453.9**	**48.5**	**1,557.0**	**68.8**	**68.8**
UPPER VOZEISKOYE													
KOMINEFT	**100.00**	**0.246**		**11.02**	**0.34**	**5,844**	**1.094**	**16.50**	**714.6**	**23.8**	**1,568.0**	**66.0**	**71.7**
VOIVOZVSKOYE													
KOMIQUEST	**27.00**	**0.098**	**7.461**	**10.31**	**0.39**	**4,267**	**1.220**	**16.50**	**575.0**	**19.2**	**0.0**	**0.0**	**68.8**
SEVERO VOZEISKOYE													
YUZHNO VOZEISKOYE													
KOMITEK	**100.00**	**0.246**	**7.388**	**11.02**	**0.29**	**5,844**	**1.094**	**16.50**	**715.5**	**23.9**	**1,568.0**	**66.0**	**71.7**
KHARYAGINSKOYE													
NIZHNEOMRINSKOYE													
USINSKOYE													
VERKHNEOMRINSKOYE													
ZAPADNO VOZEISKOYE													
CENTRAL VOZEISKOYE													
YUZHNO VOZEISKOYE													
KOSTYKOYE VOZEISKOYE													
NOBEL	**100.00**	**0.000**	**6.538**	**11.47**	**0.00**	**4,977**	**1.532**	**16.50**	**618.6**	**20.6**	**513.0**	**66.0**	**71.7**
OSHSKOYE (NOBEL)													
USINSKOYE (NOBEL)													
PARMANEFT	**100.00**	**0.000**	**7.305**	**11.99**	**0.00**	**5,844**	**1.094**	**16.50**	**655.3**	**21.8**	**1,568.0**	**66.0**	**71.7**
SEVERO KOZHVINSKOYE													
ZAPADNO TEREKOVEYSKOYE													
YUZHNO LYZHSKOYE													
SIGAVEISKOYE													
SEVERTEK	**49.90**	**0.000**	**7.339**	**10.62**	**0.34**	**5,844**	**1.094**	**16.50**	**751.8**	**25.1**	**553.0**	**28.2**	**0.0**
PASHSHORSKOYE													
SEVERO PASHSHORSKOYE													
YUZHNO SHAMPINSKOE													
YUZHNO YURYAKHINSKOYE													
VERKNEGRUBESHORSKOYE													
TEBUKNEFT	**45.60**	**0.647**	**7.387**	**11.25**	**0.41**	**1,371**	**0.597**	**16.50**	**152.0**	**5.1**	**305.1**	**2.3**	**8.6**
BEREGOVOYE													
DZHERSKOYE													
KYRTAYELSKOYE (OIL)													
KYRTAYELSKOYE (GAS)													
MICHAYUSKOYE													
VOSTOCHNO-MARKAYELSKOYE													
NIZHNE PASHNINSKOYE (OIL)													
NIZHNE PASHNINSKOYE (GAS)													
VERKHNE PASHNINSKOYE													
RASYUSKOYE													
SAVINOBORSKOYE													
SEVERO-SAVINOBORSKOYE													
VOSTOCHNO-SAVINOBORSKOYE													
ZAPADNO NIZHNE TEBUKSKOYE													
ZAPADNO VERKHNE TEBUKSKOYE													
UKTANEFT	**30.20**	**0.647**	**7.307**	**11.25**	**0.41**	**1,371**	**0.597**	**16.50**	**152.0**	**5.1**	**207.0**	**2.3**	**8.6**
BEZYMYANNOYE													
BOLSHEPURGOVSKOYE													
TURCHANINOVSKOYE													
ZAPADNO TURCHANINOVSKOYE													
BOROVOYE													
SREDNE KOSUSKOYE													
VOSTOCHNO KOSUSKOYE													
LENOVOSKOYE													
LUGOVOYE													
VOSTOCHNO LEMUSKOYE													
GEORGIEVSKOYE													
YANTK	**15.20**	**0.000**	**7.340**	**11.11**	**0.00**	**1,550,420**	**2.446**	**16.50**	**226,973.2**	**7,565.8**	**0.0**	**0.0**	**0.0**
YANTK MINE FIELD													

LUKoil - International Properties
Economic Parameters

Country/Field	Net Liquid Price,(1) $/Barrel	Net Gas Price, $/Mcf	Operating Expense,(2) $/Boe (4)	Capital Expense,(3) $/Boe (4)
Kazakhstan				
Tengiz/Korolev	13.85	0.28	1.86	1.51
Karachaganak	5.60 (5) 15.75 (6)	0.28 (7) 0.33 (8)	1.86	1.27
Kumkol	7.50	--(9)	1.96	0.39
Azerbaijan				
AIOC	15.10	--(10)	1.82	2.83
Egypt				
Meleiha	14.00	--(11)	3.37	--(11)

Notes:
1. Liquid refers to crude oil and condensate.
2. Operating expense includes fixed plus variable expenses.
3. Capital expense includes all well- and facility-related expenses.
4. Equivalency factor of 6 Mcf = 1 barrel of oil equivalent.
5. Liquids sales to Orenburg.
6. Liquids sales via CPC pipeline when available.
7. Contracted gas sales to Orenburg 2002-2003
8. Contracted gas sales to Orenburg 2004.
9. No gas market available.
10. All produced gas not used for operations is property of SOCAR.
11. No estimate due to lack of information provided.

Exhibit 17

LUKOIL SUBSIDIARIES

LISTED BY SUBSIDIARY AND NGDU

As of January 1, 2002

PERMNEFT SUBSIDIARY FIELDS BY NGDU

Chernushkaneft NGDU

Alnyashskoye
Aptugaiskoye
Aspenskoye
Birkenskoye
Charskoye
Chernushenskoye
Chikulayevskoye
Etyshskoye
Gondirevskoye
Krasnoyasko-Kuedinskoye
Kryazhevskoye
Kudryavtsevskoye
Moskudenskoye
Pavlovskoye
Pavlovskoye Gas
Shagerstko-Gonzhanskoye
Stepanovskoye
Sudanovskoye
Tanepskoye
Trushinkovskoye
Yuzhinskoye
Zuyatskoye

Kungurneft NGDU

Churakovskoye
Dorokhovskoye
Gabyshevskoye
Kamishlovskoye
Kazakovskoye
Kokueskoye-Gubanovskaya
Kokueskoye-Kokueskaya et al
Kokueskoye-Kokueskaya Gas
Kokueskoye-Mazuninskaya
Kokueskoye-Ordinskaya
Kurbatovskoye
Mokhovskoye
Mosinskoye
Novo-Semenskoye
Odenovskoye
Savarskoye
Sofenskoye
Soldatovskoye
Sosnovskoye
Stretenskoye
Tartenskoye
Trifonovskoye

Osinskneft NGDU

Andreyevskoye
Baklanovskoye
Batyrbaiskoye
Batyrbaiskoye Gas
Gorskoye
Kirillovskoye
Kustovskoye
Malo-Usenskoye
Mayachnoye
Osenskoye
Rassvetnoye
Shumovskoye
Tulvenskoye

ZAO PERM SUBSIDIARY FIELDS BY NGDU

Krasnokamskneft NGDU

Noshovskoye
Noshovskoye-Berezovskaya
Noshovskoye-Bugrovskaya
Noshovskoye-Opalikhinskaya
Noshovskoye-Padunskaya
Noshovskoye-Pervomayskaya
Noshovskoye-Zapadnaya
Noshovskoye-Zmeyevskaya
Shatovskoye-Gulyayevskaya
Shatovskoye-Martyuginskaya
Shatovskoye-Shatovskaya

Polaznaneft NGDU

Chashkenskoye
Karnashovskoye
Kasebskoye
Krutovskoye
Lemzerskoye
Mezhevskoye
Osokinskoye
Shershnevskoye
Sibirskoye
Ulyanovskoye
Unvenskoye
Verkhne-Sypanskoye
Yurchukskoye

NIZHNEVOLZHSKNEFT SUBSIDIARY FIELDS BY NGDU

Zirnovskoye NGDU

Bakhmetievskoye
Klenovskoye
Pamyatno-Sasovskoye
Tersinskoye
Zhirnovskoye

Korobkoyskoye NGDU

Alekseevskoye
Antilsko-Balykleiskoye
Burlukskoye
Demyanovskoye
Golubkovskoye
Korobkovskoye
Kotovskoye
Krasnoyarskoye
Levchunovskoye
Lomovskoye
Malyshevskoye
Miroshnikovskoye
Nikolinskoye
Nizhne-Korobkovskoye
Novo-Korobovskoye
Ovrazhnoye
Pamyatno-Sasovskoye
Petrovskoye
Pribrezhnoye
Sergeevskoye
Tsentralnoye
Vostochno-Umetovskoye
Yuzhno-Umetovskoye

Archedinskoye NGDU

Antonovskoye
Archedinskoye
Chukhonastovskoye
Dudachinskoye
Frolovskoye
Klushevskoye
Kovalevskoye
Kudinovskoye
Novo-Chernuchinskoye
Novo-Kochetkovskoye
Severo-Romanovskoye
Tishanskoye
Verkhne-Romanovskoye
Vostochno-Kudinovskoye
Zapadno- Kochetkovskoye
Zapadno-Romanovskoye
Zelenovskoye
Zimovskoye

KOGALYM SUBSIDIARY FIELDS BY NGDU

Kogalymneft NGDU

Yagunskoye South
Gribnoye

Druzhbaneft NGDU

Druzhnoye
Kochevskoye North
Kumali-Yagunskoye
Kustovoye
Pridorozhnoye East
North-Konitlorskoye
South-Konitlorskoye
North-Kogalymskoye
Ravenskoye
Taneyevskoye
Tevlinsko-Russinskoye

Povkhneft NGDU

Kotukhtinskoye West
Povkhovskoye
Vat Eganskoye (portion)
Vyintoiskoye South
Ust-Kotukhtinskoye

AIK JV

Kogalymskoye

Vatoil JV

Vat Eganskoye (portion)
Kochevskoye

RITEK Subsidiary

Beloyarskneft NGDU

Kislorskoye
Lenzintskoye
Salekaptskoye
Serginskoye
Sredne-khylymskoye
Srednelykhminskoye
Yuzhno-khylymskoye

Ritekchelnyneft NGDU

Kuchukovskoye
Lugovoye
Ozernoye

Ritekneft NGDU

Kurraganskoye
Vostochno perevolnoye
Vyintoiskoye

Tatritekneft NGDU

Cheremukhovskoye
Kiyazlinskoye
Melnikovskoye
Yenorusskinskoye

Exhibit 18

Operating Expenses
LUKoil - Western Siberia
Langepas Subsidiary
Full Year 2001
(Thousand U.S. Dollars)

Cost Item	Total
1. *Energy Expense*	*16,105*
2. *Water Injection*	*62,645*
3. *Field Workers' Salary*	*2,919*
4. *Social Insurance*	*1,037*
5. *Depreciation of Oil Wells*	*4,611*
6. *Transportation and Collection of Oil and Gas*	*23,620*
7. *Treatment of Oil*	*14,961*
8. *Maintenance*	*94,195*
9. *G&A cost, taxes, others*	*75,881*
10. *Inter-division services*	*-4,650*
11. *Mineral Replacement Fee (MRF)*	*31,584*
12. *Royalty (R)*	*24,973*
13. *Other Production Expenses (Excl. R & MRF)*	*0*
14. *Non-producing costs*	*281*
TOTAL OPERATING EXPENSE	**348,161**
15. *Less: MRF*	*31,584*
16. *Less: Total Depreciation*	*26,125*
17. *Less: Restoration, Recompletion, and Hydraulic Fracturing of Wells*	*49,867*
18. *Less: Royalty*	*24,973*
19. *Less: Road Tax*	*3,276*
Total Deductions	**135,825**
TOTAL NET OPERATING EXPENSE	**212,336**
Average Monthly Operating Costs, US $M:	*17,695*
Active Wells (Producers and Injectors):	*4,146*
Average Monthly Oil Production, M Tonnes:	*487*
Average Monthly Oil Production, M Barrels:	*3,586*

Operating Cost Distribution:

70.0 *Percent of Operating Costs Based on Well Count*

30.0 *Percent of Operating Costs Based on Oil Production*

Operating Cost: $\frac{17{,}694{,}636 \times 0.700}{4{,}146} =$ **$2,988** **Per Well**

$\frac{17{,}694{,}636 \times 0.300}{3{,}585{,}594} =$ **$1.48** **Per Barrel**

Conversion factor: *7.360 bbl/tonnes*

Operating Expenses
LUKoil - Western Siberia
Urai Subsidiary
Full Year 2001
(Thousand U.S. Dollars)

Cost Item	Total
1. *Energy Expense*	*11,743*
2. *Water Injection*	*39,963*
3. *Field Workers' Salary*	*2,470*
4. *Social Insurance*	*715*
5. *Depreciation of Oil Wells*	*5,845*
6. *Transportation and Collection of Oil and Gas*	*25,480*
7. *Treatment of Oil*	*7,999*
8. *Maintenance*	*58,630*
9. *G&A cost, taxes, others*	*56,394*
10. *Inter-division services*	*-2,075*
11. *Mineral Replacement Fee (MRF)*	*24,710*
12. *Royalty (R)*	*15,709*
13. *Other Production Expenses (Excl. R & MRF)*	*0*
14. *Non-producing costs*	*746*
TOTAL OPERATING EXPENSE	**248,331**
15. *Less: MRF*	*24,710*
16. *Less: Total Depreciation*	*30,088*
17. *Less: Restoration, Recompletion, and Hydraulic Fracturing of Wells*	*19,983*
18. *Less: Royalty*	*15,709*
19. *Less: Road Tax*	*2,564*
Total Deductions	**93,054**
TOTAL NET OPERATING EXPENSE	**155,278**
Average Monthly Operating Costs, US $M:	*12,940*
Active Wells (Producers and Injectors):	*2,576*
Average Monthly Oil Production, M Tonnes:	*380*
Average Monthly Oil Production, M Barrels:	*2,841*

Operating Cost Distribution:

70.0 *Percent of Operating Costs Based on Well Count*
30.0 *Percent of Operating Costs Based on Oil Production*

Operating Cost:

$$\frac{12{,}939{,}802 \times 0.700}{2{,}576} = \$3{,}516 \text{ Per Well}$$

$$\frac{12{,}939{,}802 \times 0.300}{2{,}841{,}328} = \$1.37 \text{ Per Barrel}$$

Conversion factor: *7.474 bbl/tonnes*

Operating Expenses
LUKoil - Western Siberia
Urai Subsidiary
Tursunt JV
Full Year 2001
(Thousand U.S. Dollars)

	Cost Item	Total
1.	*Energy Expense*	*185*
2.	*Water Injection*	*0*
3.	*Field Workers' Salary*	*490*
4.	*Social Insurance*	*147*
5.	*Depreciation of Oil Wells*	*865*
6.	*Transportation and Collection of Oil and Gas*	*2,037*
7.	*Treatment of Oil*	*1,058*
8.	*Maintenance*	*333*
9.	*G&A cost, taxes, others*	*853*
10.	*Inter-division services*	*0*
11.	*Mineral Replacement Fee (MRF)*	*3,676*
12.	*Royalty (R)*	*3,851*
13.	*Other Production Expenses (Excl. R & MRF)*	*2,242*
14.	*Non-producing costs*	*0*
	TOTAL OPERATING EXPENSE	**15,737**
15.	*Less: MRF*	*3,676*
16.	*Less: Total Depreciation*	*1,328*
17.	*Less: Restoration, Recompletion, and Hydraulic Fracturing of Wells*	*627*
18.	*Less: Royalty*	*3,851*
19.	*Less: Road Tax*	*406*
	Total Deductions	**9,888**
	TOTAL NET OPERATING EXPENSE	**5,849**

Average Monthly Operating Costs, US $M:	*487*
Active Wells (Producers and Injectors):	*79*
Average Monthly Oil Production, M Tonnes:	*25*
Average Monthly Oil Production, M Barrels:	*187*

Operating Cost Distribution:

70.0 *Percent of Operating Costs Based on Well Count*

30.0 *Percent of Operating Costs Based on Oil Production*

Operating Cost: $\frac{487,387 \times 0.700}{79}$ = **$4,319** **Per Well**

$\frac{487,387 \times 0.300}{186,915}$ = **$0.78** **Per Barrel**

Conversion factor: *7.375 bbl/tonnes*

Operating Expenses
LUKoil - Western Siberia
Kogalym Subsidiary
Kogalymneft NGDU
Full Year 2001
(Thousand U.S. Dollars)

Cost Item	Total
1. *Energy Expense*	*4,769*
2. *Water Injection*	*13,663*
3. *Field Workers' Salary*	*1,676*
4. *Social Insurance*	*489*
5. *Depreciation of Oil Wells*	*2,676*
6. *Transportation and Collection of Oil and Gas*	*6,220*
7. *Treatment of Oil*	*5,908*
8. *Maintenance*	*48,365*
9. *G&A cost, taxes, others*	*31,882*
10. *Inter-division services*	*-3,032*
11. *Mineral Replacement Fee (MRF)*	*32,111*
12. *Royalty (R)*	*33,247*
13. *Other Production Expenses (Excl. R & MRF)*	*4,424*
14. *Non-producing costs*	*1,316*
TOTAL OPERATING EXPENSE	**183,713**
15. *Less: MRF*	*32,111*
16. *Less: Total Depreciation*	*7,853*
17. *Less: Restoration, Recompletion, and Hydraulic Fracturing of Wells*	*9,604*
18. *Less: Royalty*	*33,247*
19. *Less: Road Tax*	*3,281*
Total Deductions	**86,097**
TOTAL NET OPERATING EXPENSE	**97,616**

Average Monthly Operating Costs, US $M:	*8,135*
Active Wells (Producers and Injectors):	*1,559*
Average Monthly Oil Production, M Tonnes:	*392*
Average Monthly Oil Production, M Barrels:	*2,910*

Operating Cost Distribution:

70.0 *Percent of Operating Costs Based on Well Count*

30.0 *Percent of Operating Costs Based on Oil Production*

Operating Cost:

$$\frac{8,134,705 \quad x \quad 0.700}{1,559} = \textbf{\$3,653} \quad \textbf{Per Well}$$

$$\frac{8,134,705 \quad x \quad 0.300}{2,910,225} = \textbf{\$0.84} \quad \textbf{Per Barrel}$$

Conversion factor: *7.431 bbl/tonnes*

Operating Expenses
LUKoil - Western Siberia
Kogalym Subsidiary
Druzhbaneft NGDU
Full Year 2001
(Thousand U.S. Dollars)

Cost Item	Total
1. *Energy Expense*	*8,653*
2. *Water Injection*	*40,563*
3. *Field Workers' Salary*	*1,612*
4. *Social Insurance*	*503*
5. *Depreciation of Oil Wells*	*17,415*
6. *Transportation and Collection of Oil and Gas*	*13,108*
7. *Treatment of Oil*	*13,062*
8. *Maintenance*	*75,134*
9. *G&A cost, taxes, others*	*66,248*
10. *Inter-division services*	*-4,612*
11. *Mineral Replacement Fee (MRF)*	*78,722*
12. *Royalty (R)*	*78,974*
13. *Other Production Expenses (Excl. R & MRF)*	*11,631*
14. *Non-producing costs*	*1,209*
TOTAL OPERATING EXPENSE	**402,223**
15. *Less: MRF*	*78,722*
16. *Less: Total Depreciation*	*34,535*
17. *Less: Restoration, Recompletion, and Hydraulic Fracturing of Wells*	*21,652*
18. *Less: Royalty*	*78,974*
19. *Less: Road Tax*	*8,292*
Total Deductions	**222,175**
TOTAL NET OPERATING EXPENSE	**180,047**
Average Monthly Operating Costs, US $M:	*15,004*
Active Wells (Producers and Injectors):	*3,971*
Average Monthly Oil Production, M Tonnes:	*1,059*
Average Monthly Oil Production, M Barrels:	*7,783*

Operating Cost Distribution:

70.0 *Percent of Operating Costs Based on Well Count*

30.0 *Percent of Operating Costs Based on Oil Production*

Operating Cost:

$$\frac{15{,}003{,}954 \times 0.700}{3{,}971} = \textbf{\$2,645 Per Well}$$

$$\frac{15{,}003{,}954 \times 0.300}{7{,}783{,}198} = \textbf{\$0.58 Per Barrel}$$

Conversion factor: *7.353 bbl/tonnes*

Exhibit 20
Page 3

Operating Expenses
LUKoil - Western Siberia
Kogalym Subsidiary
AIK JV
Full Year 2001
(Thousand U.S. Dollars)

Cost Item		Total
1.	*Energy Expense*	*874*
2.	*Water Injection*	*1,275*
3.	*Field Workers' Salary*	*198*
4.	*Social Insurance*	*53*
5.	*Depreciation of Oil Wells*	*1,666*
6.	*Transportation and Collection of Oil and Gas*	*1,872*
7.	*Treatment of Oil*	*931*
8.	*Maintenance*	*7,035*
9.	*G&A cost, taxes, others*	*19,176*
10.	*Inter-division services*	*-575*
11.	*Mineral Replacement Fee (MRF)*	*20,025*
12.	*Royalty (R)*	*18,742*
13.	*Other Production Expenses (Excl. R & MRF)*	*1,141*
14.	*Non-producing costs*	*410*
	TOTAL OPERATING EXPENSE	**72,823**
15.	*Less: MRF*	*20,025*
16.	*Less: Total Depreciation*	*4,865*
17.	*Less: Restoration, Recompletion, and Hydraulic Fracturing of Wells*	*910*
18.	*Less: Royalty*	*18,742*
19.	*Less: Road Tax*	*2,273*
	Total Deductions	**46,816**
	TOTAL NET OPERATING EXPENSE	**26,007**
	Average Monthly Operating Costs, US $M:	*2,167*
	Active Wells (Producers and Injectors):	*272*
	Average Monthly Oil Production, M Tonnes:	*155*
	Average Monthly Oil Production, M Barrels:	*1,178*

Operating Cost Distribution:

70.0 *Percent of Operating Costs Based on Well Count*

30.0 *Percent of Operating Costs Based on Oil Production*

Operating Cost:

$$\frac{2{,}167{,}258 \times 0.700}{272} = \mathbf{\$5{,}578} \quad \textbf{Per Well}$$

$$\frac{2{,}167{,}258 \times 0.300}{1{,}178{,}222} = \mathbf{\$0.55} \quad \textbf{Per Barrel}$$

Conversion factor: *7.578 bbl/tonnes*

Operating Expenses
LUKoil - Western Siberia
Kogalym Subsidiary
VATOIL JV
Full Year 2001
(Thousand U.S. Dollars)

	Cost Item	Total
1.	*Energy Expense*	*2,505*
2.	*Water Injection*	*4,098*
3.	*Field Workers' Salary*	*402*
4.	*Social Insurance*	*113*
5.	*Depreciation of Oil Wells*	*3,456*
6.	*Transportation and Collection of Oil and Gas*	*1,995*
7.	*Treatment of Oil*	*6,208*
8.	*Maintenance*	*13,930*
9.	*G&A cost, taxes, others*	*20,355*
10.	*Inter-division services*	*-905*
11.	*Mineral Replacement Fee (MRF)*	*28,579*
12.	*Royalty (R)*	*27,815*
13.	*Other Production Expenses (Excl. R & MRF)*	*13,463*
14.	*Non-producing costs*	*0*
	TOTAL OPERATING EXPENSE	**122,016**
15.	*Less: MRF*	*28,579*
16.	*Less: Total Depreciation*	*9,463*
17.	*Less: Restoration, Recompletion, and Hydraulic Fracturing of Wells*	*1,590*
18.	*Less: Royalty*	*27,815*
19.	*Less: Road Tax*	*3,202*
	Total Deductions	**70,650**
	TOTAL NET OPERATING EXPENSE	**51,366**
	Average Monthly Operating Costs, US $M:	*4,280*
	Active Wells (Producers and Injectors):	*736*
	Average Monthly Oil Production, M Tonnes:	*237*
	Average Monthly Oil Production, M Barrels:	*1,740*

Operating Cost Distribution:

70.0 *Percent of Operating Costs Based on Well Count*

30.0 *Percent of Operating Costs Based on Oil Production*

Operating Cost: $\frac{4,280,487 \times 0.700}{736}$ = **$4,071** **Per Well**

$\frac{4,280,487 \times 0.300}{1,740,221}$ = **$0.74** **Per Barrel**

Conversion factor: *7.341 bbl/tonnes*

Operating Expenses
LUKoil - Western Siberia
Kogalym Subsidiary
Povkhneft NGDU
Full Year 2001
(Thousand U.S. Dollars)

Cost Item		Total
1.	*Energy Expense*	*10,795*
2.	*Water Injection*	*68,882*
3.	*Field Workers' Salary*	*2,928*
4.	*Social Insurance*	*856*
5.	*Depreciation of Oil Wells*	*7,413*
6.	*Transportation and Collection of Oil and Gas*	*22,645*
7.	*Treatment of Oil*	*10,268*
8.	*Maintenance*	*112,743*
9.	*G&A cost, taxes, others*	*70,136*
10.	*Inter-division services*	*-5,177*
11.	*Mineral Replacement Fee (MRF)*	*63,989*
12.	*Royalty (R)*	*59,715*
13.	*Other Production Expenses (Excl. R & MRF)*	*15,497*
14.	*Non-producing costs*	*1,292*
	TOTAL OPERATING EXPENSE	**441,982**
15.	*Less: MRF*	*63,989*
16.	*Less: Total Depreciation*	*18,449*
17.	*Less: Restoration, Recompletion, and Hydraulic Fracturing of Wells*	*70,664*
18.	*Less: Royalty*	*59,715*
19.	*Less: Road Tax*	*6,707*
	Total Deductions	**219,525**
	TOTAL NET OPERATING EXPENSE	**222,457**
	Average Monthly Operating Costs, US $M:	*18,538*
	Active Wells (Producers and Injectors):	*4,038*
	Average Monthly Oil Production, M Tonnes:	*871*
	Average Monthly Oil Production, M Barrels:	*6,420*

Operating Cost Distribution:

70.0	*Percent of Operating Costs Based on Well Count*
30.0	*Percent of Operating Costs Based on Oil Production*

Operating Cost:

$$\frac{18{,}538{,}098 \times 0.700}{4{,}038} = \textbf{\$3,214} \quad \textbf{Per Well}$$

$$\frac{18{,}538{,}098 \times 0.300}{6{,}419{,}533} = \textbf{\$0.87} \quad \textbf{Per Barrel}$$

Conversion factor: *7.366 bbl/tonnes*

Operating Expenses
LUKoil - Western Siberia
Ritek Subsidiary
Beloyarskneft NGDU
Full Year 2001
(Thousand U.S. Dollars)

Cost Item	Total
1. *Energy Expense*	*179*
2. *Water Injection*	*1,484*
3. *Field Workers' Salary*	*109*
4. *Social Insurance*	*38*
5. *Depreciation of Oil Wells*	*404*
6. *Transportation and Collection of Oil and Gas*	*266*
7. *Treatment of Oil*	*468*
8. *Maintenance*	*907*
9. *G&A cost, taxes, others*	*1,554*
10. *Inter-division services*	*0*
11. *Mineral Replacement Fee (MRF)*	*526*
12. *Royalty (R)*	*828*
13. *Other Production Expenses (Excl. R & MRF)*	*1,697*
14. *Non-producing costs*	*0*
TOTAL OPERATING EXPENSE	**8,460**
15. *Less: MRF*	*526*
16. *Less: Total Depreciation*	*602*
17. *Less: Restoration, Recompletion, and Hydraulic Fracturing of Wells*	*1,523*
18. *Less: Royalty*	*828*
19. *Less: Road Tax*	*44*
20. *Less: Net Expenses Allocated to NGDUs*	*1,813*
Total Deductions	**5,335**
TOTAL NET OPERATING EXPENSE	**3,125**

Average Monthly Operating Costs, US $M:	*260*
Active Wells (Producers and Injectors):	*32*
Average Monthly Oil Production, M Tonnes:	*7*
Average Monthly Oil Production, M Barrels:	*50*

Operating Cost Distribution:

70.0 *Percent of Operating Costs Based on Well Count*
30.0 *Percent of Operating Costs Based on Oil Production*

Operating Cost: $\frac{260{,}387 \times 0.700}{32}$ = **$5,696** **Per Well**

$\frac{260{,}387 \times 0.300}{50{,}189}$ = **$1.556** **Per Barrel**

Conversion factor: *7.448 bbl/tonnes*

Operating Expenses
LUKoil - Western Siberia
Ritek Subsidiary
Chelnyneft NGDU
Full Year 2001
(Thousand U.S. Dollars)

	Cost Item	Total
1.	*Energy Expense*	44
2.	*Water Injection*	78
3.	*Field Workers' Salary*	51
4.	*Social Insurance*	57
5.	*Depreciation of Oil Wells*	80
6.	*Transportation and Collection of Oil and Gas*	162
7.	*Treatment of Oil*	112
8.	*Maintenance*	279
9.	*G&A cost, taxes, others*	563
10.	*Inter-division services*	0
11.	*Mineral Replacement Fee (MRF)*	467
12.	*Royalty (R)*	280
13.	*Other Production Expenses (Excl. R & MRF)*	14
14.	*Non-producing costs*	0
	TOTAL OPERATING EXPENSE	**2,186**
15.	*Less: MRF*	467
16.	*Less: Total Depreciation*	253
17.	*Less: Restoration, Recompletion, and Hydraulic Fracturing of Wells*	254
18.	*Less: Royalty*	280
19.	*Less: Road Tax*	43
20.	*Less: Net Expenses Allocated to NGDUs*	-112
	Total Deductions	**1,185**
	TOTAL NET OPERATING EXPENSE	**1,001**

Average Monthly Operating Costs, US $M:	83
Active Wells (Producers and Injectors):	25
Average Monthly Oil Production, M Tonnes:	3
Average Monthly Oil Production, M Barrels:	18

Operating Cost Distribution:

70.0 *Percent of Operating Costs Based on Well Count*

30.0 *Percent of Operating Costs Based on Oil Production*

Operating Cost: $\frac{83{,}450 \quad x \quad 0.700}{25}$ = **$2,337** **Per Well**

$\frac{83{,}450 \quad x \quad 0.300}{18{,}149}$ = **$1.379** **Per Barrel**

Conversion factor: *7.048 bbl/tonnes*

Operating Expenses
LUKoil - Western Siberia
Ritek Subsidiary
Ritekneft NGDU
Full Year 2001
(Thousand U.S. Dollars)

Cost Item	Total
1. *Energy Expense*	*218*
2. *Water Injection*	*182*
3. *Field Workers' Salary*	*518*
4. *Social Insurance*	*190*
5. *Depreciation of Oil Wells*	*521*
6. *Transportation and Collection of Oil and Gas*	*164*
7. *Treatment of Oil*	*163*
8. *Maintenance*	*3,037*
9. *G&A cost, taxes, others*	*1,821*
10. *Inter-division services*	*0*
11. *Mineral Replacement Fee (MRF)*	*1,939*
12. *Royalty (R)*	*1,202*
13. *Other Production Expenses (Excl. R & MRF)*	*1,231*
14. *Non-producing costs*	*0*
TOTAL OPERATING EXPENSE	**11,187**
15. *Less: MRF*	*1,939*
16. *Less: Total Depreciation*	*1,216*
17. *Less: Restoration, Recompletion, and Hydraulic Fracturing of Wells*	*149*
18. *Less: Royalty*	*1,202*
19. *Less: Road Tax*	*371*
20. *Less: Net Expenses Allocated to NGDUs*	*-580*
Total Deductions	**4,298**
TOTAL NET OPERATING EXPENSE	**6,889**
Average Monthly Operating Costs, US $M:	*574*
Active Wells (Producers and Injectors):	*43*
Average Monthly Oil Production, M Tonnes:	*13*
Average Monthly Oil Production, M Barrels:	*95*

Operating Cost Distribution:

70.0 *Percent of Operating Costs Based on Well Count*

30.0 *Percent of Operating Costs Based on Oil Production*

Operating Cost: $\frac{574{,}083 \times 0.700}{43}$ = **$9,346** **Per Well**

$\frac{574{,}083 \times 0.300}{95{,}335}$ = **$1.807** **Per Barrel**

Conversion factor: *7.168 bbl/tonnes*

Operating Expenses
LUKoil - Western Siberia
Ritek Subsidiary
Tatritekneft NGDU
Full Year 2001
(Thousand U.S. Dollars)

Cost Item		Total
1.	*Energy Expense*	223
2.	*Water Injection*	497
3.	*Field Workers' Salary*	187
4.	*Social Insurance*	67
5.	*Depreciation of Oil Wells*	1,664
6.	*Transportation and Collection of Oil and Gas*	228
7.	*Treatment of Oil*	792
8.	*Maintenance*	3,197
9.	*G&A cost, taxes, others*	1,759
10.	*Inter-division services*	0
11.	*Mineral Replacement Fee (MRF)*	3,526
12.	*Royalty (R)*	2,337
13.	*Other Production Expenses (Excl. R & MRF)*	7
14.	*Non-producing costs*	0
	TOTAL OPERATING EXPENSE	**14,484**
15.	*Less: MRF*	3,526
16.	*Less: Total Depreciation*	2,392
17.	*Less: Restoration, Recompletion, and Hydraulic Fracturing of Wells*	0
18.	*Less: Royalty*	2,337
19.	*Less: Road Tax*	422
20.	*Less: Net Expenses Allocated to NGDUs*	-1,122
	Total Deductions	**7,555**
	TOTAL NET OPERATING EXPENSE	**6,928**

Average Monthly Operating Costs, US $M:	577
Active Wells (Producers and Injectors):	180
Average Monthly Oil Production, M Tonnes:	26
Average Monthly Oil Production, M Barrels:	175

Operating Cost Distribution:

70.0 *Percent of Operating Costs Based on Well Count*

30.0 *Percent of Operating Costs Based on Oil Production*

Operating Cost: $\frac{577{,}360 \times 0.700}{180}$ = **$2,245** **Per Well**

$\frac{577{,}360 \times 0.300}{175{,}435}$ = **$0.987** **Per Barrel**

Conversion factor: *6.816 bbl/tonnes*

Exhibit 21

Operating Expenses
LUKoil - Western Siberia
Pokachev Subsidiary
Full Year 2001
(Thousand U.S. Dollars)

	Cost Item	Total
1.	*Energy Expense*	*7,148*
2.	*Water Injection*	*33,947*
3.	*Field Workers' Salary*	*1,096*
4.	*Social Insurance*	*397*
5.	*Depreciation of Oil Wells*	*5,760*
6.	*Transportation and Collection of Oil and Gas*	*13,502*
7.	*Treatment of Oil*	*8,316*
8.	*Maintenance*	*68,103*
9.	*G&A cost, taxes, others*	*50,053*
10.	*Inter-division services*	*-3,555*
11.	*Mineral Replacement Fee (MRF)*	*39,651*
12.	*Royalty (R)*	*43,728*
13.	*Other Production Expenses (Excl. R & MRF)*	*0*
14.	*Non-producing costs*	*716*
	TOTAL OPERATING EXPENSE	**268,860**
15.	*Less: MRF*	*39,651*
16.	*Less: Total Depreciation*	*17,157*
17.	*Less: Restoration, Recompletion, and Hydraulic Fracturing of Wells*	*25,888*
18.	*Less: Royalty*	*43,728*
19.	*Less: Road Tax*	*3,998*
	Total Deductions	**130,421**
	TOTAL NET OPERATING EXPENSE	**138,439**

Average Monthly Operating Costs, US $M:	*11,537*
Active Wells (Producers and Injectors):	*2,769*
Average Monthly Oil Production, M Tonnes:	*609*
Average Monthly Oil Production, M Barrels:	*4,503*

Operating Cost Distribution:

70.0 *Percent of Operating Costs Based on Well Count*

30.0 *Percent of Operating Costs Based on Oil Production*

Operating Cost: $\frac{11{,}536{,}551 \quad x \quad 0.700}{2{,}769}$ = **$2,916** **Per Well**

$\frac{11{,}536{,}551 \quad x \quad 0.300}{4{,}503{,}392}$ = **$0.77** **Per Barrel**

Conversion factor: *7.395 bbl/tonnes*

Operating Expenses
LUKoil - European Region
Nizhnevolzhskneft Subsidiary
NGDU Archedinskoye
Full Year 2001
(Thousand U.S. Dollars)

Cost Item	Total
1. *Energy Expense*	*171*
2. *Water Injection*	*634*
3. *Field Workers' Salary*	*217*
4. *Social Insurance*	*76*
5. *Depreciation of Oil Wells*	*332*
6. *Transportation and Collection of Oil and Gas*	*717*
7. *Treatment of Oil*	*552*
8. *Maintenance*	*1,641*
9. *G&A cost, taxes, others*	*3,499*
10. *Inter-division services*	*-640*
11. *Mineral Replacement Fee (MRF)*	*1,831*
12. *Royalty (R)*	*1,546*
13. *Other Production Expenses (Excl. R & MRF)*	*901*
14. *Non-producing costs*	*0*
TOTAL OPERATING EXPENSE	**11,477**
15. *Less: MRF*	*1,831*
16. *Less: Total Depreciation*	*882*
17. *Less: Restoration, Recompletion, and Hydraulic Fracturing of Wells*	*1,047*
18. *Less: Royalty*	*1,546*
19. *Less: Road Tax*	*97*
Total Deductions	**5,402**
TOTAL NET OPERATING EXPENSE	**6,076**
Average Monthly Operating Costs, US $M:	*506*
Active Wells (Producers and Injectors):	*216*
Average Monthly Oil Production, M Tonnes:	*21*
Average Monthly Oil Production, M Barrels:	*161*

Operating Cost Distribution:

70.0 *Percent of Operating Costs Based on Well Count*

30.0 *Percent of Operating Costs Based on Oil Production*

Operating Cost: $\frac{506{,}292 \times 0.700}{216}$ = **$1,641** **Per Well**

$\frac{506{,}292 \times 0.300}{161{,}063}$ = **$0.943** **Per Barrel**

Conversion factor: *7.659 bbl/tonnes*

Operating Expenses
LUKoil - European Region
Nizhnevolzhskneft Subsidiary
NGDU Zhirnovskoye
Full Year 2001
(Thousand U.S. Dollars)

Cost Item	Total
1. *Energy Expense*	*708*
2. *Water Injection*	*2,620*
3. *Field Workers' Salary*	*895*
4. *Social Insurance*	*316*
5. *Depreciation of Oil Wells*	*1,374*
6. *Transportation and Collection of Oil and Gas*	*2,965*
7. *Treatment of Oil*	*2,281*
8. *Maintenance*	*6,781*
9. *G&A cost, taxes, others*	*14,462*
10. *Inter-division services*	*-2,644*
11. *Mineral Replacement Fee (MRF)*	*7,567*
12. *Royalty (R)*	*6,390*
13. *Other Production Expenses (Excl. R & MRF)*	*3,724*
14. *Non-producing costs*	*0*
TOTAL OPERATING EXPENSE	**47,438**
15. *Less: MRF*	*7,567*
16. *Less: Total Depreciation*	*3,645*
17. *Less: Restoration, Recompletion, and Hydraulic Fracturing of Wells*	*4,326*
18. *Less: Royalty*	*6,390*
19. *Less: Road Tax*	*399*
Total Deductions	**22,327**
TOTAL NET OPERATING EXPENSE	**25,111**
Average Monthly Operating Costs, US $M:	*2,093*
Active Wells (Producers and Injectors):	*761*
Average Monthly Oil Production, M Tonnes:	*147*
Average Monthly Oil Production, M Barrels:	*1,104*

Operating Cost Distribution:

70.0 *Percent of Operating Costs Based on Well Count*

30.0 *Percent of Operating Costs Based on Oil Production*

Operating Cost: $\frac{2{,}092{,}624 \times 0.700}{761}$ = **$1,925** **Per Well**

$\frac{2{,}092{,}624 \times 0.300}{1{,}104{,}452}$ = **$0.568** **Per Barrel**

Conversion factor: *7.531 bbl/tonnes*

Operating Expenses
LUKoil - European Region
Nizhnevolzhskneft Subsidiary
NGDU Korobkovskoye
Full Year 2001
(Thousand U.S. Dollars)

Cost Item		Total
1.	*Energy Expense*	*403*
2.	*Water Injection*	*1,491*
3.	*Field Workers' Salary*	*509*
4.	*Social Insurance*	*180*
5.	*Depreciation of Oil Wells*	*782*
6.	*Transportation and Collection of Oil and Gas*	*1,687*
7.	*Treatment of Oil*	*1,298*
8.	*Maintenance*	*3,858*
9.	*G&A cost, taxes, others*	*8,229*
10.	*Inter-division services*	*-1,505*
11.	*Mineral Replacement Fee (MRF)*	*4,305*
12.	*Royalty (R)*	*3,636*
13.	*Other Production Expenses (Excl. R & MRF)*	*2,119*
14.	*Non-producing costs*	*0*
	TOTAL OPERATING EXPENSE	**26,992**
15.	*Less: MRF*	*4,305*
16.	*Less: Total Depreciation*	*2,074*
17.	*Less: Restoration, Recompletion, and Hydraulic Fracturing of Wells*	*2,461*
18.	*Less: Royalty*	*3,636*
19.	*Less: Road Tax*	*227*
	Total Deductions	**12,704**
	TOTAL NET OPERATING EXPENSE	**14,288**
	Average Monthly Operating Costs, US $M:	*1,191*
	Active Wells (Producers and Injectors):	*239*
	Average Monthly Oil Production, M Tonnes:	*83*
	Average Monthly Oil Production, M Barrels:	*631*

Operating Cost Distribution:

70.0 *Percent of Operating Costs Based on Well Count*

30.0 *Percent of Operating Costs Based on Oil Production*

Operating Cost: $\frac{1,190,696 \times 0.700}{239}$ = **$3,487** **Per Well**

$\frac{1,190,696 \times 0.300}{631,310}$ = **$0.566** **Per Barrel**

Conversion factor: *7.642 bbl/tonnes*

Operating Expenses
LUKoil - European Region
LUKoil-Permneft
Full Year 2001
(Thousand U.S. Dollars)

Cost Item		Total
1.	*Energy Expense*	*9,126*
2.	*Water Injection*	*26,882*
3.	*Field Workers' Salary*	*3,280*
4.	*Social Insurance*	*1,166*
5.	*Depreciation of Oil Wells*	*4,145*
6.	*Transportation and Collection of Oil and Gas*	*25,548*
7.	*Treatment of Oil and Gas*	*19,766*
8.	*Maintenance*	*78,449*
9.	*G&A cost, taxes, others*	*39,232*
10.	*Inter-division services*	*-2,129*
11.	*Mineral Replacement Fee (MRF)*	*37,090*
12.	*Royalty (R)*	*28,377*
13.	*Other Production Expenses (Excl. R & MRF)*	*1,164*
14.	*Non-producing costs*	*2,129*
	TOTAL OPERATING EXPENSE	**274,224**
15.	*Less: MRF*	*37,090*
16.	*Less: Total Depreciation*	*18,038*
17.	*Less: Restoration, Recompletion, and Hydraulic Fracturing of Wells*	*15,076*
18.	*Less: Royalty*	*28,377*
19.	*Less: Road Tax*	*3,790*
	Total Deductions	**102,372**
	TOTAL NET OPERATING EXPENSE	**171,852**
	Average Monthly Operating Costs, US $M:	*14,321*
	Active Wells (Producers and Injectors):	*5,946*
	Average Monthly Oil Production, M Tonnes:	*445*
	Average Monthly Oil Production, M Barrels:	*3,177*

Operating Cost Distribution:

70.0 *Percent of Operating Costs Based on Well Count*

30.0 *Percent of Operating Costs Based on Oil Production*

Operating Cost: $\frac{14{,}320{,}978 \times 0.700}{5{,}946}$ = **$1,686** **Per Well**

$\frac{14{,}320{,}978 \times 0.300}{3{,}176{,}778}$ = **$1.352** **Per Barrel**

Conversion factor: *7.132 bbl/tonnes*

Operating Expenses
LUKoil - European Region
LUKoil-Permneft
Chernushkaneft NGDU
Full Year 2001
(Thousand U.S. Dollars)

Cost Item	Total
1. *Energy Expense*	*4,003*
2. *Water Injection*	*11,793*
3. *Field Workers' Salary*	*1,439*
4. *Social Insurance*	*511*
5. *Depreciation of Oil Wells*	*1,818*
6. *Transportation and Collection of Oil and Gas*	*11,207*
7. *Treatment of Oil*	*8,671*
8. *Maintenance*	*34,413*
9. *G&A cost, taxes, others*	*17,210*
10. *Inter-division services*	*-934*
11. *Mineral Replacement Fee (MRF)*	*16,270*
12. *Royalty (R)*	*12,448*
13. *Other Production Expenses (Excl. R & MRF)*	*511*
14. *Non-producing costs*	*934*
TOTAL OPERATING EXPENSE	**120,293**
15. *Less: MRF*	*16,270*
16. *Less: Total Depreciation*	*7,913*
17. *Less: Restoration, Recompletion, and Hydraulic Fracturing of Wells*	*6,613*
18. *Less: Royalty*	*12,448*
19. *Less: Road Tax*	*1,663*
Total Deductions	**44,907**
TOTAL NET OPERATING EXPENSE	**75,386**

Average Monthly Operating Costs, US $M:	*6,282*
Active Wells (Producers and Injectors):	*2,369*
Average Monthly Oil Production, M Tonnes:	*192*
Average Monthly Oil Production, M Barrels:	*1,351*

Operating Cost Distribution:

70.0 *Percent of Operating Costs Based on Well Count*

30.0 *Percent of Operating Costs Based on Oil Production*

Operating Cost: $\frac{6,282,173 \times 0.700}{2,369}$ = **$1,856** **Per Well**

$\frac{6,282,173 \times 0.300}{1,351,186}$ = **$1.395** **Per Barrel**

Conversion factor: *7.052 bbl/tonnes*

Operating Expenses
LUKoil - European Region
LUKoil-Permneft
Chernushkaneft NGDU
Oil Wells
Full Year 2001
(Thousand U.S. Dollars)

Cost Item	Total
1. *Energy Expense*	*3,963*
2. *Water Injection*	*11,673*
3. *Field Workers' Salary*	*1,424*
4. *Social Insurance*	*506*
5. *Depreciation of Oil Wells*	*1,800*
6. *Transportation and Collection of Oil and Gas*	*11,094*
7. *Treatment of Oil*	*8,583*
8. *Maintenance*	*34,064*
9. *G&A cost, taxes, others*	*17,035*
10. *Inter-division services*	*-925*
11. *Mineral Replacement Fee (MRF)*	*16,105*
12. *Royalty (R)*	*12,322*
13. *Other Production Expenses (Excl. R & MRF)*	*505*
14. *Non-producing costs*	*925*
TOTAL OPERATING EXPENSE	**119,075**
15. *Less: MRF*	*16,105*
16. *Less: Total Depreciation*	*7,833*
17. *Less: Restoration, Recompletion, and Hydraulic Fracturing of Wells*	*6,546*
18. *Less: Royalty*	*12,322*
19. *Less: Road Tax*	*1,646*
Total Deductions	**44,452**
TOTAL NET OPERATING EXPENSE	**74,622**
Average Monthly Operating Costs, US $M:	*6,219*
Active Wells (Producers and Injectors):	*2,345*
Average Monthly Oil Production, M Tonnes:	*192*
Average Monthly Oil Production, M Barrels:	*1,351*

Operating Cost Distribution:

70.0 *Percent of Operating Costs Based on Well Count*

30.0 *Percent of Operating Costs Based on Oil Production*

Operating Cost:

$$\frac{6{,}218{,}529 \quad x \quad 0.700}{2{,}345} = \textbf{\$1,856} \quad \textbf{Per Well}$$

$$\frac{6{,}218{,}529 \quad x \quad 0.300}{1{,}351{,}186} = \textbf{\$1.381} \quad \textbf{Per Barrel}$$

Conversion factor: *7.052 bbl/tonnes*

Operating Expenses
LUKoil - European Region
LUKoil-Permneft
Chernushkaneft NGDU
Gas Wells
Full Year 2001
(Thousand U.S. Dollars)

Cost Item		Total
1.	*Energy Expense*	41
2.	*Water Injection*	119
3.	*Field Workers' Salary*	15
4.	*Social Insurance*	5
5.	*Depreciation of Oil Wells*	18
6.	*Transportation and Collection of Oil and Gas*	114
7.	*Treatment of Oil*	88
8.	*Maintenance*	349
9.	*G&A cost, taxes, others*	174
10.	*Inter-division services*	-9
11.	*Mineral Replacement Fee (MRF)*	165
12.	*Royalty (R)*	126
13.	*Other Production Expenses (Excl. R & MRF)*	5
14.	*Non-producing costs*	9
	TOTAL OPERATING EXPENSE	**1,219**
15.	*Less: MRF*	165
16.	*Less: Total Depreciation*	80
17.	*Less: Restoration, Recompletion, and Hydraulic Fracturing of Wells*	67
18.	*Less: Royalty*	126
19.	*Less: Road Tax*	17
	Total Deductions	**455**
	TOTAL NET OPERATING EXPENSE	**764**
	Average Monthly Operating Costs, US $M:	64
	Active Wells (Producers and Injectors):	24
	Average Monthly Gas Production, MM cubic meters:	4
	Average Monthly Gas Production, Mcf:	140

Operating Cost Distribution:

70.0	*Percent of Operating Costs Based on Well Count*
30.0	*Percent of Operating Costs Based on Gas Production*

Operating Cost: $\frac{63{,}644 \quad x \quad 0.700}{24}$ = **$1,856** **Per Well**

$\frac{63{,}644 \quad x \quad 0.300}{140{,}474}$ = **$0.136** **Per Mcf**

Conversion factor: *35.315 Mcf/Mm3*

Operating Expenses
LUKoil - European Region
LUKoil-Permneft
Kungurneft NGDU
Full Year 2001
(Thousand U.S. Dollars)

	Cost Item	Total
1.	*Energy Expense*	*1,570*
2.	*Water Injection*	*4,626*
3.	*Field Workers' Salary*	*564*
4.	*Social Insurance*	*201*
5.	*Depreciation of Oil Wells*	*713*
6.	*Transportation and Collection of Oil and Gas*	*4,396*
7.	*Treatment of Oil*	*3,401*
8.	*Maintenance*	*13,499*
9.	*G&A cost, taxes, others*	*6,751*
10.	*Inter-division services*	*-366*
11.	*Mineral Replacement Fee (MRF)*	*6,382*
12.	*Royalty (R)*	*4,883*
13.	*Other Production Expenses (Excl. R & MRF)*	*200*
14.	*Non-producing costs*	*366*
	TOTAL OPERATING EXPENSE	**47,188**
15.	*Less: MRF*	*6,382*
16.	*Less: Total Depreciation*	*3,104*
17.	*Less: Restoration, Recompletion, and Hydraulic Fracturing of Wells*	*2,594*
18.	*Less: Royalty*	*4,883*
19.	*Less: Road Tax*	*652*
	Total Deductions	**17,616**
	TOTAL NET OPERATING EXPENSE	**29,572**
	Average Monthly Operating Costs, US $M:	*2,464*
	Active Wells (Producers and Injectors):	*1,074*
	Average Monthly Oil Production, M Tonnes:	*84*
	Average Monthly Oil Production, M Barrels:	*619*

Operating Cost Distribution:

70.0 *Percent of Operating Costs Based on Well Count*

30.0 *Percent of Operating Costs Based on Oil Production*

Operating Cost: $\frac{2,464,329 \times 0.700}{1,074}$ = **$1,606 Per Well**

$\frac{2,464,329 \times 0.300}{618,828}$ = **$1.195 Per Barrel**

Conversion factor: *7.336 bbl/tonnes*

Operating Expenses
LUKoil - European Region
LUKoil-Permneft
Kungurneft NGDU
Oil Wells
Full Year 2001
(Thousand U.S. Dollars)

Cost Item	Total
1. *Energy Expense*	*1,537*
2. *Water Injection*	*4,527*
3. *Field Workers' Salary*	*552*
4. *Social Insurance*	*196*
5. *Depreciation of Oil Wells*	*698*
6. *Transportation and Collection of Oil and Gas*	*4,302*
7. *Treatment of Oil*	*3,328*
8. *Maintenance*	*13,210*
9. *G&A cost, taxes, others*	*6,606*
10. *Inter-division services*	*-359*
11. *Mineral Replacement Fee (MRF)*	*6,246*
12. *Royalty (R)*	*4,778*
13. *Other Production Expenses (Excl. R & MRF)*	*196*
14. *Non-producing costs*	*359*
TOTAL OPERATING EXPENSE	**46,177**
15. *Less: MRF*	*6,246*
16. *Less: Total Depreciation*	*3,038*
17. *Less: Restoration, Recompletion, and Hydraulic Fracturing of Wells*	*2,539*
18. *Less: Royalty*	*4,778*
19. *Less: Road Tax*	*638*
Total Deductions	**17,239**
TOTAL NET OPERATING EXPENSE	**28,939**
Average Monthly Operating Costs, US $M:	*2,412*
Active Wells (Producers and Injectors):	*1,051*
Average Monthly Oil Production, M Tonnes:	*84*
Average Monthly Oil Production, M Barrels:	*619*

Operating Cost Distribution:

70.0 *Percent of Operating Costs Based on Well Count*

30.0 *Percent of Operating Costs Based on Oil Production*

Operating Cost: $\frac{2,411,555 \times 0.700}{1,051}$ = **$1,606** **Per Well**

$\frac{2,411,555 \times 0.300}{618,828}$ = **$1.169** **Per Barrel**

Conversion factor: *7.336 bbl/tonnes*

Operating Expenses
LUKoil - European Region
LUKoil-Permneft
Kungurneft NGDU
Gas Wells
Full Year 2001
(Thousand U.S. Dollars)

Cost Item		Total
1.	*Energy Expense*	34
2.	*Water Injection*	99
3.	*Field Workers' Salary*	12
4.	*Social Insurance*	4
5.	*Depreciation of Oil Wells*	15
6.	*Transportation and Collection of Oil and Gas*	94
7.	*Treatment of Oil*	73
8.	*Maintenance*	289
9.	*G&A cost, taxes, others*	145
10.	*Inter-division services*	-8
11.	*Mineral Replacement Fee (MRF)*	137
12.	*Royalty (R)*	105
13.	*Other Production Expenses (Excl. R & MRF)*	4
14.	*Non-producing costs*	8
	TOTAL OPERATING EXPENSE	**1,011**
15.	*Less: MRF*	137
16.	*Less: Total Depreciation*	66
17.	*Less: Restoration, Recompletion, and Hydraulic Fracturing of Wells*	56
18.	*Less: Royalty*	105
19.	*Less: Road Tax*	14
	Total Deductions	**377**
	TOTAL NET OPERATING EXPENSE	**633**

Average Monthly Operating Costs, US $M:	53
Active Wells (Producers and Injectors):	23
Average Monthly Gas Production, MM cubic meters:	24
Average Monthly Gas Production, Mcf:	833

Operating Cost Distribution:

70.0 *Percent of Operating Costs Based on Well Count*

30.0 *Percent of Operating Costs Based on Gas Production*

Operating Cost: $\frac{52{,}774 \times 0.700}{23}$ = **$1,606** **Per Well**

$\frac{52{,}774 \times 0.300}{833{,}035}$ = **$0.019** **Per Mcf**

Conversion factor: *35.315 Mcf/Mm3*

Operating Expenses
LUKoil - European Region
LUKoil-Permneft
Osinskneft NGDU
Full Year 2001
(Thousand U.S. Dollars)

Cost Item	Total
1. *Energy Expense*	*3,552*
2. *Water Injection*	*10,464*
3. *Field Workers' Salary*	*1,277*
4. *Social Insurance*	*454*
5. *Depreciation of Oil Wells*	*1,613*
6. *Transportation and Collection of Oil and Gas*	*9,945*
7. *Treatment of Oil*	*7,694*
8. *Maintenance*	*30,536*
9. *G&A cost, taxes, others*	*15,271*
10. *Inter-division services*	*-829*
11. *Mineral Replacement Fee (MRF)*	*14,437*
12. *Royalty (R)*	*11,046*
13. *Other Production Expenses (Excl. R & MRF)*	*453*
14. *Non-producing costs*	*829*
TOTAL OPERATING EXPENSE	**106,742**
15. *Less: MRF*	*14,437*
16. *Less: Total Depreciation*	*7,022*
17. *Less: Restoration, Recompletion, and Hydraulic Fracturing of Wells*	*5,868*
18. *Less: Royalty*	*11,046*
19. *Less: Road Tax*	*1,475*
Total Deductions	**39,848**
TOTAL NET OPERATING EXPENSE	**66,894**

Average Monthly Operating Costs, US $M:	*5,574*
Active Wells (Producers and Injectors):	*2,503*
Average Monthly Oil Production, M Tonnes:	*169*
Average Monthly Oil Production, M Barrels:	*1,207*

Operating Cost Distribution:

70.0 *Percent of Operating Costs Based on Well Count*

30.0 *Percent of Operating Costs Based on Oil Production*

Operating Cost: $\frac{5{,}574{,}476 \times 0.700}{2{,}503}$ = **$1,559** **Per Well**

$\frac{5{,}574{,}476 \times 0.300}{1{,}206{,}764}$ = **$1.386** **Per Barrel**

Conversion factor: *7.120 bbl/tonnes*

Operating Expenses
LUKoil - European Region
LUKoil-Permneft
Osinskneft NGDU
Oil Wells
Full Year 2001
(Thousand U.S. Dollars)

Cost Item	Total
1. *Energy Expense*	*3,522*
2. *Water Injection*	*10,376*
3. *Field Workers' Salary*	*1,266*
4. *Social Insurance*	*450*
5. *Depreciation of Oil Wells*	*1,600*
6. *Transportation and Collection of Oil and Gas*	*9,861*
7. *Treatment of Oil*	*7,629*
8. *Maintenance*	*30,280*
9. *G&A cost, taxes, others*	*15,143*
10. *Inter-division services*	*-822*
11. *Mineral Replacement Fee (MRF)*	*14,316*
12. *Royalty (R)*	*10,953*
13. *Other Production Expenses (Excl. R & MRF)*	*449*
14. *Non-producing costs*	*822*
TOTAL OPERATING EXPENSE	**105,847**
15. *Less: MRF*	*14,316*
16. *Less: Total Depreciation*	*6,963*
17. *Less: Restoration, Recompletion, and Hydraulic Fracturing of Wells*	*5,819*
18. *Less: Royalty*	*10,953*
19. *Less: Road Tax*	*1,463*
Total Deductions	**39,514**
TOTAL NET OPERATING EXPENSE	**66,332**

Average Monthly Operating Costs, US $M:	*5,528*
Active Wells (Producers and Injectors):	*2,482*
Average Monthly Oil Production, M Tonnes:	*169*
Average Monthly Oil Production, M Barrels:	*1,207*

Operating Cost Distribution:

70.0 *Percent of Operating Costs Based on Well Count*

30.0 *Percent of Operating Costs Based on Oil Production*

Operating Cost: $\frac{5{,}527{,}707 \times 0.700}{2{,}482} =$ **$1,559** **Per Well**

$\frac{5{,}527{,}707 \times 0.300}{1{,}206{,}764} =$ **$1.374** **Per Barrel**

Conversion factor: *7.120 bbl/tonnes*

Operating Expenses
LUKoil - European Region
LUKoil-Permneft
Osinskneft NGDU
Gas Wells
Full Year 2001
(Thousand U.S. Dollars)

	Cost Item	Total
1.	*Energy Expense*	30
2.	*Water Injection*	88
3.	*Field Workers' Salary*	11
4.	*Social Insurance*	4
5.	*Depreciation of Oil Wells*	14
6.	*Transportation and Collection of Oil and Gas*	83
7.	*Treatment of Oil*	65
8.	*Maintenance*	256
9.	*G&A cost, taxes, others*	128
10.	*Inter-division services*	-7
11.	*Mineral Replacement Fee (MRF)*	121
12.	*Royalty (R)*	93
13.	*Other Production Expenses (Excl. R & MRF)*	4
14.	*Non-producing costs*	7
	TOTAL OPERATING EXPENSE	**896**
15.	*Less: MRF*	121
16.	*Less: Total Depreciation*	59
17.	*Less: Restoration, Recompletion, and Hydraulic Fracturing of Wells*	49
18.	*Less: Royalty*	93
19.	*Less: Road Tax*	12
	Total Deductions	**334**
	TOTAL NET OPERATING EXPENSE	**561**
	Average Monthly Operating Costs, US $M:	47
	Active Wells (Producers and Injectors):	21
	Average Monthly Gas Production, MM cubic meters:	4
	Average Monthly Gas Production, Mcf:	144

Operating Cost Distribution:

70.0 *Percent of Operating Costs Based on Well Count*

30.0 *Percent of Operating Costs Based on Gas Production*

Operating Cost: $$\frac{46{,}769 \times 0.700}{21} = \$1{,}559 \text{ Per Well}$$

$$\frac{46{,}769 \times 0.300}{144{,}202} = \$0.097 \text{ Per Mcf}$$

Conversion factor: *35.315 Mcf/Mm3*

Operating Expenses
LUKoil - European Region
LUKoil-Permneft
Aksaitovneft JV
Full Year 2001
(Thousand U.S. Dollars)

Cost Item	Total
1. *Energy Expense*	*0*
2. *Water Injection*	*0*
3. *Field Workers' Salary*	*0*
4. *Social Insurance*	*0*
5. *Depreciation of Oil Wells*	*0*
6. *Transportation and Collection of Oil and Gas*	*0*
7. *Treatment of Oil*	*0*
8. *Maintenance*	*0*
9. *G&A cost, taxes, others*	*11*
10. *Inter-division services*	*0*
11. *Mineral Replacement Fee (MRF)*	*36*
12. *Royalty (R)*	*25*
13. *Other Production Expenses (Excl. R & MRF)*	*146*
14. *Non-producing costs*	*1*
TOTAL OPERATING EXPENSE	**218**
15. *Less: MRF*	*36*
16. *Less: Total Depreciation*	*0*
17. *Less: Restoration, Recompletion, and Hydraulic Fracturing of Wells*	*0*
18. *Less: Royalty*	*25*
19. *Less: Road Tax*	*4*
Total Deductions	**64**
TOTAL NET OPERATING EXPENSE	**154**
Average Monthly Operating Costs, US $M:	*13*
Active Wells (Producers and Injectors):	*161*
Average Monthly Oil Production, M Tonnes:	*9*
Average Monthly Oil Production, M Barrels:	*62*

Operating Cost Distribution:

70.0 *Percent of Operating Costs Based on Well Count*
30.0 *Percent of Operating Costs Based on Oil Production*

Operating Cost: $\frac{12,812 \times 0.700}{161}$ = **$56** **Per Well**

$\frac{12,812 \times 0.300}{62,308}$ = **$0.062** **Per Barrel**

Conversion factor: *7.116 bbl/tonnes*

Operating Expenses
LUKoil - European Region
LUKoil-Permneft
Churs JV
Full Year 2001
(Thousand U.S. Dollars)

Cost Item	Total
1. *Energy Expense*	*0*
2. *Water Injection*	*0*
3. *Field Workers' Salary*	*0*
4. *Social Insurance*	*0*
5. *Depreciation of Oil Wells*	*0*
6. *Transportation and Collection of Oil and Gas*	*1*
7. *Treatment of Oil*	*1*
8. *Maintenance*	*1*
9. *G&A cost, taxes, others*	*8*
10. *Inter-division services*	*0*
11. *Mineral Replacement Fee (MRF)*	*4*
12. *Royalty (R)*	*3*
13. *Other Production Expenses (Excl. R & MRF)*	*11*
14. *Non-producing costs*	*3*
TOTAL OPERATING EXPENSE	*32*
15. *Less: MRF*	*4*
16. *Less: Total Depreciation*	*1*
17. *Less: Restoration, Recompletion, and Hydraulic Fracturing of Wells*	*0*
18. *Less: Royalty*	*3*
19. *Less: Road Tax*	*0*
Total Deductions	**7**
TOTAL NET OPERATING EXPENSE	**25**

Average Monthly Operating Costs, US $M:	*2*
Active Wells (Producers and Injectors):	*4*
Average Monthly Oil Production, M Tonnes:	*1*
Average Monthly Oil Production, M Barrels:	*6*

Operating Cost Distribution:

70.0 *Percent of Operating Costs Based on Well Count*

30.0 *Percent of Operating Costs Based on Oil Production*

Operating Cost:

$$\frac{2{,}074 \times 0.700}{4} = \$363 \text{ Per Well}$$

$$\frac{2{,}074 \times 0.300}{6{,}276} = \$0.099 \text{ Per Barrel}$$

Conversion factor: *6.914 bbl/tonnes*

Operating Expenses
LUKoil - European Region
ZAO LUKoil-Perm
Full Year 2001
(Thousand U.S. Dollars)

Cost Item	Total
1. *Energy Expense*	*1,913*
2. *Water Injection*	*6,381*
3. *Field Workers' Salary*	*1,112*
4. *Social Insurance*	*354*
5. *Depreciation of Oil Wells*	*8,622*
6. *Transportation and Collection of Oil and Gas*	*4,622*
7. *Treatment of Oil*	*5,496*
8. *Maintenance*	*14,762*
9. *G&A cost, taxes, others*	*21,667*
10. *Inter-division services*	*-1,061*
11. *Mineral Replacement Fee (MRF)*	*29,266*
12. *Royalty (R)*	*28,591*
13. *Other Production Expenses (Excl. R & MRF)*	*2,669*
14. *Non-producing costs*	*0*
TOTAL OPERATING EXPENSE	**124,394**
15. *Less: MRF*	*29,266*
16. *Less: Total Depreciation*	*17,164*
17. *Less: Restoration, Recompletion, and Hydraulic Fracturing of Wells*	*3,907*
18. *Less: Royalty*	*28,591*
19. *Less: Road Tax*	*7,926*
Total Deductions	**86,854**
TOTAL NET OPERATING EXPENSE	**37,539**

Average Monthly Operating Costs, US $M:	*3,128*
Active Wells (Producers and Injectors):	*1,167*
Average Monthly Oil Production, M Tonnes:	*232*
Average Monthly Oil Production, M Barrels:	*1,719*

Operating Cost Distribution:

70.0 *Percent of Operating Costs Based on Well Count*

30.0 *Percent of Operating Costs Based on Oil Production*

Operating Cost:

$$\frac{3{,}128{,}288 \times 0.700}{1{,}167} = \$1{,}876 \text{ Per Well}$$

$$\frac{3{,}128{,}288 \times 0.300}{1{,}719{,}281} = \$0.546 \text{ Per Barrel}$$

Conversion factor: *7.397 bbl/tonnes*

Operating Expenses
LUKoil - European Region
ZAO LUKoil-Perm
Kamaneft JV
Full Year 2001
(Thousand U.S. Dollars)

Cost Item	Total
1. *Energy Expense*	*1,057*
2. *Water Injection*	*1,009*
3. *Field Workers' Salary*	*546*
4. *Social Insurance*	*197*
5. *Depreciation of Oil Wells*	*702*
6. *Transportation and Collection of Oil and Gas*	*1,586*
7. *Treatment of Oil*	*1,680*
8. *Maintenance*	*5,004*
9. *G&A cost, taxes, others*	*7,400*
10. *Inter-division services*	*-192*
11. *Mineral Replacement Fee (MRF)*	*13*
12. *Royalty (R)*	*253*
13. *Other Production Expenses (Excl. R & MRF)*	*525*
14. *Non-producing costs*	*0*
TOTAL OPERATING EXPENSE	**19,778**
15. *Less: MRF*	*13*
16. *Less: Total Depreciation*	*1,659*
17. *Less: Restoration, Recompletion, and Hydraulic Fracturing of Wells*	*1,716*
18. *Less: Royalty*	*253*
19. *Less: Road Tax*	*523*
Total Deductions	**4,164**
TOTAL NET OPERATING EXPENSE	**15,615**

Average Monthly Operating Costs, US $M:	*1,301*
Active Wells (Producers and Injectors):	*287*
Average Monthly Oil Production, M Tonnes:	*36*
Average Monthly Oil Production, M Barrels:	*274*

Operating Cost Distribution:

70.0 *Percent of Operating Costs Based on Well Count*

30.0 *Percent of Operating Costs Based on Oil Production*

Operating Cost: $\frac{1{,}301{,}220 \times 0.700}{287}$ = **$3,174** **Per Well**

$\frac{1{,}301{,}220 \times 0.300}{273{,}554}$ = **$1.427** **Per Barrel**

Conversion factor: *7.572 bbl/tonnes*

Operating Expenses
LUKoil - European Region
ZAO LUKoil-Perm
PermTex JV
Full Year 2001
(Thousand U.S. Dollars)

Cost Item		Total
1.	*Energy Expense*	*224*
2.	*Water Injection*	*0*
3.	*Field Workers' Salary*	*695*
4.	*Social Insurance*	*244*
5.	*Depreciation of Oil Wells*	*52*
6.	*Transportation and Collection of Oil and Gas*	*1,495*
7.	*Treatment of Oil*	*1,005*
8.	*Maintenance*	*3,557*
9.	*G&A cost, taxes, others*	*5,553*
10.	*Inter-division services*	*0*
11.	*Mineral Replacement Fee (MRF)*	*4,346*
12.	*Royalty (R)*	*3,241*
13.	*Other Production Expenses (Excl. R & MRF)*	*630*
14.	*Non-producing costs*	*125*
	TOTAL OPERATING EXPENSE	**21,168**
15.	*Less: MRF*	*4,346*
16.	*Less: Total Depreciation*	*638*
17.	*Less: Restoration, Recompletion, and Hydraulic Fracturing of Wells*	*0*
18.	*Less: Royalty*	*3,241*
19.	*Less: Road Tax*	*808*
	Total Deductions	**9,033**
	TOTAL NET OPERATING EXPENSE	**12,135**
	Average Monthly Operating Costs, US $M:	*1,011*
	Active Wells (Producers and Injectors):	*72*
	Average Monthly Oil Production, M Tonnes:	*27*
	Average Monthly Oil Production, M Barrels:	*206*

Operating Cost Distribution:

70.0 *Percent of Operating Costs Based on Well Count*

30.0 *Percent of Operating Costs Based on Oil Production*

Operating Cost: $\frac{1{,}011{,}261 \times 0.700}{72}$ = **$9,832** **Per Well**

$\frac{1{,}011{,}261 \times 0.300}{205{,}647}$ = **$1.475** **Per Barrel**

Conversion factor: *7.583 bbl/tonnes*

Operating Expenses
LUKoil - European Region
ZAO LUKoil-Perm
PermTOTIneft JV
Full Year 2001
(Thousand U.S. Dollars)

Cost Item	Total
1. Energy Expense	*0*
2. Water Injection	*167*
3. Field Workers' Salary	*214*
4. Social Insurance	*78*
5. Depreciation of Oil Wells	*305*
6. Transportation and Collection of Oil and Gas	*373*
7. Treatment of Oil	*354*
8. Maintenance	*123*
9. G&A cost, taxes, others	*512*
10. Inter-division services	*0*
11. Mineral Replacement Fee (MRF)	*1,356*
12. Royalty (R)	*1,049*
13. Other Production Expenses (Excl. R & MRF)	*1,720*
14. Non-producing costs	*0*
TOTAL OPERATING EXPENSE	**6,251**
15. Less: MRF	*1,356*
16. Less: Total Depreciation	*603*
17. Less: Restoration, Recompletion, and Hydraulic Fracturing of Wells	*189*
18. Less: Royalty	*1,049*
19. Less: Road Tax	*148*
Total Deductions	**3,346**
TOTAL NET OPERATING EXPENSE	**2,906**

Average Monthly Operating Costs, US $M:	*242*
Active Wells (Producers and Injectors):	*53*
Average Monthly Oil Production, M Tonnes:	*11*
Average Monthly Oil Production, M Barrels:	*81*

Operating Cost Distribution:

70.0 *Percent of Operating Costs Based on Well Count*
30.0 *Percent of Operating Costs Based on Oil Production*

Operating Cost:

$$\frac{242{,}145 \times 0.700}{53} = \$3{,}198 \text{ Per Well}$$

$$\frac{242{,}145 \times 0.300}{81{,}427} = \$0.892 \text{ Per Barrel}$$

Conversion factor: *7.240 bbl/tonnes*

Operating Expenses
LUKoil - European Region
ZAO LUKoil-Perm
Russian Fuel Company JV
Full Year 2001
(Thousand U.S. Dollars)

Cost Item	Total
1. *Energy Expense*	*606*
2. *Water Injection*	*666*
3. *Field Workers' Salary*	*1,040*
4. *Social Insurance*	*370*
5. *Depreciation of Oil Wells*	*1,164*
6. *Transportation and Collection of Oil and Gas*	*412*
7. *Treatment of Oil*	*169*
8. *Maintenance*	*309*
9. *G&A cost, taxes, others*	*1,866*
10. *Inter-division services*	*-207*
11. *Mineral Replacement Fee (MRF)*	*2,927*
12. *Royalty (R)*	*2,175*
13. *Other Production Expenses (Excl. R & MRF)*	*5,224*
14. *Non-producing costs*	*0*
TOTAL OPERATING EXPENSE	**16,719**
15. *Less: MRF*	*2,927*
16. *Less: Total Depreciation*	*1,164*
17. *Less: Restoration, Recompletion, and Hydraulic Fracturing of Wells*	*58*
18. *Less: Royalty*	*2,175*
19. *Less: Road Tax*	*299*
Total Deductions	**6,624**
TOTAL NET OPERATING EXPENSE	**10,095**

Average Monthly Operating Costs, US $M:	*841*
Active Wells (Producers and Injectors):	*283*
Average Monthly Oil Production, M Tonnes:	*23*
Average Monthly Oil Production, M Barrels:	*168*

Operating Cost Distribution:

70.0 *Percent of Operating Costs Based on Well Count*
30.0 *Percent of Operating Costs Based on Oil Production*

Operating Cost: $\frac{841{,}281 \times 0.700}{283}$ = **$2,081** **Per Well**

$\frac{841{,}281 \times 0.300}{167{,}928}$ = **$1.503** **Per Barrel**

Conversion factor: *7.298 bbl/tonnes*

Exhibit 24
Page 6

Operating Expenses
LUKoil - European Region
ZAO LUKoil-Perm
VNGK JV
Full Year 2001
(Thousand U.S. Dollars)

Cost Item		Total
1.	*Energy Expense*	*0*
2.	*Water Injection*	*15*
3.	*Field Workers' Salary*	*197*
4.	*Social Insurance*	*65*
5.	*Depreciation of Oil Wells*	*0*
6.	*Transportation and Collection of Oil and Gas*	*424*
7.	*Treatment of Oil*	*96*
8.	*Maintenance*	*39*
9.	*G&A cost, taxes, others*	*499*
10.	*Inter-division services*	*-26*
11.	*Mineral Replacement Fee (MRF)*	*525*
12.	*Royalty (R)*	*304*
13.	*Other Production Expenses (Excl. R & MRF)*	*164*
14.	*Non-producing costs*	*0*
	TOTAL OPERATING EXPENSE	**2,302**
15.	*Less: MRF*	*525*
16.	*Less: Total Depreciation*	*34*
17.	*Less: Restoration, Recompletion, and Hydraulic Fracturing of Wells*	*15*
18.	*Less: Royalty*	*304*
19.	*Less: Road Tax*	*56*
	Total Deductions	**934**
	TOTAL NET OPERATING EXPENSE	**1,368**
	Average Monthly Operating Costs, US $M:	*114*
	Active Wells (Producers and Injectors):	*12*
	Average Monthly Oil Production, M Tonnes:	*4*
	Average Monthly Oil Production, M Barrels:	*30*

Operating Cost Distribution:

70.0 *Percent of Operating Costs Based on Well Count*

30.0 *Percent of Operating Costs Based on Oil Production*

Operating Cost: $\frac{114{,}013 \times 0.700}{12}$ = **$6,651** **Per Well**

$\frac{114{,}013 \times 0.300}{30{,}003}$ = **$1.140** **Per Barrel**

Conversion factor: *7.767 bbl/tonnes*

Operating Expenses
LUKoil - European Region
ZAO LUKoil-Perm
Visheraneftegas JV (Oil Wells)
Full Year 2001
(Thousand U.S. Dollars)

Cost Item		Total
1.	*Energy Expense*	*33*
2.	*Water Injection*	*0*
3.	*Field Workers' Salary*	*68*
4.	*Social Insurance*	*21*
5.	*Depreciation of Oil Wells*	*0*
6.	*Transportation and Collection of Oil and Gas*	*26*
7.	*Treatment of Oil*	*54*
8.	*Maintenance*	*72*
9.	*G&A cost, taxes, others*	*634*
10.	*Inter-division services*	*-15*
11.	*Mineral Replacement Fee (MRF)*	*292*
12.	*Royalty (R)*	*59*
13.	*Other Production Expenses (Excl. R & MRF)*	*281*
14.	*Non-producing costs*	*0*
	TOTAL OPERATING EXPENSE	**1,526**
15.	*Less: MRF*	*292*
16.	*Less: Total Depreciation*	*67*
17.	*Less: Restoration, Recompletion, and Hydraulic Fracturing of Wells*	*0*
18.	*Less: Royalty*	*59*
19.	*Less: Road Tax*	*32*
	Total Deductions	**451**
	TOTAL NET OPERATING EXPENSE	**1,075**
	Average Monthly Operating Costs, US $M:	*90*
	Active Wells (Producers and Injectors):	*32*
	Average Monthly Oil Production, M Tonnes:	*3*
	Average Monthly Oil Production, M Barrels:	*21*

Operating Cost Distribution:

70.0 *Percent of Operating Costs Based on Well Count*

30.0 *Percent of Operating Costs Based on Oil Production*

Operating Cost: $\frac{89,574 \times 0.700}{32}$ = **$1,959** **Per Well**

$\frac{89,574 \times 0.300}{20,784}$ = **$1.293** **Per Barrel**

Conversion factor: *7.713 bbl/tonnes*

Operating Expenses
LUKoil - European Region
ZAO LUKoil-Perm
Visheraneftegas JV (Gas Wells)
Full Year 2001
(Thousand U.S. Dollars)

Cost Item	Total
1. *Energy Expense*	*12*
2. *Water Injection*	*0*
3. *Field Workers' Salary*	*24*
4. *Social Insurance*	*7*
5. *Depreciation of Oil Wells*	*0*
6. *Transportation and Collection of Oil and Gas*	*9*
7. *Treatment of Oil*	*19*
8. *Maintenance*	*25*
9. *G&A cost, taxes, others*	*223*
10. *Inter-division services*	*-5*
11. *Mineral Replacement Fee (MRF)*	*103*
12. *Royalty (R)*	*21*
13. *Other Production Expenses (Excl. R & MRF)*	*99*
14. *Non-producing costs*	*0*
TOTAL OPERATING EXPENSE	**535**
15. *Less: MRF*	*103*
16. *Less: Total Depreciation*	*24*
17. *Less: Restoration, Recompletion, and Hydraulic Fracturing of Wells*	*0*
18. *Less: Royalty*	*21*
19. *Less: Road Tax*	*11*
Total Deductions	**158**
TOTAL NET OPERATING EXPENSE	**377**
Average Monthly Operating Costs, US $M:	*31*
Active Wells (Producers and Injectors):	*8*
Average Monthly Gas Production, MMm3:	*3*
Average Monthly Gas Production, Mcf:	*94*

Operating Cost Distribution:

70.0 *Percent of Operating Costs Based on Well Count*

30.0 *Percent of Operating Costs Based on Gas Production*

Operating Cost: $\frac{31,434 \times 0.700}{8}$ = **$2,750** **Per Well**

$\frac{31,434 \times 0.300}{94,192}$ = **$0.100** **Per Mcf**

Conversion factor: *35.315 mcf/Mm3*

Exhibit 25
Page 1

Operating Expenses
LUKoil - European Region
Astrakhanneft
Oil Fields
Full Year 2001
(Thousand U.S. Dollars)

Cost Item	Total
1. *Energy Expense*	*11*
2. *Water Injection*	*11*
3. *Field Workers' Salary*	*162*
4. *Social Insurance*	*55*
5. *Depreciation of Oil Wells*	*119*
6. *Transportation and Collection of Oil and Gas*	*625*
7. *Treatment of Oil*	*210*
8. *Maintenance*	*1,374*
9. *G&A cost, taxes, others*	*269*
10. *Inter-division services*	*-213*
11. *Mineral Replacement Fee (MRF)*	*778*
12. *Royalty (R)*	*683*
13. *Other Production Expenses (Excl. R & MRF)*	*61*
14. *Non-producing costs*	*0*
TOTAL OPERATING EXPENSE	**4,145**
15. *Less: MRF*	*778*
16. *Less: Total Depreciation*	*489*
17. *Less: Restoration, Recompletion, and Hydraulic Fracturing of Wells*	*181*
18. *Less: Royalty*	*683*
19. *Less: Road Tax*	*91*
Total Deductions	**2,221**
TOTAL NET OPERATING EXPENSE	**1,924**

Average Monthly Operating Costs, US $M:	*160*
Active Wells (Producers and Injectors):	*40*
Average Monthly Oil Production, M Tonnes:	*5*
Average Monthly Oil Production, M Barrels:	*35*

Operating Cost Distribution:

70.0 *Percent of Operating Costs Based on Well Count*

30.0 *Percent of Operating Costs Based on Oil Production*

Operating Cost:

$$\frac{160{,}348 \times 0.700}{40} = \$2{,}806 \quad \textbf{Per Well}$$

$$\frac{160{,}348 \times 0.300}{35{,}333} = \$1.361 \quad \textbf{Per Barrel}$$

Conversion factor: *7.657 bbl/tonnes*

Operating Expenses
LUKoil - European Region
Astrakhanneft
Gas Fields
Full Year 2001
(Thousand U.S. Dollars)

Cost Item		Total
1.	*Energy Expense*	*2*
2.	*Water Injection*	*2*
3.	*Field Workers' Salary*	*28*
4.	*Social Insurance*	*10*
5.	*Depreciation of Oil Wells*	*21*
6.	*Transportation and Collection of Oil and Gas*	*109*
7.	*Treatment of Oil*	*37*
8.	*Maintenance*	*241*
9.	*G&A cost, taxes, others*	*47*
10.	*Inter-division services*	*-37*
11.	*Mineral Replacement Fee (MRF)*	*136*
12.	*Royalty (R)*	*120*
13.	*Other Production Expenses (Excl. R & MRF)*	*11*
14.	*Non-producing costs*	*0*
	TOTAL OPERATING EXPENSE	**725**
15.	*Less: MRF*	*136*
16.	*Less: Total Depreciation*	*86*
17.	*Less: Restoration, Recompletion, and Hydraulic Fracturing of Wells*	*32*
18.	*Less: Royalty*	*120*
19.	*Less: Road Tax*	*16*
	Total Deductions	**389**
	TOTAL NET OPERATING EXPENSE	**337**
	Average Monthly Operating Costs, US $M:	*28*
	Active Wells (Producers and Injectors):	*7*
	Average Monthly Gas Production, MMm3:	*1*
	Average Monthly Gas Production, MMcf:	*52*

Operating Cost Distribution:

70.0 *Percent of Operating Costs Based on Well Count*

30.0 *Percent of Operating Costs Based on Gas Production*

Operating Cost: $\frac{28{,}061 \times 0.700}{7}$ = **$2,806** **Per Well**

$\frac{28{,}061 \times 0.300}{52{,}225}$ = **$0.161** **Per Mcf**

Conversion factor: *35.315 Mcf/Mm3*

Exhibit 26

Operating Expenses
LUKoil - European Region
Kaliningradmorneft
Full Year 2001
(Thousand U.S. Dollars)

Cost Item	Total
1. *Energy Expense*	*507*
2. *Water Injection*	*326*
3. *Field Workers' Salary*	*321*
4. *Social Insurance*	*97*
5. *Depreciation of Oil Wells*	*2,276*
6. *Transportation and Collection of Oil and Gas*	*773*
7. *Treatment of Oil*	*897*
8. *Maintenance*	*4,461*
9. *G&A cost, taxes, others*	*1,702*
10. *Inter-division services*	*-403*
11. *Mineral Replacement Fee (MRF)*	*12,012*
12. *Royalty (R)*	*9,510*
13. *Other Production Expenses (Excl. R & MRF)*	*0*
14. *Non-producing costs*	*5,580*
TOTAL OPERATING EXPENSE	**38,061**
15. *Less: MRF*	*12,012*
16. *Less: Total Depreciation*	*2,929*
17. *Less: Restoration, Recompletion, and Hydraulic Fracturing of Wells*	*326*
18. *Less: Royalty*	*9,510*
19. *Less: Road Tax*	*1,399*
Total Deductions	**26,176**
TOTAL NET OPERATING EXPENSE	**11,885**
Average Monthly Operating Costs, US $M:	*990*
Active Wells (Producers and Injectors):	*266*
Average Monthly Oil Production, M Tonnes:	*55*
Average Monthly Oil Production, M Barrels:	*406*

Operating Cost Distribution:

70.0 *Percent of Operating Costs Based on Well Count*

30.0 *Percent of Operating Costs Based on Oil Production*

Operating Cost: $$\frac{990{,}412 \quad x \quad 0.700}{266} = \textbf{\$2,606} \quad \textbf{Per Well}$$

$$\frac{990{,}412 \quad x \quad 0.300}{405{,}528} = \textbf{\$0.733} \quad \textbf{Per Barrel}$$

Conversion factor: *7.410 bbl/tonnes*

Exhibit 27

Estimated Production Cost
LUKoil - Russian Caspian Sea
Korchagina Field
As Provided by LUKoil
(Thousand U.S. Dollars)

Cost Item	Total
1. *Fixed operating costs per well*	*199,472*
2. *Salary fund*	*46,944*
3. *Variable operating costs per tonne*	*101,087*
4. *Offshore facilities and insurance costs*	*634,795*
5. *Unified social tax*	*13,648*
6. *R&D fund*	*26,241*
TOTAL OPERATING EXPENSE	**1,022,187**

Project Life, Years	*43*
Projected Wells	*101*
Average Monthly Oil Production, M Tonnes:	*56*
Average Monthly Oil Production, M Barrels:	*413,650*
*Well Months (Project Life * Active Wells * 12)*	*52,116*

Operating Cost Distribution:

75.0 *Percent of Operating Costs Based on Well Count*

25.0 *Percent of Operating Costs Based on Oil Production*

Operating Cost: $\dfrac{1{,}022{,}187{,}000 \quad x \quad 0.750}{52{,}116}$ *$14,710* **Per Well**

$\dfrac{1{,}022{,}187{,}000 \quad x \quad 0.250}{413{,}650{,}000}$ *$0.618* **Per Barrel**

Development Costs
LUKOil - Subsidiaries
Full Year 2001
(Thousand U.S. Dollars Per Well)

Subsidiary	Joint Venture	Region	Drill and Completion	Restorations	Recompletions	Hydraulic Fracturing
Langepas	-	Western Siberia	430.2	65.0	56.1	124.6
Urai	-	Western Siberia	481.7	25.1	50.0	113.7
Urai	Tursunt	Western Siberia	541.8	-	-	-
Kogalym	-	Western Siberia	568.9	67.1	57.9	148.8
Kogalym	AIK	Western Siberia	522.3	9.8	37.3	80.2
Kogalym	Vatoil	Western Siberia	549.5	10.4	27.2	87.3
Kogalym	RITEK	Western Siberia - Beloyarskneft	474.0	-	38.8	-
Kogalym	RITEK	Western Siberia - Ritekneft	599.0	-	32.3	-
Kogalym	RITEK	Tatarstan - Cheznyneft	468.0	-	32.3	-
Kogalym	RITEK	Tatarstan - Tatritekneft	161.0	-	38.8	-
Pokachev	-	Western Siberia	540.8	43.9	56.9	65.0
Nizhnevolzhneft	-	European	505.2	30.6	7.1	25.2
Permneft	-	European	615.0	28.0	22.8	44.5
ZAO Perm	-	European	619.1	24.3	19.7	55.4
ZAO Perm	Maykorskoye	European	377.0	24.3	19.7	55.4
ZAO Perm	PermTOTIneft	European	-	16.4	19.7	55.4
ZAO Perm	Kamaneft	European	432.0	56.5	3.2	55.4
ZAO Perm	Russian Fuel Co.	European	578.9	7.8	19.7	55.4
ZAO Perm	Visheraneftegas	European	578.9	14.0	19.7	55.4
Astrakhanneft	-	European	1270.6	20.3	7.1	-
Kaliningradmorneft	-	European	1006.3	-	34.5	44.9
Kaliningradmorneft	-	European (D6 Field)	7,659.3 (Cost 1)	-	506.4	-
Kaliningradmorneft	-	European (D6 Field)	9,621.6 (Cost 2)	-	506.4	-
Caspian Russian Sea	-	Timan-Pechora	2,230.0	-	28.2	-

Exhibit 28

Lease Expiration Dates Provided by LUKoil

Employed for Forecasts of Proven Reserves

Entity / Field | **Field Life**

TPP Pokachevneftegas

Entity / Field	Field Life
Kechimovskoye	**2051**
North-Pokachevskoye	**2055**
Pokachevskoye	**2052**
South-Pokachevskoye	**2045**
Nivagalskoye	**2076**
Nong-Yeganskoye	**2030**
Klyuchevoye	**2034**

TPP Uraineftegas

Entity / Field	Field Life
Symoryakhskoye	**2031**
Mansingyanskoye	**2031**
Trekhozernoye	**2031**
Mortymiya-Teterevskoye	**2027**
Ubinskoye	**2018**
Tolumskoye	**2031**
Danilovskoye	**2025**
Mulyminskoye	**2031**
North-Danilovskoye	**2025**
Lazarevskoye	**2031**
Filippovskoye	**2031**
Lovinskoye	**2085**
Shushminskoye	**2031**
Yakhlinskoye	**2031**
Uzbekskoye	**2031**
Talnikovskoye	**2031**

TPP Langepasneftegas

Entity / Field	Field Life
Lokosovskoye	**2048**
Urievskoye	**2044**
Potochnoye	**2070**
South-Pokachevskoye	**2045**
Las-Yeganskoye	**2091**
Nivagalskoye	**2076**
Pokamasovskoye	**2050**
Chumpasskoye	**2028**
North-Potochnoye	**2076**

TPP Kogalymneftegas

Entity / Field	Field Life
East-Pridorozhnoye	**2093**
Gribnoye	**2049**
Ravenskoye	**2028**
Povkhovskoye	**2027**
Tevlinsko-Russkinskoye	**2087**
South-Yagunskoye	**2032**
Druzhnoye	**2080**
Kustovoye	**2029**
Kochevskoye	**2075**
North-Kochevskoye	**2075**
South-Vyintoiskoye	**2026**
West-Kotukhtinskoye	**2025**
Vatyeganskoye	**2090**

OOO Kaliningradmorneft

Entity / Field	Field Life
North-Krasnoborskoye	**2027**
Slavskoye	**2034**
Slavinskoye	**2014**
South-Olimpiiskoye	**2028**
Aleshkinskoye	**2014**
West-Ushakovskoye	**2010**
Krasnoborskoye	**2045**
Ushakovskoye	**2045**
West-Krasnoborskoye	**2031**
Isakovskoye	**2018**
Malinovskoye	**2034**
Deiminskoye	**2032**
Gayevskoye	**2012**
Ladushkinskoye	**2062**
North-Slavinskoye	**2050**
Olimpiiskoye	**2018**
Chekhovskoye	**2018**

OOO Astrakhanneft

Entity / Field	Field Life
Oleinikovskoye	**2016**
Beshkulskoye	**2013**

OAO KomiTEK

Entity / Field	Field Life
Usinskoye	**2061**
Vozeiskoye	**2052**
Kharyaginskoye	**2057**
Nizhneomrinskoye	**2025**
Verkhneomrinskoye	**2025**
Voivozhskoye	**2010**

ZAO NobelOil

Entity / Field	Field Life
Usinskoye	**2061**

Lease Expiration Dates Provided by LUKoil

Employed for Forecasts of Proven Reserves

Entity / Field	Field Life
Kirillovskoye	**2050**
Byrkinskoye	**2033**
Kudryavtsevskoye	**2035**
Tanypskoye	**2035**
Aspinskoye	**2045**
Rassvetnoye	**2035**
Mayachnoye	**2016**
Shumovskoye	**2065**
Gorskoye	**2012**
Churakovskoye	**2050**
Osinskoye	**2064**
Baklanovskoye	**2035**
Malo-Usinskoye	**2067**
Tulvinskoye	**2090**
Batyrbaiskoye	**2025**
Shagirtsko-Gozhanskoye	**2070**
Pavlovskoye	**2080**
Krasnoyarsko-Kuyedinskoye	**2082**
Moskudinskoye	**2047**
Chernushinskoye	**2040**
Gondyrevskoye	**2094**
Kazakovskoye	**2031**
Dorokhovskoye	**2050**
Kurbatovskoye	**2077**
Alnyashskoye	**2097**
Stepanovskoye	**2031**
Sudanovskoye	**2035**
Andreyevskoye	**2028**
Sosnovskoye	**2037**
Kokuiskoye	**2095**
Charskoye	**2019**
Aptugaiskoye	**2025**
Soldatovskoye	**2095**
Chikulayevskoye	**2050**
Etyshskoye	**2030**
Yuzhinskoye	**2020**
Trushnikovskoye	**2046**
Trifonovskoye	**2052**
Mosinskoye	**2035**
Kryazhevskoye	**2018**

Entity / Field	Field Life
Petrovskoye	**2003**
Zhirnovskoye	**2050**
Bakhmetievskoye	**2044**
Klenovskoye	**2016**
Tersinskoye	**2018**
Antonovskoye	**2015**
Burlukskoye	**2017**
Novo-Korobkovskoye	**2018**
Korobkovskoye	**2025**
Kotovskoye	**2016**
Antipovsko-Balykleiskoye	**2022**
South-Umetovskoye	**2015**
Miroshnikovskoye	**2014**
Golubkovskoye	**2018**
East-Umetovskoye	**2011**
Malyshevskoye	**2014**
Nizhne-Korobkovskoye	**2012**
Ovrazhnoye	**2011**
Archedinskoye	**2018**
Frolovskoye	**2011**
Kudinovskoye	**2015**
Klyuchevskoye	**2018**
Zelenovskoye	**2012**
Chukhonastovskoye	**2018**
Dudachinskoye	**2011**
Novokochetkovskoye	**2015**
Tsentralnoye	**2019**
Kovalevskoye	**2014**
West-Kochetkovskoye	**2014**
East-Kudinovskoye	**2014**
Tishanskoye	**2022**
Nikolinskoye	**2025**
Novo-Chernushinskoye	**2017**
North-Romanovskoye	**2024**
Zimovskoye	**2005**

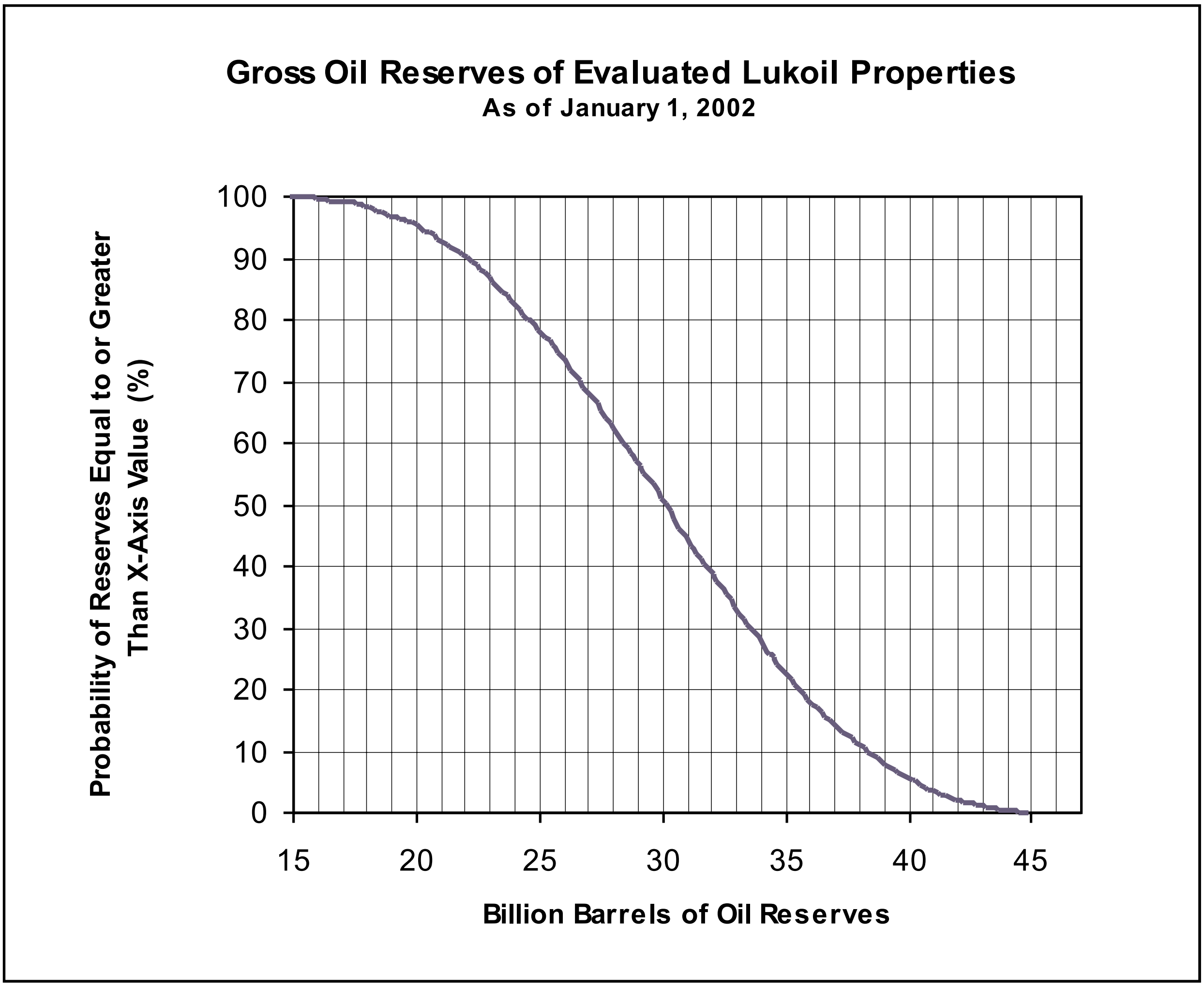

Gross Oil Reserves of Evaluated Lukoil Properties
As of January 1, 2002
Probability of Reserves Equal to or Greater Than X-Axis Value (%)
100
90
80
70
60
50
40
30
20
10
0
15
20
25
30
35
40
45
Billion Barrels of Oil Reserves

Exhibit 31

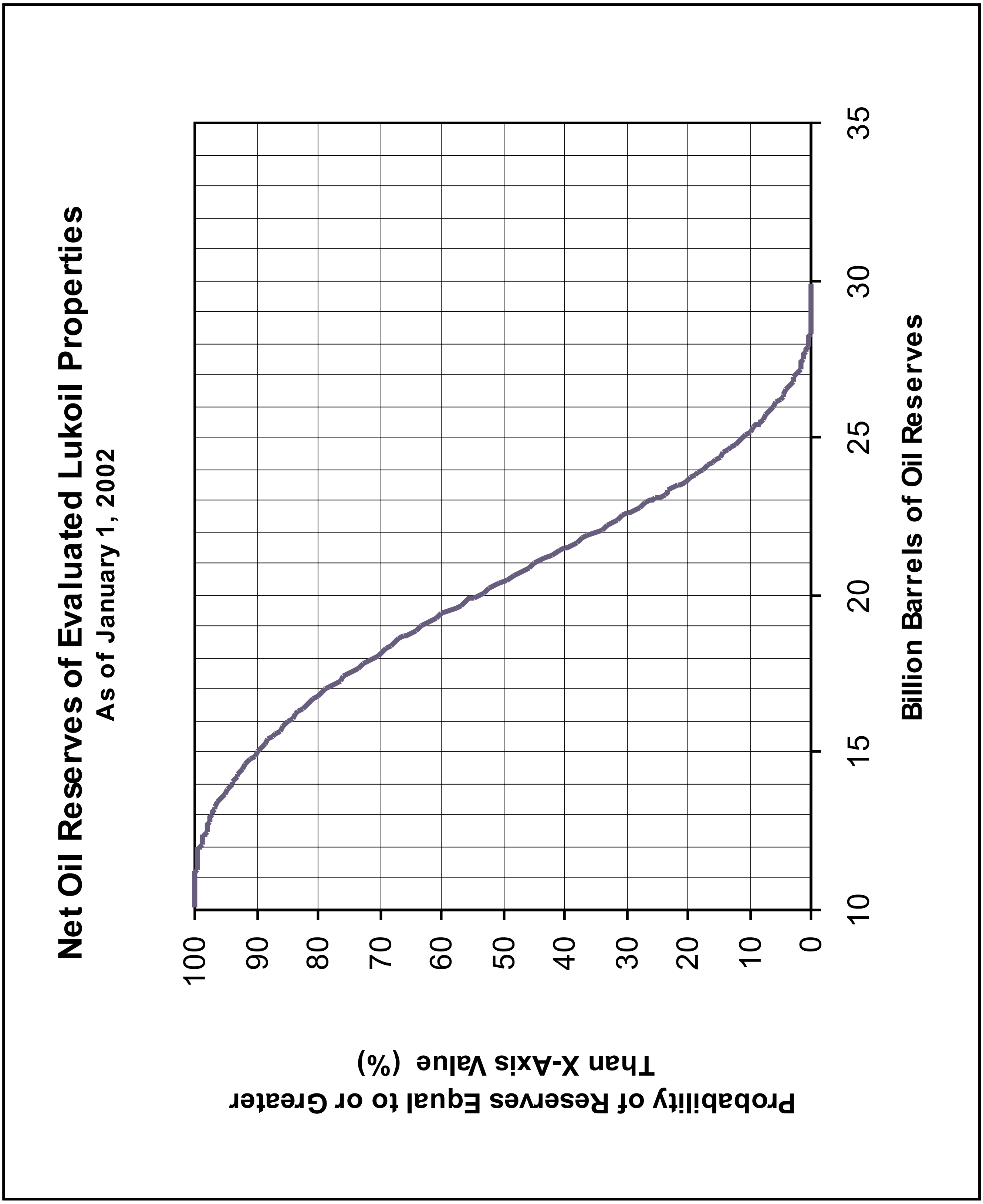
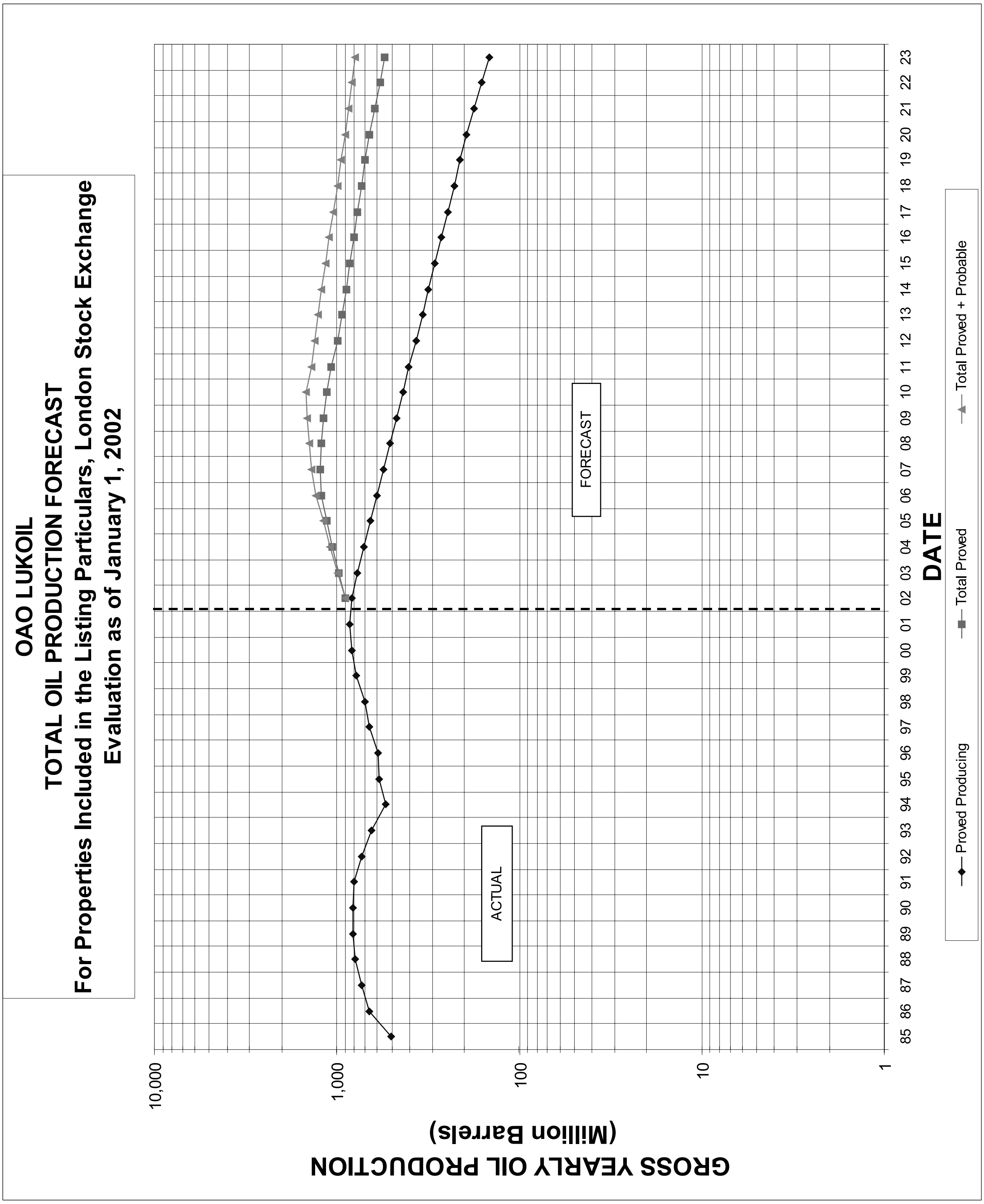

Net Oil Reserves of Evaluated Lukoil Properties
As of January 1, 2002
Probability of Reserves Equal to or Greater Than X-Axis Value (%)
Billion Barrels of Oil Reserves
100
90
80
70
60
50
40
30
20
10
0
10
15
20
25
30
35

Exhibit 32



OAO LUKOIL
TOTAL OIL PRODUCTION FORECAST
For Properties Included in the Listing Particulars, London Stock Exchange
Evaluation as of January 1, 2002
GROSS YEARLY OIL PRODUCTION
(Million Barrels)
10,000
1,000
100
10
1
ACTUAL
FORECAST
85 86 87 88 89 90 91 92 93 94 95 96 97 98 99 00 01 02 03 04 05 06 07 08 09 10 11 12 13 14 15 16 17 18 19 20 21 22 23
DATE
Proved Producing
Total Proved
Total Proved + Probable

Exhibit 33

LUKoil - Arkhangel Fields

Entities, Field Groupings, and Working Interests

Grouping Entity	Fields Included	Status Under Reporting	Reporting Interest*	Reserve Categories: Proven	Probable	Possible
I. Arkhangelskogeoldobycha (AGD) Licensed Fields		Parent Company				
A. Northern Territories						
	A01 - KHYLCHUYUSKOYE		100 %			
	A02 - SOUTH-KHYLCHUYUSKOYE		100 %	X	X	X
	A03 - YAREYUSKOYE		100 %		X	X
	A12 - INZYREISKOYE		100 %	X	X	X
B. Other Fields						
	A06 - MYADSEISKOYE		100 %			X
	A07 - TOBOYSKOYE		100 %	X	X	X
	A08 - NORTH-SAREMBOYSKOYE		100 %		X	X
	A11 - ROSSIKHINSKOYE		100 %			X
	A13 - TABROVOYAKHINSKOYE		100 %			
	A14 - SEDYAGINSKOYE		100 %	X	X	X
	A15 - MEZHDURECHENSKOYE		100 %			X
	A16 - WEST LEKEYAGINSKOYE		100 %		X	X
	A17 - MEDYNSKOYE		100 %			
	A18 - UST-TALOTINSKOYE		100 %			X
	A31- PEREVOZNAYA		100 %			
II. CJSC - Arktikneft		Consolidated Subsid.				
	A09 - PESCHANOOZERSKOYE		100 %	X	X	X
III. OJSC - Bovel		Consolidated Subsid.				
	A10 - TEDINSKOYE		100 %	X	X	X
IV. CJSC - Kolvageoldobycha		Consolidated Subsid.				
	A19 - EAST-KHARYAGINSKOYE		100 %	X	X	X
V. CJSC - Varandeineftegas		Consolidated Subsid.				
	A04 - VARANDEYSKOYE		100 %	X	X	X
	A05 -TORAVEYSKOYE		100 %	X	X	X
VI. CJSC - Kaliningradskaya GDNGE		Consolidated Subsid.				
	A20 - EAST-GORINSKOYE		100 %	X		
	A21 - EAST-GORINSKOYE II		100 %	X		
	A22 - NOVO-ISKRINSKOYE		100 %	X		X
	A30 - WEST RAKITINSKOYE		100 %	X		X
VII. Polar Lights Joint Venture		Affiliated Company				
	A23 - OSHKOTYNSKOYE	(Equity Accounting)	22.20%	X		
	A24 - DYUSUSHEVSKOYE		22.20%	X		
	A25 - EAST-KOLVINSKOYE		22.20%			
	A26 - ARDALINSKOYE		22.20%	X		

* Assumes full ownership of the consolidated subsidiaries in which LUKoil has the controlling interests

Exhibit 34

ARCTIC OCEAN
Norwegian Sea
Barents Sea
Kara Sea
Caspian Sea
Western Siberian Basin
RUSSIAN FEDERATION
Kogalymneftegas
Pokachevneftegas
Uraineftegas
Langepasneftegas
KAZAKHSTAN
NORWAY
SWEDEN
FINLAND
UKRAINE
BELARUS
TURKMENISTAN
IRAN
LUKOIL OIL COMPANY
LOCATION MAP
RUSSIAN FEDERATION
WESTERN SIBERIAN
SUBSIDIARIES
MILLER & LENTS, LTD.
5/2002

Exhibit 36

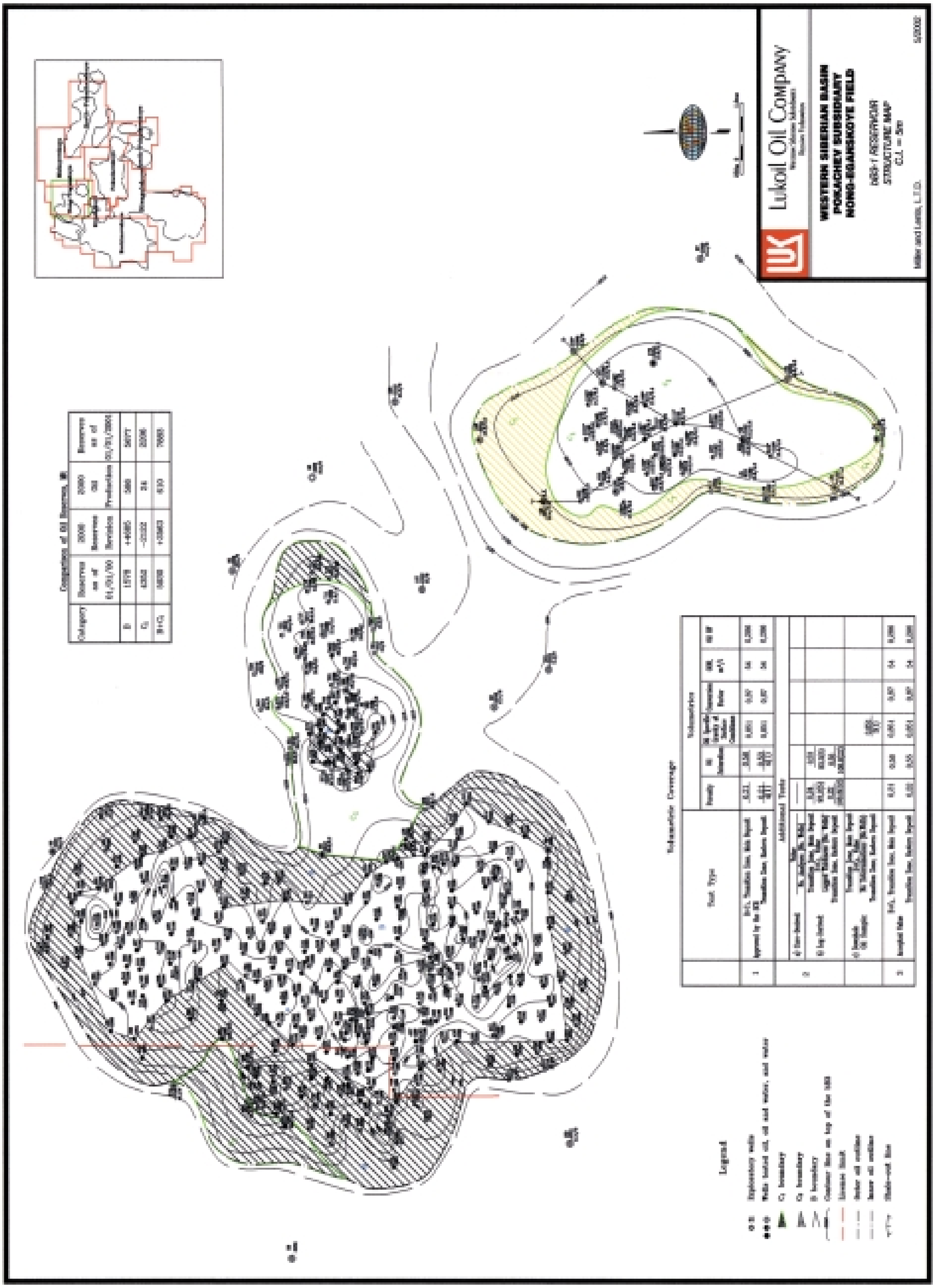


Exhibit 36

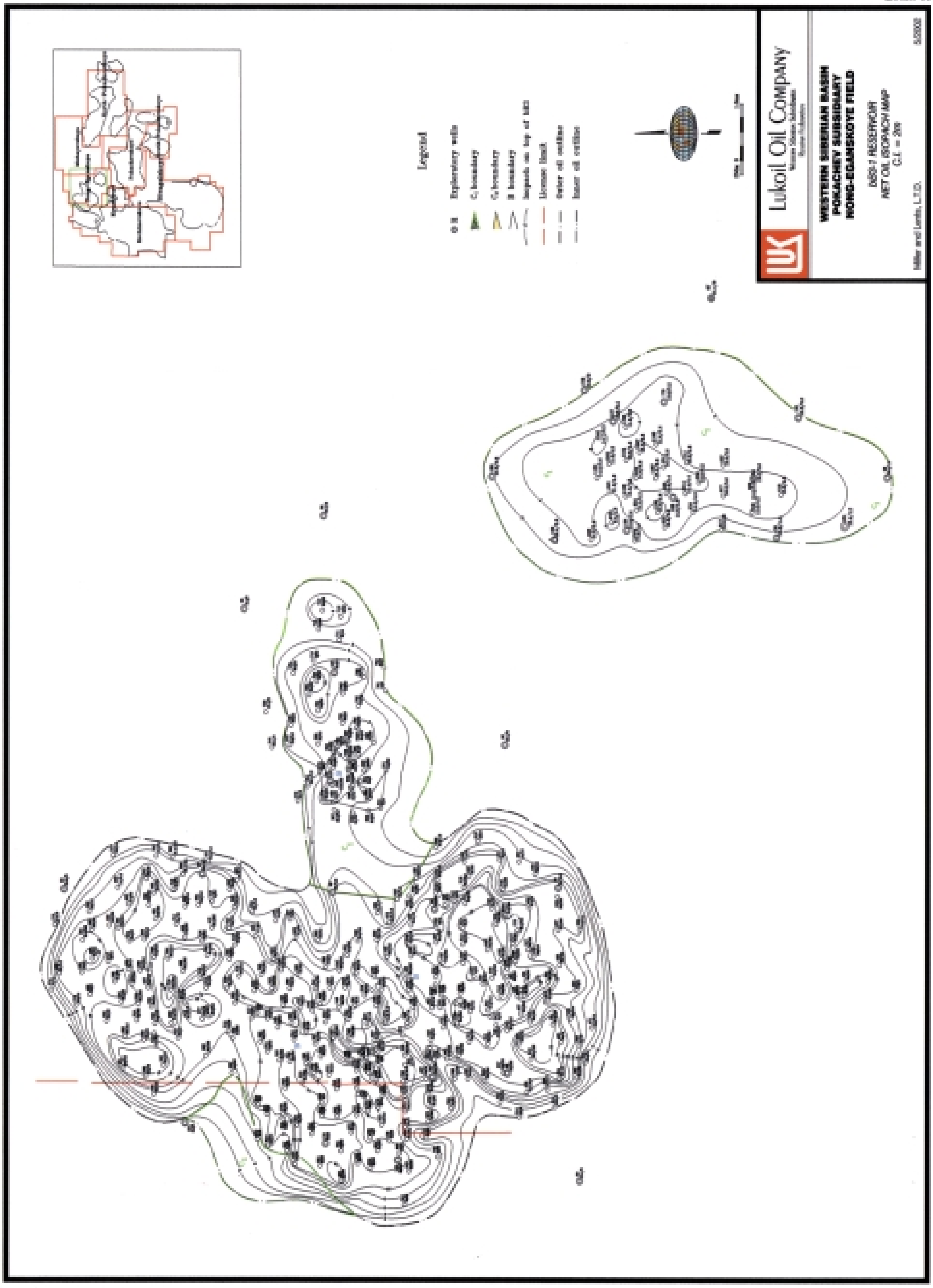
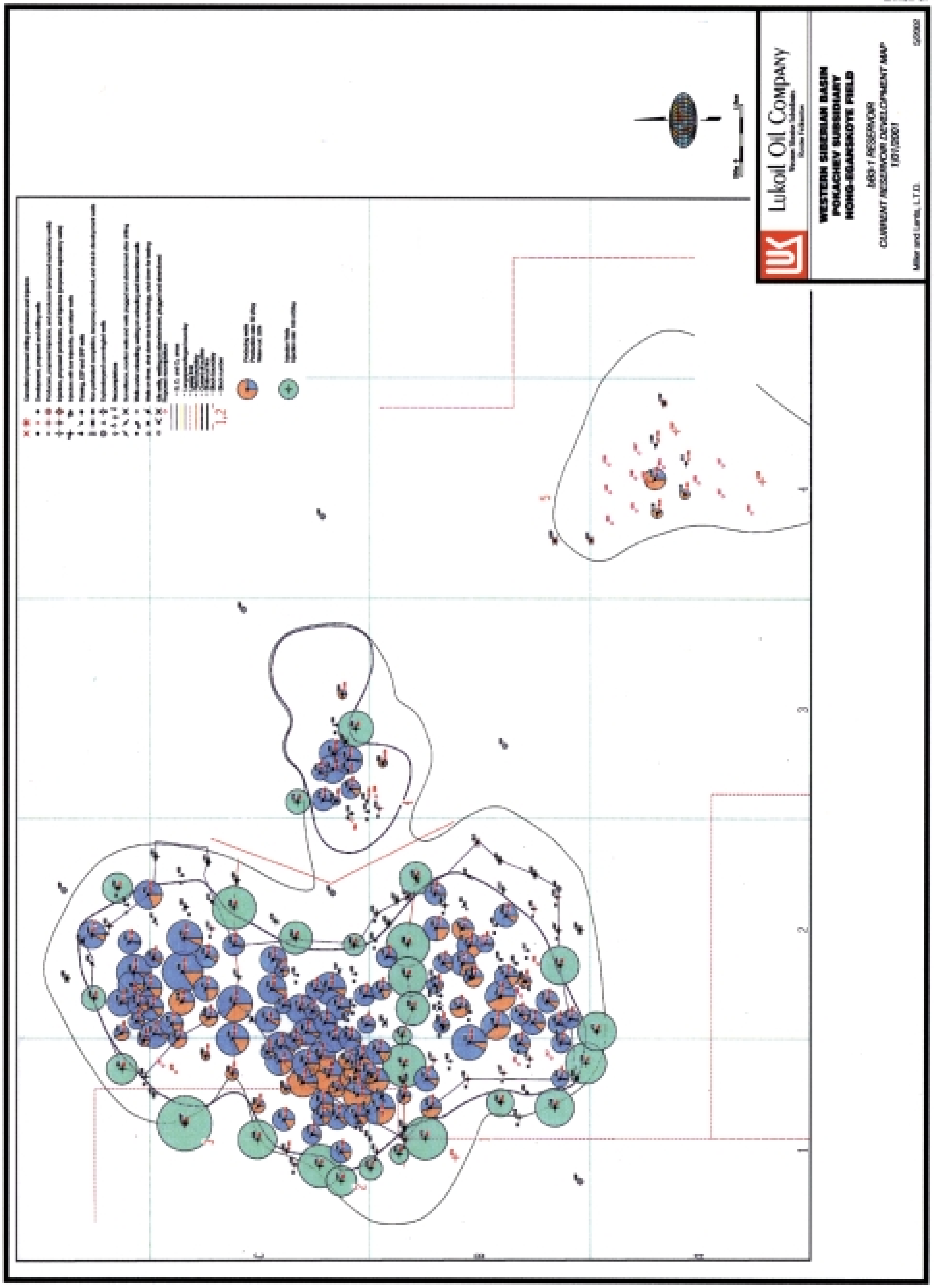

Lukoil Oil Company
WESTERN SIBERIAN BASIN
POKACHEV SUBSIDIARY
NONG-EGANSKOYE FIELD
NET OIL ISOPACH MAP
Miller and Lents, L.T.D.

Exhibit 37

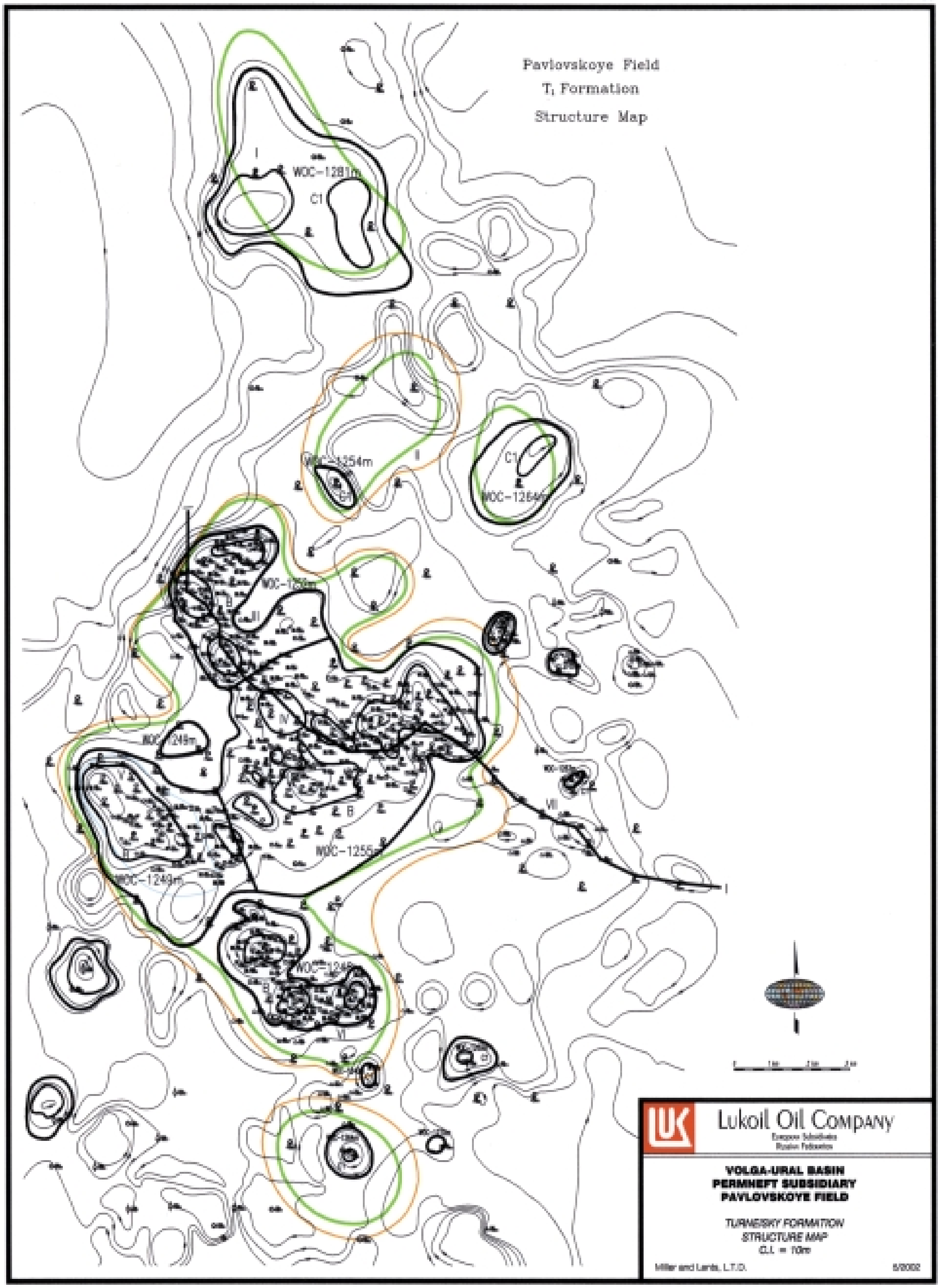


Lukoil Oil Company
WESTERN SIBERIAN BASIN
POKACHEV SUBSIDIARY
NONG-EGANSKOYE FIELD
CURRENT RESERVOIR DEVELOPMENT MAP
Miller and Lents, LTD.

Exhibit 38

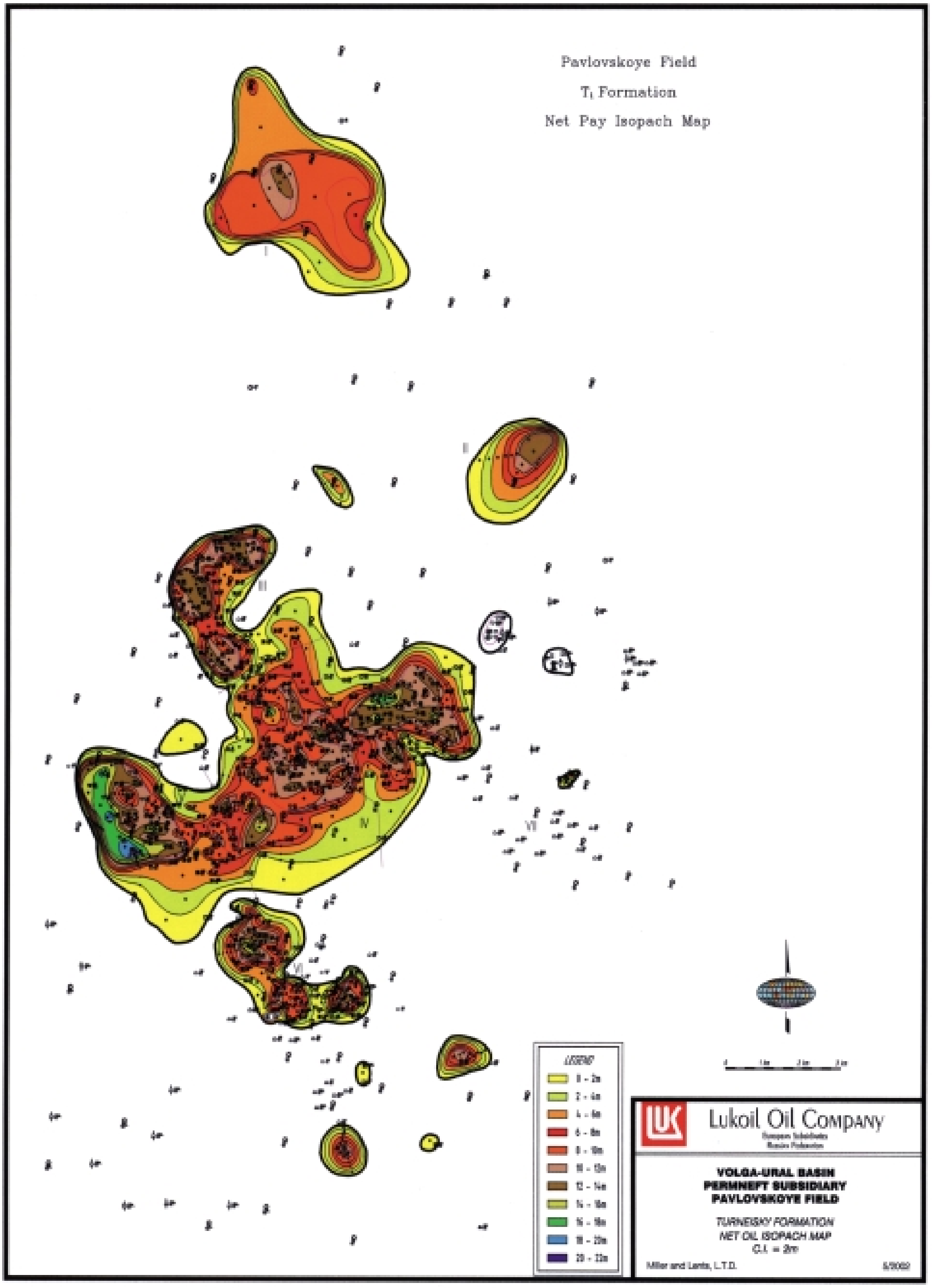

ATLANTIC OCEAN
Norwegian Sea
ARCTIC OCEA
SVALBARD
FRANZ JOSEF LAND
Barents Sea
NOVAYA ZEMLYA
Kara Sea
NORWAY
SWEDEN
FINLAND
POLAND
BELARUS
UKRAINE
Kaliningradmorneft
ZAO Perm
Permneft
Nizhnevolzhskneft
RUSSIAN FEDERATION
Volga-Ural Basin
Precaspian Basin
Astrakhanneft
KAZAKHSTAN
TURKMENISTAN
IRAN
AFGHANISTAN
LUKOIL OIL COMPANY
LOCATION MAP
RUSSIAN FEDERATION
EUROPEAN SUBSIDIARIES
MILLER AND LENTS, LTD. 5/2002

Exhibit 39



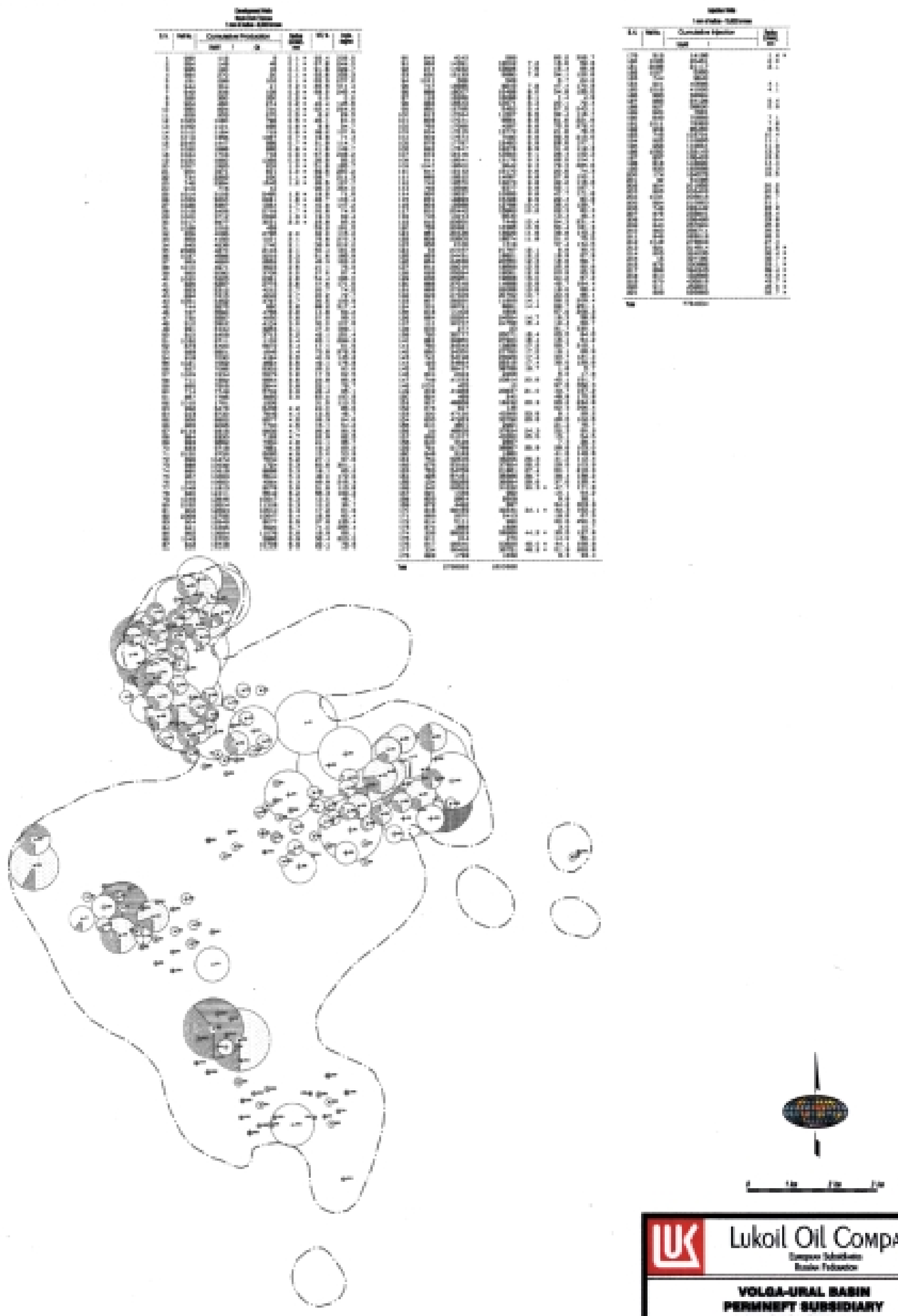
Pavlovskoye Field
T_1 Formation
Structure Map
WOC-1281m
WOC-1254m
WOC-1264m
WOC-1255
WOC-1249m
Lukoil Oil Company
VOLGA-URAL BASIN
PERMNEFT SUBSIDIARY
PAVLOVSKOYE FIELD
TURNEISKY FORMATION
STRUCTURE MAP
C.I. = 10m
Miller and Lents, L.T.D.
6/2002

Exhibit 40



Pavlovskoye Field
T_1 Formation
Net Pay Isopach Map
LEGEND
0 - 2m
2 - 4m
4 - 6m
6 - 8m
8 - 10m
10 - 12m
12 - 14m
14 - 16m
16 - 18m
18 - 20m
20 - 22m
Lukoil Oil Company
VOLGA-URAL BASIN
PERMNEFT SUBSIDIARY
PAVLOVSKOYE FIELD
TURNEISKY FORMATION
NET OIL ISOPACH MAP
C.I. = 2m
Miller and Lents, L.T.D.

Exhibit 41



CURRENT RESERVOIR DEVELOPMENT MAP
Turneisky Formation, Pavlovskaya Area,Pavlovskoye Field
as of 01/01/2001.

Lukoil Oil Company

VOLGA-URAL BASIN
PERMNEFT SUBSIDIARY
PAVLOVSKOYE FIELD

TURNEISKY FORMATION
CURRENT RESERVOIR DEVELOPMENT MAP
1/01/2001

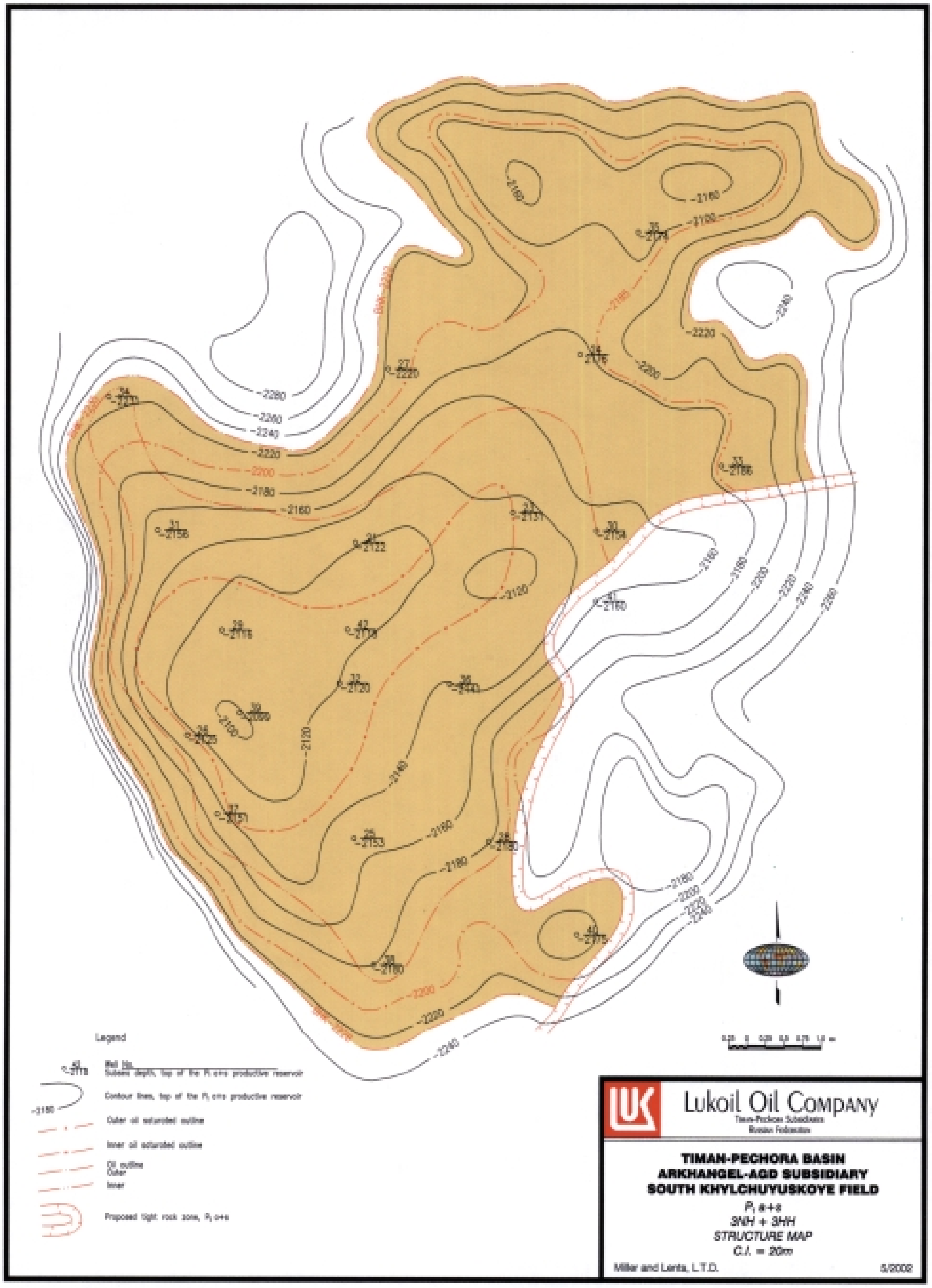
Miller and Lents, L.T.D. 7/2001

Exhibit 42

LUKOIL OIL COMPANY
LOCATION MAP
RUSSIAN FEDRATION
TIMAN-PECHORA
SUBSIDIARIES

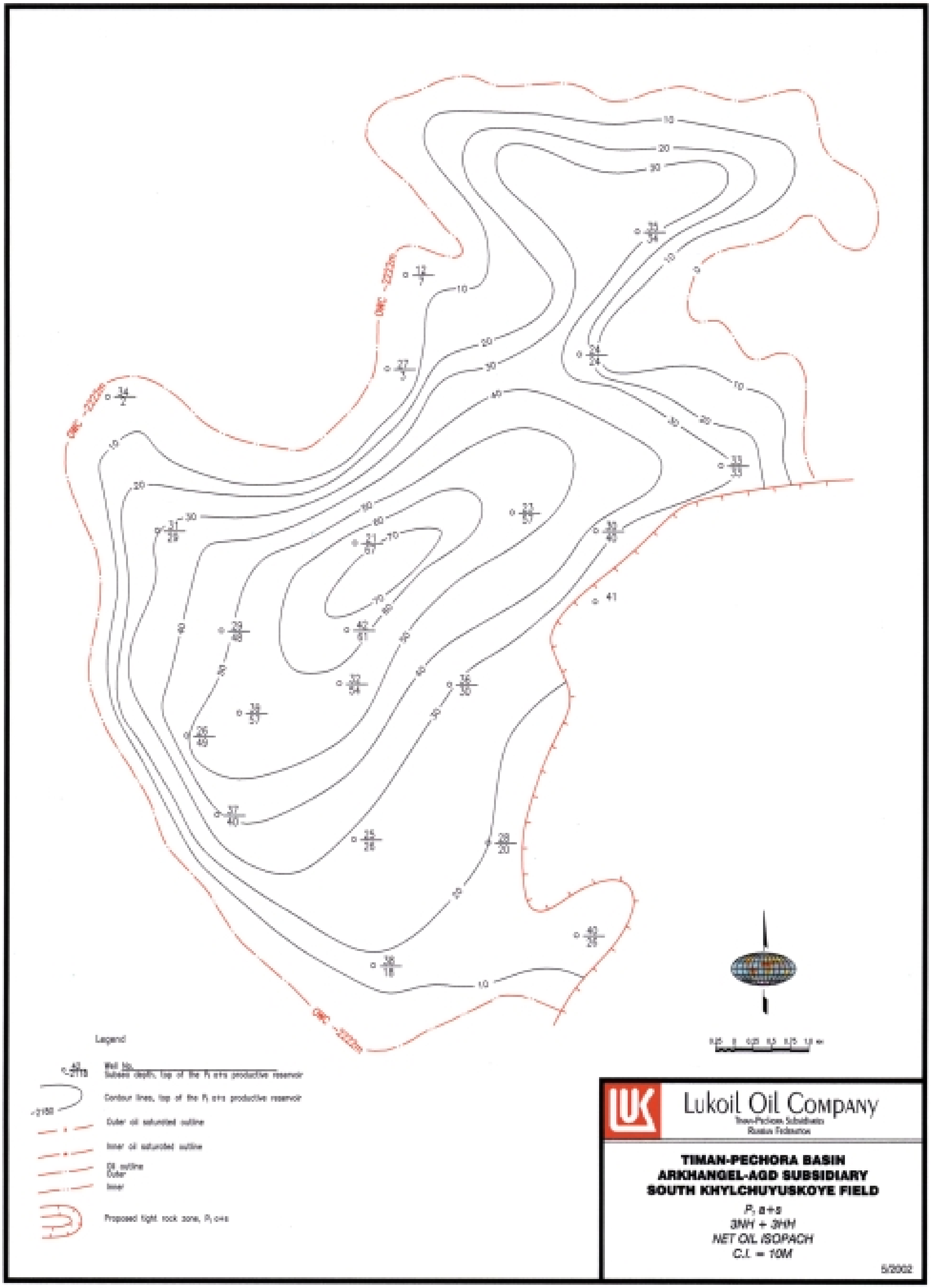
MILLER AND LENTS, LTD. 5/2002

Exhibit 43



Legend
Well No.
Subsea depth, top of the P_1 a+s productive reservoir
Contour lines, top of the P_1 a+s productive reservoir
Outer oil saturated outline
Inner oil saturated outline
Oil outline
Outer
Inner
Proposed tight rock zone, P_1 a+s
Lukoil Oil Company
TIMAN-PECHORA BASIN
ARKHANGEL-AGD SUBSIDIARY
SOUTH KHYLCHUYUSKOYE FIELD
P_1 a+s
ЗНН + ЗНН
STRUCTURE MAP
C.I. = 20m
Miller and Lents, L.T.D.
5/2002

Exhibit 44



Legend
Well No.
Subsea depth, top of the P_1 a+s productive reservoir
Contour lines, top of the P_1 a+s productive reservoir
Outer oil saturated outline
Inner oil saturated outline
Oil outline
Outer
Inner
Proposed tight rock zone, P_1 a+s
Lukoil Oil Company
TIMAN-PECHORA BASIN
ARKHANGEL-AGD SUBSIDIARY
SOUTH KHYLCHUYUSKOYE FIELD
P_1 a+s
3NH + 3HH
NET OIL ISOPACH
C.I. = 10M
5/2002

Exhibit 45

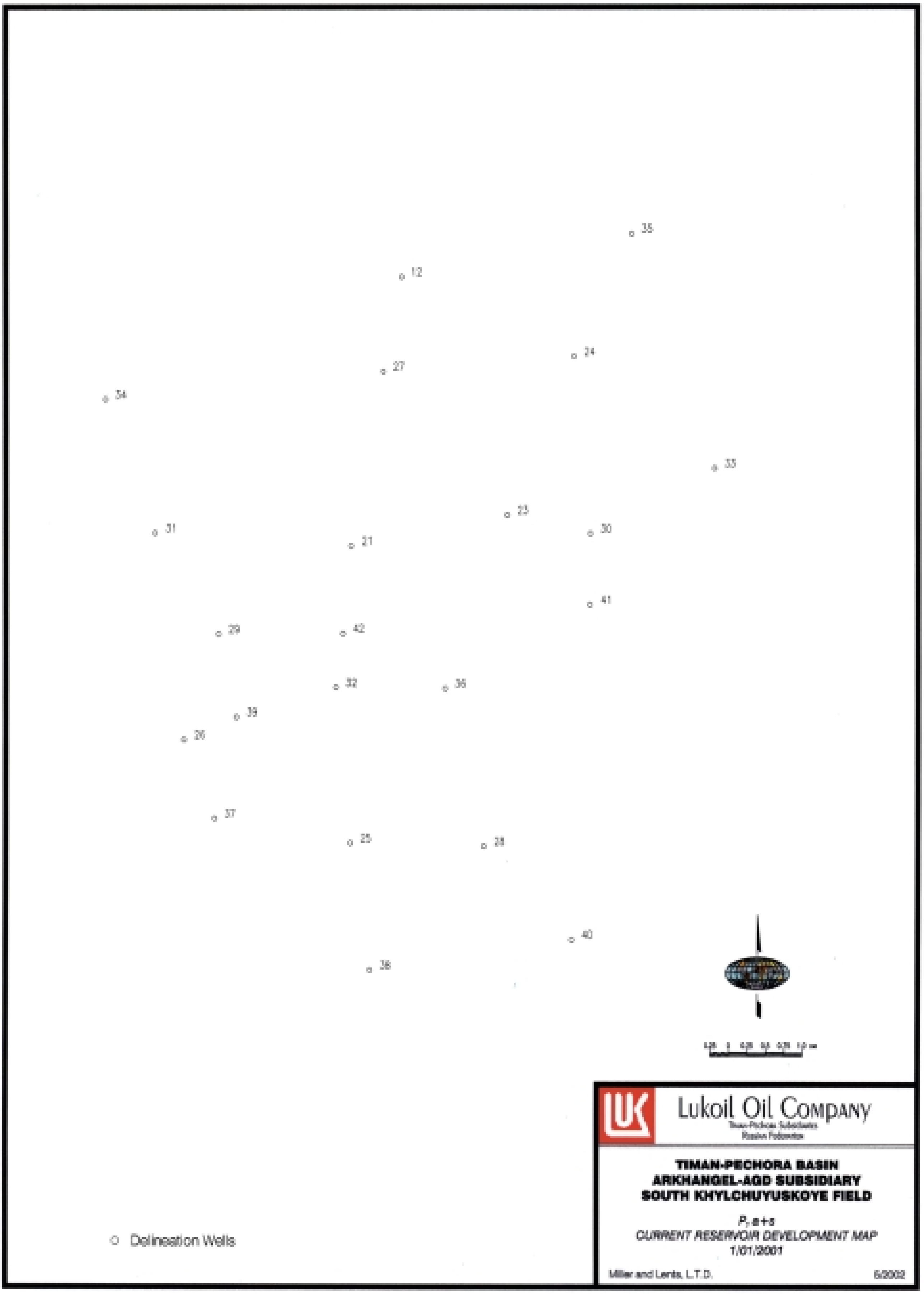
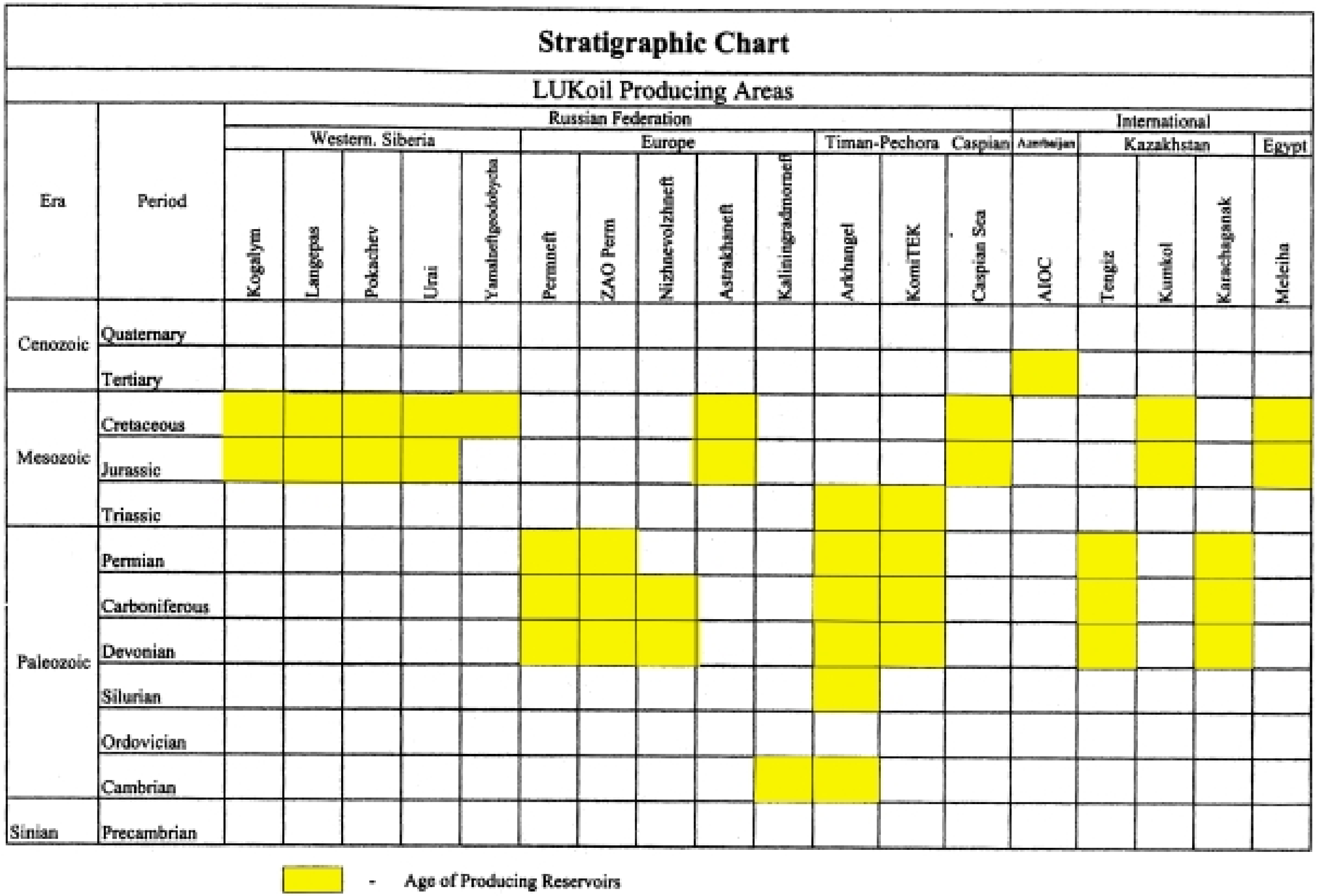

35
12
24
27
34
33
23
31
30
21
41
29
42
32
36
39
26
37
25
28
40
38
Lukoil Oil Company
TIMAN-PECHORA BASIN
ARKHANGEL-AGD SUBSIDIARY
SOUTH KHYLCHUYUSKOYE FIELD
P_1 a+s
CURRENT RESERVOIR DEVELOPMENT MAP
1/01/2001
Miller and Lents, L.T.D.
6/2002
Delineation Wells

Exhibit 46


LUKOIL OIL COMPANY
LOCATION MAP
INTERNATIONAL
SUBSIDIARIES
MILLER AND LENTS, LTD. 5/2002
RUSSIAN FE
KAZAKHSTAN
Karachaganak
Tengiz
Kumkol
AIOC
Meleiha
KYRGYZSTAN
AZERBAIJAN
ARMENIA
GEORGIA
TURKEY
IRAN
IRAQ
SYRIA
JORDAN
KUWAIT
ISRAEL
LEBANON
CYPRUS
FINLAND
SWEDEN
NORWAY
ESTONIA
LATVIA
LITHUANIA
BELORUSSIA
UKRAINE
MOLDOVA
POLAND
GERMANY
DENMARK
SLOVAKIA
HUNGARY
ROMANIA
BULGARIA
AUSTRIA
SLOVENIA
CROATIA
YUGO.
ITALY
ALBANIA
GREECE
MACEDONIA
MALTA
Mediterranean Sea
TUNISIA
LIBYA
MONACO
SAN MARINO
VATICAN CITY

Exhibit 47



Stratigraphic Chart
LUKoil Producing Areas
Russian Federation
International
Western. Siberia
Europe
Timan-Pechora
Caspian
Azerbaijan
Kazakhstan
Egypt
Era
Period
Kogalym
Langepas
Pokachev
Urai
Yamalneftgeodobycha
Permneft
ZAO Perm
Nizhnevolzhneft
Astrakhaneft
Kaliningradmorneft
Arkhangel
KomiTEK
Caspian Sea
AIOC
Tengiz
Kumkol
Karachaganak
Meleiha
Cenozoic
Quaternary
Tertiary
Mesozoic
Cretaceous
Jurassic
Triassic
Paleozoic
Permian
Carboniferous
Devonian
Silurian
Ordovician
Cambrian
Sinian
Precambrian
- Age of Producing Reservoirs

LANGEPASNEFTEGAS SUBSIDIARY
RESERVOIR PARAMETERS

Field	Reservoir	Field Area	Category	Area (Acres)	Avg Net Thickness (Feet)	Net Volume (Acre-Feet)	Porosity (fraction)	Permeability (md)	Oil Saturation (fraction)	Oil Specific Gravity	Oil FVF (RBbl/STB)	Solution Gas Ratio (SCF/STB)	Estimated Original Pressure (psi)	Oil Viscosity (cp)
CHUMPASSKOYE														
	AB1-3		Proven	12,801	14.5	185,396	0.22	258	0.55	0.862	1.099	175	2,646	2.30
	AB1-3		Probable	206	10.5	2,152	0.22	258	0.55	0.862	1.099	175	2,646	2.30
	bB6-1		Proven	6,647	17.6	116,891	0.20	103	0.56	0.851	1.136	214	3,234	1.32
	bB6-2	Achem.	Proven	8,723	31.7	276,864	0.16	12	0.46	0.838	1.203	373	3,378	0.70
	bB6-2	Achem.	Probable	2,767	31.5	87,061	0.16	11	0.46	0.838	1.205	376	3,381	0.69
	UV1-1		Proven	8,880	9.9	88,012	0.16	10	0.65	0.822	1.282	415	3,900	0.56
	UV1-1		Probable	4,896	3.3	16,062	0.16	10	0.65	0.822	1.282	415	3,900	0.56
LAS-YOGANSKOYE														
	AB1-3		Proven	18,805	9.2	172,546	0.21	72	0.52	0.854	1.099	199	2,734	2.27
	AB2		Proven	13,146	11.7	153,973	0.21	72	0.62	0.867	1.075	136	2,734	2.27
	bB6		Proven	7,247	20.0	145,042	0.20	150	0.58	0.875	1.075	125	3,308	2.60
	bB6		Probable	56	8.2	456	0.20	150	0.58	0.875	1.075	125	3,308	2.60
	bB8		Proven	2,913	16.0	46,740	0.20	150	0.55	0.851	1.124	188	3,572	0.92
	bB8		Probable	418	9.8	4,110	0.20	150	0.55	0.851	1.124	188	3,572	0.92
	bB20		Proven	1,668	15.1	25,233	0.16	12	0.52	0.836	1.176	375	3,969	2.00
	bB20		Probable	289	3.3	947	0.16	12	0.52	0.836	1.176	375	3,969	2.00
	bB23		Proven	2,965	10.3	30,596	0.16	12	0.52	0.836	1.176	375	3,969	2.00
	bB23		Probable	495	2.2	1,089	0.16	12	0.52	0.836	1.176	375	3,969	2.00
	UV1-1		Proven	13,179	21.4	281,481	0.16	12	0.50	0.836	1.220	375	4,013	0.68
	UV1-1		Probable	8,302	16.7	138,531	0.16	12	0.50	0.836	1.220	375	4,013	0.68
	UV1-1	Well 181	Proven	309	16.4	5,067	0.16	7	0.55	0.836	1.220	375	4,013	0.68
	UV1-1	Well 181	Probable	638	17.1	10,902	0.16	7	0.55	0.836	1.220	375	4,013	0.68
LOKASOVSKOYE														
	AB2		Proven	8,419	15.8	133,133	0.23	50	0.57	0.870	1.075	176	2,573	0.37
	bB5		Proven	26,409	28.2	743,621	0.21	180	0.58	0.869	1.103	176	3,219	2.39
	bB5		Probable	148	16.5	2,442	0.21	180	0.70	0.880	1.136	178	3,219	2.39
	bB6		Proven	18,422	19.8	365,048	0.21	129	0.60	0.852	1.120	172	3,234	2.29
NIVAGALSKOYE														
	AB1-2		Proven	29,599	12.5	371,100	0.22	100	0.50	0.860	1.087	203	2,720	2.27
	AB1-2		Probable	22,987	11.5	263,206	0.22	100	0.50	0.860	1.087	203	2,720	2.27
	AB1-3	water zone	Proven	30,511	16.0	488,374	0.24	74	0.65	0.861	1.087	203	2,720	2.41
	AB1-3	water zone	Probable	7,883	9.8	77,585	0.24	65	0.66	0.861	1.087	203	2,720	2.46
	AB1-3	non-water zone	Proven	14,098	11.8	166,695	0.24	93	0.61	0.860	1.087	203	2,720	2.31
	AB1-3	non-water zone	Probable	1,686	12.4	20,970	0.24	65	0.66	0.861	1.087	203	2,720	2.46
	AB1-3	water zone (Las-Egansk area)	Proven	2,310	10.3	23,752	0.24	85	0.63	0.860	1.087	203	2,720	2.36
	AB1-3	water zone (Las-Egansk area)	Probable	247	9.8	2,432	0.24	65	0.66	0.861	1.087	203	2,720	2.46
	AB1-3	non-water zone (Las-Egansk area)	Proven	2,588	8.0	20,696	0.24	94	0.61	0.860	1.087	203	2,720	2.31
	AB1-3	non-water zone (Las-Egansk area)	Probable	803	11.5	9,248	0.24	65	0.66	0.861	1.087	203	2,720	2.46
	AB2	water zone	Proven	13,853	10.1	139,679	0.24	184	0.60	0.865	1.103	204	2,720	2.08
	AB2	water zone	Probable	6,054	8.9	53,827	0.24	223	0.58	0.867	1.111	204	2,720	1.98
	AB2	non-water zone	Proven	7,944	7.6	60,720	0.25	108	0.64	0.860	1.088	203	2,720	2.25
	AB2	water zone (Las-Egansk area)	Proven	1,335	4.2	5,657	0.25	112	0.64	0.861	1.089	203	2,720	2.25
	AB2	non-water zone (Las-Egansk area)	Proven	2,168	8.7	18,777	0.25	100	0.64	0.860	1.087	203	2,720	2.27
	bB2		Proven	556	15.3	8,512	0.20	18	0.67	0.840	1.163	274	3,528	0.79
	bB2		Probable	485	11.9	5,761	0.20	18	0.67	0.840	1.163	274	3,528	0.79
	bB3		Proven	556	21.5	11,958	0.20	18	0.67	0.840	1.163	274	3,528	0.79
	bB3		Probable	485	13.5	6,541	0.20	18	0.67	0.840	1.163	274	3,528	0.79
	bB5		Proven	1,283	5.8	7,453	0.20	239	0.53	0.853	1.136	278	3,528	1.38
	bB6		Proven	3,561	6.7	23,952	0.21	278	0.54	0.853	1.136	278	3,528	1.38
	bB8		Proven	1,458	7.0	10,188	0.20	18	0.67	0.840	1.163	274	3,528	0.79

LANGEPASNEFTEGAS SUBSIDIARY
RESERVOIR PARAMETERS

Field	Reservoir	Field Area	Category	Area (Acres)	Avg Net Thickness (Feet)	Net Volume (Acre-Feet)	Porosity (fraction)	Permeability (md)	Oil Saturation (fraction)	Oil Specific Gravity	Oil FVF (RBbl/STB)	Solution Gas Ratio (SCF/STB)	Estimated Original Pressure (psi)	Oil Viscosity (cp)
NIVAGALSKOYE (cont)														
	Achem.	Main Area	Proven	2,738	15.2	41,590	0.18	18	0.67	0.835	1.190	356	3,675	0.79
	Achem.	Water zone	Proven	1,410	13.2	18,649	0.18	18	0.67	0.835	1.190	356	3,675	0.79
	Achem.	Las Egansk area	Proven	751	13.4	10,049	0.18	18	0.67	0.835	1.190	356	3,675	0.79
	UV1-1	Main area	Proven	11,892	22.3	265,695	0.18	37	0.57	0.836	1.250	357	4,072	0.82
	UV1-1	water zone	Proven	9,730	23.3	226,644	0.18	37	0.57	0.836	1.250	357	4,072	0.82
NORTH POTOCHNOYE														
	bB6		Proven	7,040	30.2	212,479	0.21	94	0.66	0.851	1.099	191	3,322	1.77
	bB8		Proven	6,950	10.4	72,057	0.22	662	0.66	0.851	1.124	220	3,440	1.18
	bB10-1		Proven	1,458	14.2	20,673	0.17	15	0.54	0.835	1.176	216	3,969	0.67
	bB10-1		Probable	1,453	6.1	8,914	0.17	15	0.54	0.835	1.176	216	3,969	0.67
	bB18		Proven	2,637	19.0	50,078	0.17	15	0.58	0.832	1.176	341	3,969	0.67
	bB18		Probable	499	14.8	7,395	0.17	15	0.58	0.832	1.176	341	3,969	0.67
	bB19-1		Proven	4,057	13.7	55,477	0.17	10	0.58	0.832	1.176	341	3,675	0.68
	bB19-1		Probable	687	9.8	6,764	0.17	10	0.58	0.832	1.176	341	3,675	0.68
	bB19-2		Proven	652	9.0	5,862	0.17	10	0.58	0.832	1.176	341	3,675	0.68
	bB19-3		Proven	163	7.0	1,136	0.17	10	0.58	0.832	1.176	341	3,675	0.68
	bB20		Proven	71	14.1	1,000	0.21	10	0.59	0.832	1.176	341	3,749	0.68
	Achem.	A (Ver)	Proven	1,320	9.8	12,988	0.19	5	0.57	0.840	1.176	354	3,822	0.68
	Achem.	A (Ver)	Probable	1,079	9.8	10,616	0.19	5	0.57	0.840	1.176	354	3,822	0.68
	Achem.	B (Nek)	Proven	2,077	9.8	20,442	0.18	5	0.43	0.840	1.176	354	3,822	0.68
	Achem.	B (Nek)	Probable	1,357	9.8	13,357	0.18	5	0.43	0.840	1.176	354	3,822	0.68
	U1-1	Offline	Proven	1,421	11.2	15,849	0.17	20	0.46	0.821	1.282	535	3,969	0.67
	U1-1		Probable	6,259	9.6	60,164	0.17	20	0.46	0.821	1.282	535	3,969	0.67
	U10-1		Proven	2,780	6.6	18,241	0.15	20	0.60	0.800	1.429	337	3,998	0.67
	U10-1		Probable	2,317	6.6	15,206	0.15	20	0.60	0.800	1.429	337	3,998	0.67
POKAMASOVSKOYE														
	UB1	Incl River Zn	Proven	23,141	23.6	545,208	0.19	54	0.69	0.840	1.235	429	4,160	0.63
	UB1	Incl River Zn	Probable	4,423	12.9	56,886	0.19	54	0.69	0.840	1.235	429	4,160	0.63
POTOCHNOYE														
	AB1-3		Proven	24,006	10.3	246,947	0.23	33	0.58	0.859	1.101	188	2,646	1.78
	AB1-3		Probable	1,034	8.0	8,312	0.19	33	0.40	0.855	1.140	187	2,646	1.78
	AB2		Proven	5,803	12.6	73,102	0.22	33	0.54	0.859	1.099	188	2,646	1.78
	AB2		Probable	1,683	12.6	21,197	0.22	33	0.54	0.859	1.099	188	2,646	1.78
	bB5	Main Area	Proven	494	8.7	4,313	0.19	140	0.45	0.857	1.111	202	3,234	1.68
	bB5	Main Area	Probable	371	6.6	2,432	0.19	140	0.45	0.857	1.111	202	3,234	1.68
	bB5	Loo. Area	Proven	1,003	15.4	15,433	0.21	140	0.53	0.857	1.111	202	3,234	1.68
	bB6	Main Area	Proven	15,430	24.5	378,673	0.21	238	0.53	0.857	1.111	202	3,278	1.68
	bB6	Main Area	Probable	477	9.8	4,699	0.21	238	0.53	0.857	1.111	202	3,278	1.68
	bB6	Loo. Area	Proven	865	13.1	11,322	0.21	238	0.53	0.857	1.111	202	3,278	1.68
	bB6	Loo. Area	Probable	594	13.1	7,776	0.21	238	0.53	0.857	1.111	202	3,278	1.68
	bB7		Proven	507	15.5	7,865	0.20	309	0.52	0.857	1.124	202	3,278	1.57
	bB8	Main Area	Proven	16,487	18.1	298,580	0.22	306	0.59	0.844	1.149	270	3,410	1.41
	bB8	Loo. Area	Proven	1,185	18.1	21,493	0.20	306	0.58	0.832	1.163	290	3,410	1.41
	bB9		Proven	62	6.6	405	0.18	24	0.49	0.844	1.181	270	3,410	1.18
	bB10-1	Potoyna	Proven	3,595	13.4	48,025	0.18	67	0.54	0.839	1.205	344	3,528	0.67
	bB10-1	Potoyna	Probable	568	9.0	5,109	0.18	67	0.54	0.839	1.205	344	3,528	0.67
	bB10-2		Proven	226	9.8	2,221	0.18	131	0.52	0.839	1.205	344	3,528	0.67

LANGEPASNEFTEGAS SUBSIDIARY
RESERVOIR PARAMETERS

Field	Reservoir	Field Area	Category	Area (Acres)	Avg Net Thickness (Feet)	Net Volume (Acre-Feet)	Porosity (fraction)	Permeability (md)	Oil Saturation (fraction)	Oil Specific Gravity	Oil FVF (RBbl/STB)	Solution Gas Ratio (SCF/STB)	Estimated Original Pressure (psi)	Oil Viscosity (cp)
POTOCHNOYE (cont)														
	Achem.	Pilot	Proven	247	16.6	4,110	0.17	4	0.54	0.832	1.250	341	3,675	2.00
	UV1-1		Proven	1,730	11.5	19,862	0.15	3	0.67	0.822	1.282	535	3,822	0.53
	UV1-1		Probable	5,807	3.3	19,052	0.15	3	0.67	0.822	1.282	535	3,822	0.53
	UV1-3		Proven	185	8.3	1,540	0.21	7	0.68	0.835	1.250	544	3,822	0.80
SOUTH POKACHOVSKOYE														
	AB1,3	Main Area	Proven	18,081	8.9	160,165	0.19	130	0.42	0.857	1.133	209	2,661	1.72
	AB1,3	Main Area	Probable	892	7.5	6,733	0.19	130	0.42	0.857	1.133	209	2,661	1.72
	AB2	Main Area	Proven	18,006	16.5	296,889	0.22	107	0.56	0.849	1.134	129	2,690	2.48
	bB6	Main Area	Proven	7,441	19.0	141,585	0.19	205	0.52	0.857	1.124	265	3,381	2.60
	bB6	Amanskaya area	Proven	2,111	14.7	31,087	0.19	205	0.56	0.857	1.111	467	3,381	2.60
	bB8	Main Area	Proven	14,688	26.8	393,219	0.20	201	0.61	0.841	1.171	274	3,528	0.92
	bB8	Amanskaya area	Proven	1,571	18.2	28,609	0.20	201	0.49	0.846	1.248	247	3,528	0.92
	bB8	Amanskaya area	Probable	463	9.8	4,560	0.20	201	0.49	0.846	1.248	247	3,528	0.92
	bB10		Proven	745	8.6	6,382	0.19	180	0.48	0.841	1.171	255	3,557	1.10
	Achem.		Proven	1,544	13.3	20,511	0.17	18	0.50	0.829	1.245	414	3,675	1.27
	Achem.		Probable	792	6.8	5,380	0.17	18	0.50	0.829	1.245	414	3,675	1.27
	UB1-1		Proven	309	13.1	4,054	0.17	14	0.63	0.829	1.245	414	3,900	0.79
	UB1-1		Probable	1,007	7.3	7,332	0.17	14	0.63	0.829	1.245	414	3,900	0.79
URYEVSKOYE														
	AB1-3	Main Area	Proven	71,432	22.5	1,609,596	0.23	296	0.58	0.859	1.099	188	2,646	1.94
	AB1-3	Main Area	Probable	11,033	9.8	108,595	0.23	296	0.58	0.859	1.099	188	2,646	1.94
	AB1-3	SE Area	Proven	6,373	18.9	120,618	0.23	296	0.61	0.859	1.099	195	2,646	1.94
	AB1-3	SE Area	Probable	2,854	9.8	28,091	0.23	296	0.61	0.859	1.099	195	2,646	1.94
	AB1-3	Chump.	Proven	618	13.1	8,107	0.24	296	0.57	0.863	1.111	174	2,646	1.94
	AB1-3	Chump.	Probable	1,446	7.5	10,908	0.24	296	0.57	0.863	1.111	174	2,646	1.94
	AB2		Proven	12,108	11.5	139,037	0.22	296	0.62	0.859	1.099	188	2,646	1.94
	AB2		Probable	6,657	6.2	41,277	0.22	296	0.62	0.859	1.099	188	2,646	1.94
	bB6	Main Area	Proven	10,885	21.3	232,127	0.21	230	0.59	0.880	1.136	217	3,175	2.55
	bB6	NE Area	Proven	4,582	23.0	105,237	0.20	230	0.50	0.880	1.136	217	3,175	2.55
	bB8	Main Area	Proven	5,401	14.8	80,093	0.21	306	0.61	0.844	1.149	270	3,278	1.41
	bB8	NE Area	Proven	3,614	17.1	61,773	0.20	306	0.55	0.842	1.220	275	3,278	1.41
	bB10-1	NE Area	Proven	2,638	14.1	37,138	0.19	15	0.58	0.832	1.176	349	3,337	0.67
	bB10-1	NE Area	Probable	704	9.8	6,932	0.19	15	0.58	0.832	1.176	349	3,337	0.67
	bB10-1	SE Area	Proven	597	20.3	12,141	0.19	15	0.58	0.832	1.176	349	3,337	0.67
	bB10-1	SE Area	Probable	251	9.8	2,469	0.19	15	0.58	0.832	1.176	349	3,337	0.67
	UB1	Urevsk., I and II	Proven	12,009	13.1	157,283	0.15	7	0.61	0.822	1.282	535	3,851	0.54
	UB1	Urevsk., I and II	Probable	8,599	12.5	107,208	0.15	7	0.62	0.822	1.282	535	3,851	0.54
	UB1	Total west (III and IV)	Proven	10,082	20.6	207,245	0.16	7	0.60	0.830	1.235	419	3,851	0.54
	UB1	Total west (III and IV)	Probable	19,274	19.4	374,353	0.16	7	0.60	0.830	1.235	419	3,851	0.54
	UB1	Chumpask., V	Proven	556	32.8	18,241	0.18	7	0.64	0.830	1.235	419	3,851	0.54
	UB1	Chumpask., V	Probable	4,534	24.7	112,169	0.18	7	0.64	0.830	1.235	419	3,851	0.54
	UB1	SE Area	Proven	1,298	10.1	13,154	0.16	7	0.60	0.830	1.235	419	3,851	0.54
	UB1	SE Area	Probable	2,196	11.9	26,064	0.16	7	0.60	0.830	1.235	419	3,851	0.54

URAINEFTEGAS SUBSIDIARY
RESERVOIR PARAMETERS

Field	Reservoir	Field Area	Category	Area (Acres)	Avg Net Thickness (Feet)	Net Volume (Acre-Feet)	Porosity (fraction)	Permeability (md)	Oil Saturation (fraction)	Oil Specific Gravity	Oil FVF (RBbl/STB)	Solution Gas Ratio (SCF/STB)	Estimated Original Pressure (psi)	Oil Viscosity (cp)
DANELOVSKOYE														
	P1	A - East	Proven	20,021	15.0	300,308	0.24	203	0.67	0.847	1.205	264	2,392	1.60
	P1	A - East	Probable	703	10.2	7,194	0.24	203	0.67	0.847	1.205	264	2,392	1.60
	P2	A+B Et+Wt	Proven	14,355	9.3	133,066	0.19	85	0.55	0.855	1.176	267	2,392	1.64
	P2	A+B Et+Wt	Probable	907	6.8	6,162	0.19	85	0.55	0.855	1.176	267	2,392	1.64
	P2	East	Proven	309	11.3	3,486	0.20	85	0.52	0.855	1.176	267	2,392	1.64
	P2	West	Proven	185	9.7	1,804	0.20	85	0.52	0.855	1.176	267	2,392	1.64
	T	A - East	Proven	1,053	12.6	13,284	0.19	135	0.59	0.860	1.176	266	2,385	1.55
	T	A - East	Probable	795	8.1	6,440	0.19	135	0.59	0.860	1.176	266	2,385	1.55
	T	B - West	Proven	8,933	11.5	102,282	0.19	135	0.59	0.850	1.176	265	2,385	1.55
	T	C - Kazan	Proven	2,224	6.1	13,462	0.19	109	0.59	0.860	1.176	285	2,385	1.55
	T	C - Kazan	Probable	1,481	6.5	9,575	0.19	109	0.59	0.860	1.176	285	2,385	1.55
	W. B.	A - East	Proven	9,395	12.3	115,621	0.16	5	0.55	0.848	1.205	290	2,354	1.55
	Well		Proven	62	6.5	405	0.19	109	0.59	0.860	1.176	285	2,385	1.55
	10577		Probable	25	6.7	168	0.19	109	0.59	0.860	1.176	285	2,385	1.55
FELEPPOVSKOYE														
	T1		Proven	6,941	6.4	44,648	0.16	12	0.51	0.840	1.266	474	2,624	0.75
	T1		Probable	285	3.5	1,009	0.16	12	0.51	0.840	1.266	474	2,624	0.75
	T2		Proven	6,811	11.1	75,449	0.19	34	0.57	0.839	1.266	474	2,653	0.67
	T2		Probable	580	3.8	2,206	0.19	34	0.57	0.839	1.266	474	2,653	0.67
LAZAREVOSKOYE														
	T1	East	Proven	933	15.2	14,154	0.17	210	0.56	0.880	1.190	442	2,801	0.88
	T1	East	Probable	1,903	9.8	18,727	0.17	210	0.56	0.880	1.190	442	2,801	0.88
	T1	Center &	Proven	13,387	9.3	125,078	0.17	210	0.57	0.827	1.190	416	2,801	0.88
	T1	West	Probable	4,306	3.3	14,127	0.17	210	0.57	0.827	1.190	416	2,801	0.88
	T2	East Area	Proven	2,409	10.9	26,368	0.18	367	0.64	0.832	1.220	418	2,815	0.88
	T2		Probable	976	7.1	6,885	0.18	367	0.64	0.832	1.220	418	2,815	0.88
	T2	Central Area	Proven	5,183	16.1	83,462	0.18	367	0.72	0.832	1.220	418	2,815	0.88
	T2		Probable	1,353	13.6	18,465	0.18	367	0.72	0.832	1.220	418	2,815	0.88
	T2	West Area	Proven	6,905	18.7	129,286	0.18	367	0.72	0.832	1.220	418	2,815	0.88
	T2		Probable	432	12.8	5,547	0.18	367	0.72	0.832	1.220	418	2,815	0.88
	T3	Center &	Proven	3,010	12.4	37,230	0.17	200	0.53	0.835	1.163	281	2,864	1.18
	T3	West	Probable	754	9.8	7,418	0.17	200	0.53	0.835	1.163	281	2,864	1.18
	T3	East Area	Proven	680	11.9	8,107	0.17	200	0.53	0.835	1.163	281	2,864	1.18
	T3		Probable	494	15.3	7,572	0.17	200	0.53	0.835	1.163	281	2,864	1.18
LOVINSKOYE														
	U2-4		Proven	49,578	24.8	1,227,681	0.18	200	0.60	0.830	1.220	382	2,080	1.21
	U2-4		Probable	5,644	13.7	77,399	0.18	200	0.60	0.830	1.220	382	2,080	1.21
	U2-4		Proven	2,100	41.1	86,300	0.16	200	0.56	0.832	1.190	383	2,080	1.21
	U2-4		Probable	2,724	33.3	90,811	0.16	200	0.56	0.832	1.190	383	2,080	1.21
	U5-6		Proven	40,200	15.9	641,046	0.18	30	0.55	0.834	1.261	459	2,145	1.21
	U5-6		Probable	4,495	17.4	78,149	0.18	30	0.56	0.834	1.253	459	2,145	1.21
MANSENGYANSKOYE														
	T1		Proven	4,633	9.7	45,043	0.18	90	0.53	0.828	1.176	302	2,511	1.36
	T1		Probable	2,889	6.0	17,342	0.18	90	0.53	0.828	1.176	302	2,511	1.36
	T2		Proven	3,459	16.8	57,982	0.18	180	0.55	0.831	1.250	303	2,525	0.99
	T2		Probable	1,387	8.1	11,198	0.18	180	0.55	0.831	1.250	303	2,525	0.99

URAINEFTEGAS SUBSIDIARY
RESERVOIR PARAMETERS

Field	Reservoir	Field Area	Category	Area (Acres)	Avg Net Thickness (Feet)	Net Volume (Acre-Feet)	Porosity (fraction)	Permeability (md)	Oil Saturation (fraction)	Oil Specific Gravity	Oil FVF (RBbl/STB)	Solution Gas Ratio (SCF/STB)	Estimated Original Pressure (psi)	Oil Viscosity (cp)
MAPTEMJA-TETEROVSKOYE														
	P		Proven	49,375	23.4	1,156,901	0.24	455	0.74	0.834	1.293	448	2,117	0.63
	T		Proven	979	6.8	6,691	0.14	11	0.69	0.834	1.306	539	2,159	0.96
	W. B.		Proven	1,036	10.7	11,118	0.14	11	0.67	0.830	1.351	536	2,124	1.00
MULYMINSKOYE														
	P		Proven	4,027	12.5	50,407	0.21	192	0.81	0.815	1.250	363	1,997	2.23
	W. B.		Proven	988	9.8	9,729	0.14	309	0.50	0.815	1.250	325	1,982	2.20
NORTH DANELOVSKOYE														
	P1		Proven	17,151	18.3	314,487	0.23	103	0.65	0.838	1.205	376	2,356	3.41
	P1		Probable	100	7.7	773	0.23	103	0.65	0.838	1.205	376	2,356	3.41
	P2		Proven	8,044	9.8	78,481	0.19	95	0.55	0.837	1.205	376	2,370	2.28
	T		Proven	281	4.0	1,136	0.19	56	0.55	0.838	1.212	376	2,392	3.19
	W. B.		Proven	914	8.2	7,499	0.14	103	0.50	0.838	1.212	376	2,385	2.20
SHUSHYNSKOYE														
	T1	A	Proven	185	10.5	1,946	0.19	30	0.57	0.836	1.205	342	2,582	0.94
	T1	A	Probable	177	3.3	580	0.19	30	0.57	0.836	1.205	342	2,582	0.94
	T1	B	Proven	4,941	6.7	32,905	0.19	30	0.57	0.836	1.205	333	2,582	0.94
	T1	C	Proven	5,940	8.7	51,685	0.19	30	0.57	0.836	1.205	333	2,582	0.94
	T1	C	Probable	268	8.7	2,333	0.19	30	0.57	0.836	1.205	333	2,582	0.94
	T1	D	Proven	865	6.6	5,675	0.19	30	0.57	0.836	1.205	333	2,582	0.94
	T1	D	Probable	247	6.6	1,621	0.19	30	0.57	0.836	1.205	333	2,582	0.94
	T1	E	Proven	1,682	8.8	14,732	0.19	30	0.57	0.836	1.205	333	2,582	0.94
	T1	E	Probable	3,842	4.5	17,271	0.19	30	0.57	0.836	1.205	333	2,582	0.94
	T2	A	Proven	371	9.8	3,648	0.20	165	0.58	0.836	1.205	342	2,596	0.94
	T2	A	Probable	290	21.8	6,314	0.20	165	0.58	0.836	1.205	342	2,596	0.94
	T2	B	Proven	3,140	7.2	22,459	0.20	165	0.58	0.836	1.205	333	2,596	0.94
	T2	C	Proven	2,764	10.3	28,539	0.20	165	0.58	0.836	1.205	333	2,596	0.94
	T2	C	Probable	703	8.6	6,055	0.20	165	0.58	0.836	1.205	333	2,596	0.94
	T2	D	Proven	2,409	18.2	43,791	0.20	165	0.58	0.836	1.205	333	2,596	0.94
	T2	D	Probable	1,677	8.1	13,532	0.20	165	0.58	0.836	1.205	333	2,596	0.94
	T2	E	Proven	1,774	15.5	27,537	0.20	165	0.58	0.836	1.205	333		
	T2	E	Probable	1,166	10.2	11,860	0.20	165	0.58	0.836	1.205	333		
	T2	Malosush-	Proven	432	11.2	4,824	0.20	165	0.58	0.836	1.205	333	2,596	0.94
	T2	minskaya	Probable	2,610	13.3	34,597	0.20	165	0.58	0.836	1.205	333	2,596	0.94
	T		Proven	1,668	21.7	36,117	0.20	165	0.65	0.836	1.205	342	2,596	0.94
	T		Probable	880	19.1	16,773	0.20	165	0.65	0.836	1.205	342	2,596	0.94
SREDNE MULYMIYNSKOYE														
		Andreevskoe	Proven	1,544	8.7	13,397	0.20	269	0.85	0.875	1.176	98	2,587	2.12
			Probable	840	6.6	5,513	0.20	269	0.85	0.875	1.176	98	2,587	2.12
SYMORYAKSKOYE														
	T1	center	Proven	12,584	15.8	198,847	0.18	20	0.57	0.838	1.186	289	2,631	1.45
	T1	center	Probable	17,137	13.0	222,080	0.18	20	0.57	0.838	1.186	289	2,631	1.45
	T1	south	Proven	7,574	9.8	74,545	0.18	20	0.57	0.838	1.186	289	2,631	1.45
	T1	south	Probable	7,611	6.7	50,939	0.18	20	0.57	0.838	1.186	289	2,631	1.45
	T2	center	Proven	2,718	11.5	31,212	0.18	275	0.57	0.838	1.186	289	2,631	1.45
	T2	center	Probable	1,452	6.3	9,097	0.18	275	0.57	0.838	1.186	289	2,631	1.45
	T2	south	Proven	5,257	14.0	73,754	0.18	235	0.57	0.838	1.186	289	2,631	1.45
	T2	south	Probable	4,442	19.2	85,249	0.18	235	0.57	0.838	1.186	289	2,631	1.45
	P		Proven	4,127	14.0	57,697	0.18	235	0.57	0.838	1.186	289	2,631	1.45
	P		Probable	2,175	19.6	42,663	0.18	235	0.57	0.838	1.186	289	2,631	1.45

URAINEFTEGAS SUBSIDIARY
RESERVOIR PARAMETERS

Field	Reservoir	Field Area	Category	Area (Acres)	Avg Net Thickness (Feet)	Net Volume (Acre-Feet)	Porosity (fraction)	Permeability (md)	Oil Saturation (fraction)	Oil Specific Gravity	Oil FVF (RBbl/STB)	Solution Gas Ratio (SCF/STB)	Estimated Original Pressure (psi)	Oil Viscosity (cp)
TALNIKOVOYE														
	P	A	Proven	2,595	11.5	29,794	0.18	60	0.52	0.853	1.176	359	2,441	1.43
	P	A	Probable	4,238	12.6	53,251	0.18	60	0.52	0.853	1.176	359	2,441	1.43
	T	A	Proven	7,846	26.1	204,907	0.19	31	0.55	0.860	1.124	362	2,497	2.12
	T	A	Probable	11,021	32.5	358,322	0.19	31	0.55	0.860	1.124	362	2,497	2.12
	W. B.		Probable	1,722	3.3	5,650	0.18	1	0.46	0.840	1.176	354	2,483	4.64
TOLUMSKOYE														
	P	A - NW	Proven	988	20.9	20,655	0.22	431	0.77	0.842	1.099	143	2,469	1.98
	P		Probable	1,476	19.4	28,628	0.22	431	0.77	0.842	1.099	143	2,469	1.98
	P	B - west	Proven	2,850	1.6	4,552	0.22	215	0.66	0.842	1.099	143	2,469	1.98
	P	B - west	Probable	877	10.9	9,581	0.22	215	0.66	0.842	1.099	143	2,469	1.98
	P	C - south	Proven	7,389	18.7	138,188	0.17	450	0.61	0.857	1.099	146	2,469	1.98
	P	C - south	Probable	336	12.8	4,286	0.22	215	0.66	0.857	1.099	146	2,469	1.98
	P	D - malo	Proven	1,480	16.4	24,285	0.22	431	0.72	0.857	1.099	146	2,469	1.98
	P	E - east	Proven	10,319	26.2	270,829	0.22	431	0.80	0.854	1.087	107	2,469	1.98
	T	E - east	Proven	1,708	10.2	17,346	0.17	344	0.80	0.854	1.087	145	2,483	1.89
	T	B - west	Proven	580	10.7	6,203	0.17	344	0.68	0.842	1.099	143	2,483	1.89
	T	B - west	Probable	212	7.2	1,527	0.17	344	0.68	0.842	1.099	143	2,483	1.89
	W. B.	B - west	Proven	121	9.5	1,154	0.14	348	0.50	0.842	1.099	143	2,314	1.72
	W. B.	C - south	Proven	336	8.5	2,865	0.14	348	0.50	0.842	1.099	143	2,314	1.72
TROEKHOZERNOYE														
	P1		Proven	6,892	10.7	73,626	0.22	9	0.76	0.819	1.176	285	2,025	3.59
	P2		Proven	11,602	16.1	186,520	0.24	259	0.80	0.819	1.176	285	2,039	3.59
	T		Proven	1,296	7.2	9,355	0.16	5	0.50	0.841	1.176	293	2,060	0.57
UBINSKOYE														
	P	A-Central	Proven	8,951	5.0	44,639	0.19	49	0.64	0.832	1.205	350	2,526	0.88
	T1	A-Central	Proven	3,711	7.4	27,612	0.19	45	0.66	0.839	1.235	372	2,526	1.94
	T1	B - SE	Proven	1,359	16.6	22,619	0.20	45	0.51	0.839	1.235	372	2,526	1.94
	T1	B - SE	Probable	494	12.7	6,291	0.20	45	0.51	0.839	1.235	372	2,526	1.94
	T1 + T2	C - West	Proven	10,333	12.8	132,296	0.17	24	0.65	0.839	1.235	272	2,526	1.94
	T1 + T2	C - West	Probable	3,368	9.6	32,485	0.17	24	0.65	0.839	1.235	272	2,526	1.94
	W. B.	C - West	Proven	2,315	23.6	54,726	0.19	49	0.64	0.844	1.176	256	2,582	2.60
	W. B.	C - West	Probable	494	4.3	2,108	0.19	49	0.64	0.844	1.176	256	2,582	2.60
	W. B.	A-Central	Proven	3,155	10.1	31,795	0.18	49	0.66	0.834	1.220	337	2,582	2.60
	W. B.	A-Central	Probable	526	5.2	2,759	0.18	49	0.66	0.834	1.220	337	2,582	2.60
UZBEKSKOYE														
	P		Proven	4,726	6.3	29,624	0.18	9	0.64	0.862	1.136	494	2,265	6.45
	P		Probable	1,487	6.6	9,756	0.18	9	0.64	0.862	1.136	494	2,265	6.45
	T		Proven	2,329	12.5	29,148	0.20	5	0.74	0.840	1.205	481	2,279	0.86
	T		Probable	212	13.1	2,786	0.20	5	0.74	0.840	1.205	481	2,279	0.86
YAKLINSKOYE														
	U2-3		Proven	6,548	21.9	143,082	0.15	9	0.59	0.834	1.261	429	3,202	3.60
	U2-3		Probable	4,357	21.9	95,201	0.15	9	0.59	0.834	1.261	429	3,202	3.60
	U2-4		Proven	3,310	23.0	76,022	0.17	60	0.57	0.834	1.261	429	3,284	3.60
	U2-4		Probable	947	5.9	5,622	0.17	60	0.57	0.834	1.261	429	3,284	3.60

URAINEFTEGAS SUBSIDIARY
RESERVOIR PARAMETERS

Field	Reservoir	Field Area	Category	Area (Acres)	Avg Net Thickness (Feet)	Net Volume (Acre-Feet)	Porosity (fraction)	Permeability (md)	Oil Saturation (fraction)	Oil Specific Gravity	Oil FVF (RBbl/STB)	Solution Gas Ratio (SCF/STB)	Estimated Original Pressure (psi)	Oil Viscosity (cp)
TURSUNT JOINT VENTURE														
KULTURSKYA														
	P	Kulturskaya	Proven	1,167	14.6	17,043	0.19	30	0.63	0.863	1.111	494	2,234	1.00
	P	Turskaya	Proven	1,004	16.3	16,367	0.19	30	0.64	0.863	1.111	494	2,234	1.00
	T	Kulturskaya	Proven	424	7.9	3,335	0.20	50	0.74	0.840	1.205	481	2,234	2.50
	T	Turskaya	Proven	63	4.5	281	0.19	30	0.61	0.863	1.111	494	2,234	1.00
SLAVENSKOYE														
			Proven	4,510	11.5	51,784	0.20	50	0.74	0.840	1.205	481	2,234	2.50
			Probable	2,329	11.5	26,743	0.20	50	0.74	0.840	1.205	481	2,234	2.50

KOGALYMNEFTEGAS SUBSIDIARY
RESERVOIR PARAMETERS

Field	Reservoir	Field Area	Category	Area (Acres)	Avg Net Thickness (Feet)	Net Volume (Acre-Feet)	Porosity (fraction)	Permeability (md)	Oil Saturation (fraction)	Oil Specific Gravity	Oil FVF (RBbl/STB)	Solution Gas Ratio (SCF/STB)	Estimated Original Pressure (psi)	Oil Viscosity (cp)
DRUZHNOYE														
	bC10-0		Proven	1,575	17.0	26,772	0.24	124	0.54	0.863	1.103	204	3,381	1.80
	bC10-0		Probable	1,081	14.3	15,429	0.24	124	0.54	0.863	1.103	204	3,381	1.80
	bC10-1		Proven	24,334	20.9	508,417	0.22	124	0.65	0.863	1.103	204	3,381	1.80
	bC10-1		Probable	8,513	14.1	120,374	0.22	124	0.65	0.863	1.103	204	3,381	1.80
	bC10-2		Proven	17,934	17.7	317,230	0.23	173	0.64	0.865	1.156	204	3,381	1.80
	bC10-2		Probable	575	19.7	11,309	0.23	173	0.64	0.865	1.156	204	3,381	1.80
	bC10-3		Proven	3,096	22.5	69,787	0.24	104	0.54	0.865	1.114	204	3,381	1.80
	bC11-0		Proven	2,513	6.2	15,556	0.21	55	0.48	0.909	1.166	194	3,528	1.90
	bC11-0		Probable	292	3.5	1,024	0.21	55	0.48	0.909	1.166	194	3,528	1.90
	bC11-1		Proven	19,455	11.1	215,775	0.22	55	0.59	0.855	1.119	182	3,528	1.90
	bC11-1		Probable	2,979	7.3	21,696	0.22	55	0.59	0.855	1.119	182	3,528	1.90
	bC11-2		Proven	8,424	12.3	103,852	0.22	123	0.59	0.857	1.107	183	3,528	1.90
	bC11-2		Probable	13,525	20.7	279,547	0.22	123	0.59	0.857	1.107	183	3,528	1.90
	UC1		Proven	5,876	19.4	113,937	0.18	11	0.46	0.832	1.263	504	3,480	1.70
	UC1		Probable	5,849	12.0	70,420	0.18	11	0.46	0.832	1.263	504	3,480	1.70
EAST PRIDOROZHNOYE														
	AB8-2a		Proven	2,378	14.4	34,334	0.21	79	0.58	0.875	1.176	147	3,396	0.94
	AB8-2a		Probable	499	4.8	2,391	0.21	79	0.49	0.875	1.176	147	3,396	0.94
	AB8-2b		Proven	1,918	8.8	16,797	0.21	79	0.58	0.875	1.176	147	3,396	0.94
	AB8-2b		Probable	436	6.3	2,747	0.21	79	0.49	0.875	1.176	147	3,396	0.94
	AB8		Proven	1,236	6.7	8,269	0.23	194	0.62	0.855	1.175	259	3,396	0.94
	AB8		Probable	1,087	2.9	3,103	0.21	194	0.51	0.855	1.175	259	3,396	0.94
	bB0		Proven	4,985	31.8	158,595	0.21	262	0.64	0.861	1.198	329	3,425	0.93
	bB0		Probable	803	25.3	20,314	0.21	262	0.64	0.861	1.198	329	3,425	0.93
	bB3		Proven	556	22.4	12,440	0.17	6	0.49	0.855	1.203	360	3,568	0.74
	bB3		Probable	750	7.0	5,241	0.17	6	0.49	0.855	1.203	360	3,568	0.74
	bB4-1	Main	Proven	5,252	19.8	134,227	0.21	172	0.64	0.808	1.203	340	3,484	0.74
	bB4-1	Main	Probable	4,120	11.7	48,315	0.17	172	0.46	0.808	1.203	340	3,484	0.74
	bB4-2		Proven	1,923	8.9	17,043	0.20	172	0.58	0.863	1.205	363	3,484	0.74
	UB0-1		Proven	4,015	14.4	57,966	0.16	3	0.60	0.808	1.203	445	4,167	0.74
	UB0-1		Probable	2,824	5.8	16,494	0.16	3	0.60	0.808	1.203	445	4,167	0.74
	UB0-2		Proven	1,112	6.7	7,406	0.16	3	0.60	0.808	1.203	445	4,167	0.74
	UB1-1a	Main	Proven	9,575	12.8	122,904	0.18	281	0.64	0.808	1.203	445	4,190	0.74
	UB1-1a	Main	Probable	14,178	12.4	175,825	0.18	281	0.64	0.808	1.203	445	4,190	0.74
	UB1-1b		Proven	2,294	9.2	21,094	0.16	13	0.59	0.808	1.203	445	4,190	0.74
	UB1-1b		Probable	3,320	9.4	31,151	0.16	13	0.56	0.808	1.203	445	4,190	0.74
GRIBNOYE														
	U 1-1		Proven	4,874	31.1	151,599	0.19	35	0.63	0.789	1.225	483	4,351	0.74
	U 1-1		Probable	4,139	24.2	100,352	0.19	35	0.63	0.789	1.225	483	4,351	0.74
	U 1-1		Proven	309	15.7	4,864	0.19	35	0.63	0.789	1.225	483	4,351	0.74
	U 1-1		Probable	321	10.6	3,394	0.19	35	0.63	0.789	1.225	483	4,351	0.74
KOCHEVSKOYE (Vatoil Joint Venture Field)														
	bC 10-1		Proven	4,998	20.7	85,866	0.19	50	0.51	0.850	1.136	253	3,763	1.60
	bC 10-1		Probable	10,298	22.7	169,630	0.19	50	0.51	0.850	1.136	253	3,763	1.60
	bC 16		Proven	556	8.3	4,615	0.16	6	0.55	0.838	1.266	405	4,101	0.78
	bC 16		Probable	741	8.2	6,080	0.16	6	0.55	0.838	1.266	405	4,101	0.78
	bC 18,19		Proven	1,112	36.7	40,860	0.16	6	0.53	0.838	1.266	423	4,101	0.82
	bC 18,19		Probable	6,709	12.6	84,521	0.16	6	0.53	0.838	1.266	423	4,101	0.82
	bC 20		Proven	3,954	28.7	113,499	0.16	6	0.49	0.838	1.266	423	4,101	0.82
	bC 20		Probable	15,759	18.0	283,333	0.16	6	0.49	0.838	1.266	423	4,101	0.82
	UC 1-1		Proven	3,151	14.8	46,514	0.16	6	0.61	0.822	1.244	457	4,234	0.52
	UC 1-1		Probable	40,606	10.2	414,314	0.16	6	0.61	0.822	1.244	457	4,234	0.52

KOGALYMNEFTEGAS SUBSIDIARY
RESERVOIR PARAMETERS

Field	Reservoir	Field Area	Category	Area (Acres)	Avg Net Thickness (Feet)	Net Volume (Acre-Feet)	Porosity (fraction)	Permeability (md)	Oil Saturation (fraction)	Oil Specific Gravity	Oil FVF (RBbl/STB)	Solution Gas Ratio (SCF/STB)	Estimated Original Pressure (psi)	Oil Viscosity (cp)
KUMALI-YAGUNSKOYE														
	UC1		Proven	1,601	19.0	30,407	0.18	26	0.48	0.849	1.263	405	3,925	1.70
	UC1		Probable	2,032	19.6	39,875	0.18	26	0.48	0.849	1.263	405	3,925	1.70
KUSTOVOYE														
	Achem C4-1		Proven	2,894	12.5	36,226	0.21	14	0.49	0.860	1.099	159	3,366	1.10
	Achem C4-1		Probable	1,771	5.8	10,223	0.21	14	0.49	0.860	1.099	159	3,366	1.10
	bC 10-1		Proven	5,150	7.5	38,864	0.20	12	0.54	0.859	1.099	203	3,440	1.11
	bC 10-1		Probable	2,363	6.1	14,316	0.20	12	0.54	0.859	1.099	203	3,440	1.11
	bC 10-2,3		Proven	1,236	10.7	13,174	0.21	43	0.60	0.859	1.099	207	3,440	1.11
	bC 10-2,3		Probable	9,664	6.0	57,639	0.21	43	0.60	0.859	1.099	207	3,440	1.11
	bC 11-1		Proven	11,880	16.7	198,062	0.22	49	0.55	0.853	1.163	302	3,440	1.11
	bC 11-1		Probable	7,410	17.1	126,578	0.22	49	0.55	0.853	1.163	302	3,440	1.11
	bC 11-2		Proven	8,500	20.5	174,051	0.21	80	0.64	0.836	1.190	296	3,469	1.11
	bC 11-2		Probable	2,218	13.3	29,468	0.21	80	0.64	0.836	1.190	296	3,469	1.11
	bC 19		Proven	1,792	20.1	36,030	0.19	2	0.63	0.832	1.220	420	3,995	0.62
	bC 19		Probable	1,050	12.9	13,541	0.19	2	0.55	0.832	1.220	420	3,995	0.62
	UC 0		Proven	7,104	44.3	314,657	0.08	2	0.85	0.817	1.449	826	4,175	0.62
	UC 0		Probable	14,029	30.5	427,601	0.08	2	0.85	0.817	1.449	826	4,175	0.62
	UC 1-0		Proven	988	8.1	8,010	0.17	2	0.61	0.832	1.220	420	4,204	0.62
	UC 1-1		Proven	8,945	14.8	132,515	0.18	23	0.59	0.832	1.220	420	4,234	0.62
	UC 1-1		Probable	19,713	11.1	218,599	0.18	23	0.58	0.832	1.220	420	4,234	0.62
NORTH KOCHEVSKOYE														
	bC10-2,3		Proven	2,718	16.7	45,400	0.21	134	0.67	0.858	1.130	246	3,822	1.08
	bC10-2,3		Probable	3,262	10.7	34,779	0.21	134	0.67	0.858	1.130	246	3,822	1.08
	bC11-1		Proven	556	15.1	8,391	0.19	23	0.58	0.858	1.130	246	3,822	1.25
	bC11-1		Probable	988	13.1	12,971	0.19	23	0.58	0.858	1.130	246	3,822	1.25
	bC 16		Proven	2,409	26.2	63,235	0.17	4	0.60	0.838	1.266	423	4,145	0.76
	bC 16		Probable	34,570	14.2	492,236	0.17	4	0.60	0.838	1.266	423	4,145	0.76
	bC 18,19		Proven	1,112	14.8	16,417	0.17	7	0.60	0.838	1.266	423	4,190	0.72
	bC 18,19		Probable	22,536	8.9	201,108	0.17	7	0.60	0.838	1.266	423	4,190	0.72
	bC 20		Proven	1,112	23.0	25,537	0.17	6	0.60	0.850	1.316	430	4,204	0.80
	bC 20		Probable	6,772	12.7	85,766	0.17	6	0.60	0.850	1.316	430	4,204	0.80
	UC 1-1		Proven	3,459	13.5	46,819	0.16	6	0.60	0.860	1.333	478	4,381	0.72
	UC 1-1		Probable	7,364	11.9	87,263	0.16	6	0.60	0.860	1.333	478	4,381	0.72
NORTH KOGAYLMSKOYE														
	bc18		Proven	371	16.4	6,080	0.18	5	0.60	0.850	1.333	406	3,963	1.70
	bc18		Probable	259	21.1	5,463	0.18	5	0.60	0.850	1.333	406	3,963	1.70
NORTH KONITLORSKOYE														
	U1		Proven	988	21.0	20,774	0.16	5	0.60	0.822	1.250	572	4,148	0.67
	U1		Probable	8,352	16.4	137,149	0.16	5	0.60	0.822	1.250	572	4,148	0.67
POVKHOVSKOYE														
	bB 7-1		Proven	556	9.9	5,509	0.19	50	0.61	0.837	1.176	385	3,646	0.75
	bB 7-1		Probable	3,555	3.5	12,597	0.19	50	0.61	0.837	1.176	385	3,646	0.75
	bB 7-2		Proven	6,734	17.9	120,842	0.19	51	0.66	0.837	1.176	385	3,654	0.75
	bB 7-2		Probable	15,611	4.2	65,557	0.19	51	0.66	0.837	1.176	385	3,654	0.75
	bB 7-3		Proven	865	9.8	8,512	0.19	51	0.80	0.837	1.176	385	3,662	0.75
	bB 7-3		Probable	4,592	5.3	24,559	0.19	51	0.80	0.837	1.176	385	3,662	0.75

KOGALYMNEFTEGAS SUBSIDIARY
RESERVOIR PARAMETERS

Field	Reservoir	Field Area	Category	Area (Acres)	Avg Net Thickness (Feet)	Net Volume (Acre-Feet)	Porosity (fraction)	Permeability (md)	Oil Saturation (fraction)	Oil Specific Gravity	Oil FVF (RBbl/STB)	Solution Gas Ratio (SCF/STB)	Estimated Original Pressure (psi)	Oil Viscosity (cp)
POVKHOVSKOYE (cont)														
	bB 8		Proven	111,704	40.7	4,541,426	0.19	480	0.61	0.842	1.205	373	3,602	0.87
	bB 8		Probable	15,753	25.7	405,211	0.19	480	0.58	0.842	1.205	373	3,602	0.87
	bB 9		Proven	10,087	11.2	112,851	0.19	54	0.54	0.837	1.282	399	3,602	0.93
	bB 9		Probable	859	11.2	9,607	0.19	54	0.48	0.837	1.282	399	3,602	0.93
	bB 10		Proven	4,529	11.4	51,562	0.19	57	0.53	0.837	1.282	399	3,602	0.94
	bB 10		Probable	542	11.4	6,169	0.19	57	0.53	0.837	1.282	399	3,602	0.94
	bB 14		Proven	556	6.8	3,776	0.19	50	0.88	0.837	1.176	385	3,454	1.08
	Achem. 2		Proven	2,965	25.4	75,396	0.17	11	0.47	0.832	1.125	397	4,012	0.43
	Achem. 2		Probable	25,699	18.9	486,010	0.17	11	0.47	0.832	1.125	397	4,012	0.43
	Achem. 3		Proven	2,656	25.5	67,674	0.15	5	0.63	0.812	1.250	388	4,033	0.43
	Achem. 3		Probable	6,088	7.4	45,142	0.15	5	0.63	0.812	1.250	388	4,033	0.43
	UB1		Proven	11,429	19.2	218,973	0.18	6	0.67	0.844	1.351	588	4,337	0.71
	UB1		Probable	13,183	19.0	250,565	0.18	6	0.67	0.844	1.351	588	4,337	0.71
	UB 1-1		Proven	11,807	20.5	241,787	0.18	6	0.67	0.844	1.351	588	4,337	0.71
	UB 1-1		Probable	11,965	16.3	195,091	0.15	6	0.57	0.844	1.351	588	4,337	0.71
	YU/1		Proven	1,421	17.9	25,456	0.16	na	0.57	0.828	1.351	576	na	na
	YU/1		Probable	1,730	13.1	22,700	0.16	na	0.57	0.828	1.351	576	na	na
RAVENSKOYE														
	UC 1-1		Proven	556	16.4	9,120	0.16	44	0.60	0.840	1.163	509	3,985	0.62
	UC 1-1		Probable	420	15.6	6,552	0.16	44	0.60	0.840	1.163	514	3,985	0.62
	UC 2-1		Proven	5,560	9.1	50,791	0.16	5	0.75	0.880	1.163	534	4,130	0.62
	UC 2-1		Probable	12,602	9.8	123,625	0.16	5	0.75	0.880	1.163	534	4,130	0.62
	bc187 (ach)		Proven	247	2.0	486	0.2	na	0.6	0.8	1.2	508.0	3,771.0	0.62
SOUTH KONITLORSKOYE														
	Achem 4		Proven	1,050	29.0	30,414	0.20	21	0.50	0.862	1.111	247	3,974	1.50
	Achem 4		Probable	2,119	30.2	64,026	0.20	21	0.50	0.862	1.111	247	3,974	1.50
	Achem 5		Proven	1,050	29.0	30,414	0.20	21	0.50	0.862	1.111	247	3,974	1.50
	Achem 5		Probable	2,119	30.2	64,026	0.20	21	0.50	0.862	1.111	247	3,974	1.50
	Achem 6		Proven	494	22.4	11,066	0.19	8	0.56	0.862	1.111	247	3,974	1.50
	Achem 6		Probable	793	29.8	23,622	0.19	8	0.56	0.862	1.111	247	3,974	1.50
	Achem 7		Proven	247	10.5	2,594	0.18	8	0.54	0.862	1.111	247	3,974	1.50
	Achem 7		Probable	185	10.5	1,946	0.18	8	0.54	0.862	1.111	247	3,974	1.50
	U0-1V		Proven	865	41.7	36,085	0.19	6	0.50	0.862	1.111	299	4,133	2.27
	U0-1V		Probable	1,483	26.2	38,914	0.19	6	0.50	0.862	1.111	299	4,133	2.27
	U0-1N		Proven	309	9.2	2,837	0.19	6	0.50	0.862	1.111	299	4,133	2.27
	U0-1N		Probable	185	6.6	1,216	0.19	6	0.50	0.862	1.111	299	4,133	2.27
	U1-1		Proven	680	7.9	5,351	0.18	13	0.59	0.822	1.250	285	4,133	2.27
	U1-1		Probable	927	7.9	7,296	0.18	13	0.59	0.822	1.250	285	4,133	2.27
	U2		Proven	927	13.1	12,161	0.17	1	0.68	0.856	1.136	297	4,133	2.36
	U2		Probable	877	11.8	10,389	0.17	1	0.68	0.856	1.136	297	4,133	2.36
	U3		Proven	4,201	21.6	90,597	0.16	8	0.47	0.856	1.136	301	4,133	2.36
	U3		Probable	5,424	39.4	213,541	0.16	8	0.47	0.856	1.136	307	4,133	2.36
SOUTH VYINTOISKOYE														
	bB4-2		Proven	8,525	17.6	149,671	0.18	7	0.60	0.809	1.235	268	3,836	0.60
	bB4-2		Probable	22,480	16.0	359,184	0.18	7	0.60	0.809	1.235	268	3,836	0.60
	bB5		Proven	556	23.3	12,969	0.18	50	0.66	0.809	1.235	268	3,853	0.60
	bB5		Probable	630	4.1	2,584	0.18	50	0.66	0.809	1.235	268	3,853	0.60
	UB 1-1		Proven	309	3.4	1,044	0.16	6	0.60	0.837	1.242	559	4,133	0.43
SOUTH YAGUNSKOYE														
	bC10-1		Proven	50,780	10.0	505,292	0.19	987	0.48	0.853	1.124	244	3,469	1.35
	bC10-1		Probable	7,986	7.8	62,361	0.19	987	0.48	0.853	1.124	244	3,469	1.35

KOGALYMNEFTEGAS SUBSIDIARY
RESERVOIR PARAMETERS

Field	Reservoir	Field Area	Category	Area (Acres)	Avg Net Thickness (Feet)	Net Volume (Acre-Feet)	Porosity (fraction)	Permeability (md)	Oil Saturation (fraction)	Oil Specific Gravity	Oil FVF (RBbl/STB)	Solution Gas Ratio (SCF/STB)	Estimated Original Pressure (psi)	Oil Viscosity (cp)
SOUTH YAGUNSKOYE (cont)														
	bC10-2		Proven	58,465	14.5	848,570	0.22	198	0.63	0.853	1.124	216	3,366	1.60
	bC10-2		Probable	3,756	9.8	36,968	0.22	198	0.63	0.853	1.124	216	3,366	1.60
	bC11-1		Proven	17,524	10.0	175,868	0.20	32	0.47	0.855	1.136	221	3,469	0.80
	bC11-1		Probable	432	7.7	3,320	0.20	32	0.47	0.855	1.136	221	3,469	0.80
	bC11-1a		Proven	969	2.3	2,258	0.20	32	0.48	0.855	1.136	221	3,469	0.80
	bC11-2		Proven	61,739	15.5	956,273	0.22	121	0.79	0.839	1.205	339	3,602	0.80
	bC11-2		Probable	1,878	16.4	30,807	0.22	121	0.79	0.839	1.205	339	3,602	0.80
	bC18		Proven	656	3.3	2,152	0.18	10	0.59	0.839	1.205	339	4,072	0.80
	UV1-1		Proven	13,646	15.8	215,480	0.18	10	0.61	0.823	1.205	286	4,219	0.70
	UV1-1		Probable	8,179	12.5	102,508	0.18	10	0.61	0.823	1.205	286	4,219	0.70
TANEYEVSKOYE														
	U1		Proven	927	22.9	21,241	0.18	26	0.60	0.833	1.185	398	3,932	1.70
	U1		Probable	1,271	23.0	29,192	0.18	26	0.60	0.833	1.185	398	3,932	1.70
TEVLINSKO - RUSSKINSKOYE														
	bC10-0		Proven	4,263	27.2	116,073	0.22	106	0.59	0.853	1.163	292	3,261	1.54
	bC10-0		Probable	10,564	17.5	184,726	0.22	106	0.57	0.853	1.163	292	3,261	1.54
	bC10-1		Proven	1,174	7.1	8,279	0.19	5	0.52	0.857	1.124	245	3,295	1.54
	bC10-2,3		Proven	86,611	52.0	4,505,604	0.20	134	0.61	0.858	1.130	246	3,366	1.54
	bC10-2,3		Probable	17,676	21.2	374,713	0.20	134	0.61	0.858	1.130	246	3,366	1.54
	bC11-1		Proven	5,992	22.1	132,561	0.19	45	0.57	0.858	1.130	246	3,469	1.54
	bC11-1		Probable	25,374	12.3	312,179	0.19	45	0.57	0.858	1.130	246	3,469	1.54
	bC11-2		Proven	9,310	31.8	296,035	0.18	26	0.55	0.847	1.130	243	3,469	1.54
	bC11-2		Probable	7,061	14.4	101,699	0.18	26	0.45	0.847	1.130	243	3,469	1.54
	bC12		Proven	3,948	17.8	70,230	0.17	26	0.54	0.858	1.130	246	3,469	1.54
	bC12		Probable	2,372	12.2	28,874	0.17	26	0.44	0.858	1.130	246	3,469	1.54
	bC16		Proven	1,668	14.9	24,789	0.18	4	0.61	0.838	1.266	508	3,712	1.54
	bC16		Probable	4,887	8.2	40,079	0.18	4	0.49	0.838	1.266	508	3,712	1.54
	bC17		Proven	1,668	34.1	56,802	0.18	4	0.52	0.838	1.266	508	3,800	1.54
	bC17		Probable	2,162	34.7	75,122	0.18	4	0.52	0.838	1.266	508	3,800	1.54
	bC17-0		Probable	12,751	1.6	20,916	0.16	4	0.52	0.838	1.266	508	3,967	1.54
	bC18,19		Proven	3,707	23.1	85,489	0.17	4	0.49	0.838	1.266	508	3,969	1.54
	bC18,19		Probable	19,843	17.1	339,171	0.17	4	0.49	0.838	1.266	508	3,969	1.54
	bC20		Proven	927	44.6	41,346	0.18	4	0.49	0.838	1.266	508	3,768	1.54
	bC20		Probable	9,402	40.3	378,499	0.18	4	0.49	0.838	1.266	508	3,768	1.54
	bC 18-20		Proven	741	13.1	9,729	0.17	4	0.49	0.838	1.266	508	3,969	1.54
	bC 18-20		Probable	1,146	5.1	5,789	0.17	4	0.49	0.838	1.266	508	3,969	1.54
	bC21,22		Proven	2,224	22.1	49,251	0.18	4	0.49	0.838	1.266	508	3,830	1.54
	bC21,22		Probable	7,636	14.5	110,976	0.18	4	0.48	0.838	1.266	508	3,830	1.54
	UC0		Proven	3,645	29.7	108,143	0.07	19	0.85	0.817	1.266	472	4,092	4.55
	UC0		Probable	27,468	20.1	550,975	0.07	19	0.85	0.817	1.266	472	4,092	4.55
	UC1-1		Proven	26,082	14.3	372,568	0.18	19	0.63	0.822	1.244	475	4,219	0.67
	UC1-1		Probable	74,555	13.7	1,019,993	0.18	19	0.62	0.822	1.244	475	4,219	0.67
	UC1-2		Proven	1,668	8.9	14,775	0.18	19	0.59	0.822	1.244	272	4,219	0.67
	UC1-2		Probable	6,066	6.7	40,602	0.18	19	0.59	0.822	1.244	272	4,219	0.67
	UC2-1		Proven	15,172	13.9	210,866	0.16	36	0.67	0.856	1.139	293	4,263	0.67
	UC2-1		Probable	61,406	11.0	676,910	0.16	36	0.67	0.856	1.139	293	4,263	0.67
	UC2-2		Proven	3,583	13.8	49,372	0.17	36	0.67	0.856	1.139	293	4,263	0.67
	UC2-2		Probable	30,493	13.9	423,176	0.17	36	0.67	0.856	1.139	293	4,263	0.67
VAT EGANSKOYE (including VATOIL JOINT VENTURE)														
	AB1-2		Proven	150,462	29.7	4,472,766	0.24	244	0.59	0.860	1.087	159	2,896	2.80
	AB1-2		Probable	25,835	14.5	375,146	0.24	244	0.59	0.860	1.087	159	2,896	2.80
	AB3		Proven	5,603	16.6	93,215	0.24	94	0.58	0.860	1.087	159	2,896	2.50

KOGALYMNEFTEGAS SUBSIDIARY
RESERVOIR PARAMETERS

Field	Reservoir	Field Area	Category	Area (Acres)	Avg Net Thickness (Feet)	Net Volume (Acre-Feet)	Porosity (fraction)	Permeability (md)	Oil Saturation (fraction)	Oil Specific Gravity	Oil FVF (RBbl/STB)	Solution Gas Ratio (SCF/STB)	Estimated Original Pressure (psi)	Oil Viscosity (cp)
VAT EGANSKOYE (including VATOIL JOINT VENTURE) (cont)														
	AB6		Proven	10,650	10.0	105,993	0.23	29	0.54	0.849	1.190	156	2,940	2.48
	AB7-1		Proven	14,344	8.0	114,197	0.23	94	0.54	0.862	1.190	160	2,934	3.00
	AB7-1a		Proven	2,329	8.0	18,551	0.23	94	0.54	0.862	1.190	160	2,934	3.00
	AB7-1b		Proven	692	10.3	7,105	0.23	94	0.54	0.862	1.190	160	2,934	3.00
	AB7-2		Proven	4,417	11.7	51,749	0.23	36	0.54	0.862	1.190	160	2,934	3.00
	AB7-3		Proven	1,804	10.8	19,463	0.21	94	0.56	0.863	1.075	160	2,934	3.00
	AB7-4		Proven	1,792	9.8	17,530	0.21	94	0.56	0.863	1.075	160	2,940	3.00
	AB8-1		Proven	17,804	17.0	303,016	0.22	520	0.57	0.844	1.156	156	3,396	3.00
	AB8-2a		Proven	20,948	13.5	283,272	0.22	520	0.65	0.844	1.124	156	3,396	3.00
	AB8-2b		Proven	12,046	16.7	201,390	0.22	520	0.65	0.844	1.124	156	3,396	3.00
	AB8-2b		Probable	9,526	16.3	155,238	0.22	520	0.65	0.844	1.124	156	3,396	3.00
	bB0		Proven	1,112	27.7	30,827	0.15	5	0.64	0.872	1.198	162	3,425	2.60
	bB0		Probable	3,274	27.7	90,769	0.15	5	0.64	0.872	1.198	162	3,425	2.60
	bB1		Proven	44,540	15.7	700,286	0.22	45	0.55	0.844	1.075	156	3,455	2.60
	bB1		Probable	15,728	11.7	183,866	0.21	45	0.55	0.844	1.075	156	3,455	2.60
	bB2		Proven	1,977	9.8	19,457	0.20	45	0.61	0.831	1.250	154	3,440	2.60
	bB2		Probable	310	7.2	2,228	0.20	45	0.61	0.831	1.250	154	3,440	2.60
	bB4-1		Proven	556	12.5	6,932	0.21	45	0.60	0.861	1.203	160	3,455	2.60
	bB4-1		Probable	2,378	12.5	29,652	0.21	45	0.60	0.861	1.203	160	3,455	2.60
	bB6-1		Proven	327	15.4	5,050	0.20	45	0.66	0.844	1.087	157	3,528	2.31
	bB6-1		Probable	1,859	9.9	18,424	0.20	45	0.66	0.844	1.087	157	3,528	2.31
	bB6-2		Proven	2,959	18.8	55,557	0.20	45	0.56	0.839	1.250	155	3,528	2.31
	bB6-2		Probable	1,859	9.9	18,424	0.20	45	0.56	0.839	1.250	155	3,528	2.31
	bB7		Proven	3,076	10.7	32,813	0.20	45	0.61	0.831	1.250	154	3,675	2.60
	bB7		Probable	272	9.2	2,488	0.20	45	0.61	0.831	1.250	154	3,675	2.60
	bB10		Proven	556	29.5	16,417	0.20	35	0.60	0.839	1.205	317	3,969	0.75
	bB10		Probable	988	26.2	25,943	0.20	35	0.60	0.839	1.205	476	3,969	0.75
	Achem.		Proven	1,476	13.4	19,818	0.20	35	0.60	0.839	1.205	476	4,145	0.75
	Achem.		Probable	1,569	10.0	15,701	0.20	35	0.60	0.839	1.205	476	4,145	0.75
	UB1-1		Proven	32,272	12.1	390,037	0.18	48	0.59	0.830	1.205	471	4,047	0.75
	UB1-1		Probable	36,992	8.7	323,424	0.18	48	0.59	0.830	1.205	471	4,047	0.75
WEST KOTUKHTINSKOYE														
	Achem Ia		Proven	12,849	17.6	225,961	0.15	20	0.50	0.837	1.176	517	4,219	0.43
	Achem Ia		Probable	30,898	13.2	407,512	0.15	20	0.50	0.837	1.176	517	4,219	0.43
	Achem Ib		Proven	1,606	6.9	11,066	0.15	20	0.50	0.837	1.176	517	4,219	0.43
	Achem Ib		Probable	4,491	6.5	29,173	0.15	20	0.50	0.837	1.176	517	4,219	0.43
	Achem II		Proven	3,212	14.6	46,900	0.15	20	0.50	0.837	1.176	517	4,116	0.43
	Achem II		Probable	13,853	12.7	175,431	0.15	20	0.50	0.837	1.176	517	4,116	0.43
	US 1		Proven	680	17.2	11,705	0.17	6	0.59	0.810	1.282	450	4,395	0.71
	US 1		Probable	24,711	17.2	425,623	0.17	6	0.59	0.810	1.282	450	4,395	0.71
AIK JOINT VENTURE														
KOGALYMSKOYE														
	bC10-1b		Proven	9,427	9.1	85,650	0.18	22	0.54	0.849	1.149	257	3,469	1.87
	bC10-1b		Probable	3,459	7.9	27,467	0.17	22	0.45	0.849	1.149	257	3,469	1.87
	bC10-2		Proven	371	4.7	1,727	0.21	58	0.56	0.849	1.149	257	3,469	1.87
	bC10-2		Probable	1,988	4.6	9,130	0.21	58	0.56	0.849	1.149	257	3,469	1.87
	bC11-2		Proven	25,612	27.3	698,926	0.20	75	0.57	0.832	1.190	369	3,469	0.92
	bC11-2		Probable	9,161	9.6	88,365	0.19	75	0.55	0.832	1.190	369	3,469	0.92
	bC11-2b		Proven	432	45.9	19,862	0.20	75	0.57	0.832	1.190	369	3,469	0.92
	bC11-2b		Probable	2,905	39.5	114,654	0.19	75	0.55	0.832	1.190	369	3,469	0.92

KOGALYMNEFTEGAS SUBSIDIARY
RESERVOIR PARAMETERS

Field	Reservoir	Field Area	Category	Area (Acres)	Avg Net Thickness (Feet)	Net Volume (Acre-Feet)	Porosity (fraction)	Permeability (md)	Oil Saturation (fraction)	Oil Specific Gravity	Oil FVF (RBbl/STB)	Solution Gas Ratio (SCF/STB)	Estimated Original Pressure (psi)	Oil Viscosity (cp)
KOGALYMSKOYE (cont)														
	bC16-1		Proven	247	19.7	4,864	0.19	26	0.62	0.840	1.235	406	3,822	1.01
	bC16-1		Probable	5,727	14.4	82,413	0.19	26	0.62	0.840	1.235	406	3,822	1.01
	bC16-2		Proven	185	35.4	6,567	0.19	26	0.62	0.840	1.235	406	3,822	1.01
	bC16-2		Probable	3,196	13.1	41,709	0.20	26	0.63	0.840	1.235	406	3,822	1.01
	bC18		Proven	680	14.4	9,765	0.17	15	0.50	0.840	1.235	406	3,969	1.01
	bC18		Probable	15,986	18.2	291,184	0.17	15	0.50	0.840	1.235	406	3,969	1.01
	bC19		Proven	62	16.4	1,013	0.17	3	0.52	0.840	1.235	406	3,969	1.01
	bC19		Probable	7,566	18.2	137,670	0.17	3	0.52	0.840	1.235	406	3,969	1.01
	UC1		Proven	8,020	16.3	130,507	0.18	300	0.68	0.828	1.250	460	4,116	0.52
	UC1		Probable	12,426	15.6	193,653	0.18	280	0.68	0.828	1.250	460	4,116	0.52
RITEK JOINT VENTURE														
CHEREMUKHOVSKOYE														
	Vereysky		Proven	1,305	10.1	13,231	0.15	303	0.71	0.928	1.020	24	1,432	88.00
	Vereysky		Probable	3,835	6.6	25,164	0.15	303	0.71	0.928	1.020	24	1,432	88.00
	Bashkirsky		Proven	1,700	20.3	34,543	0.13	394	0.70	0.942	1.031	23	1,813	88.00
	Bashkirsky		Probable	2,224	12.5	27,726	0.13	394	0.70	0.942	1.031	23	1,813	88.00
	Tulsky		Proven	356	9.6	3,424	0.19	468	0.67	0.930	1.031	40	1,768	29.00
	Bobrikovsky		Proven	474	11.5	5,435	0.24	479	0.81	0.933	1.031	35	1,827	29.00
	Bobrikovsky		Probable	667	9.8	6,567	0.24	479	0.81	0.933	1.031	35	1,827	29.00
	Turneisky		Proven	1,384	26.2	36,320	0.12	156	0.66	0.935	1.053	44	1,827	40.00
	Turneisky		Probable	1,458	7.5	11,001	0.12	156	0.66	0.935	1.053	44	1,827	40.00
KISLORSKOYE														
	U2		Proven	2,137	12.5	26,648	0.16	56	0.56	0.850	1.136	301	2,872	2.00
	U2		Probable	2,296	11.2	25,608	0.16	56	0.56	0.850	1.136	301	2,872	2.00
	U3-4		Proven	2,691	28.1	75,485	0.18	22	0.61	0.850	1.163	282	2,895	2.00
	U3-4		Probable	2,069	28.1	58,031	0.18	22	0.61	0.850	1.163	282	2,895	2.00
KIYAZLINSKOYE														
	Vereysky		Proven	4,863	13.5	65,705	0.15	221	0.70	0.902	1.019	23	1,363	76.60
	Vereysky		Probable	4,023	5.7	23,097	0.15	221	0.70	0.902	1.019	23	1,363	76.60
	Bashkirsky		Proven	2,926	26.7	78,084	0.14	167	0.81	0.922	1.014	16	1,363	174.80
	Bashkirsky		Probable	3,511	13.1	46,081	0.14	167	0.81	0.922	1.014	16	1,363	174.80
	Bobrikovsky		Proven	870	8.6	7,466	0.22	188	0.87	0.906	1.016	45	1,871	67.02
	Bobrikovsky		Probable	577	6.6	3,822	0.22	188	0.87	0.906	1.016	45	1,871	67.02
	Turneisky		Proven	1,858	29.4	54,719	0.13	34	0.73	0.924	1.033	25	1,827	103.27
	Turneisky		Probable	2,179	9.6	20,899	0.13	34	0.73	0.924	1.033	25	1,827	103.27
	Kynovsky		Proven	198	7.9	1,557	0.24	856	0.89	0.875	1.059	104	2,930	15.90
KURRAGANSKOYE														
	bB8-1	Main - wells 4,7,10	Proven	2,039	15.9	32,347	0.21	20	0.51	0.842	1.205	373	3,910	0.93
		Main - wells 4,7,10	Probable	886	8.1	7,152	0.21	20	0.51	0.842	1.205	373	3,910	0.93
	bB8-1	South - well 19	Proven	309	7.1	2,189	0.21	20	0.50	0.842	1.205	373	3,910	0.93
	UB1-1	Main - well 4	Proven	1,297	32.9	42,724	0.20	24	0.64	0.832	1.149	243	4,100	0.94
		Main - well 4	Probable	420	7.1	2,987	0.20	24	0.64	0.832	1.149	243	4,100	0.94
	UB1-1	South - well 12	Proven	185	8.3	1,540	0.20	24	0.62	0.832	1.202	243	4,100	0.94
KYCHUKOVSKOYE														
	Kashirsky		Proven	158	34.3	5,422	0.14	204	0.65	0.919	1.031	5	898	165.20
	Kashirsky		Probable	119	9.5	1,136	0.14	204	0.65	0.919	1.031	5	898	165.20
	Vereysky 2-3		Proven	316	7.5	2,387	0.19	204	0.67	0.921	1.031	5	1,048	165.20

KOGALYMNEFTEGAS SUBSIDIARY
RESERVOIR PARAMETERS

Field	Reservoir	Field Area	Category	Area (Acres)	Avg Net Thickness (Feet)	Net Volume (Acre-Feet)	Porosity (fraction)	Permeability (md)	Oil Saturation (fraction)	Oil Specific Gravity	Oil FVF (RBbl/STB)	Solution Gas Ratio (SCF/STB)	Estimated Original Pressure (psi)	Oil Viscosity (cp)
KYCHUKOVSKOYE (cont)														
	Bashkirsky		Proven	32	4.6	149	0.14	258	0.71	0.921	1.031	5	1,279	71.30
	Tulsky Total		Proven	767	9.7	7,425	0.20	604	0.75	0.891	1.016	11	1,456	19.30
	Tulsky Total		Probable	356	5.6	1,985	0.20	604	0.75	0.891	1.016	11	1,456	19.30
	Bobrikovsky		Proven	605	9.0	5,469	0.23	410	0.81	0.893	1.018	10	1,483	25.40
	Turneisky		Proven	277	11.5	3,178	0.11	50	0.70	0.896	1.042	10	1,510	25.00
	Turneisky		Probable	97	5.9	573	0.11	50	0.70	0.896	1.042	10	1,510	25.00
LENZINTSKOYE														
	Yu2-5		Proven	712	32.8	23,373	0.13	50	0.54	0.796	1.299	492	4,659	1.29
	Yu2-5		Probable	1,267	40.0	50,700	0.13	50	0.54	0.796	1.299	492	4,659	1.29
LUGOVOYE														
	Tulsky 2		Proven	435	5.9	2,568	0.18	299	0.75	0.904	1.046	32	1,426	47.00
	Tulsky 2		Probable	277	4.6	1,271	0.18	299	0.75	0.904	1.046	32	1,426	47.00
	Tulsky 3		Proven	554	5.6	3,100	0.18	299	0.75	0.904	1.046	32	1,426	47.00
	Tulsky 3		Probable	1,147	3.9	4,514	0.18	299	0.75	0.904	1.046	32	1,426	47.00
	Bobrikovsky		Proven	1,344	16.8	22,622	0.21	299	0.81	0.913	1.040	32	1,426	47.00
	Bobrikovsky		Probable	1,265	9.8	12,453	0.21	299	0.81	0.913	1.040	32	1,426	47.00
	Kynovsky A		Proven	751	6.2	4,683	0.19	679	0.68	0.871	1.044	226	2,196	8.00
	Kynovsky A		Probable	1,186	4.9	5,837	0.19	679	0.68	0.871	1.044	226	2,196	8.00
	Kynovsky B		Proven	633	5.5	3,507	0.19	679	0.68	0.871	1.044	226	2,196	8.00
	Kynovsky B		Probable	712	4.6	3,269	0.19	679	0.68	0.871	1.044	226	2,196	8.00
	Pashysky		Proven	672	7.2	4,851	0.21	679	0.75	0.879	1.082	228	2,196	8.00
	Pashysky		Probable	791	4.1	3,243	0.21	679	0.75	0.879	1.082	228	2,196	8.00
MELNIKOVSKOYE														
	Vereysky		Proven	3,479	14.2	49,331	0.15	190	0.71	0.933	1.034	29	1,324	71.30
	Vereysky		Probable	3,435	8.0	27,383	0.15	190	0.71	0.933	1.034	29	1,324	71.30
	Bashkirsky		Proven	2,095	17.0	35,657	0.15	190	0.78	0.939	1.034	21	1,339	71.30
	Bashkirsky		Probable	1,915	11.3	21,674	0.15	190	0.78	0.939	1.034	21	1,339	71.30
	Tulsky		Proven	198	5.2	1,038	0.20	925	0.80	0.938	1.026	36	1,730	58.30
	Bobrikovsky		Proven	1,067	15.5	16,583	0.24	1,270	0.92	0.930	1.040	63	1,740	64.80
	Bobrikovsky		Probable	430	2.0	861	0.24	1,270	0.92	0.930	1.040	63	1,740	64.80
	Turneisky		Proven	2,214	28.3	62,561	0.14	143	0.64	0.941	1.025	42	1,740	81.60
	Turneisky		Probable	1,409	7.5	10,630	0.14	143	0.64	0.941	1.025	42	1,740	81.60
OZERNOYE														
	Tul+Bob+Rad		Proven	712	51.4	36,570	0.18	281	0.82	0.907	1.026	27	1,426	50.00
	Tul+Bob+Rad		Probable	69	25.6	1,768	0.18	281	0.82	0.907	1.026	27	1,426	50.00
	Kynovsky		Proven	848	15.0	12,688	0.19	184	0.80	0.883	1.060	101	2,148	10.00
	Kynovsky		Probable	126	7.7	969	0.19	184	0.80	0.883	1.060	101	2,148	10.00
SALEKAPTSKOYE														
	BV8/0		Proven	712	42.7	30,385	0.10	41	0.66	0.813	1.379	730	4,128	0.54
	BV8/0		Probable	3,087	26.2	81,032	0.10	41	0.66	0.813	1.379	730	4,128	0.54
	BV13		Proven	2,770	21.7	59,981	0.10	54	0.50	0.813	1.379	730	4,631	0.54
	BV13		Probable	3,721	18.5	68,969	0.10	54	0.50	0.813	1.379	730	4,631	0.54
	BV14		Proven	2,137	33.2	71,038	0.10	80	0.62	0.814	1.376	731	4,670	0.54
	BV14		Probable	2,850	21.8	62,083	0.10	80	0.62	0.814	1.376	731	4,670	0.54
	BV15		Probable	712	22.3	15,893	0.10	52	0.58	0.811	1.370	729	4,720	0.54
SERGINSKOYE														
	UK1		Proven	712	3.4	2,389	0.10	50	0.90	0.825	1.408	741	2,989	2.00
	U2-3		Proven	2,296	24.9	57,239	0.16	50	0.51	0.829	1.333	698	3,068	2.00
	U2-3		Probable	2,375	16.4	38,959	0.16	50	0.51	0.829	1.333	698	3,068	2.00

KOGALYMNEFTEGAS SUBSIDIARY
RESERVOIR PARAMETERS

Field	Reservoir	Field Area	Category	Area (Acres)	Avg Net Thickness (Feet)	Net Volume (Acre-Feet)	Porosity (fraction)	Permeability (md)	Oil Saturation (fraction)	Oil Specific Gravity	Oil FVF (RBbl/STB)	Solution Gas Ratio (SCF/STB)	Estimated Original Pressure (psi)	Oil Viscosity (cp)
SERGINSKOYE (cont)														
	U4		Proven	712	18.4	13,090	0.17	50	0.54	0.829	1.333	698	3,102	2.00
	U4		Probable	1,821	20.3	37,035	0.17	50	0.55	0.829	1.333	698	3,102	2.00
	U10-0		Proven	3,800	14.1	53,668	0.17	250	0.64	0.829	1.333	698	3,329	2.00
	U10-0		Probable	7,362	6.8	50,239	0.17	250	0.64	0.829	1.333	698	3,329	2.00
SREDNELYKHMINSKOYE														
	U2 South		Proven	2,850	17.6	50,021	0.16	56	0.53	0.850	1.136	282	3,626	2.00
	U2 South		Probable	3,721	14.8	55,174	0.16	56	0.53	0.850	1.136	282	3,626	2.00
	AS10		Proven	2,452	22.4	54,890	na	na	na	na	na	na	na	na
	AS10		Probable	5,298	20.9	110,547	na	na	na	na	na	na	na	na
VOSTOCHNO PEREVOLNOYE														
	AS-9-1		Proven	6,774	12.5	84,820	0.19	na	0.49	0.842	1.087	159	na	na
	AS-9-1		Probable	4,453	9.8	43,827	0.19	na	0.49	0.842	1.087	159	na	na
	BS1		Proven	949	20.1	19,094	0.21	na	0.48	0.859	1.080	162	na	na
	BS1		Probable	1,755	25.0	43,827	0.21	na	0.48	0.859	1.080	162	na	na
	Ach3		Proven	237	14.0	3,326	0.19	na	0.49	0.860	1.124	381	na	na
	Ach3		Probable	237	9.6	2,280	0.19	na	0.49	0.860	1.124	381	na	na
VYINTOISKOYE														
	BV4-1 Total		Proven	4,271	22.6	96,516	0.17	80	0.56	0.837	1.176	418	3,940	0.87
	BV4-1 Total		Probable	5,744	11.8	67,837	0.17	80	0.56	0.837	1.176	418	3,940	0.87
	BV4-2		Proven	79	4.6	363	0.17	154	0.62	0.837	1.176	406	3,956	0.75
	BV4-2		Probable	632	3.3	2,073	0.17	154	0.62	0.837	1.176	406	3,956	0.75
	BV5		Proven	79	6.6	518	0.17	38	0.46	0.837	1.176	706	3,916	0.75
	BV5		Probable	632	6.6	4,146	0.17	38	0.46	0.837	1.176	706	3,916	0.75
	Achimov 0		Proven	712	17.6	12,558	0.17	21	0.57	0.837	1.176	417	4,133	0.86
	Achimov 0		Probable	1,265	13.1	16,597	0.17	21	0.57	0.837	1.176	417	4,133	0.86
	Achimov 1 Total		Proven	9,410	20.9	196,572	0.17	87	0.67	0.837	1.176	385	4,181	0.86
	Achimov 1 Total		Probable	10,336	15.8	162,792	0.17	87	0.67	0.837	1.176	385	4,181	0.86
	Achimov 1/1		Proven	79	5.3	415	0.16	87	0.77	0.837	1.176	380	4,153	0.86
	Achimov 1/1		Probable	633	4.9	3,114	0.16	87	0.77	0.837	1.176	380	4,153	0.86
	Achimov 2		Proven	2,135	16.1	34,331	0.17	39	0.55	0.837	1.176	389	4,221	0.86
	Achimov 2		Probable	3,005	5.9	17,760	0.17	39	0.55	0.837	1.176	389	4,221	0.86
	Achimov 3		Proven	2,926	26.2	76,778	0.15	13	0.53	0.837	1.176	385	4,225	0.86
	Achimov 3		Probable	14,723	20.0	294,607	0.15	13	0.53	0.837	1.176	385	4,225	0.86
	Achimov 4		Proven	2,135	21.0	44,835	0.15	12	0.55	0.837	1.176	385	4,239	0.86
	Achimov 4		Probable	7,165	11.8	84,619	0.15	12	0.55	0.837	1.176	385	4,239	0.86
	U1 TOTAL		Proven	5,061	11.3	57,057	0.17	129	0.55	0.801	1.235	400	4,385	0.45
	U1 TOTAL		Probable	5,535	12.5	69,021	0.17	129	0.55	0.801	1.235	400	4,385	0.45
YENORUSSKINSKOYE														
	Vereysky		Proven	5,892	10.0	58,662	0.15	130	0.72	0.909	1.040	23	1,384	75.50
	Vereysky		Probable	3,479	6.6	22,831	0.15	130	0.72	0.909	1.040	23	1,384	75.50
	Bashkirsky		Proven	4,823	29.5	142,064	0.15	150	0.71	0.927	1.026	22	1,432	81.00
	Bashkirsky		Probable	3,758	9.8	36,990	0.15	150	0.71	0.927	1.026	22	1,432	81.00
	Tulsky		Proven	1,028	8.6	8,797	0.21	70	0.86	0.901	1.031	38	1,813	42.50
	Tulsky		Probable	496	3.3	1,627	0.21	70	0.86	0.901	1.031	38	1,813	42.50
	Bobrikovsky		Proven	594	10.3	6,144	0.22	370	0.86	0.913	1.033	34	1,768	47.20
	Turneisky		Proven	3,439	34.4	118,328	0.14	100	0.64	0.920	1.034	43	1,827	54.50
	Turneisky		Probable	2,088	9.8	20,551	0.14	100	0.64	0.920	1.034	43	1,827	54.50
YUZHNO-KHYLYMSKOYE														
	AC8		Proven	712	6.1	4,311	0.16	10	0.50	0.848	1.176	405	3,861	2.00
	AC8		Probable	1,108	5.6	6,181	0.16	10	0.50	0.848	1.176	405	3,861	2.00
	ACh1		Proven	2,217	25.8	57,086	0.15	46	0.58	0.820	1.389	981	4,406	2.00
	ACh1		Probable	4,196	23.0	96,355	0.15	40	0.58	0.820	1.389	981	4,406	2.00

POKACHEVNEFTEGAS SUBSIDIARY
RESERVOIR PARAMETERS

Field	Reservoir	Field Area	Category	Area (Acres)	Avg Net Thickness (Feet)	Net Volume (Acre-Feet)	Porosity (fraction)	Permeability (md)	Oil Saturation (fraction)	Oil Specific Gravity	Oil FVF (RBbl/STB)	Solution Gas Ratio (SCF/STB)	Estimated Original Pressure (psi)	Oil Viscosity (cp)
KECHIMOVSKOYE														
	AB1-3		Proven	10,891	14.7	160,453	0.25	37	0.58	0.863	1.053	107	2,540	3.62
	AB1-3		Probable	30,209	16.2	489,600	0.25	37	0.58	0.863	1.053	107	2,540	3.62
	AB2		Proven	2,162	18.4	39,725	0.25	319	0.58	0.863	1.053	107	2,587	3.62
	AB2		Probable	14,635	11.5	168,530	0.25	319	0.58	0.863	1.053	107	2,587	3.62
	bB6	Wells 57, 45 & 51	Proven	1,606	17.8	28,667	0.22	85	0.55	0.841	1.099	194	3,499	1.41
	bB6	Wells 57, 45 & 51	Probable	2,941	14.4	42,256	0.22	85	0.55	0.841	1.099	194	3,499	1.41
	bB6	well 301 area	Proven	556	8.5	4,743	0.19	169	0.56	0.841	1.099	194	3,499	1.41
	bB6	well 301 area	Probable	1,384	6.7	9,262	0.19	169	0.56	0.841	1.099	194	3,499	1.41
	UB0-Achem Upper	Well 7095 & 26	Proven	2,903	39.6	115,072	0.17	2	0.56	0.828	1.205	437	4,116	0.80
	UB0-Achem Upper	Well 7095 & 27	Probable	5,918	28.0	165,429	0.17	2	0.56	0.828	1.205	437	4,116	0.80
	UB0-Achem Upper	Well 13 & 15	Proven	6,672	20.9	139,653	0.17	2	0.56	0.828	1.205	437	4,116	0.80
	UB0-Achem Upper	Well 13 & 15	Probable	5,115	10.1	51,688	0.17	2	0.56	0.828	1.205	437	4,116	0.80
	UB0-Achem Upper	Well 50	Proven	2,533	16.5	41,798	0.17	2	0.56	0.828	1.205	437	4,116	0.80
	UB0-Achem Upper	Well 50	Probable	4,985	12.9	64,116	0.17	2	0.56	0.828	1.205	437	4,116	0.80
	UBO-Ach Lower		Proven	5,313	16.2	86,280	0.15	3	0.45	0.828	1.205	437	4,116	0.80
	UBO-Ach Lower		Probable	4,232	11.8	49,980	0.15	3	0.45	0.828	1.205	437	4,116	0.80
	UB1-1		Proven	17,483	25.5	445,757	0.18	36	0.58	0.850	1.205	449	4,145	0.80
	UB1-1		Probable	16,241	16.6	269,084	0.18	36	0.58	0.850	1.205	449	4,145	0.80
	UB2-1		Proven	15,815	17.9	283,424	0.15	4	0.55	0.856	1.136	293	4,190	0.80
	UB2-1		Probable	37,937	12.0	455,539	0.15	4	0.55	0.856	1.136	293	4,190	0.80
	UB2-2		Proven	5,189	12.0	62,141	0.17	5	0.56	0.856	1.136	293	4,190	0.80
	UB2-2		Probable	13,924	13.4	186,846	0.17	5	0.56	0.856	1.136	293	4,190	0.80
KLUCHEVOYE														
	AB1-3		Proven	11,472	8.1	93,267	0.18	9	0.33	0.852	1.205	263	2,643	1.72
	AB1-3		Probable	4,720	11.4	53,577	0.18	9	0.33	0.852	1.205	263	2,643	1.72
	AB2		Proven	6,459	16.4	106,082	0.22	90	0.49	0.864	1.190	267	2,653	1.56
	AB2		Probable	1,926	16.6	32,036	0.22	90	0.49	0.864	1.190	267	2,653	1.56
	bB2		Proven	8,175	15.8	128,899	0.20	153	0.61	0.858	1.190	316	3,181	1.50
	bB2		Probable	1,430	3.3	4,691	0.20	153	0.61	0.858	1.190	316	3,181	1.50
	bB3		Proven	8,075	15.8	127,730	0.20	144	0.50	0.848	1.235	366	3,278	1.50
	bB3		Probable	1,722	15.8	27,176	0.20	144	0.50	0.848	1.235	366	3,278	1.50
	bB6	East Area	Proven	1,808	8.7	15,688	0.20	164	0.57	0.853	1.235	345	3,900	1.27
	bB6	East Area	Probable	80	5.3	424	0.20	164	0.57	0.853	1.235	345	3,900	1.27
	bB6	West Area	Proven	2,851	11.0	31,436	0.20	164	0.57	0.853	1.235	345	3,900	1.27
	bB6	West Area	Probable	737	3.1	2,320	0.20	164	0.57	0.853	1.235	345	3,900	1.27
	bB18,22		Proven	432	14.3	6,202	0.18	164	0.50	0.856	1.190	346	3,900	1.27
	bB18,22		Probable	185	2.6	486	0.18	164	0.50	0.856	1.190	346	3,900	1.27
	bB16	Well 4581	Proven	309	8.5	2,635	0.20	na	0.57	0.853	1.235	na	na	na
	bB16	Well 4581	Probable	46	1.5	71	0.20	na	0.57	0.853	1.235	na	na	na
	A Chem		Proven	1,437	18.3	26,278	0.22	na	0.49	0.864	1.190	na	na	na
	A Chem		Probable	1,668	9.8	16,417	0.22	na	0.49	0.864	1.190	na	na	na
NIVAGALSKOYE														
	AB1-3	water zone	Proven	19,404	15.5	300,480	0.24	65	0.66	0.861	1.087	203	2,720	2.46
	AB1-3	water zone	Probable	19,117	9.1	173,732	0.24	65	0.66	0.861	1.087	203	2,720	2.46
	AB1-3	non-water zone	Proven	7,957	12.0	95,147	0.24	84	0.63	0.860	1.087	203	2,720	2.36
	AB1-3	non-water zone	Probable	8,111	10.3	83,560	0.24	65	0.66	0.861	1.087	203	2,720	2.46
	AB2	Water zone	Proven	6,542	8.5	55,512	0.24	202	0.59	0.866	1.107	204	2,720	2.04
	AB2	Water zone	Probable	6,894	7.9	54,738	0.24	223	0.58	0.867	1.111	204	2,720	1.98
	AB2	non-water zone	Proven	5,109	13.0	66,538	0.25	112	0.63	0.861	1.089	203	2,720	2.24
	AB2	non-water zone	Probable	1,458	10.8	15,785	0.24	223	0.58	0.867	1.111	204	2,720	1.98
	bB6	well 261 area	Proven	556	20.2	11,236	0.21	45	0.59	0.853	1.136	278	3,528	1.38
	bB6	well 261 area	Probable	794	10.2	8,124	0.21	45	0.59	0.853	1.136	278	3,528	1.38
	UV1-0		Proven	927	9.2	8,512	0.18	37	0.62	0.836	1.250	375	3,822	0.79
	UV1-0		Probable	723	7.4	5,383	0.18	37	0.62	0.836	1.250	375	3,822	0.79
	UV1-1	well 261 area	Proven	596	17.7	10,512	0.19	25	0.67	0.836	1.171	357	4,072	0.79

POKACHEVNEFTEGAS SUBSIDIARY
RESERVOIR PARAMETERS

Field	Reservoir	Field Area	Category	Area (Acres)	Avg Net Thickness (Feet)	Net Volume (Acre-Feet)	Porosity (fraction)	Permeability (md)	Oil Saturation (fraction)	Oil Specific Gravity	Oil FVF (RBbl/STB)	Solution Gas Ratio (SCF/STB)	Estimated Original Pressure (psi)	Oil Viscosity (cp)
NONG-EGANSKOYE														
	AB1-3		Proven	436	6.9	3,001	0.18	153	0.53	0.851	1.149	258	3,234	1.35
	bB2-1	Main Area (Nong-Yegan)	Proven	10,483	25.7	269,286	0.22	128	0.65	0.851	1.149	258	3,234	1.35
	bB2-1	Main Area (Nong-Yegan)	Probable	1,069	9.8	10,519	0.22	128	0.65	0.851	1.149	258	3,234	1.35
	bB2-1	Main Area	Proven	1,643	33.7	55,372	0.22	128	0.65	0.851	1.149	258	3,234	1.35
	bB2-1	Main Area	Probable	185	9.8	1,824	0.22	128	0.65	0.851	1.149	258	3,234	1.35
	bB2-1	East Area	Proven	2,706	14.9	40,328	0.16	153	0.57	0.851	1.149	258	3,234	1.35
	bB2-1	East Area	Probable	512	9.2	4,718	0.16	153	0.57	0.851	1.149	258	3,234	1.35
	bB3-1	Main Area	Proven	13,523	32.7	441,984	0.21	189	0.50	0.851	1.149	258	3,308	0.78
	bB3-1	Main Area	Probable	1,273	11.6	14,822	0.21	189	0.50	0.851	1.149	258	3,308	0.78
	bB3-1	East Area	Proven	2,990	13.5	40,262	0.21	219	0.53	0.851	1.149	258	3,308	0.78
	bB3-1	East Area	Probable	124	9.3	1,151	0.21	219	0.53	0.851	1.149	258	3,308	0.78
	bB6-1	Main Area	Proven	4,324	15.5	67,157	0.19	68	0.56	0.851	1.149	258	3,381	0.78
	bB6-1	Main Area	Probable	2,020	12.1	24,456	0.19	68	0.56	0.851	1.149	258	3,381	0.78
	bB6-1	East Area	Proven	1,056	12.1	12,772	0.22	45	0.59	0.851	1.149	258	3,381	0.78
	bB7-1	East Area	Proven	718	7.5	5,419	0.19	57	0.57	0.863	1.149	262	3,950	0.78
	UV1	Main-well 95 area	Proven	496	18.2	9,042	0.19	16	0.63	0.840	1.266	255	3,822	0.78
	UV1	Main-well 162 area	Proven	2,187	11.0	24,107	0.19	16	0.63	0.840	1.266	255	3,822	0.78
	UV1	East-well 59 area	Proven	3,206	17.2	55,274	0.19	16	0.63	0.840	1.266	255	3,822	0.78
	UV1	East-well 59 area	Probable	1,297	9.8	12,769	0.19	16	0.63	0.840	1.266	255	3,822	0.78
	UV1	Well 170 (Nong-Yegan)	Proven	1,236	22.4	27,706	0.19	16	0.63	0.840	1.266	255	3,822	0.78
	UV1	Well 170 (Nong-Yegan)	Probable	5,031	17.5	87,948	0.19	16	0.63	0.840	1.266	255	3,822	0.78
	UV1	Well 170 (Nizhnevar Area)	Proven	2,945	13.8	40,495	0.19	16	0.63	0.840	1.266	255	3,822	0.78
	UV1	Well 170 (Nizhnevar Area)	Probable	2,824	13.0	36,689	0.19	16	0.63	0.840	1.266	255	3,822	0.78
	UV1	East-well 180	Proven	62	26.2	1,621	0.19	16	0.63	0.840	1.266	255	3,822	0.78
	UV1	East-well 180	Probable	259	18.7	4,852	0.19	16	0.63	0.840	1.266	255	3,822	0.78
POKACHEVSKOYE														
	AB1-3	Main (Pokachev)	Proven	49,353	10.0	492,547	0.18	27	0.38	0.857	1.133	217	2,690	1.56
	AB1-3	Main (Pokachev)	Probable	9,382	10.8	100,959	0.18	27	0.38	0.857	1.133	217	2,690	1.56
	AB1-3	Amanskaya	Proven	4,590	9.7	44,467	0.18	27	0.38	0.857	1.133	217	2,690	1.56
	AB1-3	Amanskaya	Probable	1,343	10.5	14,139	0.18	27	0.38	0.857	1.133	217	2,690	1.56
	AB1-3	Axtamarskaya	Proven	2,718	9.9	26,893	0.18	27	0.38	0.857	1.133	217	2,690	1.56
	AB1-3	Axtamarskaya	Probable	2,582	7.7	19,990	0.18	27	0.38	0.857	1.133	217	2,690	1.56
	AB2	Main (Pokachev)	Proven	44,059	16.4	723,530	0.23	149	0.55	0.849	1.143	257	2,690	2.08
	AB2	Main (Pokachev)	Probable	2,687	9.8	26,361	0.22	149	0.50	0.849	1.143	257	2,690	2.08
	AB3		Proven	8,448	21.9	184,859	0.23	144	0.53	0.849	1.121	238	2,734	0.70
	AB4-1		Proven	2,204	8.9	19,725	0.23	96	0.52	0.849	1.121	238	2,793	0.78
	AB4-2		Proven	259	7.6	1,975	0.23	96	0.52	0.849	1.121	238	2,793	0.78
	AB5		Proven	9,487	22.2	210,376	0.23	165	0.60	0.846	1.181	252	2,867	1.68
	AB6		Proven	1,637	12.1	19,867	0.23	80	0.57	0.846	1.181	252	2,940	0.82
	AB7		Proven	1,607	15.7	25,287	0.23	139	0.59	0.846	1.181	252	2,999	1.50
	AB8-1		Proven	429	11.2	4,828	0.23	80	0.56	0.846	1.181	252	3,014	0.88
	AB8-2		Proven	235	7.6	1,779	0.23	80	0.56	0.846	1.181	252	3,014	0.88
	bB0		Proven	1,200	14.1	16,900	0.21	134	0.56	0.857	1.122	221	3,087	1.30
	bB0-1		Proven	1,109	19.5	21,644	0.20	134	0.60	0.857	1.122	221	3,087	1.30
	bB0-2		Proven	985	8.6	8,501	0.20	134	0.60	0.857	1.122	221	3,087	1.30
	bB1-1		Proven	1,982	12.4	24,564	0.19	100	0.54	0.857	1.122	221	3,161	1.30
	bB1-1		Probable	621	6.9	4,258	0.19	100	0.54	0.857	1.122	221	3,161	1.30
	bB1-2		Proven	834	8.9	7,388	0.19	100	0.54	0.857	1.122	221	3,161	1.30
	bB3		Proven	1,402	11.1	15,577	0.20	100	0.53	0.857	1.122	221	3,308	1.50
	bB6	Main (Pokachev)	Proven	20,133	18.2	366,476	0.21	161	0.60	0.857	1.122	221	3,455	1.27
	bB6	Main (Pokachev)	Probable	494	6.4	3,146	0.21	161	0.60	0.857	1.122	221	3,455	1.27
	bB6	Amanskaya	Proven	4,763	16.9	80,476	0.21	161	0.53	0.857	1.122	221	3,455	1.27

POKACHEVNEFTEGAS SUBSIDIARY
RESERVOIR PARAMETERS

Field	Reservoir	Field Area	Category	Area (Acres)	Avg Net Thickness (Feet)	Net Volume (Acre-Feet)	Porosity (fraction)	Permeability (md)	Oil Saturation (fraction)	Oil Specific Gravity	Oil FVF (RBbl/STB)	Solution Gas Ratio (SCF/STB)	Estimated Original Pressure (psi)	Oil Viscosity (cp)
POKACHEVSKOYE (cont)														
	bB6	Axtamarskaya	Proven	432	7.4	3,202	0.19	161	0.59	0.830	1.190	242	3,455	1.27
	bB8-1	Main	Proven	31,710	25.9	821,884	0.21	159	0.64	0.846	1.248	451	3,528	0.88
	bB8-1	Axtamarskaya	Proven	2,819	8.8	24,788	0.21	159	0.49	0.846	1.248	451	3,528	0.88
	Achem 1		Proven	1,106	15.4	17,024	0.17	18	0.50	0.829	1.245	414	3,675	1.27
	Achem 1		Probable	128	12.4	1,584	0.17	18	0.50	0.829	1.245	414	3,675	1.27
	Achem. 2		Proven	371	13.1	4,864	0.17	18	0.50	0.829	1.245	414	3,675	1.27
	Achem. 2		Probable	202	9.3	1,886	0.17	18	0.50	0.829	1.245	414	3,675	1.27
	UV1	Main (Pokachev)	Proven	11,477	14.9	170,796	0.17	17	0.68	0.829	1.245	414	3,822	0.30
	UV1	Main (Pokachev)	Probable	431	11.7	5,033	0.17	17	0.68	0.829	1.245	414	3,822	0.30
	UB1-1	Axtamarskaya	Proven	494	11.1	5,472	0.18	17	0.63	0.830	1.190	494	3,822	0.30
	UB1-1	Axtamarskaya	Probable	320	5.2	1,678	0.18	17	0.63	0.830	1.190	494	3,822	0.30
	UB1-1	New area	Proven	558	16.4	9,150	0.17	17	0.66	0.829	1.245	493	3,822	0.30
	UB1-1	New area	Probable	402	9.8	3,952	0.17	17	0.66	0.829	1.245	493	3,822	0.30
POKACHEVSKOYE NORTH														
	UV1-1	Ochovhaq area	Proven	23,895	22.8	545,334	0.17	40	0.64	0.830	1.235	419	4,131	0.60
	UV1-1	Ochovhaq area	Probable	10,650	9.8	104,825	0.17	40	0.64	0.830	1.235	419	4,131	0.60
	UV1-1	Well 118 & 124 area	Proven	2,199	15.4	33,833	0.17	1	0.66	0.830	1.235	419	4,131	0.60
	UV1-1	Well 118 & 124 area	Probable	4,843	9.8	47,670	0.17	1	0.66	0.830	1.235	419	4,131	0.60
	UV1-1	Well 47 area	Proven	1,730	32.8	56,750	0.18	40	0.66	0.834	1.235	421	4,131	0.60
	UV1-1	Well 47 area	Probable	3,411	24.7	84,158	0.18	40	0.66	0.834	1.235	421	4,131	0.60
	UV1-1	Pokkyhckaq	Proven	1,679	13.3	22,341	0.18	40	0.66	0.834	1.235	421	4,131	0.60
	UV1-1	Pokkyhckaq	Probable	5,400	9.8	53,147	0.18	40	0.66	0.834	1.235	421	4,131	0.60
	UV1-1	UK Kunskaya Area	Proven	185	49.3	9,120	0.18	na	0.66	0.834	1.235	na	na	na
	UV1-1	UK Kunskaya Area	Probable	1,257	25.2	31,630	0.18	na	0.66	0.834	1.235	na	na	na
	UV1	UK Kunskaya Area	Proven	1,174	17.1	20,065	0.18	na	0.66	0.834	1.235	na	na	na
	UV1	Well 211,213	Probable	5,408	18.7	100,921	0.18	na	0.66	0.834	1.235	na	na	na
	UV1	Mogutlorsk	Probable	142	8.8	1,244	0.18	na	0.66	0.834	1.235	na	na	na
	UV1	Well 143 Area	Proven	432	19.7	8,512	0.18	na	0.66	0.834	1.235	na	na	na
	UV1	Well 143 Area	Probable	2,061	16.0	33,035	0.18	na	0.66	0.834	1.235	na	na	na
POKACHEVSKOYE SOUTH														
	AB1,3	Main Area	Proven	3,462	8.5	29,531	0.19	130	0.42	0.857	1.133	209	2,661	1.72
	AB1,3	Nevagal. Area	Proven	3,198	11.4	36,377	0.19	130	0.42	0.857	1.133	209	2,661	1.72
	AB1,3	Nevagal. Area	Probable	1,435	9.2	13,186	0.19	130	0.42	0.857	1.133	209	2,661	1.72
	AB2	Main Area	Proven	5,184	19.5	101,187	0.22	107	0.56	0.849	1.134	129	2,690	2.48
	AB2	Nevagal. Area	Proven	3,481	16.2	56,485	0.22	107	0.56	0.849	1.134	129	2,690	2.48
	AB2	Nevagal. Area	Probable	83	9.0	751	0.22	107	0.56	0.849	1.134	129	2,690	2.48
	bB6	Main Area	Proven	2,698	15.4	41,506	0.19	205	0.53	0.857	1.122	290	3,381	2.60
	bB6	Main Area	Probable	931	6.1	5,682	0.19	205	0.56	0.857	1.111	467	3,381	2.60
	bB8	Main Area	Proven	4,626	24.6	113,818	0.20	201	0.61	0.841	1.171	274	3,528	0.92
	bB8	Nevagal. Area	Proven	125	7.3	907	0.20	201	0.49	0.846	1.248	247	3,528	0.92
	bB10		Proven	745	8.6	6,382	0.19	180	0.48	0.841	1.171	255	3,557	1.10
	Achem.		Proven	927	10.8	10,033	0.17	18	0.50	0.829	1.245	414	3,675	1.27
	Achem.		Probable	1,843	6.7	12,395	0.17	18	0.50	0.829	1.245	414	3,675	1.27
	UB1-1		Proven	4,571	19.0	86,803	0.17	14	0.63	0.829	1.245	414	3,900	0.79
	UB1-1		Probable	7,900	15.8	124,934	0.17	14	0.63	0.829	1.245	414	3,900	0.79

Exhibit 52

YAMALNEFTEGAZDOBYCHA SUBSIDIARY
RESERVOIR PARAMETERS

Field	Reservoir	Field Area	Category	Area (Acres)	Avg Net Thickness (feet)	Net Volume (Acre-Feet)	Porosity (fraction)	Permeability (md)	Gas Saturation (fraction)	Init. Pressure atm.	Gas Dev. Factor
------	--------------	-----------	-----------	-----------	-----------	-----------	-----------	------------	------------	------------	------------
SOUTH MESSOYAKHSKOYE											
	Gazsalinskaya		Probable	1,668	37.7	62,914	0.270	na	0.60	110.00	0.99
	PK1		Proven	11,120	32.8	364,720	0.300	na	0.60	122.57	0.98
	PK1		Probable	3,447	28.5	98,365	0.300	na	0.60	122.57	0.98
	BU13		Proven	36,694	32.8	1,203,575	0.128	na	0.698	315.40	0.82
	BU13		Probable	15,567	26.2	408,486	0.128	na	0.898	315.40	0.82
	BU14		Proven	22,795	19.7	448,605	0.124	na	0.675	319.10	0.82
	BU14		Probable	13,146	14.1	185,407	0.120	na	0.74	315.20	0.82
	BU15-1		Proven	8,896	29.5	262,598	0.137	na	0.68	330.50	0.82
	BU15-1		Probable	13,343	32.8	437,664	0.137	na	0.68	330.50	0.81
	BU15-2		Proven	5,004	19.7	98,474	0.110	na	0.68	330.50	0.82
	BU15-2		Probable	6,103	16.4	100,095	0.110	na	0.68	330.50	0.82
PYAKYAKHINSKOYE(GAS)											
	PK18-0		Proven	4,448	13.1	58,269	0.190	na	0.58	212.30	0.90
	PK18-0		Probable	3,336	6.6	22,018	0.190	na	0.58	212.30	0.90
	PK18		Proven	7,228	19.7	142,392	0.190	na	0.70	212.20	0.90
	PK19		Proven	3,336	31.2	104,083	0.190	na	0.70	214.00	0.89
	PK19		Probable	556	23.3	12,955	0.190	na	0.65	210.30	0.89
	PK20		Proven	3,608	27.2	98,138	0.203	na	0.66	216.05	0.89
	PK21		Proven	1,668	19.7	32,860	0.190	na	0.82	215.60	0.89
	PK21		Probable	1,112	16.4	18,237	0.190	na	0.82	215.60	0.89
	BU5-1		Proven	2,224	16.4	36,474	0.170	na	0.54	253.70	0.86
	BU5-1		Probable	1,730	16.4	28,372	0.170	na	0.54	253.70	0.86
	BU12		Proven	12,787	36.1	461,611	0.140	na	0.69	302.70	0.83
	BU12		Probable	4,890	9.8	47,922	0.140	na	0.69	302.70	0.83
	BU18-1		Proven	37,250	23.6	879,100	0.140	na	0.70	325.40	0.81
	BU18-1		Probable	11,120	16.4	182,368	0.140	na	0.70	325.40	0.81
	BU18-2		Proven	21,683	23.0	498,709	0.130	na	0.73	326.60	0.81
	BU18-2		Probable	8,340	16.4	136,776	0.130	na	0.73	326.60	0.81
	BU20		Proven	10,564	19.7	208,111	0.120	na	0.67	365.50	0.80
	BU20		Probable	8,340	16.4	136,776	0.120	na	0.67	365.50	0.80
KHALMERPAYUTINSKOYE											
	BU18		Proven	18,347	96.1	1,763,147	0.100	na	0.77	309.00	na
	BU18		Probable	3,991	96.1	383,535	0.100	na	0.77	309.00	na
	BU19		Proven	16,123	8.2	132,209	0.200	na	0.58	314.00	na
	BU19		Probable	4,448	8.2	36,474	0.200	na	0.58	314.00	na
	BU20		Proven	26,687	108.2	2,887,533	0.100	na	0.76	317.00	na
	BU20		Probable	6,116	101.7	621,997	0.100	na	0.76	317.00	na
	BU21		Proven	13,899	65.6	911,774	0.200	na	0.76	314.00	na
	BU21		Probable	1,112	26.2	29,134	0.200	na	0.76	314.00	na

NIZHNEVOLZHSKNEFT SUBSIDIARY
RESERVOIR PARAMETERS

Field	Reservoir	Field Area	Category	Area (Acres)	Avg Net Thickness (Feet)	Net Volume (Acre-Feet)	Porosity (fraction)	Permeability (md)	Oil Saturation (fraction)	Oil Specific Gravity	Oil FVF (RBbl/STB)	Solution Gas Ratio (SCF/STB)	Estimated Original Pressure (psi)	Oil Viscosity (cp)
ALEKSEEVSKOYE														
	bobrikovsky		Proven	865	20.2	17,430	0.18	na	0.69	0.81	1.45	1,005	na	na
	bobrikovsky		Probable	151	9.1	1,375	0.18	na	0.69	0.81	1.45	1,005	na	na
	turneysky		Proven	927	108.2	100,224	0.08	237	0.85	0.82	1.62	1,208	6,976	0.43
	turneysky		Probable	309	80.5	24,869	0.08	237	0.85	0.82	1.62	1,208	6,976	0.43
ANTILVSKO - BALYKLEISKOYE														
	zason - eletsky		Proven	10,985	12.3	135,150	0.14	40	0.84	0.82	1.83	531	7,861	0.32
ANTONOVSKOYE														
	evl. - levensky		Proven	319	23.0	7,348	0.15	229	0.87	0.83	1.28	na	na	1.27
	voronezhsky		Proven	236	12.4	2,913	0.12	229	0.90	0.83	1.28	717	na	1.27
ARCHEDINSKOYE														
	bobrikovsky		Proven	6,669	8.2	54,703	0.20	500	0.76	0.88	1.12	357	1,392	6.50
	turneysky		Proven	709	11.5	8,144	0.17	380	0.83	0.89	1.06	499	1,378	12.00
	zad - eletsky		Proven	2,680	19.4	51,869	0.21	1,200	0.79	0.82	1.10	535	2,582	1.00
	evl. - levensky		Proven	1,334	8.9	11,820	0.22	665	0.82	0.82	1.12	1,152	2,828	1.00
BAKHMETEVSKOYE														
	melekessky 1-3 (1)		Proven	1,753	6.9	12,077	0.15	30	0.58	0.90	1.05	136	856	22.00
	melekessky 4 (2)		Proven	4,408	4.4	19,233	0.13	30	0.57	0.90	1.05	243	856	22.00
	nizhnebashkersky		Proven	2,700	32.8	88,571	0.11	300	0.70	0.91	1.08	269	1,030	24.00
	tulsky A2		Proven	740	26.9	19,896	0.27	1,170	0.90	0.87	1.10	245	1,378	10.40
	tulsky B1		Proven	4,063	35.4	143,976	0.28	600	0.89	0.86	1.11	298	1,537	4.37
	bobrikovsky		Proven	1,622	27.2	44,165	0.23	1,000	0.87	0.87	1.12	292	1,537	5.99
	voronezhsky		Proven	340	32.8	11,147	0.12	na	0.70	0.82	1.45	1,039	na	na
	buregsk (alatyr)		Proven	570	11.8	6,725	0.06	80	0.70	0.79	1.57	2,345	3,278	0.38
BURLUKSKOYE														
	evl. - levensky		Proven	497	39.4	19,553	0.06	30	0.84	0.80	1.83	1,558	4,047	0.50
	evl. - levensky		Probable	84	5.2	436	0.06	30	0.84	0.80	1.83	1,558	4,047	0.50
CHUKHONASTOVSKOYE														
	bobrikovsky		Proven	1,083	10.8	11,729	0.20	164	0.90	0.82	1.30	329	4,076	0.65
DEMYANOVSKOYE														
	evl. - levensky		Proven	290	171.8	49,783	0.07	38	0.91	0.81	1.49	940	4,018	0.65
DUDACHINSKOYE														
	semiluksko - rudkinsky		Proven	103	26.2	2,692	0.12	27	0.75	0.81	1.42	455	4,076	0.66
FROLOVSKOYE														
	semiluksky		Proven	148	54.1	7,986	0.10	37	0.79	0.81	1.45	455	4,467	0.47
	voronezhsky		Proven	185	21.3	3,952	0.15	165	0.75	0.81	1.44	457	4,221	0.53
GOLUBKOVSKOYE														
	evl. - levensky		Proven	561	21.8	12,214	0.08	37	0.71	0.81	1.52	994	4,192	0.38

NIZHNEVOLZHSKNEFT SUBSIDIARY
RESERVOIR PARAMETERS

Field	Reservoir	Field Area	Category	Area (Acres)	Avg Net Thickness (Feet)	Net Volume (Acre-Feet)	Porosity (fraction)	Permeability (md)	Oil Saturation (fraction)	Oil Specific Gravity	Oil FVF (RBbl/STB)	Solution Gas Ratio (SCF/STB)	Estimated Original Pressure (psi)	Oil Viscosity (cp)
KLENOVSKOYE														
	bobrikovsky		Proven	1,030	29.2	30,066	0.27	2,300	0.93	0.85	1.06	342	2,408	4.40
KLYUCHEVSKOYE														
	evl. - levensky		Proven	615	31.2	19,189	0.10	na	0.93	0.83	1.28	1,164	4,018	0.65
	semiluksky-rudkinsky		Proven	675	106.7	71,975	0.12	302	0.79	0.82	1.23	na	4,409	0.74
	vorobievsky		Proven	988	8.4	8,269	na	na	na	na	na	na	na	na
KOROBKOVSKOYE														
	melekessky		Proven	5,197	10.9	56,538	0.22	110	0.62	0.84	1.17	382	1,740	1.56
	bobrikovsky		Proven	14,320	42.7	611,688	0.21	465	0.90	0.82	1.37	837	2,596	0.63
	bobrikovsky		Probable	1,212	12.5	15,105	0.21	465	0.90	0.82	1.37	837	2,596	0.63
	turneysky		Proven	6,783	17.3	117,512	0.04	50	0.90	0.82	1.39	1,060	2,611	0.50
KOTOVSKOYE														
	evl. - levensky		Proven	1,680	178.9	300,518	0.11	193	0.83	0.82	1.54	1,004	4,090	0.55
KOVALEVSKOYE														
	evl. - levensky		Proven	1,236	35.4	43,778	0.13	71	0.87	0.82	1.43	1,155	na	0.70
	evl. - levensky		Probable	605	35.4	21,425	0.13	71	0.87	0.82	1.43	1,155	na	0.70
	voronezhsky		Proven	1,236	32.8	40,535	0.10	na	0.81	0.83	1.43	713	na	na
	voronezhsky		Probable	429	32.8	14,090	0.10	na	0.81	0.83	1.43	713	na	na
	semiluksko-rudkin.		Proven	741	37.7	27,969	0.12	3	0.81	0.84	1.43	493	na	1.31
	semiluksko-rudkin.		Probable	237	37.7	8,950	0.12	3	0.81	0.84	1.43	493	na	1.31
KRASNOYARKOYE														
	evl. - levensky		Proven	124	27.8	3,446	0.12	na	0.86	0.79	1.72	1,434	na	na
	evl. - levensky		Probable	20	164.0	3,279	0.12	na	0.86	0.79	0.17	1,434	na	na
KUDINOVSKOYE														
	zad - eletsky		Proven	554	7.9	4,388	0.19	70	0.82	0.82	1.25	535	3,263	0.82
	zad - eletsky		Probable	230	3.5	814	0.19	70	0.82	0.82	1.25	535	3,263	0.82
	buregsky (petin)		Proven	2,256	4.9	11,103	0.14	70	0.60	0.81	2.00	456	3,858	0.65
	pashiysky		Proven	14,051	7.2	101,420	0.16	1	0.79	0.82	1.64	460	4,351	0.59
	ardatovskie		Proven	692	4.3	2,951	0.08	1	0.80	0.81	2.00	456	12,618	0.26
	vorobevsky		Proven	18,236	9.5	173,508	0.13	2	0.81	0.82	1.68	462	4,699	0.59
	voronezhsky		Proven	324	5.8	1,890	0.12	na	0.87	0.78	1.22	na	na	na
LEVCHUNOVSKOYE														
	bobrikovsky		Proven	247	23.0	5,675	0.12	na	0.88	0.81	1.45	1,005	na	na
	bobrikovsky		Probable	278	11.2	3,122	0.12	na	0.88	0.81	1.45	1,005	na	na
	turneysky I		Proven	556	40.1	22,295	0.12	62	0.86	0.81	1.61	1,296	6,904	0.53
	turneysky I		Probable	1,188	20.4	24,250	0.12	62	0.86	0.81	1.61	1,296	6,904	0.53
	turneysky II		Proven	371	10.9	4,054	0.08	62	0.77	0.81	1.61	1,296	6,904	0.53
	turneysky II		Probable	226	5.9	1,337	0.08	62	0.77	0.81	1.61	1,296	6,904	0.53
LINEVOSKOYE														
	bobrikovsky		Proven	9,420	2.6	24,723	0.20	1,600	0.70	0.87	1.23	350	1,929	1.00
LOMOVSKOYE														
	evl. - levensky		Proven	202	30.8	6,234	0.08	78	0.80	0.80	1.54	983	3,814	0.55

NIZHNEVOLZHSKNEFT SUBSIDIARY
RESERVOIR PARAMETERS

Field	Reservoir	Field Area	Category	Area (Acres)	Avg Net Thickness (Feet)	Net Volume (Acre-Feet)	Porosity (fraction)	Permeability (md)	Oil Saturation (fraction)	Oil Specific Gravity	Oil FVF (RBbl/STB)	Solution Gas Ratio (SCF/STB)	Estimated Original Pressure (psi)	Oil Viscosity (cp)
MALYSHEVSKOYE														
	bobrikovsky		Proven	791	11.2	8,835	0.18	136	0.85	0.82	1.44	1,013	6,918	0.82
	bobrikovsky		Probable	373	9.3	3,474	0.18	136	0.85	0.82	1.44	1,013	6,918	0.82
	T		Proven	277	9.6	2,659	0.10	136	0.57	0.82	1.56	1,008	6,918	0.82
	T		Probable	158	3.3	519	0.10	136	0.57	0.82	1.56	1,008	6,918	0.82
MIROSHNIKOVSKOYE														
	evl. - levensky		Proven	436	54.0	23,524	0.12	200	0.78	0.81	1.66	1,281	4,177	0.40
	evl. - levensky		Probable	208	13.9	2,894	0.12	200	0.78	0.81	1.66	1,281	4,177	0.40
NIKOLINSKOYE														
	evl. - levensky		Proven	40	17.1	675	0.15	na	0.90	0.83	1.28	na	4,076	na
	evl. - levensky		Probable	134	10.3	1,380	0.15		0.90	0.83	1.28	na	4,076	na
	petlnsky		Proven	119	19.4	2,296	0.22	na	0.85	0.81	1.35	594	4,496	na
	petlnsky		Probable	50	10.8	542	0.22		0.85	0.81	1.35	594	4,496	na
	semiluksky		Proven	40	29.5	1,167	0.11	na	0.88	0.81	1.35	457	4,496	na
	semiluksky		Probable	26	5.1	133	0.11		0.88	0.81	1.35	457	4,496	na
NIZHNE - KOROBKOVSKOYE														
	bobrikovsky		Proven	247	8.9	2,189	0.24	200	0.75	0.81	1.37	686	2,364	0.55
	evl. - levensky		Proven	685	106.9	73,171	0.07	217	0.83	0.80	2.34	2,322	4,148	0.30
	evl. - levensky		Probable	49	49.8	2,460	0.07	217	0.83	0.80	2.34	2,322	4,148	0.30
NOVINSKOYE														
	bobrikovsky		Proven	1,532	6.9	10,555	0.25	1,200	0.86	0.85	1.30	342	2,263	0.67
NOVO - KOCHETKOVSKOYE														
	evl. - levensky		Proven	309	34.1	10,539	0.14	na	0.81	0.82	1.43	708	na	na
	evl. - levensky		Probable	71	2.6	184	0.14	na	0.81	0.82	1.43	708	na	na
	voronezhsky		Proven	185	7.4	1,378	0.08	160	0.81	0.82	1.45	705	na	0.53
	petensky		Proven	185	20.3	3,770	0.17	na	0.81	0.84	1.43	610	na	na
	petensky		Probable	162	14.7	2,392	0.17	na	0.81	0.84	1.43	610	na	na
	semiluksko-rudkin.		Proven	185	138.9	25,740	0.08	na	0.81	0.79	1.43	467	na	na
	semiluksko-rudkin.		Probable	72	98.6	7,114	0.08	na	0.81	0.79	1.43	467	na	na
NOVO - KOROBKOVSKOYE														
	bobrikovsky		Proven	114	6.6	746	0.20	500	0.90	0.81	1.37	4,972	2,263	0.70
	evl. - levensky		Proven	883	20.0	17,670	0.08	70	0.81	0.82	1.72	1,899	3,902	0.77
NOVOCHERNUSHINSKOYE														
	evl. - levensky		Proven	158	15.8	2,503	0.10	13	0.82	0.83	1.28	na	na	1.27
	evl. - levensky		Probable	40	4.9	195	0.10	13	0.82	0.83	1.28	na	na	1.27
	petlnsky		Proven	79	10.3	817	0.20	35	0.86	0.83	1.22	604	na	3.20
	petlnsky		Probable	44	7.8	344	0.20	35	0.86	0.83	1.22	604	na	3.20
OVRAZHNOYE														
	zad - eletsky		Proven	335	20.7	6,932	0.11	12	0.81	0.81	1.48	530	3,858	0.78
	evl. levensky		Proven	435	34.3	14,941	0.09	60	0.90	0.79	1.50	980	4,076	0.60
PAMYATNOYE-SASOVSKOYE														
	evl. - levensky		Proven	778	476.6	370,777	0.74	109	0.93	0.83	1.34	1,162	4,074	0.90
PETROVSKOYE														
	evl. - levensky		Proven	182	55.8	10,143	0.08	10	0.75	0.80	1.54	912	4,018	0.49

NIZHNEVOLZHSKNEFT SUBSIDIARY
RESERVOIR PARAMETERS

Field	Reservoir	Field Area	Category	Area (Acres)	Avg Net Thickness (Feet)	Net Volume (Acre-Feet)	Porosity (fraction)	Permeability (md)	Oil Saturation (fraction)	Oil Specific Gravity	Oil FVF (RBbl/STB)	Solution Gas Ratio (SCF/STB)	Estimated Original Pressure (psi)	Oil Viscosity (cp)
SERGEEVSKOYE														
	bobrikovsky		Proven	371	8.4	3,101	0.17	22	0.89	0.81	1.64	1,572	6,831	0.79
	bobrikovsky		Probable	613	6.6	4,023	0.17	22	0.89	0.81	1.64	1,572	6,831	0.79
SEVERO-ROMANOVSKOYE														
	aleksinsky		Proven	40	15.1	597	0.23	na	0.69	0.87	1.23	na	3,655	na
	aleksinsky		Probable	119	15.1	1,790	0.23	na	0.69	0.87	1.23	na	3,655	na
	evl. - levensky		Proven	79	10.7	843	0.10	22	0.89	0.83	1.23	na	4,946	0.47
	evl. - levensky		Probable	40	32.8	1,297	0.10	22	0.89	0.83	1.23	na	4,946	0.47
TERSINSKOYE														
	starooskolsky		Proven	1,945	8.8	17,120	0.17	211	0.82	0.81	1.27	454	3,703	1.28
TISHANSKOYE														
	petlnsky		Proven	79	10.5	830	0.20	na	0.86	0.83	1.22	604	na	4,786.00
	petlnsky		Probable	40	3.3	130	0.20	na	0.86	0.83	1.22	604	na	4,786.00
TSENTRALNOYE														
	bobrikovsky		Proven	185	7.7	1,419	0.17	na	0.81	0.81	1.45	1,005	na	na
	turneysky I		Proven	494	55.8	27,564	0.08	14	0.78	0.82	1.48	920	6,556	0.45
	turneysky I		Probable	396	14.5	5,735	0.08	14	0.78	0.82	1.48	920	6,556	0.45
	turneysky II		Proven	185	10.9	2,027	0.12	14	0.69	0.82	1.48	920	6,556	0.45
UZHNO - UMETOVSKOYE														
	bobrikovsky		Proven	660	7.9	5,199	0.17	150	0.71	0.83	1.49	334	4,235	0.78
	turneysky		Proven	1,721	14.1	24,273	0.10	10	0.57	0.83	1.55	1,071	4,322	0.98
VERKHNE-ROMANOVSKOYE														
	aleksinsky 1		Proven	239	10.6	2,549	0.23	298	0.75	0.87	1.23	na	3,423	1.14
	aleksinsky 2		Proven	100	8.4	836	0.22	298	0.82	0.87	1.23	na	3,423	1.14
	bobrikovsky		Proven	40	17.1	675	0.26	na	0.79	0.85	1.23	na	na	na
	bobrikovsky		Probable	79	9.3	730	0.26	na	0.79	0.85	1.23	na	na	na
VOST - UMETOVSKOYE														
	starooskolsky		Proven	741	10.5	7,783	0.10	10	0.10	0.80	1.68	451	9,065	0.73
	kynovsky		Proven	1,483	8.5	12,558	0.11	30	0.83	0.81	1.64	453	10,660	0.73
			Probable	383	8.9	3,420	0.11	30	0.83	0.81	1.64	453	10,660	0.73
VOSTONOCHO-KUDINOVSKOYE														
	evl. - levensky		Proven	260	27.8	7,225	0.08	na	0.88	0.81	1.35	na	na	na
	voronezhsky		Proven	269	27.4	7,350	0.07	na	0.90	0.81	1.35	704	na	na
	petlnsky		Proven	348	12.6	4,388	0.17	na	0.88	0.81	1.35	594	na	na
	semiluksko-rudkin.		Proven	102	44.1	4,485	0.09	80	0.93	0.81	1.35	na	na	0.69
WEST ROMANOVSKOYE														
	aleksinsky		Proven	119	7.2	856	0.23	131	0.82	0.88	1.24	na	na	1.08
	aleksinsky		Probable	79	6.6	519	0.23	131	0.82	0.88	1.24	na	na	1.08
	evl. - levensky		Proven	119	16.2	1,920	0.12	na	0.88	0.81	1.23	na	na	0.47
	evl. - levensky		Probable	198	23.0	4,540	0.12	na	0.88	0.81	1.23	na	na	0.47
ZAPADNO-KOCHETKOVSHOYE														
	evl. - levensky		Proven	149	28.3	4,221	0.11	na	0.92	0.84	1.28	na	na	na
	semiluksko-rudkin.		Proven	216	102.0	21,995	0.09	13	0.84	0.82	1.25	na	na	0.97

NIZHNEVOLZHSKNEFT SUBSIDIARY
RESERVOIR PARAMETERS

Field	Reservoir	Field Area	Category	Area (Acres)	Avg Net Thickness (Feet)	Net Volume (Acre-Feet)	Porosity (fraction)	Permeability (md)	Oil Saturation (fraction)	Oil Specific Gravity	Oil FVF (RBbl/STB)	Solution Gas Ratio (SCF/STB)	Estimated Original Pressure (psi)	Oil Viscosity (cp)
ZELENOVSKOYE														
	pash + vorobevsky		Proven	326	18.4	5,988	0.16	65	0.85	0.81	1.72	457	4,119	0.47
ZHIRNOVSKOYE														
	melekessky 1-3		Proven	6,768	14.4	97,696	0.26	80	0.52	0.87	1.05	122	856	25.40
	melekessky 4		Proven	8,647	8.9	76,904	0.22	30	0.47	0.90	1.05	116	856	25.40
	melekessky 4		Probable	281	7.8	2,185	0.22	30	0.47	0.90	1.05	116	856	25.40
	nizhnebashkersky		Proven	2,303	33.8	77,770	0.12	345	0.71	0.91	1.08	391	885	29.00
	tulsky A2		Proven	834	18.4	15,326	0.22	600	0.88	0.89	1.10	435	1,407	11.50
	tulsky B1		Proven	6,086	47.2	287,532	0.26	1,000	0.89	0.86	1.11	318	1,537	4.90
	bobrikovsky 2-I		Proven	514	4.4	2,285	0.24	500	0.84	0.86	1.12	348	1,508	8.99
	bobrikovsky 2-II		Proven	1,033	6.6	6,804	0.24	500	0.84	0.86	1.12	348	1,508	8.99
	bobrikovsky 2-III		Proven	1,321	9.8	12,967	0.24	500	0.84	0.86	1.12	348	1,508	8.99
	bobrikovsky 3		Proven	832	7.8	6,494	0.24	500	0.84	0.86	1.12	348	1,508	8.99
	evl.-levensky I		Proven	1,236	4.6	5,673	0.08	40	0.68	0.80	1.43	1,316	2,741	0.30
	evl.-levensky II		Proven	2,507	45.9	115,148	0.08	40	0.68	0.80	1.43	1,316	2,741	0.30
	semeluksky 1 + 2		Proven	294	17.4	5,105	0.08	10	0.64	0.80	1.22	506	3,539	3.00
ZIMOVSKOYE														
	zad - eletsky		Proven	964	15.7	15,176	0.22	731	0.79	0.82	1.22	534	2,553	1.90
VOLGODEMINOIL JOINT VENTURE														
PRIBORTOVSKOYE														
	evl. - levensky		Proven	119	52.8	6,265	0.13	92	0.80	0.80	1.59	1,129	3,919	0.30
	evl. - levensky		Probable	237	34.9	8,289	0.13	92	0.80	0.80	1.59	1,129	3,919	0.30
PAMYATNOYE-SASOVSKOYE														
	evl. - levensky		Proven	778	476.3	370,777	0.07	109	0.93	0.83	1.34	1,162	4,074	0.90

PERMNEFT SUBSIDIARY
RESERVOIR PARAMETERS

Field	Reservoir	Field Area	Category	Area (Acres)	Avg Net Thickness (Feet)	Net Volume (Acre-Feet)	Porosity (fraction)	Permeability (md)	Oil Saturation (fraction)	Oil Specific Gravity	Oil FVF (RBbl/STB)	Solution Gas Ratio (SCF/STB)	Estimated Original Pressure (psi)	Oil Viscosity (cp)
ALNAYSHSKOYE														
	K		Proven	1,912	9.3	17,790	0.16	18	0.56	0.868	1.045	97	1,356	9.85
	K		Probable	120	6.6	789	0.16	18	0.56	0.868	1.045	97	1,356	9.85
	V3V4		Proven	701	13.5	9,497	0.14	26	0.70	0.868	1.045	97	1,356	9.85
	V3V4		Probable	536	3.3	1,758	0.14	26	0.70	0.868	1.045	97	1,356	9.85
	Bsh		Proven	927	10.2	9,440	0.16	26	0.83	0.895	1.046	100	1,356	15.79
	TL2-a		Proven	1,351	6.0	8,146	0.20	492	0.88	0.918	1.029	77	2,161	67.00
			Probable	62	3.3	203	0.20	492	0.88	0.918				67.00
	TL2-b		Proven	1,529	6.8	10,359	0.20	492	0.88	0.918	1.029	77	2,161	67.00
	Bb1		Proven	304	6.3	1,916	0.24	1,163	0.92	0.913	1.030	75	2,161	12.60
	Bb2		Proven	1,019	18.1	18,401	0.24	1,163	0.92	0.913	1.030	75	2,161	12.60
	D1		Proven	1,915	9.2	17,602	0.14	1	0.79	0.868	1.091	73	2,161	4.25
	D1		Probable	488	7.0	3,418	0.14	1	0.79	0.868	1.091	73	2,161	4.25
	D2-a		Proven	247	2.5	608	0.14	1	0.79	0.868	1.091	73	2,161	4.25
	D2-b		Probable	247	4.9	1,216	0.14	1	0.79	0.868	1.091	73	2,161	4.25
ANDREEVSKOYE														
	P3		Proven	494	6.6	3,243	0.19	na	0.64	0.862	na	na	na	na
	P3		Probable	432	4.9	2,128	0.19	na	0.64	0.862	na	na	na	na
	D0		Proven	803	12.3	9,911	0.17	304	0.87	0.902	1.109	228	3,305	8.32
	D0		Probable	1,137	7.8	8,876	0.17	304	0.87	0.902	1.109	228	3,305	8.32
	D1		Proven	556	6.6	3,689	0.17	304	0.86	0.902	na	na	na	8.32
	D1		Probable	1,044	5.7	5,960	0.17	304	0.86	0.902	na	na	na	8.32
	D2a		Proven	1,173	10.6	12,485	0.17	304	0.86	0.902	na	na	na	8.32
	D2a		Probable	439	8.1	3,554	0.17	304	0.86	0.902	na	na	na	8.32
APTUGAYSKOYE														
	K1		Proven	62	6.5	405	0.16	40	0.63	0.863	na	na	na	7.20
	K1		Probable	100	2.9	290	0.16	40	0.63	0.863	na	na	na	7.20
	V3V4		Proven	247	6.2	1,540	0.15	294	0.66	0.872	na	na	na	10.37
	V3V4		Probable	1,044	5.7	5,960	0.15	294	0.66	0.872	na	na	na	10.37
	TL2-a		Proven	185	5.9	1,094	0.18	625	0.71	0.898	na	na	na	20.90
	TL2-a		Probable	250	2.2	558	0.18	625	0.71	0.898	na	na	na	20.90
	TL Bb		Proven	1,236	16.4	20,251	0.18	625	0.71	0.898	na	na	na	20.90
	TL Bb		Probable	497	6.4	3,181	0.18	625	0.71	0.898	na	na	na	20.90
	T1+T2		Proven	803	14.0	11,218	0.11	56	0.58	0.901	na	na	na	20.90
	T1+T2		Probable	215	3.0	648	0.11	56	0.58	0.901	na	na	na	20.90
ASPENSKOYE														
	V3V4	Aspenskaya	Proven	608	8.2	4,985	0.12	157	0.76	0.871	1.093	196	1,595	6.39
	TL1-a	Aspenskaya	Proven	775	3.6	2,798	0.22	402	0.89	0.868	1.163	366	2,234	3.83
	TL1-b	Aspenskaya	Proven	541	3.6	1,951	0.22	402	0.89	0.868	1.163	366	2,234	3.83
	TL2-a	Aspenskaya	Proven	930	3.2	3,019	0.22	402	0.89	0.868	1.163	366	2,234	3.83
	TL2-b	Aspenskaya	Proven	1,708	6.9	11,766	0.22	402	0.89	0.868	1.163	366	2,234	3.83
	Bb1	Aspenskaya	Proven	1,158	4.9	5,699	0.22	402	0.89	0.868	1.163	366	2,234	3.83
	Bb2	Aspenskaya	Proven	1,406	14.0	19,733	0.22	402	0.89	0.868	1.163	366	2,234	3.83
	Bb2	Aspenskaya	Probable	62	4.9	304	0.22	402	0.89	0.868	1.163	366	2,234	3.83
	ML	Aspenskaya	Proven	428	5.2	2,246	0.22	136	0.90	0.868	1.163	366	2,234	3.65
	T	Aspenskaya	Proven	216	16.4	3,546	0.22	136	0.90	0.868	1.163	366	2,234	3.65

PERMNEFT SUBSIDIARY
RESERVOIR PARAMETERS

Field	Reservoir	Field Area	Category	Area (Acres)	Avg Net Thickness (Feet)	Net Volume (Acre-Feet)	Porosity (fraction)	Permeability (md)	Oil Saturation (fraction)	Oil Specific Gravity	Oil FVF (RBbl/STB)	Solution Gas Ratio (SCF/STB)	Estimated Original Pressure (psi)	Oil Viscosity (cp)
ASPENSKOYE (cont)														
	DO-1	Aspenskaya	Proven	865	7.8	6,717	0.16	48	0.75	0.872	1.133	367	2,234	6.55
	DO-1	Aspenskaya	Probable	1,236	3.2	3,973	0.16	48	0.75	0.872	1.133	367	2,234	6.55
	DO-2	Aspenskaya	Probable	700	2.9	2,019	0.16	48	0.75	0.872	1.133	367	2,234	6.55
	Bsh	Krasnogrskaya	Proven	62	6.6	405	0.17	895	0.84	0.915	1.022	406	2,103	38.45
	TL1-a	Krasnogrskaya	Proven	124	9.0	1,115	0.17	150	0.78	0.855	1.176	379	2,103	2.41
	T	Krasnogrskaya	Proven	278	12.5	3,469	0.15	13	0.87	0.880	1.157	390	2,103	5.40
BAKLANOVSKOYE														
	V3V4	Baklanovskaya	Proven	5,426	12.6	68,179	0.14	130	0.70	0.852	1.054	134	1,772	4.13
	Bsh	Baklanovskaya	Proven	4,042	7.2	29,172	0.15	31	0.67	0.852	1.058	144	1,845	5.52
	Yasn	Baklanovskaya	Proven	2,295	13.5	30,875	0.20	187	0.86	0.860	na	na	na	6.45
	V3V4	Blagodatnata	Proven	988	8.7	8,573	0.15	42	0.67	0.896	1.034	65	1,769	35.43
	Bsh	Blagodatnata	Proven	1,432	9.2	13,152	0.18	49	0.77	0.880	1.078	143	1,835	12.41
	Yasn	Blagodatnata	Proven	4,079	21.7	88,318	0.20	194	0.90	0.841	na	na	na	3.38
	V3V4	Kuleshovkaya	Proven	5,533	14.3	79,178	0.16	40	0.67	0.852	1.054	134	1,740	4.13
	Bsh	Kuleshovkaya	Proven	2,278	8.2	18,685	0.14	23	0.68	0.852	1.058	152	1,787	5.52
	Yasn	Kuleshovkaya	Proven	2,789	14.9	41,514	0.20	201	0.87	0.846	na	na	na	3.77
	V3V4	Sukhobezyarskaya	Proven	8,439	14.8	124,585	0.15	31	0.67	0.852	1.054	134	1,769	4.13
	Bsh	Sukhobezyarskaya	Proven	7,224	13.1	94,802	0.14	29	0.72	0.852	1.058	144	1,827	5.52
	Yasn	Sukhobezyarskaya	Proven	5,543	20.0	110,928	0.19	332	0.88	0.851	na	na	na	4.15
BATIRBACSKOYE														
	K	Asulskaya	Proven	9,890	7.7	76,055	0.16	47	0.68	0.873	1.155	358	1,595	2.88
	V1	Asulskaya	Proven	6,653	5.8	38,549	0.16	38	0.67	0.881	1.124	277	2,103	4.89
	V1	Asulskaya	Probable	1,194	2.5	3,016	0.16	38	0.67	0.881	1.124	277	2,103	4.89
	V3V4	Asulskaya	Proven	10,982	14.6	160,344	0.16	38	0.67	0.881	1.124	277	1,595	4.89
	V3V4	Asulskaya	Probable	928	13.8	12,850	0.16	38	0.67	0.881	1.124	277	1,595	4.89
	Bsh1	Asulskaya	Proven	10,623	8.6	91,680	0.13	79	0.75	0.880	1.129	267	1,595	6.30
	Bsh2	Asulskaya	Proven	3,379	18.5	62,465	0.13	79	0.75	0.880	1.129	267	1,595	6.30
	Bsh2	Asulskaya	Probable	476	10.9	5,166	0.13	79	0.75	0.880	1.129	267	1,595	6.30
	Yasn	Asulskaya	Proven	9,472	0.0	96	0.20	307	0.86	0.872	na	na	na	4.66
	T	Asulskaya	Proven	1,468	5.9	8,668	0.08	16	0.79	0.873	1.109	245	2,103	4.47
	Bsh1	Iskilydinskaya	Proven	185	11.8	2,189	0.12	96	0.76	0.870	na	na	na	5.80
	K	Konstantenovskaya	Proven	4,856	7.4	35,748	0.16	35	0.68	0.876	1.147	317	1,503	4.34
	K	Konstantenovskaya	Probable	3,052	6.6	20,124	0.16	35	0.68	0.876	1.147	317	1,503	4.34
	V1	Konstantenovskaya	Proven	2,014	7.1	14,380	0.17	47	0.70	0.880	1.122	277	1,503	3.86
	V3V4	Konstantenovskaya	Proven	12,479	9.7	121,593	0.17	47	0.70	0.880	1.122	259	1,484	3.86
	Bsh1	Konstantenovskaya	Proven	18,617	21.5	401,014	0.18	280	0.82	0.879	1.129	89	1,503	6.30
	Bsh1	Konstantenovskaya	Probable	570	10.3	5,875	0.18	280	0.82	0.879	1.129	89	1,503	6.30
	Bsh2	Konstantenovskaya	Proven	10,953	0.0	100	0.18	280	0.82	0.879	1.129	89	1,503	6.30
	Yasn		Proven	14,219	14.1	201,022	0.17	328	0.85	0.885	na	na	na	8.20
	ML	Konstantenovskaya	Proven	111	9.8	1,094	0.17	154	0.85	0.913	1.224	205	2,147	17.59
	T	Konstantenovskaya	Proven	1,679	13.2	22,142	0.16	10	0.87	0.923	1.091	207	2,147	17.59
BIRKENSKOYE														
	KV1		Proven	2,299	11.2	25,648	0.18	80	0.67	0.868	1.068	122	1,305	8.89
	V3V4		Proven	2,773	14.9	41,342	0.15	149	0.67	0.858	1.081	120	1,305	5.37

PERMNEFT SUBSIDIARY
RESERVOIR PARAMETERS

Field	Reservoir	Field Area	Category	Area (Acres)	Avg Net Thickness (Feet)	Net Volume (Acre-Feet)	Porosity (fraction)	Permeability (md)	Oil Saturation (fraction)	Oil Specific Gravity	Oil FVF (RBbl/STB)	Solution Gas Ratio (SCF/STB)	Estimated Original Pressure (psi)	Oil Viscosity (cp)
------	--------------	-----------------	----------	----------	------------	------------	------------	--------------	------------	------------	------------	------------	------------	------------
BIRKENSKOYE (cont)														
	Bsh		Proven	2,146	31.8	68,311	0.15	225	0.64	0.858	1.081	169	1,421	5.37
	TL2-b		Proven	1,986	6.6	13,062	0.24	593	0.94	0.906	1.025	81	2,147	38.81
	Bb1		Proven	967	6.5	6,258	0.24	593	0.94	0.906	1.025	81	2,147	38.81
	Bb2		Proven	1,551	18.7	29,048	0.24	593	0.94	0.906	1.025	81	2,147	38.81
	T		Proven	1,692	34.4	58,284	0.13	44	0.74	0.906	1.025	86	2,176	37.10
	D1		Proven	1,131	4.0	4,519	0.16	186	0.75	0.909	1.028	87	2,176	79.30
	D2		Proven	1,568	9.1	14,231	0.16	186	0.75	0.909	1.028	87	2,176	79.30
CHARSKOYE														
	TL		Proven	300	9.5	2,854	0.19	240	0.88	0.877	na	na	na	6.70
	Bb		Proven	292	5.1	1,488	0.19	240	0.88	0.877	na	na	na	6.70
	ML		Proven	86	2.0	169	0.18	178	0.88	0.896	na	na	na	14.74
	T		Proven	383	42.0	16,077	0.16	95	0.85	0.911	na	na	na	14.85
	T		Probable	126	25.6	3,222	0.16	95	0.85	0.911	na	na	na	14.85
CHERNUSHENSKOYE														
	V3V4	Chernushenskaya	Proven	371	12.3	4,560	0.16	28	0.62	0.863	1.091	97	1,595	5.02
	V3V4	Chernushenskaya	Probable	164	2.1	349	0.16	28	0.62	0.863	1.091	97	1,595	5.02
	Bsh	Chernushenskaya	Proven	618	11.8	7,313	0.17	35	0.71	0.886	1.050	99	1,595	15.40
	Bsh	Chernushenskaya	Probable	208	8.8	1,822	0.17	35	0.71	0.886	1.050	99	1,595	15.40
	TL2-a	Chernushenskaya	Proven	1,050	10.6	11,178	0.21	124	0.91	0.885	1.095	248	2,176	11.50
	TL2-a	Chernushenskaya	Probable	534	4.9	2,613	0.18	124	0.88	0.910	1.095	248	2,176	11.50
	TL2-b	Chernushenskaya	Proven	261	5.6	1,472	0.21	124	0.91	0.885	1.095	248	2,176	11.50
	Bb1	Chernushenskaya	Proven	384	2.4	921	0.21	124	0.91	0.885	1.095	248	2,176	11.50
	Bb2	Chernushenskaya	Proven	556	8.3	4,641	0.21	124	0.91	0.885	1.095	248	2,176	11.50
	Bb2	Chernushenskaya	Probable	213	6.5	1,385	0.18	124	0.88	0.910	1.095	248	2,176	11.50
	ML	Chernushenskaya	Proven	371	19.5	7,211	0.22	125	0.94	0.905	1.081	254	2,176	15.64
	ML	Chernushenskaya	Probable	131	5.3	693	0.22	125	0.94	0.905	1.081	254	2,176	15.64
	T1,T2	Chernushenskaya	Proven	1,168	21.6	25,174	0.21	166	0.67	0.916	1.065	170	2,190	18.10
	T1,T2	Chernushenskaya	Probable	394	17.0	6,706	0.21	166	0.67	0.916	1.065	170	2,190	18.10
CHIKULAYESKOYE														
	V3V4		Proven	271	11.1	3,021	0.17	168	0.66	0.863	1.091	na	1,435	5.02
	Bsh		Proven	201	6.9	1,384	0.15	186	0.84	0.856	1.050	na	1,506	15.40
	Yasn		Proven	879	18.2	16,016	0.22	427	0.91	0.883	1.085	na	2,018	9.86
	ML		Proven	126	6.2	782	0.22	584	0.95	0.904	1.073	na	2,075	17.16
	T		Proven	1,121	25.8	28,909	0.14	240	0.68	0.900	1.090	na	2,124	19.19
	T		Probable	88	9.8	863	0.14	240	0.68	0.900	1.090	na	2,124	19.19
	D		Proven	62	8.5	527	0.20	na	0.91	0.878	1.109	na	2,799	na
CHURAVSKOYE														
	Bsh	main area	Proven	1,295	13.9	17,972	0.18	320	0.83	0.883	1.198	535	1,958	3.24
	TL1	main area	Proven	3,572	20.4	72,715	0.18	320	0.83	0.883	1.199	456	2,393	3.24
	TL1	main area	Probable	316	1.3	425	0.19	320	0.88	0.883	1.199	456	2,393	3.24
CHURAVSKOYE (cont)														
	Bb	main area	Proven	1,295	13.9	17,972	0.18	320	0.83	0.883	1.199	436	2,567	3.24
	ML	main area	Proven	1,064	6.3	6,722	0.17	62	0.86	0.889	1.199	436	2,567	3.57
	T	main area	Proven	2,953	21.8	64,320	0.12	35	0.78	0.886	1.230	519	2,567	1.51
	D (Kyn)	south area	Proven	1,540	9.1	14,051	0.14	192	0.80	0.890	1.198	535	1,878	7.22

PERMNEFT SUBSIDIARY
RESERVOIR PARAMETERS

Field	Reservoir	Field Area	Category	Area (Acres)	Avg Net Thickness (Feet)	Net Volume (Acre-Feet)	Porosity (fraction)	Permeability (md)	Oil Saturation (fraction)	Oil Specific Gravity	Oil FVF (RBbl/STB)	Solution Gas Ratio (SCF/STB)	Estimated Original Pressure (psi)	Oil Viscosity (cp)
DOROKHOVSKOYE														
	Maychkovsky		Proven	2,239	6.5	14,622	0.14	na	0.43	0.110	9.900	na	na	na
	K+V gas		Proven	2,462	5.5	13,491	0.10	336	0.64	0.874	1.138	na	1,712	7.80
	K+V oil		Proven	97	6.0	580	0.14	15	0.64	0.886	1.092	422	1,759	7.80
	V3V4		Proven	1,741	14.7	25,590	0.12	22	0.62	0.884	1.092	437	1,819	8.96
	V3V4		Probable	294	77.2	22,717	0.12	22	0.62	0.884	1.092	437	1,819	8.96
	Bsh		Proven	3,459	14.4	49,960	0.19	52	0.68	0.856	1.085	224	1,847	2.29
	Bsh		Probable	556	6.6	3,648	0.19	52	0.68	0.856	1.085	224	1,847	2.29
	Yasn		Proven	3,620	15.0	54,187	0.19	132	0.90	0.856	1.159	na	2,473	4.84
	Yasn		Probable	124	9.8	1,216	0.19	132	0.90	0.856	1.159	na	2,473	4.84
	ML		Proven	962	15.5	14,904	0.21	65	0.92	0.832	1.256	709	2,508	1.45
	T		Proven	1,347	8.4	11,256	0.11	19	0.76	0.834	1.287	677	2,586	1.11
	Fm		Proven	207	15.2	3,154	0.10	69	0.64	0.874	1.233	388	2,984	2.80
	Fm		Probable	124	9.8	1,216	0.10	69	0.64	0.874	1.233	388	2,984	2.80
	D		Proven	247	3.4	851	0.16	na	0.63	0.825	1.381	na	3,346	7.30
	D		Probable	247	3.3	811	0.16	na	0.63	0.825	1.381	na	3,346	7.30
ETYSHSKOYE														
	Bash		Proven	309	10.5	3,245	0.17	11	0.71	0.866	na	na	na	15.40
	TL2a		Proven	803	8.0	6,405	0.17	248	0.88	0.889	na	na	na	12.40
	TL2b		Proven	247	6.9	1,702	0.14	421	0.88	0.889	na	na	na	12.40
	Bb		Proven	124	14.9	1,844	0.16	682	0.88	0.891	na	na	na	14.10
	Bb		Probable	267	6.0	1,611	0.16	682	0.83	0.891	na	na	na	14.10
	T		Proven	865	17.2	14,876	0.12	333	0.70	0.911	na	na	na	17.40
GABISHEVSKOYE (YENAPAEVSKAYA)														
	Fm	Yenapaevskaya	Proven	752	19.7	14,778	0.10	53	0.70	0.888	na	na	na	9.00
	Fm	Yenapaevskaya	Probable	185	19.7	3,648	0.10	53	0.70	0.888	na	na	na	9.00
GONDIREVSKOYE														
	KV1		Proven	4,786	10.8	51,821	0.12	43	0.55	0.866	1.098	115	2,103	13.03
	V3V4		Proven	3,693	9.2	33,922	0.14	479	0.62	0.866	1.111	113	2,103	13.03
	Bsh		Proven	4,514	18.7	84,421	0.16	80	0.74	0.877	1.046	116	2,103	12.27
	TL2-a		Proven	6,274	14.4	90,561	0.22	515	0.85	0.869	1.066	115	2,103	12.80
	TL2-b		Proven	4,439	6.6	29,124	0.22	515	0.85	0.869	1.066	115	2,103	12.80
	Bb1		Proven	1,991	4.6	9,143	0.22	515	0.85	0.869	1.066	115	2,103	12.80
	Bb2		Proven	2,661	25.9	68,971	0.22	515	0.85	0.869	1.066	115	2,103	12.80
	T		Proven	402	11.5	4,611	0.13	143	0.76	8.650	1.073	114	2,103	12.27
GORSKOYE														
	Yasn	Gorskaya	Proven	489	12.7	6,206	0.21	350	0.78	0.878	1.033	70	2,361	28.04
	T	E. Gorskaya	Proven	750	10.5	7,883	0.14	366	0.75	0.910	1.022	51	2,509	37.20
KAMISHLOVSKOYE														
	TL2-a		Proven	618	7.5	4,660	0.17	100	0.84	0.878	1.052	108	2,093	18.07
	TL2-a		Probable	225	3.3	739	0.17	100	0.84	0.878	1.052	108	2,093	18.07
	Bb2		Proven	803	6.9	5,532	0.17	100	0.84	0.878	1.052	108	2,093	18.07
	Bb2		Probable	429	4.9	2,109	0.17	100	0.84	0.878	1.052	108	2,093	18.07
	T1		Proven	2,471	21.4	52,906	0.12	12	0.70	0.866	1.093	146	2,185	11.21
	T1		Probable	630	13.1	8,267	0.12	12	0.70	0.866	1.093	146	2,185	11.21

PERMNEFT SUBSIDIARY
RESERVOIR PARAMETERS

Field	Reservoir	Field Area	Category	Area (Acres)	Avg Net Thickness (Feet)	Net Volume (Acre-Feet)	Porosity (fraction)	Permeability (md)	Oil Saturation (fraction)	Oil Specific Gravity	Oil FVF (RBbl/STB)	Solution Gas Ratio (SCF/STB)	Estimated Original Pressure (psi)	Oil Viscosity (cp)
KAMISHLOVSKOYE (cont)														
	Fm1		Proven	432	7.4	3,201	0.12	4	0.64	0.885	1.068	149	2,312	19.52
	Fm1		Probable	293	3.3	961	0.12	4	0.64	0.885	1.068	149	2,312	19.52
	Fm2		Proven	927	9.2	8,510	0.12	4	0.64	0.885	1.068	149	2,312	19.52
	Fm2		Probable	635	6.6	4,164	0.12	4	0.64	0.885	1.068	149	2,312	19.52
	Fm3		Proven	494	8.7	4,316	0.12	4	0.64	0.885	1.068	149	2,312	19.52
	Fm3		Probable	280	3.3	917	0.12	4	0.64	0.885	1.068	149	2,312	19.52
	TL		Proven	185	9.8	1,824	0.20	na	0.80	0.829	1.218	140	na	16.32
	D02		Proven	124	7.9	973	0.14	160	0.59	0.813	1.167	347	3,085	6.61
	D02		Probable	62	7.9	486	0.14	160	0.59	0.813	1.167	347	3,085	6.61
KAZAKOVSKOYE														
	TL2-a		Proven	1,276	5.7	7,323	0.16	96	0.78	0.817	1.285	506	2,103	1.59
	TL2-b		Proven	1,251	10.2	12,722	0.16	96	0.78	0.817	1.285	506	2,103	1.59
	Bb1		Proven	371	4.4	1,648	0.16	96	0.78	0.817	1.285	588	2,292	1.59
	Bb2		Proven	267	5.9	1,588	0.16	96	0.78	0.817	1.285	588	2,292	1.59
	ML		Proven	1,229	12.8	15,730	0.19	649	0.88	0.822	1.230	504	2,342	1.33
	T		Proven	576	9.6	5,556	0.12	22	0.76	0.822	1.230	504	2,350	1.33
KIRILLOVSKOYE														
	D0		Proven	432	8.3	3,610	0.19	405	0.90	0.900	1.114	212	2,959	6.81
	D0		Probable	275	3.3	902	0.19	405	0.90	0.900	1.114	212	2,959	6.81
	D1		Proven	198	7.9	1,557	0.19	405	0.90	0.900	1.114	180	3,024	6.81
KOKUESKOYE - GUBANOVSKAYA														
	Bsh1	Gubanovskaya	Proven	1,977	7.7	15,306	0.17	42	0.79	0.861	1.256	1,378	1,885	1.47
	Bsh1	Gubanovskaya	Probable	334	0.8	252	0.17	42	0.79	0.861	1.256	1,378	1,885	1.47
	TL 2-a	Gubanovskaya	Proven	154	1.6	253	0.16	36	0.84	0.876	1.297	1,402	1,885	1.34
	TL 2-b	Gubanovskaya	Proven	1,198	10.9	13,054	0.16	36	0.89	0.876	1.297	639	2,524	1.34
	TL 2-b	Gubanovskaya	Probable	62	9.1	567	0.14	36	0.84	0.876	1.297	639	2,524	1.34
	Bb1	Gubanovskaya	Proven	550	9.8	5,411	0.16	36	0.89	0.876	1.297	639	2,524	1.34
	Bb2	Gubanovskaya	Proven	575	9.8	5,653	0.16	36	0.89	0.876	1.297	639	2,524	1.34
	Bb3	Gubanovskaya	Proven	544	13.1	7,134	0.16	36	0.89	0.876	1.297	639	2,524	1.34
	ML	Gubanovskaya	Proven	785	19.3	15,180	0.17	136	0.88	0.874	1.297	638	2,524	1.37
KOKUESKOYE - VESLYANSKAYA														
	Srp	Kokueskaya	Proven	3,849	21.3	82,084	0.19	46	0.77	0.869	1.211	446	1,885	1.72
	Bsh1	Kokueskaya	Proven	15,132	19.4	294,165	0.18	46	0.79	0.861	1.256	619	1,885	1.47
	Bsh1	Kokueskaya	Probable	2,330	5.7	13,316	0.18	46	0.79	0.861	1.256	619	1,885	1.47
	Bsh2	Kokueskaya	Proven	14,425	9.9	142,582	0.18	46	0.79	0.861	1.256	619	1,885	1.47
	Bsh3	Kokueskaya	Proven	7,055	6.8	47,832	0.18	46	0.79	0.861	1.256	619	1,885	1.47
	TL 1b	Kokueskaya	Proven	3,429	1.6	5,624	0.15	na	0.86	0.861	na	na	na	na
	TL 2-a	Kokueskaya	Proven	4,636	3.8	17,643	0.16	na	0.89	0.876	1.297	615	2,408	na
	TL 2-b	Kokueskaya	Proven	8,290	8.4	69,923	0.17	30	0.83	0.863	1.217	606	2,408	1.98
	Bb1	Kokueskaya	Proven	6,025	9.6	58,089	0.18	48	0.85	0.872	1.255	661	2,408	1.78
	Bb2	Kokueskaya	Proven	7,049	9.7	68,565	0.18	48	0.85	0.872	1.255	661	2,408	1.78
	Bb3	Kokueskaya	Proven	4,720	6.6	30,969	0.18	48	0.92	0.872	1.255	661	2,408	1.78
	ML	Kokueskaya	Proven	2,224	8.1	18,038	0.19	45	0.91	0.867	1.256	604	2,408	1.96
	T	Kokueskaya	Proven	2,304	15.7	36,279	0.14	20	0.75	0.877	1.277	669	2,408	1.25

PERMNEFT SUBSIDIARY
RESERVOIR PARAMETERS

Field	Reservoir	Field Area	Category	Area (Acres)	Avg Net Thickness (Feet)	Net Volume (Acre-Feet)	Porosity (fraction)	Permeability (md)	Oil Saturation (fraction)	Oil Specific Gravity	Oil FVF (RBbl/STB)	Solution Gas Ratio (SCF/STB)	Estimated Original Pressure (psi)	Oil Viscosity (cp)
KOKUESKOYE - LUZKOVSKAYA														
	Bsh1	Luzkovskaya	Proven	741	9.8	7,296	0.18	na	0.79	0.861	1.256	619	1,885	na
	TL 2-a	Luzkovskaya	Proven	371	7.0	2,590	0.16	na	0.89	0.876	1.297	615	2,408	na
	TL 2-a	Luzkovskaya	Probable	371	7.0	2,590	0.16	na	0.89	0.876	1.297	615	2,408	na
	TL 2-b	Luzkovskaya	Proven	988	10.7	10,539	0.17	na	0.83	0.863	1.217	606	2,408	na
	TL 2-b	Luzkovskaya	Probable	280	6.6	1,837	0.17	na	0.83	0.863	1.217	606	2,408	na
	Bb1	Luzkovskaya	Proven	1,050	8.2	8,614	0.17	32	0.92	0.865	1.266	656	2,408	2.02
	Bb2	Luzkovskaya	Proven	537	6.6	3,527	0.17	32	0.92	0.865	1.266	656	2,408	2.02
	ML	Luzkovskaya	Proven	185	6.6	1,216	0.19	na	0.91	0.867	1.256	604	2,408	na
KOKUESKOYE - MAKAROVSKAYA														
	Bsh1	Makarovskaya	Proven	1,112	6.6	7,296	0.15	28	0.82	0.861	1.256	619	1,885	1.63
	Bsh1	Makarovskaya	Probable	1,297	16.4	21,294	0.15	28	0.82	0.861	1.256	619	1,885	1.63
	Bsh2	Makarovskaya	Proven	2,471	8.3	20,632	0.15	28	0.82	0.861	1.256	619	1,885	1.63
	TL 2-a	Makarovskaya	Proven	741	4.9	3,648	0.15	na	0.86	0.861	1.235	604	2,408	na
	TL 2-b	Makarovskaya	Proven	927	7.9	7,296	0.15	28	0.83	0.858	1.186	602	2,408	1.76
	Bb1	Makarovskaya	Proven	834	13.1	10,944	0.17	39	0.92	0.858	1.214	650	2,408	2.02
	Bb2	Makarovskaya	Proven	797	6.2	4,925	0.17	39	0.92	0.858	1.214	650	2,408	2.02
	Bb3	Makarovskaya	Proven	117	6.6	770	0.17	39	0.92	0.858	1.214	650	2,408	2.02
	ML	Makarovskaya	Proven	124	4.9	608	0.19	na	0.91	0.867	1.256	604	2,408	na
KOKUESKOYE - MAZUNENSKAYA														
	V3V4	Mazunenskaya	Proven	3,775	5.7	21,671	0.15	na	0.82	0.861	1.256	532	2,466	na
	Bsh1	Mazunenskaya	Proven	1,112	7.8	8,715	0.15	80	0.82	0.861	1.256	532	2,466	1.40
	TL 1-a	Mazunenskaya	Proven	2,817	2.5	6,932	0.15	42	0.86	0.860	1.235	532	2,466	2.30
	TL 1-b	Mazunenskaya	Proven	4,065	9.0	36,765	0.15	42	0.86	0.861	1.235	532	2,466	2.30
	TL 1-b	Mazunenskaya	Probable	635	4.9	3,124	0.15	42	0.86	0.861	1.235	532	2,466	2.30
	TL 1-v	Mazunenskaya	Proven	4,040	6.6	26,510	0.15	42	0.86	0.861	1.235	532	2,466	2.30
	TL 2-a	Mazunenskaya	Proven	2,477	4.9	12,191	0.15	42	0.86	0.861	1.235	532	2,466	2.30
	TL 2-b	Mazunenskaya	Proven	995	6.6	6,525	0.15	42	0.86	0.861	1.235	532	2,466	2.30
	Bb1	Mazunenskaya	Proven	605	6.6	3,972	0.19	56	0.90	0.892	1.190	551	2,466	5.00
	T	Mazunenskaya	Proven	136	5.5	750	0.14	na	0.75	0.877	1.277	542	2,466	na
KOKUESKOYE - ORDENSKAYA														
	TL 2-b	Ordenskaya	Proven	1,056	6.6	6,932	0.15	na	0.83	0.858	1.186	517	2,408	na
	Bb1	Ordenskaya	Proven	1,198	24.6	29,489	0.14	49	0.87	0.812	1.709	1,432	2,727	0.51
	ML	Ordenskaya	Proven	1,606	10.3	16,601	0.15	14	0.93	0.862	1.709	1,520	2,727	1.73
	ML	Ordenskaya	Probable	192	6.7	1,275	0.15	14	0.93	0.862	1.709	1,520	2,727	1.73
KOKUESKOYE - YASLASKAYA														
	Bb2	Yaslaskaya	Proven	124	9.0	1,115	0.15	40	0.92	0.876	1.238	664	2,408	1.78
	Bsh1	Yaslskaya	Proven	5,189	9.3	48,237	0.14	41	0.79	0.861	1.256	619	1,885	1.63
	Bsh1	Yaslskaya	Probable	2,196	3.5	7,782	0.14	41	0.79	0.861	1.256	619	1,885	1.63
	Bsh2	Yaslskaya	Proven	2,162	12.1	26,247	0.14	41	0.79	0.861	1.256	619	1,885	1.63
	TL 2-b	Yaslskaya	Proven	124	9.0	1,115	0.15	30	0.83	0.877	1.255	615	2,408	2.22
	TL 2-b	Yaslskaya	Probable	309	4.9	1,520	0.15	30	0.83	0.877	1.255	615	2,408	2.22

PERMNEFT SUBSIDIARY
RESERVOIR PARAMETERS

Field	Reservoir	Field Area	Category	Area (Acres)	Avg Net Thickness (Feet)	Net Volume (Acre-Feet)	Porosity (fraction)	Permeability (md)	Oil Saturation (fraction)	Oil Specific Gravity	Oil FVF (RBbl/STB)	Solution Gas Ratio (SCF/STB)	Estimated Original Pressure (psi)	Oil Viscosity (cp)
KRACNOYARSKO - KUEDENSKOYE														
	KV1 (GAS CAP)		Proven	6,877	5.9	40,613	0.16	na	0.70	0.866	na	na	na	na
	V3V4 (GAS CAP)		Proven	2,621	7.5	19,559	0.16	na	0.66	0.862	na	na	na	na
	KV1		Proven	31,333	11.4	358,660	0.16	40	0.70	0.866	1.092	78	1,421	5.90
	KV1		Probable	185	8.2	1,520	0.16	40	0.70	0.866	1.092	78	1,421	5.90
	V3V4		Proven	25,395	11.5	293,276	0.16	16	0.66	0.862	1.091	77	1,479	4.76
	V3V4		Probable	309	8.2	2,533	0.16	16	0.66	0.862	1.091	77	1,479	4.76
	Bsh Total		Proven	36,266	19.8	716,672	0.14	101	0.72	0.882	1.056	158	1,537	12.88
	Bsh Total		Probable	865	6.6	5,675	0.14	101	0.72	0.882	1.056	158	1,537	12.88
	TL2-a		Proven	7,408	7.0	51,840	0.19	225	..88	0.890	1.055	200	2,103	14.80
	TL2-a		Probable	865	6.9	5,979	0.19	225	0.88	0.890	1.055	200	2,103	14.80
	TL2-b		Proven	16,735	10.0	166,807	0.18	225	0.88	0.890	1.064	200	2,103	14.80
	TL2-b		Probable	618	6.7	4,155	0.18	225	0.88	0.890	1.064	200	2,103	14.80
	Bb1		Proven	4,538	5.4	24,532	0.19	225	0.88	0.898	1.058	200	2,103	14.80
	Bb2		Proven	5,784	14.4	83,190	0.19	225	0.88	0.890	1.057	200	2,103	14.80
	T		Proven	5,365	16.0	85,617	0.11	9	0.55	0.891	1.065	170	2,103	13.81
	D1		Proven	4,201	10.7	44,771	0.19	326	0.89	0.884	1.088	227	2,103	4.45
	D1		Probable	247	9.4	2,331	0.19	326	0.89	0.884	1.088	227	2,103	4.45
KRYAZHEVSKOYE														
	TL		Proven	284	9.2	2,599	0.23	216	0.80	0.827	1.040	na	2,046	17.81
	TL		Probable	31	5.5	172	0.23	216	0.80	0.827	1.040	na	2,046	17.81
	Bb		Proven	62	7.4	456	0.20	89	0.86	0.901	na	na	na	22.70
	Bb		Probable	105	5.5	582	0.20	89	0.86	0.901	na	na	na	22.70
	ML		Proven	62	8.2	507	0.21	346	0.81	0.895	na	na	na	18.49
	ML		Probable	63	5.6	355	0.21	346	0.81	0.895	na	na	na	18.49
	T		Proven	494	14.6	7,195	0.13	85	0.57	0.789	na	na	na	18.62
	T		Probable	491	5.5	2,676	0.13	85	0.57	0.789	na	na	na	18.62
KUDRYAVTSEVKOYE														
	KV1		Proven	1,161	9.2	10,669	0.15	5	0.61	0.860	1.093	115	1,711	8.85
	V3V4		Proven	1,096	10.1	11,041	0.16	42	0.73	0.891	1.022	160	1,711	19.44
	TL2-b		Proven	522	9.3	4,865	0.17	61	0.80	0.919	1.033	77	2,321	57.89
	Bb		Proven	765	11.8	9,007	0.17	61	0.80	0.919	1.033	77	2,321	57.89
	T1		Proven	303	9.8	2,979	0.18	2	0.84	0.903	1.033	61	2,393	31.40
	T2+T3		Proven	457	25.6	11,698	0.10	2	0.65	0.903	1.031	61	2,393	31.40
KURBATOVSKOYE														
	KV1	I AREA	Proven	331	9.9	3,279	0.16	102	0.74	0.854	1.116	836	2,470	9.60
	KV1	I AREA	Probable	321	3.3	1,054	0.16	102	0.74	0.854	1.116	836	2,470	9.60
	TL2	I AREA	Proven	131	4.9	641	0.18	50	0.90	0.838	1.244	821	2,470	1.65
	Bb	I AREA	Proven	328	4.1	1,355	0.16	50	0.89	0.813	1.344	721	2,509	1.65
	ML	I AREA	Proven	182	13.2	2,389	0.17	163	0.92	0.848	1.377	726	2,538	1.74
	T	I AREA	Proven	422	11.0	4,621	0.12	11	0.78	0.849	1.300	572	2,561	2.09
	Bsh	II AREA	Proven	124	2.9	365	0.12	25	0.71	0.838	1.129	821	2,470	1.84
	Bsh	II AREA	Probable	292	3.0	864	0.12	25	0.71	0.838	1.129	821	2,470	1.84
	TL2 (OIL)	II AREA	Proven	512	10.0	5,100	0.18	50	0.90	0.838	1.230	804	2,470	1.65
	Bb	II AREA	Proven	322	8.3	2,660	0.16	50	0.89	0.813	1.230	728	2,509	1.65
	ML	II AREA	Proven	366	9.9	3,631	0.17	163	0.92	0.848	1.192	756	2,538	1.74
	T	II AREA	Proven	571	13.6	7,786	0.12	11	0.78	0.849	1.259	563	2,561	2.09

PERMNEFT SUBSIDIARY
RESERVOIR PARAMETERS

Field	Reservoir	Field Area	Category	Area (Acres)	Avg Net Thickness (Feet)	Net Volume (Acre-Feet)	Porosity (fraction)	Permeability (md)	Oil Saturation (fraction)	Oil Specific Gravity	Oil FVF (RBbl/STB)	Solution Gas Ratio (SCF/STB)	Estimated Original Pressure (psi)	Oil Viscosity (cp)
KURBATOVSKOYE (cont)														
	Bsh	III AREA	Proven	665	5.6	3,733	0.12	25	0.71	0.838	1.129	821	2,470	1.84
	TL	III AREA	Proven	699	6.7	4,696	0.18	50	0.90	0.838	1.244	821	2,470	1.65
	TL	III AREA	Probable	107	2.5	271	0.18	50	0.90	0.838	1.244	821	2,470	1.65
	Bb	III AREA	Proven	368	3.5	1,283	0.16	50	0.89	0.813	1.344	721	2,509	1.65
	Bb	III AREA	Probable	309	3.5	1,084	0.16	50	0.89	0.813	1.344	721	2,509	1.65
	ML	III AREA	Proven	320	10.4	3,328	0.17	163	0.92	0.848	1.192	756	2,538	1.74
	T	III AREA	Proven	594	5.1	3,039	0.12	11	0.78	0.849	1.259	563	2,561	2.09
	KV1	IV AREA	Proven	247	9.8	2,432	0.16	102	0.74	0.854	1.116	836	2,470	9.60
	KV1	IV AREA	Probable	276	5.0	1,376	0.16	102	0.74	0.854	1.116	836	2,470	9.60
	Bsh	IV AREA	Proven	124	7.2	892	0.12	25	0.71	0.838	1.129	821	2,470	1.84
	TL2	IV AREA	Proven	132	4.9	646	0.18	50	0.90	0.838	1.244	821	2,470	1.65
	Bb	IV AREA	Proven	62	6.6	405	0.16	105	0.89	0.821	1.230	728	2,509	1.65
	ML	IV AREA	Proven	62	8.0	491	0.21	640	0.87	0.836	1.192	756	2,538	1.88
	T	IV AREA	Probable	62	3.3	203	0.13	94	0.70	0.835	1.259	563	2,561	1.58
	TL2	V AREA	Proven	186	5.5	1,031	0.18	105	0.86	0.821	1.244	821	2,470	1.56
	ML	V AREA	Proven	290	6.9	2,014	0.21	640	0.87	0.836	na	na	na	1.88
	T	V AREA	Probable	148	3.3	486	0.13	94	0.70	0.835	1.259	563	2,561	1.58
	T	Well 19	Proven	62	3.9	243	0.13	94	0.70	0.835	na	na	na	13.58
KUSTOVSKOYE														
	D0		Proven	1,421	9.7	13,831	0.18	214	0.86	0.890	1.083	190	2,998	6.61
	D1	SE extension	Proven	803	12.5	10,014	0.18	214	0.86	0.890	1.083	190	2,998	6.61
	D1	SE extension	Probable	592	4.2	2,484	0.18	214	0.86	0.890	1.083	190	2,998	6.61
	D1	main part	Proven	2,656	13.3	35,213	0.18	214	0.86	0.890	1.083	190	2,998	6.61
	D2-a		Proven	4,046	9.2	37,183	0.18	214	0.86	0.890	1.083	190	2,998	6.61
	D2-b		Proven	717	13.8	9,856	0.18	214	0.86	0.890	1.083	190	2,998	6.61
MALO-USENSKOYE														
	ML		Proven	556	12.5	6,932	0.24	1,765	0.85	0.891	1.032	75	2,466	32.17
	ML		Probable	1,173	10.5	12,351	0.24	1,765	0.85	0.891	1.032	75	2,466	32.17
	D0		Proven	2,508	11.7	29,382	0.16	246	0.86	0.898	1.109	223	3,365	5.89
	D0		Probable	939	11.7	11,029	0.16	246	0.86	0.898	1.109	223	3,365	5.89
	D1		Proven	698	5.7	3,954	0.16	246	0.86	0.898	1.109	223	3,365	5.89
	D1		Probable	1,008	1.5	1,488	0.15	246	0.84	0.898	1.109	223	3,365	5.89
	D2-a		Proven	667	7.8	5,210	0.16	246	0.86	0.898	1.109	223	3,365	5.89
	D2-a		Probable	435	5.5	2,397	0.16	246	0.86	0.898	1.109	223	3,365	5.89
MAYACHNOYE														
	Bsh1		Proven	1,625	9.7	15,725	0.14	259	0.75	0.869	na	na	na	44.42
	TL2		Proven	607	13.8	8,363	0.20	241	0.86	0.901	na	na	na	22.15
	T		Proven	2,635	42.3	111,504	0.13	432	0.69	0.902	na	na	na	12.72
MOKHOVSKOYE														
	T		Proven	124	22.2	2,756	0.12	14	0.66	0.869	1.124	na	2,330	3.75
	Fm		Proven	124	10.7	1,317	0.10	2	0.62	0.864	1.119	na	2,586	4.42
MOSINSKOYE														
	TL2-b	Bakhtnhskaya	Proven	124	6.6	811	0.17	318	0.85	0.803	1.339	681	2,512	1.15
	TL2-b	Bakhtnhskaya	Probable	112	5.0	562	0.17	318	0.85	0.803	1.339	681	2,512	1.15
	Bb	Bakhtnhskaya	Proven	432	20.0	8,634	0.17	78	0.79	0.800	1.449	912	2,525	1.05
	Bb	Bakhtnhskaya	Probable	190	9.1	1,720	0.17	78	0.79	0.800	1.449	912	2,525	1.05

PERMNEFT SUBSIDIARY
RESERVOIR PARAMETERS

Field	Reservoir	Field Area	Category	Area (Acres)	Avg Net Thickness (Feet)	Net Volume (Acre-Feet)	Porosity (fraction)	Permeability (md)	Oil Saturation (fraction)	Oil Specific Gravity	Oil FVF (RBbl/STB)	Solution Gas Ratio (SCF/STB)	Estimated Original Pressure (psi)	Oil Viscosity (cp)
MOSINSKOYE (cont)														
	T	Bakhtnhskaya	Proven	124	11.5	1,419	0.12	13	0.78	0.826	1.297	640	2,600	1.36
	T	Bakhtnhskaya	Probable	209	5.7	1,197	0.12	13	0.78	0.826	1.297	640	2,600	1.36
	Bsh	Karabaevskaya	Proven	124	6.6	811	0.14	63	0.68	0.862	1.239	467	2,015	0.86
	Bsh	Karabaevskaya	Probable	185	2.7	505	0.14	63	0.68	0.862	1.239	467	2,015	0.86
	Bb	Karabaevskaya	Proven	124	6.6	811	0.13	8	0.80	0.835	1.239	452	2,639	0.86
	Bb	Karabaevskaya	Probable	127	3.6	462	0.13	8	0.80	0.835	1.239	452	2,639	0.86
	ML	Karabaevskaya	Proven	62	6.6	405	0.17	57	0.83	0.827	1.389	789	2,626	0.98
	ML	Karabaevskaya	Probable	120	6.6	789	0.17	57	0.83	0.827	1.389	789	2,626	0.98
	KV	Mosinskaya	Proven	741	12.0	8,877	0.11	1	0.65	0.837	1.239	451	1,896	0.86
	KV	Mosinskaya	Probable	252	5.1	1,281	0.11	1	0.65	0.837	1.239	451	1,896	0.86
	Bsh	Mosinskaya	Proven	62	6.6	405	0.10	7	0.68	0.932	1.297	465	2,011	30.23
	Bsh	Mosinskaya	Probable	136	4.2	566	0.10	7	0.68	0.932	1.297	465	2,011	30.23
	ML	Mosinskaya	Proven	432	8.1	3,496	0.17	57	0.83	0.834	1.389	796	2,690	0.98
	ML	Mosinskaya	Probable	185	3.0	559	0.17	57	0.83	0.834	1.389	796	2,690	0.98
	T	Mosinskaya	Proven	467	8.7	4,051	0.12	13	0.78	0.834	1.297	788	2,721	0.98
MOSKUDENSKOYE														
	KV1		Proven	14,434	10.4	150,605	0.16	70	0.66	0.860	1.093	162	1,668	8.85
	KV1		Probable	803	7.9	6,384	0.16	70	0.66	0.860	1.093	162	1,668	8.85
	V3V4		Proven	15,923	11.3	179,280	0.16	25	0.73	0.868	1.045	162	1,668	8.17
	V3V4		Probable	440	7.7	3,392	0.16	25	0.73	0.868	1.045	162	1,668	8.17
	Bsh1		Proven	9,098	8.7	79,193	0.16	25	0.81	0.874	1.052	164	1,668	10.26
	Bsh1		Probable	124	6.6	811	0.16	25	0.81	0.874	1.052	164	1,668	10.26
	TL2a		Proven	5,679	7.1	40,039	0.20	462	0.79	0.920	1.087	93	2,234	68.58
	TL2b		Proven	13,698	11.8	162,288	0.21	462	0.82	0.635	1.578	93	2,234	68.62
	TL2b		Probable	4,049	5.2	20,856	0.21	462	0.82	0.635	1.578	93	2,234	68.62
	Bb		Proven	3,277	8.1	26,589	0.21	462	0.85	0.929	1.017	93	2,234	98.28
	T1		Proven	4,126	9.5	39,048	0.15	20	0.80	0.912	1.035	92	2,234	38.68
	T2		Proven	3,645	11.3	41,024	0.15	20	0.80	0.912	1.026	92	2,234	38.68
	T2		Probable	257	6.3	1,624	0.15	20	0.80	0.912	1.026	92	2,234	38.68
	D1		Proven	3,647	5.7	20,932	0.16	186	0.80	0.878	1.072	146	3,263	5.39
	D2		Proven	2,602	6.3	16,501	0.16	186	0.80	0.878	1.080	146	3,263	5.39
NOVO-SEMENSKOYE														
	TL2-b		Proven	124	7.2	892	0.16	565	0.91	0.906	1.052	134	2,092	16.32
	TL2-b		Probable	56	2.0	113	0.16	565	0.91	0.906	1.052	134	2,092	16.32
	ML		Proven	124	6.7	831	0.19	97	0.83	0.924	1.022	137	2,161	61.54
	ML		Probable	174	3.4	601	0.19	97	0.83	0.924	1.022	137	2,161	61.54
	T1		Proven	371	15.7	5,837	0.10	15	0.67	0.907	1.082	199	2,174	17.49
	T1		Probable	66	1.9	128	0.10	15	0.67	0.907	1.082	199	2,174	17.49
	Fm2		Proven	247	4.8	1,176	0.10	19	0.61	0.917	1.073	170	2,373	17.97
	Fm2		Probable	96	0.9	85	0.10	19	0.61	0.917	1.073	170	2,373	17.97
	Fm3		Proven	988	11.1	10,944	0.10	19	0.61	0.917	1.073	170	2,373	17.97
	Fm3		Probable	430	6.1	2,639	0.10	19	0.61	0.917	1.073	170	2,373	17.97
ODENOVSKOYE														
	TL2-b		Proven	371	5.1	1,885	0.21	45	0.76	0.893	1.029	81	2,063	23.45
	TL2-b		Probable	267	3.1	833	0.21	45	0.76	0.893	1.029	81	2,063	23.45
	T1		Proven	494	9.8	4,864	0.12	69	0.72	0.900	1.071	188	2,139	11.39
	T1		Probable	73	2.2	157	0.12	69	0.72	0.900	1.071	188	2,139	11.39
	D0		Proven	803	9.2	7,375	0.15	300	0.89	0.857	1.148	348	2,906	3.03
	D0		Probable	382	3.7	1,427	0.15	300	0.89	0.857	1.148	348	2,906	3.03

PERMNEFT SUBSIDIARY
RESERVOIR PARAMETERS

Field	Reservoir	Field Area	Category	Area (Acres)	Avg Net Thickness (Feet)	Net Volume (Acre-Feet)	Porosity (fraction)	Permeability (md)	Oil Saturation (fraction)	Oil Specific Gravity	Oil FVF (RBbl/STB)	Solution Gas Ratio (SCF/STB)	Estimated Original Pressure (psi)	Oil Viscosity (cp)
OSENSKOYE														
	Bsh	total	Proven	34,913	36.5	1,274,385	0.14	100	0.81	0.875	1.033	59	1,711	11.64
	Bsh	total	Probable	14,029	11.4	159,676	0.14	100	0.81	0.875	1.033	59	1,711	11.64
	Srp	total	Proven	12,366	23.4	288,985	0.13	75	0.77	0.900	1.022	61	1,711	35.30
	DO-2	Elpachekhenskaya	Proven	2,409	18.6	44,832	0.17	400	0.75	0.915	1.100	62	1,711	23.05
	DO-2	Elpachekhenskaya	Probable	3,636	16.4	59,521	0.17	400	0.75	0.915	1.100	62	1,711	23.05
PAVLOVSKOYE														
	Vereisky		Proven	24,135	12.3	296,415	0.15	127	0.67	0.884	1.120	278	1,479	6.39
	Vereisky		Probable	988	9.0	8,918	0.15	127	0.67	0.884	1.120	278	1,479	6.39
	Bsh1		Proven	17,834	21.1	375,472	0.10	30	0.72	0.892	0.958	190	1,479	16.00
	Bsh1		Probable	4,510	4.9	22,193	0.10	30	0.72	0.892	0.958	190	1,479	16.00
	Bsh2		Proven	6,236	8.2	51,150	0.10	30	0.72	0.892	1.050	190	1,479	16.00
	TL2-a		Proven	15,091	10.7	162,041	0.20	590	0.88	0.888	1.107	189	1,479	6.00
	TL2-a		Probable	258	6.2	1,586	0.20	590	0.88	0.888	1.107	189	1,479	6.00
	TL2-b		Proven	11,982	10.3	123,912	0.20	590	0.88	0.888	1.107	189	1,479	6.00
	TL2-b		Probable	289	7.3	2,110	0.20	590	0.88	0.888	1.107	189	1,479	6.00
	Bb1		Proven	1,488	8.3	12,288	0.20	590	0.88	0.888	1.107	189	1,479	6.00
	Bb1		Probable	62	16.4	1,013	0.20	590	0.88	0.888	1.107	189	1,479	6.00
	Bb2		Proven	2,761	5.9	16,391	0.20	590	0.88	0.888	1.107	189	1,479	6.00
	ML		Proven	2,462	10.6	26,087	0.20	590	0.88	0.871	1.115	229	2,234	6.00
	Turneisky		Proven	2,039	25.7	52,392	0.10	40	0.72	0.907	1.076	234	2,234	9.00
	Turneisky		Probable	1,174	19.7	23,105	0.10	40	0.72	0.907	1.076	234	2,234	9.00
RASSVETNOYE														
	Bsh1 + Bsh2		Proven	6,424	29.9	191,783	0.15	167	0.79	0.912	1.040	77	1,922	34.70
	Yasn		Proven	4,112	17.3	70,962	0.20	181	0.87	0.902	1.046	111	2,292	30.80
	D1		Proven	124	9.8	1,216	0.19	8	0.82	0.860	na	na	na	4.03
SAVARSKOYE														
	Bsh		Proven	62	21.2	1,317	0.13	77	0.76	0.893	1.087	na	1,634	2.29
	ML		Proven	124	13.8	1,702	0.20	296	0.88	0.859	1.055	na	2,330	5.30
SHAGERSTKO - GOZHANSKOYE														
	KV1		Proven	18,440	8.3	152,249	0.17	22	0.60	0.865	1.053	117	1,479	8.56
	KV1		Probable	235	7.8	1,841	0.17	22	0.60	0.865	1.053	117	1,479	8.56
	V3V4		Proven	14,136	17.6	249,376	0.17	134	0.71	0.866	1.028	117	1,479	6.62
	Bsh		Proven	11,163	19.7	220,069	0.15	121	0.72	0.865	1.071	136	1,523	7.08
	Yasn		Proven	16,692	21.5	358,465	0.22	1,022	0.96	0.894	1.036	97	2,103	43.48
	T		Proven	7,905	17.4	137,197	0.12	48	0.70	0.905	1.036	97	2,103	36.95
	Psh-Zhv		Proven	4,211	10.5	44,208	0.16	200	0.79	0.880	1.107	203	3,002	6.95
	Psh-Zhv		Probable	513	4.6	2,355	0.16	200	0.79	0.880	1.107	203	3,002	6.95
SHUMOVSKOYE														
	Sm1		Proven	5,909	13.1	77,503	0.17	219	0.65	0.913	1.030	22	798	63.00
	Sm1		Probable	633	6.6	4,151	0.17	219	0.65	0.913	1.030	22	798	63.00
	Sm2		Proven	4,267	14.8	63,120	0.17	219	0.65	0.913	1.030	22	798	63.00
	Sm2		Probable	119	6.6	778	0.16	219	0.65	0.913	1.030	22	798	63.00
	Pd		Proven	4,909	13.1	64,425	0.19	136	0.63	0.890	1.026	48	1,494	18.60
	K		Proven	4,684	9.8	45,839	0.16	192	0.63	0.911	1.033	41	1,610	45.70
	K		Probable	158	9.8	1,557	0.16	192	0.63	0.911	1.033	41	1,610	45.70
	V3V4		Proven	5,147	15.6	80,254	0.17	334	0.78	0.895	1.019	50	1,698	29.86
	V3V4		Probable	581	3.4	1,955	0.17	334	0.78	0.895	1.019	50	1,698	29.86

PERMNEFT SUBSIDIARY
RESERVOIR PARAMETERS

Field	Reservoir	Field Area	Category	Area (Acres)	Avg Net Thickness (Feet)	Net Volume (Acre-Feet)	Porosity (fraction)	Permeability (md)	Oil Saturation (fraction)	Oil Specific Gravity	Oil FVF (RBbl/STB)	Solution Gas Ratio (SCF/STB)	Estimated Original Pressure (psi)	Oil Viscosity (cp)
SHUMOVSKOYE (cont)														
	Bsh1		Proven	4,152	9.7	40,347	0.20	320	0.82	0.890	1.020	55	1,682	25.10
	Bsh1		Probable	723	7.7	5,534	0.20	320	0.82	0.890	1.020	55	1,682	25.10
	Bsh2		Proven	2,609	8.8	22,884	0.20	320	0.82	0.890	1.020	55	1,682	25.10
	TL2-a		Proven	1,102	3.4	3,704	0.21	339	0.78	0.893	1.018	51	1,900	39.18
	TL2-b		Proven	1,629	10.7	17,363	0.21	339	0.79	0.893	1.094	51	1,900	39.18
	TL2-b		Probable	107	5.2	556	0.21	339	0.78	0.893	1.094	51	1,900	39.18
	Bb		Proven	1,044	12.8	13,376	0.21	237	0.81	0.893	1.019	40	2,132	28.10
	Bb		Probable	225	6.9	1,540	0.21	237	0.81	0.893	1.019	40	2,132	28.10
SOFINSKOYE-YENAPAEVSKAYA														
	V3V4 Gas		Proven	206	5.9	1,216	na	na	na	na	na	na	na	na
	TL		Proven	1,559	11.4	17,836	0.19	164	0.84	0.800	na	na	na	2.75
	Bb		Proven	927	11.3	10,478	0.18	384	0.83	0.883	na	na	na	9.40
	Bb		Probable	247	3.3	811	0.18	384	0.83	0.883	na	na	na	9.40
	T		Proven	556	13.8	7,681	0.10	37	0.78	0.866	na	na	na	3.90
	Fm		Proven	796	11.5	9,177	0.12	5	0.77	0.874	na	na	na	4.44
	Kyn		Proven	309	7.0	2,148	0.16	9	0.85	0.862	na	na	na	4.16
	Psh		Probable	62	6.5	405	0.16	9	0.85	0.862	na	na	na	4.16
SOLDATOVSKOYE														
	TL2-b	Gorbatovskoye	Proven	1,112	12.9	14,309	0.18	183	0.82	0.863	1.083	207	2,160	4.83
	TL2-b	Gorbatovskoye	Probable	399	3.3	1,308	0.20	320	0.86	0.863	1.083	207	2,160	5.25
	Bb	S. Soldatovskoye	Proven	124	9.8	1,216	0.16	63	0.79	0.912	1.047	128	2,281	22.36
	Bb	S. Soldatovskoye	Probable	56	3.3	182	0.16	63	0.79	0.912	1.047	128	2,281	22.36
	ML	Gorbatovskoye	Proven	309	13.8	4,256	0.22	411	0.93	0.876	1.075	206	2,217	9.27
	ML	Gorbatovskoye	Probable	71	3.7	266	0.22	411	0.93	0.876	1.075	206	2,217	9.27
	T	Gorbatovskoye	Proven	1,050	19.6	20,572	0.13	28	0.77	0.885	1.107	250	2,231	7.56
	T	Gorbatovskoye	Probable	125	4.0	496	0.13	28	0.77	0.885	1.107	250	2,231	7.56
SOSNOVSKOYE														
	V3V4		Proven	3,763	7.5	28,398	0.12	na	na	0.884	1.13	na	na	na
	Bsh		Proven	1,936	4.3	8,405	0.18	na	na	0.856	1.17	na	na	na
	TL		Proven	1,336	12.8	17,040	0.16	213	0.71	0.842	1.190	615	2,422	1.49
	TL		Probable	247	8.1	1,992	0.16	122	0.74	0.842	1.190	615	2,422	1.36
	Bb		Proven	100	6.5	649	0.16	213	0.71	0.842	1.145	615	2,422	1.49
	Bb		Probable	62	6.6	405	0.16	122	0.74	0.842	1.145	615	2,422	1.36
	T		Proven	2,671	13.5	36,111	0.13	29	0.79	0.885	1.115	na	2,461	17.46
	D (Kynovsky)		Proven	185	3.7	689	0.14	230	0.87	0.863	1.127	na	3,275	3.36
	D (Kynovsky)		Probable	494	3.2	1,581	0.14	230	0.87	0.863	1.127	na	3,275	3.36
STEPANOVSKOYE														
	V3V4		Proven	389	9.8	3,826	0.15	30	0.66	0.859	1.105	227	1,523	4.91
	Bsh1		Proven	736	14.1	10,394	0.17	393	0.77	0.883	1.059	233	1,523	13.18
	TL1-B		Proven	174	1.7	298	0.20	783	0.90	0.865	1.070	136	2,161	17.90
	TL2-a		Proven	1,372	4.7	6,392	0.20	783	0.90	0.865	1.070	136	2,161	17.90
	TL2-b		Proven	396	6.4	2,546	0.20	783	0.90	0.865	1.070	136	2,161	17.90
	Bb1		Proven	424	5.2	2,223	0.20	783	0.90	0.865	1.070	136	2,161	17.90
	Bb2		Proven	369	4.3	1,585	0.20	783	0.90	0.865	1.070	136	2,161	17.90
	ML		Proven	537	15.4	8,287	0.21	383	0.90	0.913	1.029	136	2,161	44.59
	T		Proven	642	34.1	21,921	0.15	11	0.82	0.933	1.021	58	2,248	94.39

PERMNEFT SUBSIDIARY
RESERVOIR PARAMETERS

Field	Reservoir	Field Area	Category	Area (Acres)	Avg Net Thickness (Feet)	Net Volume (Acre-Feet)	Porosity (fraction)	Permeability (md)	Oil Saturation (fraction)	Oil Specific Gravity	Oil FVF (RBbl/STB)	Solution Gas Ratio (SCF/STB)	Estimated Original Pressure (psi)	Oil Viscosity (cp)
STRETENSKOYE														
	Bb		Proven	62	7.8	486	0.18	166	0.78	0.839	na	na	na	3.25
	D (Pash)		62	62	12.4	770	0.12	355	0.90	0.879	na	na	na	6.40
SUDANOVSKOYE														
	TL2-a		Proven	394	6.7	2,630	0.19	313	0.84	0.878	1.078	113	2,074	8.10
	TL2-b		Proven	728	6.7	4,867	0.19	313	0.84	0.878	1.078	113	2,074	8.10
	Bb1		Proven	440	13.5	5,922	0.19	313	0.84	0.878	1.078	113	2,074	8.10
	Bb2		Proven	96	7.5	722	0.19	313	0.84	0.878	1.078	113	2,074	8.10
	Bb2		Proven	305	6.6	1,999	0.19	313	0.84	0.878	1.078	113	2,074	8.10
	ML		Proven	116	7.9	913	0.34	470	0.93	0.829	1.115	113	2,074	6.10
	T		Proven	816	19.2	15,706	0.12	313	0.73	0.903	1.080	173	2,205	12.20
TANEPSKOYE														
	KV1		Proven	3,953	7.7	30,497	0.14	31	0.73	0.871	1.096	132	1,595	6.95
	KV1		Probable	661	4.4	2,926	0.14	31	0.73	0.871	1.096	132	1,595	6.95
	V3V4		Proven	3,309	15.9	52,466	0.14	59	0.74	0.878	1.096	133	1,595	6.95
	Yasn		Proven	6,929	26.1	181,049	0.23	792	0.87	0.881	na	na	na	5.25
	ML		Proven	2,647	9.5	25,208	0.20	32	0.87	0.876	1.157	272	2,176	3.91
	T		Proven	4,360	17.5	76,284	0.15	72	0.84	0.880	1.157	272	2,176	3.87
TARTENSKOYE														
	TL		Proven	62	3.3	203	0.18	109	0.83	0.840	1.151	na	2,330	2.38
	T1		Proven	247	7.4	1,824	0.11	11	0.69	0.861	1.105	na	2,387	3.85
	T1		Probable	62	6.6	405	0.11	11	0.69	0.861	1.105	na	2,387	3.85
	T3		Proven	185	15.4	2,858	0.10	11	0.69	0.861	1.098	na	2,387	3.85
	T3		Probable	62	6.5	405	0.10	11	0.69	0.861	1.098	na	2,387	3.85
	Fm		Proven	185	8.2	1,520	0.12	22	0.77	0.872	1.139	na	2,586	4.17
TRIFONOVSKOYE														
	TL2-a		Proven	593	13.3	7,912	0.19	208	0.87	0.875	1.087	na	2,346	5.77
	TL2-b		Proven	395	6.6	2,594	0.19	25	0.72	0.873	1.072	na	2,366	5.45
	TL2-b		Probable	119	6.5	778	0.19	25	0.72	0.873	1.072	na	2,366	5.45
	Bb1		Proven	474	9.3	4,410	0.17	519	0.73	0.865	1.072	na	2,386	5.82
	Bb2		Proven	593	20.8	12,323	0.22	886	0.90	0.869	1.075	na	2,399	5.98
	ML		Proven	316	5.9	1,868	0.16	126	0.73	0.872	1.088	na	2,427	4.71
	T		Proven	395	9.7	3,814	0.12	32	0.70	0.876	1.057	na	2,386	7.49
TRUSHINIKOVSKOYE														
	TL		Proven	556	8.7	4,844	0.19	67	0.88	0.881	1.072	na	1,933	12.72
	TL		Proble	116	3.6	418	0.19	67	0.88	0.881	1.072	na	1,933	12.72
	T		Proven	618	11.2	6,932	0.15	94	0.74	0.912	na	na	na	17.97
	T		Probale	116	3.6	418	0.15	94	0.74	0.912	na	na	na	17.97
	Pash		Proven	124	6.1	756	0.19	60	0.83	0.882	na	na	na	4.94
TULVENSKOYE														
	D0-a		Proven	933	8.2	7,651	0.17	120	0.86	0.898	1.111	230	3,336	6.55
	D0-a		Probable	426	5.5	2,335	0.17	45	0.75	0.898	1.111	230	3,336	6.55

PERMNEFT SUBSIDIARY
RESERVOIR PARAMETERS

Field	Reservoir	Field Area	Category	Area (Acres)	Avg Net Thickness (Feet)	Net Volume (Acre-Feet)	Porosity (fraction)	Permeability (md)	Oil Saturation (fraction)	Oil Specific Gravity	Oil FVF (RBbl/STB)	Solution Gas Ratio (SCF/STB)	Estimated Original Pressure (psi)	Oil Viscosity (cp)
TULVENSKOYE (cont)														
	D0-b		Proven	1,353	12.3	16,630	0.17	120	0.86	0.898	1.111	230	3,336	6.55
	D0-b		Probable	1,606	11.1	17,811	0.17	45	0.75	0.898	1.111	230	3,336	6.55
YUZHUNSKOYE														
	Yasn		Proven	79	5.2	414	0.21	96	0.92	0.893	1.067	na	2,068	9.38
	T		Proven	124	19.6	2,432	0.14	na	0.67	0.902	na	na	na	16.23
ZUYATSKOYE														
	Bsh		Proven	865	12.4	10,742	0.11	14	0.70	0.889	1.171	444	2,203	3.46
	Bsh		Probable	185	8.2	1,520	0.11	14	0.70	0.889	1.171	444	2,203	3.46
	ML		Proven	741	7.1	5,259	0.12	46	0.77	0.808	1.276	612	2,735	1.28
	ML		Probable	239	2.2	531	0.12	46	0.77	0.808	1.276	612	2,735	1.28
AKSAITOVNEFT JOINT VENTURE														
KUEDA-BASHKIRSKSKOYE														
		Producing	Proven	na	na	na	na	na	na	na	na	na	na	na

ZAO LUKOIL-PERM SUBSIDIARY
RESERVOIR PARAMETERS

Field	Reservoir	Field Area	Category	Area (Acres)	Avg Net Thickness (Feet)	Net Volume (Acre-Feet)	Porosity (fraction)	Permeability (md)	Oil Saturation (fraction)	Oil Specific Gravity	Oil FVF (RBbl/STB)	Solution Gas Ratio (SCF/STB)	Estimated Original Pressure (psi)	Oil Viscosity (cp)
KAMANEFT JOINT VENTURE														
KUKHTIMSKOYE														
	Yasnopolyansky	(Tul2+Bob)	Proven	519	21.0	9,980	0.14	33	0.82	0.819	1.38	na	2,487	0.82
	T Turneysky		Proven	785	11.7	9,434	0.11	na	0.80	0.827	1.37	na	na	na
OLKHOVSKOYE														
	Sm		Probable	1,328	15.1	20,025	0.08	20	0.70	0.818	1.17	na	1,066	1.88
	Bsh		Proven	2,824	14.8	41,863	0.10	20	0.80	0.836	1.28	na	2,203	1.22
	Yasnopolyansky	(Tl2+Bb)	Proven	7,667	52.1	461,910	0.14	49	0.80	0.825	1.39	na	2,558	0.72
	Yasnopolyansky	(Tl2+Bb)	Probable	262	9.2	2,410	0.14	49	0.80	0.825	1.39	na	2,558	0.72
	ML		Proven	754	10.5	7,913	0.18	49	0.86	0.864	1.20	na	2,700	2.57
	T		Proven	2,339	16.4	38,375	0.08	54	0.80	0.827	1.37	na	2,743	0.76
PEKHTOVOYE														
	Bb		Proven	468	34.7	17,338	0.12	7	0.79	0.839	1.15	na	3,049	1.74
	T + Fm		Proven	804	50.2	30,802	0.11	10	0.77	0.823	1.35	na	3,105	0.73
	T + Fm		Probable	68	7.5	504	0.11	10	0.77	0.823	1.35	na	3,105	0.73
POLAZNENSKOYE														
	Comingled	(V3V4+Bsh)	Proven	3,091	29.7	125,855	0.06	49	0.65	0.838	1.20	na	1,563	3.10
	Comingled	(V3V4+Bsh)	Probable	294	11.8	3,471	0.06	49	0.65	0.838	1.20	na	1,563	3.10
	Yasnopolyansky	(Tl2+B1+B2)	Proven	1,702	40.4	64,318	0.16	281	0.83	0.833	1.14	na	1,847	3.36
	T		Proven	672	12.1	7,176	0.14	na	0.83	0.859	1.09	na	1,847	na
SHEMETENSKOYE														
	Bsh		Proven	916	7.0	6,910	0.13	78	0.71	0.857	1.05	na	1,677	6.73
	Combined	(TL2a+TL2B)	Proven	1,679	20.1	33,676	na	85	na	na	1.06	na	1,975	4.10
	ML		Proven	232	14.7	3,405	0.16	120	0.85	0.859	1.08	na	2,046	2.50
	T		Proven	676	6.0	4,076	0.14	22	0.83	0.859	1.08	na	2,110	0.97
YARENO - KAMENOLOSHSKOYE														
	Bsh		Proven	13,344	47.9	639,164	0.10	100	0.85	0.829	1.28	na	2,060	1.27
	Combined	(TL+Bb)	Proven	19,633	66.9	1,313,983	0.18	202	0.85	0.822	1.36	na	na	0.99
	T		Proven	5,328	21.0	108,841	0.09	87	0.80	0.827	1.37	na	2,629	0.99
YUZHNO-MEZHEVSKOYE														
	Bsh		Proven	247	10.1	2,169	0.11	67	0.69	0.852	1.03	na	1,712	9.35
TALOYE														
	TL		Proven	62	3.3	203	0.12	20	0.69	0.869	1.15	na	na	1
MAYKORSKOYE JOINT VENTURE														
Maykorskoye														
	TL2b		Proven	618	6.6	4,418	0.17	542	0.75	0.872	1.02	na	na	13.570
	TL2b		Probable	233	6.3	1,462	0.17	542	0.75	0.872	1.02	na	na	13.570
	Bb		Proven	556	18.9	12,363	0.18	542	0.85	0.872	1.02	na	na	13.57
	Bb		Probable	159	7.9	1,258	0.18	542	0.85	0.872	1.02	na	na	13.57

ZAO LUKOIL-PERM SUBSIDIARY
RESERVOIR PARAMETERS

Field	Reservoir	Field Area	Category	Area (Acres)	Avg Net Thickness (Feet)	Net Volume (Acre-Feet)	Porosity (fraction)	Permeability (md)	Oil Saturation (fraction)	Oil Specific Gravity	Oil FVF (RBbl/STB)	Solution Gas Ratio (SCF/STB)	Estimated Original Pressure (psi)	Oil Viscosity (cp)
PERMTECKS JOINT VENTURE														
LOGOVSKOYE														
	Bsh		Proven	803	11.5	10,882	0.12	42	0.78	0.818	1.10	na	na	2.41
	Bsh		Probable	470	4.8	2,269	0.12	42	0.78	0.818	1.10	na	na	2.41
	Bb		Proven	2,656	13.5	34,151	0.14	272	0.90	0.829	1.19	na	na	1.82
	Bb		Probable	471	10.8	5,084	0.14	272	0.90	0.829	1.19	na	na	1.82
	Fm		Proven	1,977	17.4	33,263	0.10	13	0.88	0.834	1.21	na	na	1.10
	Fm		Probable	499	5.8	2,879	0.10	13	0.88	0.834	1.21	na	na	1.10
MISENSKOYE														
	Bsh		Proven	556	17.1	7,783	0.13	43	0.79	0.805	1.35	na	na	1.15
	Bsh		Probable	455	6.2	2,836	0.13	43	0.79	0.805	1.35	na	na	1.15
OZERNOYE														
	Sm		Proven	309	8.2	3,040	0.16	107	0.76	0.856	1.11	na	na	2.37
	Bsh total		Proven	2,348	10.5	51,894	0.16	20	0.73	0.839	1.36	na	na	2.41
	Bsh total		Probable	332	0.9	1,380	0.16	20	0.73	0.839	1.36	na	na	
	Dk/Kny		Proven	1,483	17.1	26,308	0.13	3	0.67	0.833	1.17	na	na	2.08
	Fm		Proven	4,324	49.2	213,967	0.11	7	0.83	0.823	1.30	na	na	1.02
	Fm		Probable	1,423	32.3	45,926	0.11	7	0.83	0.823	1.30	na	na	1.02
BOROVETSKOYE														
	Bb		Proven	62	6.6	405	0.11	32	0.72	0.810	1.43	na	na	0.96
	Fm		Proven	803	18.1	10,233	0.10	13	0.75	0.808	1.46	na	na	1.10
MAGOVSKOYE														
	Bsh - Srp		Proven	2,348	19.6	53,438	0.12	6	0.73	0.839	1.24	na	na	0.54
	Bsh - Srp		Probable	2,326	8.2	19,006	0.12	6	0.73	0.839	1.24	na	na	0.54
	T-Fm		Proven	4,695	56.2	210,766	0.10	2	0.73	0.800	1.61	na	na	0.92
	T-Fm		Probable	1,459	14.9	21,733	0.10	2	0.73	0.800	1.61	na	na	0.92
TARKHOVSKOYE														
	Bsh		Proven	494	21.3	11,147	0.12	36	0.76	0.850	1.11	na	na	2.40
	Bsh		Probable	151	11.7	1,771	0.12	36	0.76	0.850	1.11	na	na	2.40
	Fm		Proven	680	26.3	19,173	0.13	47	0.80	0.809	1.43	na	na	1.10
	Fm		Probable	96	9.6	919	0.13	47	0.80	0.809	1.43	na	na	1.10
PermTOTIneft JOINT VENTURE														
GARYUSHKENSKOYE														
	Tulsky	West + East	Proven	501	8.9	2,681	0.20	386	0.91	0.874	1.02	na	na	11.21
	Kynovsky Commingled		Proven	3,268	17.7	59,668	0.20	150	0.88	0.882	1.10	na	na	6.22
	Kynovsky Commingled		Probable	2,319	9.7	22,371	0.20	150	0.88	0.882	1.10	na	na	6.22
	D1 Psh		Proven	62	9.8	608	0.20	150	0.88	0.882	1.10	na	na	6.22
TURKENSKOYE														
	Tulsky TL1-a		Proven	497	18.4	8,948	0.20	355	0.92	0.853	1.07	na	na	4.80
	Tulsky TL1-a		Probable	220	3.2	706	0.20	355	0.92	0.853	1.07	na	na	4.80
RUSSIAN FUEL COMPANY (RTK) JOINT VENTURE														

ZAO LUKOIL-PERM SUBSIDIARY
RESERVOIR PARAMETERS

Field	Reservoir	Field Area	Category	Area (Acres)	Avg Net Thickness (Feet)	Net Volume (Acre-Feet)	Porosity (fraction)	Permeability (md)	Oil Saturation (fraction)	Oil Specific Gravity	Oil FVF (RBbl/STB)	Solution Gas Ratio (SCF/STB)	Estimated Original Pressure (psi)	Oil Viscosity (cp)
ALEKSANDROVSKOYE														
	Bsh		Proven	213	13.1	2,662	0.12	7	0.77	0.837	1.14	na	na	2.51
ALEKSANDROVSKOYE 9CONT0														
	Yasn	Tul 2 + Bob1	Proven	194	19.7	3,324	0.15	1	0.84	0.850	1.25	na	na	1.50
	Yasn	Tul 2 + Bob1	Probable	50	5.6	280	0.15	1	0.84	0.850	1.25	na	na	1.50
	ML		Proven	154	6.8	1,403	15.00	12	0.82	0.850	1.25	na	na	1.50
	T		Proven	62	15.6	963	0.12	72	0.76	0.846	1.30	na	na	1.30
	T		Probable	22	15.0	333	0.12	72	0.76	0.846	1.30	na	na	1.30
ARYASHSKOYE														
	Bsh		Proven	494	11.5	5,432	0.16	141	0.84	0.885	1.06	na	1,430	13.07
	Bsh		Probable	31	8.2	255	0.16	141	0.84	0.885	1.06	na	1,430	13.07
	TL2-b		Proven	183	11.5	2,203	0.14	111	0.71	0.902	1.03	na	1,881	39.30
	Bb2		Proven	114	7.2	825	0.18	12	0.77	0.902	1.03	na	na	39.26
	TOTAL T1+T2+T3		Proven	639	28.7	19,092	0.11	19	0.66	0.924	1.02	na	1,968	68.92
	TOTAL T1+T2+T3		Probable	185	28.5	5,279	0.11	19	0.66	0.924	1.02	na	1,968	68.92
BATIPBAISKOYE (SEVERO-KACHINSKOYE)														
	TL2-a		Proven	185	8.5	1,459	0.17	202	0.67	0.869	1.09	na	na	5.17
	TL2-a		Probable	190	12.3	2,338	0.17	202	0.67	0.869	1.09	na	na	5.17
	T		Proven	1,050	11.9	13,944	0.13	67	0.78	0.872	1.08	na	2,222	5.11
	T		Probable	783	4.1	3,186	0.13	67	0.78	0.872	1.08	na	2,222	5.11
ILECHEVSKOYE														
	V3V4		Proven	712	13.5	10,045	0.14	68	0.68	0.837	1.12	na	2,032	2.60
	V3V4		Probable	232	9.8	2,281	0.14	68	0.68	0.837	1.12	na	2,032	2.60
	Bsh		Proven	2,100	23.0	48,886	0.14	226	0.80	0.838	1.20	na	2,075	2.13
	Bsh		Probable	677	10.0	6,770	0.14	226	0.80	0.838	1.20	na	2,075	2.13
	TL2-b		Proven	62	13.1	811	0.16	61	0.87	0.800	1.39	na	2,622	1.07
	Bb1		Proven	68	10.5	713	0.14	81	0.87	0.812	1.34	na	2,581	1.18
KALMEYARSKOYE														
	V3V4		Proven	375	9.3	3,507	0.16	81	0.71	0.869	1.03	na	1,506	8.99
	Bsh1		Proven	331	6.8	2,240	0.18	17	0.80	0.876	1.03	na	1,528	6.19
	Tul2a+Bb1		Proven	185	7.4	1,368	0.20	75	0.87	0.891	1.08	na	2,004	13.74
	ML		Proven	551	13.4	10,198	0.20	176	0.87	0.904	1.05	na	2,066	21.73
	ML		Probable	414	17.1	7,082	0.20	176	0.87	0.904	1.05	na	2,066	21.73
	T1		Proven	865	24.1	23,186	0.13	103	0.79	0.911	1.04	na	2,103	28.06
	T1		Probable	522	16.7	8,726	0.13	103	0.79	0.911	1.04	na	2,103	28.06
	D0-1 Kn		Proven	124	6.6	811	0.18	2	0.93	0.893	1.09	na	na	7.40
KHATIMSKOYE														
	ML		Proven	219	7.6	1,798	0.22	436	0.90	0.941	1.02	na	2,178	217.94
	TL2+DO		Proven	1,047	11.5	12,053	0.17	300	0.84	0.870	1.11	na	na	5.00
	TL2+DO		Probable	2,159	8.0	17,341	0.16	267	0.83	0.890	1.13	na	na	4.52
KILASOVSKOYE														
	V3V4		Proven	2,628	11.3	29,926	0.10	44	0.80	0.900	1.10	na	1,847	5.20
	V3V4		Probable	1,118	24.9	27,799	0.10	44	0.80	0.900	1.10	na	1,847	5.20

ZAO LUKOIL-PERM SUBSIDIARY
RESERVOIR PARAMETERS

Field	Reservoir	Field Area	Category	Area (Acres)	Avg Net Thickness (Feet)	Net Volume (Acre-Feet)	Porosity (fraction)	Permeability (md)	Oil Saturation (fraction)	Oil Specific Gravity	Oil FVF (RBbl/STB)	Solution Gas Ratio (SCF/STB)	Estimated Original Pressure (psi)	Oil Viscosity (cp)
KILASOVSKOYE (CONT)														
	Bsh		Proven	1,532	9.7	14,551	0.10	78	0.80	0.836	1.31	na	1,934	1.81
	Bsh		Probable	732	11.0	8,052	0.10	78	0.80	0.836	1.31	na	1,934	1.81
	Tulsky Total	Tul2a+Tul2b	Proven	1,013	15.2	14,656	0.16	30	0.78	0.838	1.36	na	2,274	0.86
	Tulsky Total	Tul2a+Tul2b	Probable	1,379	25.8	35,591	0.16	30	0.78	0.838	1.36	na	2,274	0.86
	Bb1		Proven	1,356	30.0	39,385	0.19	650	0.85	0.847	1.35	na	2,345	0.94
	Bb1		Probable	229	15.4	3,518	0.19	650	0.85	0.847	1.35	na	2,345	0.94
KOZUBAEVSKOYE														
	Yasn		Proven	5,464	13.7	74,959	0.19	100	0.80	0.849	1.09	na	2,274	3.60
	Yasn		Probable	371	13.7	5,083	0.19	100	0.80	0.849	1.09	na	2,274	3.60
KUKUSHTANSKOYE														
	Bsh		Proven	386	14.5	4,296	0.15	30	0.65	0.835	1.15	na	1,975	4.60
	TL+Bb		Proven	383	16.8	7,041	0.19	84	0.82	0.865	1.30	na	2,416	2.59
	TL+Bb		Probable	189	15.8	2,988	0.19	84	0.82	0.865	1.30	na	2,416	2.59
KUZNETSOVSKOYE														
	TL2-b1		Proven	62	6.6	405	0.17	247	0.87	0.891	1.03	na	na	16.95
	TL2-b1		Probable	128	12.4	1,587	0.17	247	0.87	0.891	1.03	na	na	16.95
	T		Proven	62	6.6	405	0.10	36	0.83	0.873	1.09	na	na	0.97
	T		Probable	100	6.6	658	0.10	36	0.83	0.873	1.09	na	na	0.97
LAZUKOVSKOYE														
	TL2-a, TL2-b, Bb		Proven	2,267	24.7	43,221	0.14	268	0.81	0.874	1.14	na	2,416	2.90
	TL2-a, TL2-b, Bb		Probable	397	3.9	1,536	0.14	268	0.81	0.874	1.14	na	2,416	2.90
	ML		Proven	1,566	7.9	12,330	0.14	147	0.86	0.894	1.20	na	2,501	4.50
	T		Proven	309	10.5	3,243	0.10	15	0.71	0.894	1.20	na	2,544	3.70
LOBANOVSKOYE														
	Bsh	Lobanovskoye	Proven	672	16.4	11,026	0.10	10	0.70	0.890	1.04	na	1,776	10.50
	Tul-Bob		Proven	2,432	27.2	64,815	0.17	130	0.87	0.840	1.10	na	2,160	3.26
	Tul-Bob		Probable	306	11.2	3,426	0.17	130	0.87	0.840	1.10	na	2,160	3.26
OBLEVSKOYE														
	Bsh	Kurashemskoe	Proven	803	12.5	8,553	0.13	33	0.75	0.874	1.12	na	2,035	5.73
	TL2-a	Kurashemskoe	Proven	1,676	14.7	22,741	0.13	26	0.82	0.847	1.17	na	2,482	2.91
	TL2-a	Kurashemskoe	Probable	510	13.3	6,794	0.13	26	0.82	0.847	1.17	na	2,482	2.91
	TL2-a	Oblevskoe	Proven	1,348	7.5	10,063	0.13	171	0.80	0.812	1.29	na	2,482	1.10
	TL2-a	Oblevskoe	Probable	303	9.3	2,815	0.13	171	0.80	0.812	1.29	na	2,482	1.10
	Bb2	Kurashemskoe	Proven	775	14.8	12,052	0.14	12	0.89	0.854	1.16	na	2,509	2.91
	ML1	Kurashemskoe	Proven	62	4.8	298	0.16	460	0.91	0.851	1.17	na	2,576	2.91
	ML2	Kurashemskoe	Proven	148	7.9	1,167	0.16	460	0.91	0.851	1.17	na	2,576	2.91
	TL2-a	Oblevskoe	Proven	1,409	11.5	15,862	0.13	171	0.80	0.812	1.29	na	2,576	1.10
	ML2	Oblevskoe	Proven	700	9.5	6,794	0.14	0	0.83	0.827	1.25	na	na	1.57
RUSOKOVSKOYE														
	Yasn	Tul + Bob1&2	Proven	1,505	8.9	13,344	0.16	213	0.78	0.845	1.07	na	2,515	4.61
	Turneysky		Proven	208	10.4	2,121	0.13	28	0.80	0.846	1.08	na	na	3.12

ZAO LUKOIL-PERM SUBSIDIARY
RESERVOIR PARAMETERS

Field	Reservoir	Field Area	Category	Area (Acres)	Avg Net Thickness (Feet)	Net Volume (Acre-Feet)	Porosity (fraction)	Permeability (md)	Oil Saturation (fraction)	Oil Specific Gravity	Oil FVF (RBbl/STB)	Solution Gas Ratio (SCF/STB)	Estimated Original Pressure (psi)	Oil Viscosity (cp)
SEVERO - KAMOSKOYE														
	VER-BASHK		Proven	17,433	40.5	691,941	0.08	15	0.50	0.846	1.10	na	1,350	7.40
	VER-BASHK		Probable	1,470	22.9	33,670	0.08	15	0.50	0.846	1.10	na	1,350	7.40
	TL2-a		Proven	219	5.5	920	0.16	na	0.80	0.862	1.01	na	na	12.72
SLUDSKOYE														
	Yasn	Tul+Bob	Proven	520	11.0	5,702	0.16	50	0.76	0.859	1.03	na	na	9.20
TROELSHANSKOYE														
	TL+Bb		Proven	1,934	15.8	114,040	0.16	70	0.82	0.864	1.27	na	na	1.70
	Turneysky		Proven	507	47.9	24,288	0.10	148	0.70	0.930	1.11	na	na	1.70
VASELEVSKOYE														
	TL2	Kataevsky	Proven	303	8.8	2,660	0.14	48	0.79	0.856	1.05	1,003	2,558	6.81
	TL2+Bb1+Bb2	Kuzmensky	Proven	693	37.5	22,363	0.18	162	0.84	0.856	1.08	411	2,558	4.60
	Tul+Bob1&2&2	Sev (North)	Proven	1,579	31.2	47,179	0.17	512	0.88	0.862	1.05	807	2,487	7.57
	TL+Bb		Proven	185	29.9	2,922	0.18	360	0.89	0.874	1.04	na	na	9.17
	TL+Bb		Probable	23	17.3	400	0.15	na	0.66	0.868	1.03	na	na	9.17
	TL2	Serkovsky	Proven	62	3.9	243	0.17	na	0.89	0.862	1.05	na	na	na
YERGACHENSKOYE														
	Bsh		Proven	1,977	9.8	22,408	0.10	na	0.80	0.836	1.31	na	na	na
	Bsh		Probable	96	6.6	629	0.10	na	0.80	0.836	1.31	na	na	na
	TL1		Proven	927	13.0	11,634	0.17	31	0.85	0.840	1.36	na	na	1.30
	TL1		Probable	925	13.8	12,746	0.17	31	0.85	0.840	1.36	na	na	1.30
ZORENSKOYE														
	TL2-a		Proven	62	9.8	405	0.16	266	0.89	0.851	1.03	na	2,123	9.91
	DO-1		Proven	490	6.3	3,082	0.13	46	0.81	0.840	1.16	na	2,870	2.30
VISHERA OIL AND GAS COMPANY JOINT VENTURE														
GAGARINSKOYE														
	Sm		Proven	185	12.7	2,351	0.12	5	0.66	0.836	1.19	na	1,508	1.74
	Bsh		Proven	1,028	26.3	32,610	0.14	134	0.78	0.802	1.41	na	na	0.71
	Bsh		Probable	195	13.9	2,705	0.14	134	0.78	0.802	1.41	na	na	0.71
	Turn-Fm		Proven	1,107	42.7	53,157	0.11	15	0.77	0.814	1.37	na	2,949	1.13
	Turn-Fm		Probable	427	18.1	7,724	0.11	15	0.77	0.814	1.37	na	2,949	1.13
KISLOVSKOYE														
	Tulsky 2b		Proven	1,112	8.2	9,141	0.11	11	0.72	0.818	1.33	na	na	1.37
	Tulsky 2b		Probable	124	6.6	811	0.11	11	0.72	0.818	1.33	na	na	1.37
VISHERANEFTEGAS JOINT VENTURE														
GEZHSKOYE														
	Bsh		Proven	2,592	20.2	52,109	0.09	31	0.80	0.828	1.39	na	2,245	0.73
	Bsh		Probable	286	9.8	2,820	0.09	31	0.80	0.828	1.39	na	2,245	0.73
	Okskoy		Proven	198	50.9	10,053	0.03	30	0.80	0.794	1.67	na	2,529	0.39
	T-Fm		Proven	7,554	110.9	850,767	0.09	9	0.82	0.816	1.68	na	na	0.67
	T-Fm		Probable	2,018	24.6	49,609	0.09	9	0.82	0.816	1.68	na	na	0.67

ZAO LUKOIL-PERM SUBSIDIARY
RESERVOIR PARAMETERS

Field	Reservoir	Field Area	Category	Area (Acres)	Avg Net Thickness (Feet)	Net Volume (Acre-Feet)	Porosity (fraction)	Permeability (md)	Oil Saturation (fraction)	Oil Specific Gravity	Oil FVF (RBbl/STB)	Solution Gas Ratio (SCF/STB)	Estimated Original Pressure (psi)	Oil Viscosity (cp)
TSEPELSKOYE														
	T-Fm Oil		Proven	1,236	14.7	18,241	0.08	1	0.70	0.792	1.39	na	na	0.83
	T-Fm Oil		Probable	618	6.6	4,054	0.08	1	0.70	0.792	1.39	na	na	0.83
ZAO PERM														
ARKHANGELSKOYE														
	Yasn (Bb)		Proven	1,174	26.9	31,618	0.18	577	0.88	0.839	1.17	na	2,953	2.24
	Yasn (Bb)		Probable	1,792	16.4	29,388	0.18	577	0.88	0.839	1.17	na	2,953	2.24
	Fm		Proven	1,730	29.6	51,196	0.08	131	0.74	0.832	1.20	na	2,961	1.79
	Fm		Probable	1,421	23.0	32,631	0.08	131	0.74	0.832	1.20	na	2,961	1.79
	Aleksinsky		Proven	247	12.8	3,162	0.16	557	0.80	0.855	1.10	na	2,905	3.94
BELYAYEVSKOYE														
	TL		Proven	247	8.9	2,209	0.16	117	0.86	0.906	1.01	na	2,078	39.63
	TL		Probable	62	6.6	405	0.16	117	0.86	0.906	1.01	na	2,078	39.63
CHASHKENSKOYE														
	Yasn		Proven	2,034	30.5	62,051	0.16	207	0.88	0.846	1.23	na	2,977	1.53
	T - Fm		Proven	1,467	14.4	21,182	0.11	60	0.85	0.845	1.22	na	2,918	1.77
DOLDINSKOYE														
	TL		Proven	124	3.9	486	0.14	na	0.82	0.837	1.08	na	na	na
	Fm		Proven	62	9.8	608	0.10	na	0.75	0.839	1.06	na	na	na
KARNASHOVSKOYE														
	TL2		Proven	62	9.8	608	0.19	831	0.92	0.872	1.02	na	2,410	12.08
	TL2		Probable	127	4.4	561	0.19	831	0.92	0.872	1.02	na	2,410	12.08
KASEBSKOYE														
	TL2		Proven	1,151	11.3	12,314	0.15	67	0.74	0.825	1.20	na	2,544	2.25
	TL2		Probable	153	10.7	1,642	0.15	67	0.74	0.825	1.20	na	2,544	2.25
	Fm		Proven	286	6.8	1,931	0.11	96	0.77	0.864	1.08	na	2,566	7.20
KRUTOVSKOYE														
	Bsh Total		Proven	234	27.1	5,563	0.10	25	0.78	0.822	1.39	941	2,885	0.72
	Bsh Total		Probable	118	13.2	1,551	0.10	25	0.78	0.822	1.39	941	2,885	0.72
	Bb		Proven	247	28.4	6,384	0.12	48	0.84	0.799	1.72	1,463	3,361	0.58
	Bb		Probable	239	15.1	3,600	0.12	48	0.84	0.799	1.72	1,463	3,361	0.58
	Fm		Proven	161	12.1	1,950	0.07	14	0.76	0.804	1.84	na	3,481	0.54
MEZHEVSK														
	Bsh		Proven	339	20.8	7,904	0.13	94	0.65	0.843	1.19	na	na	4.10
	Bsh		Probable	102	29.7	3,027	0.13	94	0.65	0.843	1.19	na	na	4.10
	TL		Proven	215	22.1	3,794	0.14	94	0.80	0.835	1.14	na	na	8.06
	TL		Probable	74	6.4	474	0.14	94	0.80	0.835	1.14	na	na	8.06
NOSHOVSKOYE - BEREZOVSKAYA														
	YASN	Tul+Bb	Proven	1,903	14.9	34,900	0.19	454	0.82	0.900	1.02	na	na	26.90
	T		Proven	1,922	16.5	31,656	0.16	406	0.86	0.919	1.02	na	1,245	49.00
	T		Probable	508	9.8	4,997	0.16	406	0.86	0.919	1.02	na	na	49.00

ZAO LUKOIL-PERM SUBSIDIARY
RESERVOIR PARAMETERS

Field	Reservoir	Field Area	Category	Area (Acres)	Avg Net Thickness (Feet)	Net Volume (Acre-Feet)	Porosity (fraction)	Permeability (md)	Oil Saturation (fraction)	Oil Specific Gravity	Oil FVF (RBbl/STB)	Solution Gas Ratio (SCF/STB)	Estimated Original Pressure (psi)	Oil Viscosity (cp)
NOSHOVSKOYE - BUGROVSKAYA														
		Burgovskaya	Proven	1,876	18.7	29,153	0.19	227	0.85	0.890	1.03	na	na	39.00
NOSHOVSKOYE - NOSHOVSKOYE														
	Ver 3-4		Proven	62	6.6	405	0.16	14	0.71	0.882	1.05	na	na	11.93
	Ver 3-4		Probable	397	6.7	2,642	0.16	14	0.71	0.882	1.05	na	na	11.93
	Bash		Proven	680	13.0	8,877	0.16	256	0.81	0.878	1.05	na	na	11.93
	Bash		Probable	142	7.9	1,125	0.16	256	0.81	0.878	1.05	na	na	11.93
	Yashnop		Proven	741	11.2	8,918	0.16	138	0.80	0.905	1.03	na	na	22.40
	Yashnop		Probable	598	14.0	8,340	0.16	138	0.80	0.905	1.03	na	na	22.40
	Turn		Proven	2,595	29.3	75,147	0.16	722	0.84	0.918	1.02	na	na	81.90
	Turn		Probable	1,327	8.6	11,345	0.16	722	0.84	0.918	1.02	na	na	81.90
NOSHOVSKOYE - OPALEKHENSKAYA														
	Bsh	Opalekhenska	Proven	1,637	13.0	24,173	0.19	35	0.83	0.872	1.03	na	na	9.60
	TL	Opalekhenska	Proven	1,947	8.5	16,612	0.18	37	0.76	0.918	1.03	na	2,089	26.40
	Bb	Opalekhenska	Proven	298	8.7	3,124	0.18	486	0.74	0.931	1.03	na	2,117	26.40
	T	Opalekhenska	Proven	1,761	17.3	30,442	0.14	130	0.79	0.918	1.02	na	2,207	87.05
NOSHOVSKOYE - PADUNSKAYA														
	Bsh	Padunskaya	Proven	3,599	12.8	45,953	0.18	200	0.86	0.883	1.05	na	1,670	11.93
	YASN	Tul2a+Tul2b+Bob	Proven	3,578	41.4	147,045	0.22	1,297	0.93	0.902	1.04	na	2,019	15.70
	T	Padunskaya	Proven	3,986	28.2	112,054	0.19	52	0.90	0.922	1.02	na	2,150	48.80
NOSHOVSKOYE - PERVOMAYSKAYA														
	Bsh+Tl	Pervomayskay	Proven	na	na	12,977	0.22	420	0.85	0.897	1.02	na	na	21.84
	Bsh+Tl	Pervomayskay	Probable	na	na	10,226	0.17	199	0.77	0.874	1.03	na	na	14.34
	Bb	Pervomayskay	Proven	1,580	15.1	23,844	0.22	554	0.85	0.900	1.01	na	2,140	30.64
	T	Pervomayskay	Proven	1,206	17.4	20,974	0.15	17	0.86	0.938	1.02	na	2,224	48.80
NOSHOVSKOYE - ZAPADNAYA														
	Bsh	Zapadnaya	Proven	1,483	11.2	16,631	0.15	126	0.81	0.873	1.05	na	135	11.93
	TOTAL TULSKY	(Tul2b+Tul2a)	Proven	na	na	8,737	0.18	197	0.84	0.899	1.02	na	na	24.54
	T	Zapadnaya	Proven	2,252	18.4	41,476	0.15	46	0.80	0.934	1.02	na	1,346	73.80
NOSHOVSKOYE - ZMEEVSKAYA														
	Bsh	Zmeevskaya	Proven	2,539	8.6	21,838	0.08	199	0.45	0.523	1.72	na	1,755	14.34
	TL	Zmeevskaya	Proven	3,157	7.9	25,023	0.20	420	0.77	0.897	1.02	na	2,137	3.23
	Bb	Zmeevskaya	Proven	384	10.4	4,011	0.22	na	0.84	0.894	1.01	na	2,137	18.35
	T	Zmeevskaya	Proven	3,725	21.7	76,978	0.14	17	0.81	0.937	1.02	na	2,225	48.80
OSOKENSKOYE														
	Bsh		Proven	62	9.8	608	0.11	2	0.67	0.850	1.21	na	na	2.41
	ML		Proven	62	8.2	507	0.22	na	0.93	0.876	1.08	na	na	na
	ML		Probable	49	4.5	224	0.22	na	0.93	0.876	1.08	na	na	na
	Fm		Proven	384	14.8	5,372	0.09	93	0.85	0.814	1.33	na	3,197	1.30

ZAO LUKOIL-PERM SUBSIDIARY
RESERVOIR PARAMETERS

Field	Reservoir	Field Area	Category	Area (Acres)	Avg Net Thickness (Feet)	Net Volume (Acre-Feet)	Porosity (fraction)	Permeability (md)	Oil Saturation (fraction)	Oil Specific Gravity	Oil FVF (RBbl/STB)	Solution Gas Ratio (SCF/STB)	Estimated Original Pressure (psi)	Oil Viscosity (cp)
------	--------------	--------------------	------------	------------	------------	------------	------------	--------------	------------	------------	------------	------------	------------	------------
SHATOVSKOYE - GULYAYEVSKAYA														
	Bb		Proven	803	26.8	20,470	0.17	235	0.82	0.880	1.02	na	2,558	12.91
	Bb		Probable	125	15.5	1,935	0.17	235	0.82	0.880	1.02	na	2,558	12.91
	ML		Proven	62	9.8	608	0.18	844	0.87	0.876	1.02	na	2,602	12.28
SHATOVSKOYE - MARTYUGINSKAYA														
	Bb		Proven	445	14.1	6,070	0.16	918	0.74	0.893	1.02	na	2,720	42.57
	ML		Proven	65	3.0	193	0.16	1,213	0.87	0.874	1.02	na	2,657	10.88
SHATOVSKOYE - SHATOVSKAYA														
	Bb		Proven	494	11.0	5,675	0.15	53	0.89	0.880	1.03	na	2,612	14.73
SHERSHNYEVSKOYE														
	TOTAL Tl+Bb		Probable	na	na	23,065	0.18	360	0.91	0.850	1.12	na	na	4.32
	T-Fm		Proven	1,483	27.0	39,968	0.10	23	0.73	0.861	1.13	na	2,872	4.24
	T-Fm		Probable	1,544	23.0	35,469	0.10	23	0.73	0.861	1.13	na	2,872	4.24
SIBIRSKOYE														
	Bsh+Srp		Proven	9,920	31.5	421,430	0.10	13	0.63	0.840	1.24	na	na	1.91
	Bsh+Srp		Probable	805	9.8	7,920	0.10	13	0.63	0.840	1.24	na	na	1.91
	Bb Total	BB1+2+3+4	Proven	3,415	64.8	204,001	0.14	136	0.81	0.815	1.33	na	na	1.20
	Bb Total		Probable	1,050	21.0	22,092	0.14	136	0.79	0.815	1.33	na	na	1.20
	Fm		Proven	2,162	8.5	18,444	0.09	22	0.68	0.811	1.36	na	3,365	1.18
	Fm		Probable	371	6.6	2,432	0.09	22	0.68	0.811	1.36	na	3,365	1.18
ULYANOVSKOYE														
	Art + Sm		Proven	934	13.2	12,261	0.08	43	0.85	0.849	1.17	na	1,030	1.15
	Bb		Proven	124	11.2	1,378	0.10	20	0.72	0.817	1.39	128	2,963	0.85
	Bb		Probable	131	4.8	629	0.10	20	0.72	0.817	1.39	128	2,963	0.85
UNVENSKOYE														
	V3V4		Proven	496	7.9	3,903	0.15	23	0.69	0.863	1.15	na	na	3.99
	Bsh		Proven	9,461	30.5	288,684	0.13	23	0.78	0.830	1.22	na	1,800	1.24
	TL2-a		Proven	9,637	5.8	55,689	0.14	20	0.87	0.835	1.29	na	1,978	1.09
	TL2-a		Probable	119	5.8	685	0.14	20	0.87	0.835	1.29	na	na	1.09
	Bb		Proven	12,128	26.4	319,523	0.17	81	0.88	0.825	1.28	na	1,894	1.09
	T + Fm		Proven	9,674	18.7	181,023	0.10	22	0.80	0.832	1.29	na	1,850	1.30
VERKH. SYNAPANSKOYE														
	Fm		Proven	494	17.7	5,351	0.09	34	0.08	0.874	1.68	na	na	13.86
	Fm		Probable	432	8.2	3,547	0.09	34	0.08	0.874	1.68	na	na	13.86
YURCHUKSKOYE														
	Bsh		Proven	5,036	28.7	147,010	0.12	160	0.80	0.883	1.11	na	2,480	10.55
	Yasn		Proven	4,408	35.3	158,537	0.13	350	0.64	0.829	1.21	na	2,950	1.17
	Yasn		Probable	497	9.8	4,887	0.13	350	0.64	0.829	1.21	na	2,950	1.17
	T - Fm		Proven	2,780	11.5	31,922	0.12	61	0.85	0.839	1.22	na	2,998	1.28

Exhibit 56

ASTRAKHANNEFT SUBSIDIARY
RESERVOIR PARAMETERS

Field	Reservoir	Field Area	Category	Area (Acres)	Avg Net Thickness (Feet)	Net Volume (Acre-Feet)	Porosity (fraction)	Permeability (md)	Oil Saturation (fraction)	Oil Specific Gravity	Oil FVF (RBbl/STB)	Solution Gas Ratio (SCF/STB)	Estimated Original Pressure (psi)	Oil Viscosity (cp)
BESHKULSKOYE														
	Bathonian III		Proven	572	4.8	2,774	0.19	na	0.63	0.880	1.116	na	2,351	4.80
	Bajocian I, II		Proven	944	12.5	11,780	0.26	na	0.70	0.878	1.070	163	2,351	4.80
DOLBANSKOYE														
	Upper Albanian		Proven	125	6.1	762	0.33	na	0.62	0.817	1.111	222	na	na
OLEINIKOVSKOYE														
	Lower Albanian	Block I	Proven	1,151	33.9	39,030	0.27	na	0.75	0.818	1.111	451	1,636	2.62
	Lower Albanian	Block III	Proven	482	57.2	27,555	0.27	na	0.75	0.818	1.111	451	1,518	2.62

KALININGRADMORNEFT SUBSIDIARY
RESERVOIR PARAMETERS

Field	Reservoir	Field Area	Category	Area (Acres)	Avg Net Thickness (Feet)	Net Volume (Acre-Feet)	Porosity (fraction)	Permeability (md)	Oil Saturation (fraction)	Oil Specific Gravity	Oil FVF (RBbl/STB)	Solution Gas Ratio (SCF/STB)	Estimated Original Pressure (psi)	Oil Viscosity (cp)
ALESHKINSKOYE														
	Middle Cambrian		Proven	534	25.9	13,834	0.12	313	0.94	0.821	1.181	247	3,420	0.96
CHECKOVSKOYE														
	Middle Cambrian		Proven	81	18.4	1,485	0.12	434	0.91	0.815	1.064	87	3,537	1.81
DEEMINSKOYE														
	Level	I	Proven	1,526	27.6	42,125	0.11	313	0.85	0.836	1.047	57	3,051	2.76
	Level	I	Probable	284	3.9	1,119	0.11	313	0.85	0.836	1.047	57	3,051	2.76
	Level	II + III	Proven	1,154	17.1	19,773	0.11	313	0.83	0.836	1.047	57	3,051	2.29
	Level	II + III	Probable	172	3.3	565	0.11	313	0.83	0.836	1.047	57	3,051	2.29
GAEVSKOYE														
	Middle Cambrian		Proven	529	21.5	11,357	0.09	146	0.79	0.842	1.067	96	3,349	2.64
	Middle Cambrian		Probable	89	6.6	585	0.09	146	0.79	0.842	1.067	96	3,349	2.64
ISAKOVSKOYE														
	C - 2		Proven	237	36.1	8,561	0.11	275	0.91	0.816	1.179	233	3,303	0.82
KRASNOBORSKOYE														
	Middle Cambrian		Proven	2,196	53.8	118,145	0.14	289	0.89	0.830	1.052	50	2,761	2.62
KRAVTSHOVSKOYE														
	Offshore		Proven	2,676	54.5	145,905	0.12	552	0.88	0.826	1.083	115	3,537	1.81
			Probable	1,556	24.3	37,881	0.12	552	0.88	0.826	1.083	115	3,537	1.81
LADUSHKINSKOYE														
	I - 1		Proven	2,850	18.3	52,089	0.07	97	0.73	0.816	1.789	1,301	3,541	0.51
	I - 2		Proven	4,059	32.9	133,527	0.07	97	0.73	0.816	1.789	1,301	3,541	0.51
	I - 2		Probable	453	9.8	4,463	0.07	97	0.73	0.816	1.789	1,301	3,541	0.51
	II		Proven	1,798	36.7	65,940	0.07	97	0.80	0.816	1.789	1,301	3,541	0.51
	II		Probable	27	6.6	177	0.07	97	0.80	0.816	1.789	1,301	3,541	0.51
MALINOVSKOYE														
	Middle Cambrian	Layer 1 North	Proven	473	19.0	8,996	0.14	452	0.89	0.821	1.073	93	3,134	1.72
	Middle Cambrian	Layer 1 South	Proven	1,317	25.8	33,941	0.15	452	0.91	0.821	1.091	93	3,134	1.72
	Middle Cambrian	Layer 1 South	Probable	11	6.6	70	0.15	452	0.91	0.821	1.091	93	3,134	1.72
	Middle Cambrian	Layer 2 North	Proven	123	16.4	2,019	0.13	452	0.87	0.821	1.091	93	3,134	1.72
	Middle Cambrian	Layer 2 South	Proven	731	16.7	12,238	0.11	452	0.83	0.821	1.073	93	3,134	1.72
	Middle Cambrian	Layer 2 South	Probable	47	9.8	467	0.11	452	0.83	0.821	1.073	93	3,134	1.72
	Middle Cambrian	Layer 3	Proven	109	8.9	968	0.12	452	0.81	0.821	1.091	93	3,134	1.72
OLYMPIESKOYE														
	Cambrian		Proven	99	11.8	1,167	0.22	-	0.75	0.828	1.064	88	3,537	1.81
RATNOYE														
	Cambrian		Proven	112	4.3	480	0.09		0.70	0.841	1.053			
SEMENOVSKOYE														
	Cambrian		Probable	32	5.0	160	0.11		0.85	0.792	1.075			

KALININGRADMORNEFT SUBSIDIARY
RESERVOIR PARAMETERS

Field	Reservoir	Field Area	Category	Area (Acres)	Avg Net Thickness (Feet)	Net Volume (Acre-Feet)	Porosity (fraction)	Permeability (md)	Oil Saturation (fraction)	Oil Specific Gravity	Oil FVF (RBbl/STB)	Solution Gas Ratio (SCF/STB)	Estimated Original Pressure (psi)	Oil Viscosity (cp)
SEV. - KRASNOBORSKOYE														
	Middle Cambrian		Proven	234	15.1	3,528	0.11	115	0.77	0.845	1.048	49	2,847	4.84
			Probable	49	3.3	161	0.11	115	0.77	0.845	1.048	49	2,847	4.84
SEV. - SLAVINSKOYE														
	Middle Cambrian		Proven	343	10.2	3,493	0.11	238	0.84	0.844	1.050	55	3,212	4.55
SLAVINSKOYE														
	Middle Cambrian		Proven	288	11.6	3,346	0.14	232	0.87	0.840	1.041	59	3,042	3.89
SLAVSKOYE														
	Middle Cambrian IV + V		Proven	494	9.9	4,897	0.09	135	0.81	0.832	1.100	133	2,817	2.62
	Middle Cambrian IV + V		Probable	62	9.8	608	0.09	135	0.81	0.832	1.100	133	2,817	2.62
USHAKOVSKOYE														
	Middle Cambrian	North	Proven	952	39.7	37,777	0.13	270	0.90	0.822	1.087	98	3,070	1.57
	Middle Cambrian	South	Proven	1,219	51.6	62,895	0.12	251	0.91	0.822	1.087	98	3,070	1.57
YUZHNO - OLYMPIESKOYE														
	Middle Cambrian		Proven	207	13.9	2,880	0.12	447	0.83	0.840	1.059	86	3,144	2.60
ZAP-KRASNOBORSKOYE														
	Middle Cambrian		Proven	1,503	60.0	90,119	0.14	289	0.86	0.822	1.046	54	2,902	2.26
	Middle Cambrian		Probable	261	13.8	3,592	0.14	289	0.86	0.822	1.046	54	2,902	2.26
ZAP-USHAKOVSKOYE														
	Middle Cambrian		Proven	149	21.9	3,259	0.11	340	0.91	0.819	1.087	143	3,232	1.40

KOMITEK SUBSIDIARY
RESERVOIR PARAMETERS

Field	Reservoir	Field Area	Category	Area (Acres)	Avg Net Thickness (Feet)	Net Volume (Acre-Feet)	Porosity (fraction)	Oil Saturation (fraction)	Oil Specific Gravity	Oil FVF (RBbl/STB)	Solution Gas Ratio (SCF/STB)	Estimated Original Pressure (psi)	Oil Viscosity (cp)
KARAYAGA-NEFT													
KOMANDIRSHORSKOYE													
	Mid Devonian D2	Target I	Proven	556	28.9	16,052	0.09	0.87	0.825	1.481	na	6,800	2.00
	Mid Devonian D2	Target I	Probable	3,104	12.9	40,129	0.09	0.87	0.825	1.481	na	6,800	2.00
SEVERO KOMANDIRSHORSKOYE													
	Devonian D3	Target II	Proven	1,112	19.4	21,524	0.20	0.77	0.962	1.047	na	6,800	2.00
	Devonian D3	Target II	Probable	1,236	12.5	15,444	0.20	0.77	0.962	1.047	na	6,800	2.00
ZAPADNO KOMANDIRSKORSKOYE													
	Devonian D2	Target III	Probable	4,927	23.3	114,926	0.20	0.77	0.962	1.047	na	6,800	2.00
KOMI ARCTIC OIL													
UPPER VOZEISKOYE													
	S1 vk	Main	Proven	6,981	66.0	460,686	0.10	0.88	0.828	1.418	26	5,300	0.67
	S1 vk	Main	Probable	7,820	32.5	254,000	0.10	0.88	0.828	1.418	26	5,300	0.67
	S1 sn+mk	NW. Block	Proven	12,989	79.3	1,030,058	0.10	0.95	0.826	1.214	26	5,300	0.67
	S1 sn+mk	NW. Block	Probable	2,236	45.9	102,717	0.10	0.95	0.826	1.214	26	5,300	0.67
KOMI QUEST OIL													
SOUTH VOZEISKOYE													
	Devonian (D3fm1)	Target III	Proven	3,112	32.7	101,692	0.11	0.71	0.844	1.120	479	3,200	0.67
KOMITEK													
KHARYAGINSKOYE													
	Devonian (D2+D3)	Target I	Proven	9,334	48.2	450,372	0.12	0.90	0.833	1.452	1,014	5,650	0.96
	Devonian (D2+D3)	Target I	Probable	2,808	12.8	35,924	0.12	0.90	0.833	1.452	1,014	5,650	0.96
	Permian (P2 I-IV)	Target IV	Proven	13,578	38.9	528,220	0.22	0.54	0.837	1.125	230	2,495	2.83
	Permian (P2 I-IV)	Target IV	Probable	2,681	28.9	77,407	0.22	0.54	0.837	1.125	230	2,495	2.83
	Permian (P2 V-XIII)	Target V	Proven	8,508	22.6	192,123	0.22	0.53	0.835	1.111	246	2,240	3.22
	Permian (P2 V-XIII)	Target V	Probable	3,049	11.8	36,009	0.22	0.53	0.835	1.111	246	2,240	3.22
	Triassic (T1)	Target VI	Proven	4,510	13.2	59,547	0.24	0.49	0.837	1.070	153	2,090	3.88
	Triassic (T1)	Target VI	Probable	1,511	8.9	13,381	0.24	0.49	0.837	1.070	153	2,090	3.88
NIZHNEOMRISNKOYE													
	Devonian	Fieldwide	Proven	6,563	16.5	108,375	0.20	0.81	0.841	1.176	1	1,388	8.66
	Devonian	Fieldwide	Probable	1,286	26.3	33,878	0.20	0.80	0.848	1.155	1	1,388	4.41
USINSKOYE													
	Permian (P2-IV)	Ufimskaya	Proven	1,084	25.6	27,798	0.20	0.72	0.923	1.064	120	1,580	2.10
	Perm Carboniferous P1C2+3	Target I	Proven	2,360	71.1	167,898	0.20	0.70	0.955	1.027	124	1,800	2.10
	Perm Carboniferous P1C2+3	Target I	Probable	133	58.7	7,807	0.20	0.70	0.955	1.027	124	1,800	2.10
	Perm Carboniferous P1C2+3	Target II	Proven	3,552	118.8	422,015	0.20	0.70	0.955	1.027	124	1,800	2.10
	Perm Carboniferous P1C2+3	Target II	Probable	194	49.2	9,546	0.20	0.70	0.955	1.027	124	1,800	2.10
	Perm Carboniferous P1C2+3	Target III	Proven	5,059	54.8	277,084	0.20	0.70	0.955	1.027	124	1,800	2.10
	Perm Carboniferous P1C2+3	Target III	Probable	1,964	#VALUE!	na	0.20	0.70	0.955	1.027	124	1,800	2.10
	Mid Devonian D2ST(IV)	Starooskolsky	Proven	467	17.1	7,968	0.14	0.86	0.844	1.250	410	4,550	2.10
	Mid Devonian (D2 III+D2ST(IV))	Upper Target II	Proven	16,457	31.9	525,081	0.13	0.86	0.843	1.196	307	4,630	2.11
	Mid Devonian (D2 III+D2ST(IV))	Upper Target II	Probable	1,773	9.8	17,451	0.13	0.86	0.843	1.196	307	4,630	2.11
	Mid Devonian (D2I+II)	Lower Target I	Proven	28,059	60.4	1,693,833	0.13	0.86	0.843	1.196	307	4,630	2.10

KOMITEK SUBSIDIARY
RESERVOIR PARAMETERS

Field	Reservoir	Field Area	Category	Area (Acres)	Avg Net Thickness (Feet)	Net Volume (Acre-Feet)	Porosity (fraction)	Oil Saturation (fraction)	Oil Specific Gravity	Oil FVF (RBbl/STB)	Solution Gas Ratio (SCF/STB)	Estimated Original Pressure (psi)	Oil Viscosity (cp)
VERKHNEOVWRINKOYE													
	Devonian	Fieldwide	Proven	5,029	14.8	74,630	0.20	0.80	0.875	1.155	na	1,250	2.50
	Devonian	Fieldwide	Probable	278	10.9	3,034	0.20	0.80	0.875	1.155	na	1,250	2.50
	Devonian	Fieldwide	Proven	1,962	10.5	20,599	0.15	0.70	0.843	1.111	na	1,100	2.50
	Permian (P1AS)	Asselskoye	Proven	14,537	44.1	641,309	0.16	0.85	0.850	1.040	44	2,100	11.10
	Carboniferous (C2+C3)	Carboniferous	Proven	13,287	54.6	724,919	0.16	0.82	0.820	1.025	30	2,300	27.48
	Devonian (D3FM)	Central Faminskaya	Proven	3,489	24.6	85,877	0.11	0.75	0.838	1.309	530	3,050	10.19
	Devonian (D3FM)	Central Faminskaya	Probable	232	18.7	4,344	0.11	0.75	0.838	1.309	530	3,050	10.19
	Mid Devonian D2ST(IV)	Kostykoye	Proven	556	27.4	15,262	0.11	0.80	0.829	1.828	46	2,000	2.35
	Mid Devonian D2ST(IV)	Kostykoye	Probable	1,579	21.4	33,787	0.11	0.80	0.829	1.828	46	2,000	2.35
	Permian (P1+2)	Kostykoye	Proven	3,089	39.7	122,610	0.24	0.71	0.840	1.045	67	1,570	3.63
	Devonian (D3FM)	S. Faminskaya	Proven	1,853	31.6	58,554	0.11	0.71	0.844	1.120	155	3,000	2.18
	Devonian (D3FM)	N. Dome	Probable	1,423	29.6	42,106	0.11	0.71	0.844	1.120	155	3,000	2.18
	Lower Devonian (DIII)	S. Ufimskaya	Proven	1,907	15.7	30,038	0.09	0.70	0.842	1.190	166	2,100	2.10
	Lower Devonian (D3PS)	S. Pericline	Proven	11,160	21.6	240,557	0.15	0.88	0.832	1.355	612	4,000	2.35
	Mid Devonian (D2I+II)	S. Pericline (Lower)	Proven	20,185	44.9	905,416	0.13	0.88	0.827	1.383	668	4,600	2.35
	Mid Devonian (D2I+II)	S. Pericline (Lower)	Probable	237	9.8	2,335	0.13	0.88	0.827	1.383	668	4,600	2.35
	Mid Devonian (D2III)	S. Pericline (Upper)	Proven	14,968	18.6	278,783	0.11	0.87	0.827	1.383	665	4,600	2.35
	Mid Devonian (D2 AF-ST)	W. Region	Proven	3,573	99.8	356,699	0.15	0.88	0.829	1.730	1,838	4,600	0.62
	Silurian (S1-vk1)	Central Deposit	Proven	247	149.3	36,887	0.13	0.90	0.822	1.531	933	4,800	5.60
	Silurian (S1-vk1)	Central Deposit	Probable	363	131.2	47,637	0.13	0.90	0.822	1.531	933	4,800	5.60
NOBEL OIL													
USINSKOYE													
	Perm Carboniferous P1+C2	Target I	Proven	9,106	116.2	1,058,412	0.20	0.77	0.962	1.047	124	1,800	7.10
	Perm Carboniferous P1+C2	Target I	Probable	2,187	39.4	86,097	0.20	0.77	0.962	1.047	124	1,800	7.10
	Perm Carboniferous P1+C2	Target II	Proven	10,860	85.3	926,804	0.20	0.77	0.962	1.047	124	1,800	7.10
	Perm Carboniferous P1+C2	Target II	Probable	2,454	55.8	136,897	0.20	0.77	0.962	1.047	124	1,800	7.10
	Perm Carboniferous P1+C2	Target III	Proven	10,440	63.7	665,212	0.20	0.77	0.962	1.047	124	1,800	7.10
	Perm Carboniferous P1+C2	Target III	Probable	1,118	44.3	49,524	0.20	0.77	0.962	1.047	124	1,800	7.10
PARMANEFT													
SEVERO-KOZHVINSKOYE													
	D3DZR	NW. Block	Proven	782	21.0	16,399	0.15	0.91	0.835	1.359	na	2,900	1.14
	D3DZR	NW. Block	Probable	251	15.8	3,954	0.15	0.91	0.835	1.359	na	2,900	1.14
	D2DZ	NW. Block	Proven	865	145.6	125,984	0.15	0.91	0.835	1.359	na	2,900	1.14
	D2DZ	NW. Block	Probable	266	87.8	23,357	0.15	0.91	0.835	1.359	na	2,900	1.14
SIGAVEISKOYE													
	Foel D3fm1	NW. Block	Proven	803	23.0	18,444	0.11	0.91	0.808	1.070	na	5,000	2.00
	Foel D3fm1	NW. Block	Probable	988	13.1	12,971	0.11	0.91	0.808	1.070	na	5,000	2.00
	Fodz D3fm1	NW. Block	Proven	309	131.2	40,535	0.11	0.91	0.808	1.070	na	5,000	2.00
	Fodz D3fm1	NW. Block	Probable	124	82.0	10,134	0.11	0.91	0.808	1.070	na	5,000	2.00
YUZHNO-LYZHSKOYE													
	D3PS2	NW. Block	Proven	371	29.5	10,945	0.12	0.85	0.835	1.220	na	4,000	2.40
	D3PS2	NW. Block	Probable	247	19.7	4,864	0.12	0.85	0.835	1.220	na	4,000	2.40
	D3 PS 1 MAIN + LOWER	NW. Block	Proven	803	116.1	93,272	0.12	0.85	0.835	1.220	na	4,000	2.40
	D3 PS 1 MAIN + LOWER	NW. Block	Probable	449	98.4	44,192	0.12	0.85	0.835	1.220	na	4,000	2.40
	d3 ps1 main	NW. Block	Proven	803	114.8	92,218	0.12	0.85	0.835	1.220	na	4,000	2.40
	d3 ps1 main	NW. Block	Probable	449	94.8	42,571	0.12	0.85	0.835	1.220	na	4,000	2.40

KOMITEK SUBSIDIARY
RESERVOIR PARAMETERS

Field	Reservoir	Field Area	Category	Area (Acres)	Avg Net Thickness (Feet)	Net Volume (Acre-Feet)	Porosity (fraction)	Oil Saturation (fraction)	Oil Specific Gravity	Oil FVF (RBbl/STB)	Solution Gas Ratio (SCF/STB)	Estimated Original Pressure (psi)	Oil Viscosity (cp)
YUZHNO-LYZHSKOYE (cont)													
	d3ps1 lower	NW. Block	Proven	124	7.9	973	0.12	0.85	0.835	1.220	na	4,000	2.40
	d3ps1 lower	NW. Block	Probable	247	6.6	1,621	0.12	0.85	0.835	1.220	na	4,000	2.40
	D2ST UPPER + MAIN	NW. Block	Proven	741	70.5	52,291	0.12	0.85	0.835	1.220	na	4,000	2.40
	D2ST UPPER + MAIN	NW. Block	Probable	469	48.2	22,607	0.12	0.85	0.835	1.220	na	4,000	2.40
	d2st upper	NW. Block	Proven	741	16.4	12,161	0.12	0.85	0.835	1.220	na	4,000	2.40
	d2st upper	NW. Block	Probable	247	9.8	2,432	0.12	0.85	0.835	1.220	na	4,000	2.40
	d2 st main	NW. Block	Proven	680	59.1	40,130	0.12	0.85	0.835	1.220	na	4,000	2.40
	d2 st main	NW. Block	Probable	469	43.0	20,147	0.12	0.85	0.835	1.220	na	4,000	2.40
	D2AF II	NW. Block	Proven	494	13.1	6,486	0.12	0.85	0.835	1.220	na	4,000	2.40
	D2AF II	NW. Block	Probable	124	13.1	1,621	0.12	0.85	0.835	1.220	na	4,000	2.40
	D2 AF I	NW. Block	Proven	432	16.4	7,094	0.12	0.85	0.835	1.220	na	4,000	2.40
	D2 AF I	NW. Block	Probable	112	6.6	735	0.12	0.85	0.835	1.220	na	4,000	2.40
YUZHNOTEREKHOVEYSKOYE													
	D3DZR	NW. Block	Proven	556	49.2	27,361	0.11	0.91	0.808	1.070	na	5,000	2.00
	D3DZR	NW. Block	Probable	680	49.2	33,442	0.11	0.91	0.808	1.070	na	5,000	2.00
	D2ST	NW. Block	Probable	309	8.2	2,533	0.11	0.91	0.808	1.070	na	5,000	2.00
SEVERTEK OIL													
NORTH PASHSHORSKOYE													
	DEVONIAN (D3)	Fransky Supra Reef	Probable	62	1.6	101	0.11	0.86	0.842	1.524	na	na	na
	DEVONIAN (D3)	Reef Deposit	Probable	329	16.0	5,248	0.11	0.86	0.850	1.462	na	na	na
	Devonian (D2)	Zhivetsky III	Proven	556	57.3	31,881	0.09	0.80	0.801	1.582	na	4,800	0.46
	Devonian (D2)	Zhivetsky III	Probable	1,266	36.4	46,119	0.09	0.80	0.801	1.582	na	4,800	0.46
PASHSHORSKOYE													
	Devonian (D2)	Fransky Supra Reef	Proven	309	5.9	1,824	0.11	0.86	0.842	1.524	na	5,400	0.80
	Devonian (D2)	Fransky Supra Reef	Probable	124	8.2	1,013	0.11	0.86	0.842	1.524	na	5,400	0.80
	Devonian (D3)	Reef Deposit	Proven	1,915	104.5	200,063	0.11	0.86	0.850	1.462	na	5,400	0.86
	Devonian (D3)	Reef Deposit	Probable	270	88.6	23,947	0.11	0.86	0.850	1.462	na	5,400	0.86
	Devonian (D2)	Zhivetsky III	Proven	988	25.8	25,497	0.09	0.80	0.801	1.582	na	5,400	0.46
	Devonian (D2)	Zhivetsky III	Probable	429	25.3	10,843	0.09	0.80	0.801	1.582	na	5,400	0.46
	Carbonate (C1)	Zhivetsky III	Probable	1,544	11.9	18,444	0.10	0.78	0.888	1.025	na	3,800	19.20
	Carbonate (C1)	Member II	Probable	1,378	11.8	16,271	0.22	0.83	0.881	1.065	na	3,800	19.20
	Carbonate (C1)	Member I	Probable	2,533	6.6	16,620	0.22	0.81	0.886	1.065	na	3,800	9.95
	Devonian (D3)	Reef Carbonate	Probable	1,736	53.8	93,402	0.09	0.86	0.808	1.065	na	3,800	1.22
SOUTH SHAPKINSKOYE													
	Permian (P1a+s)	S. Shapkinsky	Proven	988	37.3	36,887	0.17	0.78	0.856	1.190	na	2,900	1.50
	Permian (P1a+s)	S. Shapkinsky	Probable	494	34.1	16,863	0.17	0.78	0.856	1.190	na	2,900	1.50
	Permian (P1a)	S. Shapkinsky	Proven	803	73.4	58,918	0.17	0.78	0.852	1.205	na	2,900	1.55
	Carbonate (C2+3)	S. Shapkinsky	Proven	2,409	145.5	350,612	0.17	0.78	0.860	1.176	na	2,900	1.50
	Carbonate (C2+3)	S. Shapkinsky	Probable	534	92.2	49,252	0.17	0.78	0.860	1.176	na	2,900	1.50
	Permian (P1u)	Sredne-Sercheyusky	Probable	1,148	35.4	40,679	0.16	0.90	0.860	1.124	na	2,900	3.24
	Permian (P1ar)	Sredne-Sercheyusky	Probable	898	32.8	29,469	0.16	0.90	0.851	1.136	na	2,900	3.24
	Devonian (D3)	Fransky Supra Reef	Probable	62	1.6	101	0.11	0.86	0.842	1.524	na	4,800	0.80
	Devonian (D3)	Reef Deposit	Probable	329	15.9	5,248	0.11	0.86	0.850	1.462	na	4,800	0.86
	DEVONIAN (D2)	ZHIVETSKY III	Proven	556	57.3	31,881	0.09	0.80	0.801	1.582	na	na	na
	DEVONIAN (D2)		Probable	1,266	36.4	46,119	0.09	0.80	0.801	1.582	na	na	na

KOMITEK SUBSIDIARY
RESERVOIR PARAMETERS

Field	Reservoir	Field Area	Category	Area (Acres)	Avg Net Thickness (Feet)	Net Volume (Acre-Feet)	Porosity (fraction)	Oil Saturation (fraction)	Oil Specific Gravity	Oil FVF (RBbl/STB)	Solution Gas Ratio (SCF/STB)	Estimated Original Pressure (psi)	Oil Viscosity (cp)
VERKHNEGRUBESHORSKOYE													
	Devonian (D2)	Zhivetsky I	Proven	185	102.9	19,072	0.09	0.80	0.807	1.161	na	6,000	1.23
	Devonian (D2)	Zhivetsky I	Probable	289	49.9	14,424	0.09	0.80	0.807	1.161	na	6,000	1.23
	Devonian (D2)	Zhivetsky II	Proven	185	65.9	12,221	0.09	0.79	0.808	1.151	na	6,000	1.23
	Devonian (D2)	Zhivetsky II	Probable	429	46.6	20,008	0.09	0.79	0.808	1.151	na	6,000	1.23
YANTK													
YERAGA													
	D2st + D3 ps	Oil Area	Proven	1,652	36.1	59,607	0.26	0.87	0.945	1.020	na	15	2.10
	D2st + D3 ps	Deplered Area	Proven	1,247	44.3	55,221	0.26	0.87	0.950	1.020	na	na	na
	D2st + D3 ps	Central Area	Proven	513	95.1	48,808	0.26	0.87	0.945	1.020	na	15	2.10
TEBUKNEFT													
VERKHNE-PASHNINSKOYE													
	PERMIAN - P1		Proven	3,137	50.3	157,763	0.18	0.78	0.873	1.030	na	na	na
	DEVONIAN -D3FM		Proven	3,396	28.2	95,825	0.13	0.78	0.873	1.030	na	na	na
NIXHNE-PASHNINSKOYE													
	DEVONIAN -D3F1		Proven	9,717	24.5	238,422	0.14	0.91	0.837	1.350	na	na	na
	DEVONIAN - D21V		Proven	5,106	33.7	172,036	0.13	0.90	0.842	1.323	na	na	na
	DEVONIAN - D2IV0		Proven	4,436	100.6	446,172	0.13	0.92	0.836	1.305	na	na	na
	DEVONIAN - D2IIIb+v		Proven	741	24.6	18,241	0.13	0.91	0.833	1.305	na	na	na
	DEVONIAN - D2IIIb+v		Probable	865	16.4	14,187	0.13	0.91	0.833	1.305	na	na	na
ZAPADNO VERKHNE TEBUKSKOYE													
	DEVONIAN-D3FM0		Proven	3,469	28.7	99,578	0.19	0.64	0.895	1.020	na	na	na
	DEVONIAN - D3FM1		Proven	6,984	19.2	133,810	0.14	0.80	0.865	1.064	na	na	na
	DEVONIAN - D3FM2		Proven	3,253	27.0	87,822	0.11	0.89	0.889	1.053	na	na	na
ZAPADNO NIZHNE TEBUKSKOYE													
	DEVONIAN - D3F1		Proven	1,421	9.5	13,515	0.17	0.84	0.848	1.333	na	na	na
	DEVONIAN - D3F1		Probable	1,834	5.7	10,530	0.17	0.84	0.848	1.333	na	na	na
	DEVONIAN - D2IV		Proven	1,853	23.5	43,519	0.15	0.84	0.848	1.333	na	na	na
	DEVONIAN - D2IV		Probable	185	23.0	4,256	0.15	0.84	0.848	1.333	na	na	na
	DEVONIAN - D2EFIIa		Proven	7,307	22.0	160,837	0.15	0.80	0.851	1.235	na	na	na
	DEVONIAN - D2EFIIIb		Proven	9,109	47.5	432,304	0.18	0.85	0.846	1.233	na	na	na
DEZHERSKOYE													
	DEVONIAN - D3FM		Proven	556	28.4	15,809	0.10	0.80	0.949	1.111	na	na	na
	DEVONIAN - D3FM		Probable	988	21.1	20,884	0.10	0.80	0.949	1.111	na	na	na
	DEVONIAN - D3F1Ia		Proven	2,156	15.2	32,679	0.22	0.87	0.848	1.211	na	na	na
	DEVONIAN - D3F1Ib		Proven	2,238	7.3	16,372	0.18	0.82	0.845	1.211	na	na	na
	DEVONIAN - D2Iv		Proven	3,253	24.3	78,968	0.18	0.85	0.847	1.250	na	na	na
	DEVONIAN - D2IIA		Proven	185	9.9	1,824	0.18	0.85	0.847	1.250	na	na	na
	DEVONIAN - D2IIA		Probable	344	3.5	1,187	0.18	0.85	0.847	1.250	na	na	na
SEVERO-SAVINOBORSKOYE													
	PERMIAN - P1K		Proven	1,174	15.1	17,763	0.18	0.81	0.874	1.005	na	na	na
			Probable	1,609	11.3	18,162	0.18	0.81	0.874	1.005	na	na	na
	PERMIAN - P1K +AR		Probable	488	21.9	10,664	0.18	0.81	0.874	1.005	na	na	na
	DEVONIAN - D3FM		Proven	905	16.7	15,071	0.16	0.82	0.868	1.005	na	na	na
	DEVPMOAM -D3F1		Proven	4,470	9.7	43,552	0.17	0.85	0.858	0.122	na	na	na
	DEVONIAN - D2IV		Proven	4,777	31.3	149,666	0.14	0.79	0.849	1.239	na	na	na
	DEVONIAN - D2IV		Probable	161	10.8	1,739	0.14	0.79	0.849	1.239	na	na	na

KOMITEK SUBSIDIARY
RESERVOIR PARAMETERS

Field	Reservoir	Field Area	Category	Area (Acres)	Avg Net Thickness (Feet)	Net Volume (Acre-Feet)	Porosity (fraction)	Oil Saturation (fraction)	Oil Specific Gravity	Oil FVF (RBbl/STB)	Solution Gas Ratio (SCF/STB)	Estimated Original Pressure (psi)	Oil Viscosity (cp)
VOSTOCHNO - SAVINOBORSKOYE													
	CARBONIFEROUS - C1		Proven	680	12.3	8,350	0.11	0.71	0.838	1.025	na	na	na
	CARBONIFEROUS - C1		Probable	474	9.9	4,670	0.11	0.71	0.838	1.025	na	na	na
	DEVONIAN - D3FM		Proven	247	9.5	2,349	0.09	0.72	0.867	1.020	na	na	na
	DEVONIAN - D3FM		Probable	185	6.6	1,216	0.90	0.72	0.867	1.020	na	na	na
	DEVONIAN - D3F1		Proven	2,471	11.7	28,973	0.12	0.81	0.842	1.259	na	na	na
	DEVONIAN - D3F1		Probable	297	9.8	2,919	0.16	0.81	0.842	1.259	na	na	na
	DEVONIAN - D2IV		Proven	1,228	18.7	22,995	0.13	0.80	0.843	1.290	na	na	na
RASYUSKOYE													
	DEVONIAN - D3F1IaUP		Proven	247	11.0	2,716	0.12	0.78	0.858	1.332	na	na	na
	DEVONIAN - D3F1IaUP		Probable	148	7.0	1,031	0.12	0.78	0.858	1.332	na	na	na
	DEVONIAN - D3F1IaLR		Proven	371	9.5	3,506	0.12	0.78	0.858	1.332	na	na	na
	DEVONIAN - D3F1IaLR		Probable	247	7.3	1,792	0.12	0.78	0.858	1.332	na	na	na
	DEVONIAN - D3F1Ib		Proven	309	11.0	3,405	0.14	0.84	0.851	1.364	na	na	na
	DEVONIAN - D3F1Ib		Probable	25	7.4	186	0.14	0.84	0.851	1.364	na	na	na
BEREGOVOYE													
	PERMIAN - P2		Proven	62	32.7	2,027	0.23	0.51	0.869	1.003	na	na	na
	PERMIAN - P2		Probable	432	16.4	7,094	0.23	0.51	0.869	1.003	na	na	na
	PERMIAN - P1K		Proven	556	13.8	7,645	0.14	0.71	0.873	1.013	na	na	na
	PERMIAN - P1K		Probable	1,166	10.6	12,319	0.14	0.71	0.873	1.013	na	na	na
	DEVONIAN - D3F1Ia		Proven	618	23.3	14,406	0.13	0.86	0.842	1.342	na	na	na
	DEVONIAN - D3F1Ia		Probable	62	9.8	608	0.13	0.86	0.842	1.342	na	na	na
	DEVONIAN - D3F1Ib		Proven	344	8.5	2,916	0.10	0.77	0.846	1.326	na	na	na
	DEVONIAN - D2IV		Proven	397	68.5	27,212	0.13	0.85	0.837	1.250	na	na	na
	DEVONIAN - D2IV		Probable	74	53.6	3,964	0.13	0.85	0.837	1.250	na	na	na
KYRTAYELSKOYE													
	DEVONIAN - D3F1		Proven	185	18.8	3,486	0.10	0.84	0.834	1.582	na	na	na
	DEVONIAN - D3F1		Probable	494	11.6	5,740	0.10	0.84	0.834	1.582	na	na	na
	DEVONIAN - D2lv		Proven	1,285	127.3	163,561	0.10	0.81	0.837	1.582	na	na	na
	DEVONIAN - D2lv		Probable	247	49.2	12,161	0.10	0.81	0.837	1.582	na	na	na
	DEVONIAN - D2llaf		Proven	482	36.8	17,714	0.12	0.82	0.835	1.577	na	na	na
	DEVONIAN - D2llaf		Probable	470	29.5	13,863	0.12	0.82	0.835	1.577	na	na	na
	DEVONIAN - D2laf		Proven	247	11.9	2,939	0.20	0.83	0.856	1.351	na	na	na
	DEVONIAN - D2laf		Probable	309	8.2	2,533	0.20	0.83	0.856	1.351	na	na	na
MICHAYUSKOYE													
	PERMIAN - P2KZ		Proven	371	18.7	6,932	0.23	0.59	0.848	1.009	na	na	na
	PERMIAN - P2KZ		Probable	371	9.8	3,648	0.23	0.59	0.848	1.009	na	na	na
	DEVONIAN - D3F1		Probable	335	5.9	1,979	0.14	0.78	0.853	1.290	na	na	na
	DEVONIAN - D2IV		Proven	5,530	22.7	125,263	0.14	0.78	0.853	1.229	na	na	na
	DEVONIAN - D2IV		Probable	371	6.6	2,432	0.14	0.78	0.853	1.229	na	na	na
VOSTOCHNO-MARKAYELSKOYE													
	DEVONIAN - D3F1		Proven	309	13.5	4,175	0.16	0.85	0.859	1.318	na	na	na
	DEVONIAN - D3F1		Probable	124	12.3	1,528	0.16	0.85	0.859	1.318	na	na	na
UKHTANEFT													
TURCHANINOVSKOYE													
	DEVONIAN - D3F1AS		Proven	62	6.5	405	0.17	0.68	0.867	1.332	na	na	na
	DEVONIAN - D3F1AS		Probable	1,236	5.1	6,283	0.17	0.68	0.867	1.332	na	na	na
	DEVONIAN - D3F1A2		Proven	432	5.5	2,369	0.17	0.68	0.858	1.332	na	na	na
	DEVONIAN - D3F1A2		Probable	988	6.6	6,486	0.17	0.68	0.858	1.332	na	na	na
	DEVONIAN - D3F1Ia		Proven	1,174	5.4	6,344	0.11	0.76	0.858	1.332	na	na	na
	DEVONIAN - D3F1Ia		Probable	284	21.4	6,088	0.11	0.76	0.858	1.332	na	na	na

KOMITEK SUBSIDIARY
RESERVOIR PARAMETERS

Field Reservoir	Field Area	Category	Area (Acres)	Avg Net Thickness (Feet)	Net Volume (Acre-Feet)	Porosity (fraction)	Oil Saturation (fraction)	Oil Specific Gravity	Oil FVF (RBbl/STB)	Solution Gas Ratio (SCF/STB)	Estimated Original Pressure (psi)	Oil Viscosity (cp)
TURCHANINOVSKOYE (cont)												
DEVONIAN - D3F1lb		Probable	371	9.0	3,356	0.12	0.79	0.851	1.282	na	na	na
DEVONIAN - D2IV		Proven	3,149	21.4	67,245	0.12	0.79	0.851	1.282	na	na	na
DEVONIAN - D2IV		Probable	916	9.3	8,563	0.12	0.79	0.851	1.282	na	na	na
ZAPADNO TURCHANINOVSKOYE												
DEVONIAN - D3F1la		Probable	494	6.6	3,243	0.14	0.84	0.858	1.302	na	na	na
DEVONIAN - D3F1lb		Proven	185	6.6	1,216	0.14	0.84	0.858	1.302	na	na	na
BOYORVOYE												
DEVONIAN - D3F1A		Probable	927	16.4	15,201	0.11	0.69	0.847	1.284	na	na	na
BEZYMYANNOYE												
PERMIAN - P2KZXI		Proven	435	6.0	2,611	0.21	0.51	0.882	1.005	na	na	na
PERMIAN - P2KZXI		Probable	124	4.1	507	0.21	0.51	0.882	1.005	na	na	na
PERMIAN - P2KZXII		Proven	629	14.1	8,876	0.21	0.58	0.868	1.007	na	na	na
PERMIAN - P2KZXII		Probable	45	5.9	267	0.21	0.58	0.868	1.007	na	na	na
PERMIAN - P2KZXIII		Proven	128	8.2	1,049	0.22	0.51	0.890	1.007	na	na	na
PERMIAN - P2U20		Proven	202	10.1	2,040	0.21	0.54	0.889	1.001	na	na	na
PERMIAN 0 P2U17		Proven	14	9.7	136	0.19	0.46	0.934	1.000	na	na	na
SREDNEKOSUSKOYE												
PERMIAN - P2KZXII		Proven	371	11.7	4,358	0.26	0.65	0.891	1.010	na	na	na
PERMIAN - P2KZXII		Probable	226	9.8	2,221	0.26	0.65	0.891	1.010	na	na	na
VOSTOCHNO KOSUSKOYE												
DEVONIAN - D3F1 II		Proven	148	23.0	3,405	0.25	0.74	0.953	1.010	na	na	na
DEVONIAN - D3F1 II		Probable	124	18.0	2,229	0.25	0.74	0.953	1.010	na	na	na
BOLSHEPURGOVSKOYE												
PERMIAN - P2KZ + T		Proven	124	10.6	1,317	0.23	0.51	0.907	1.007	na	na	na
		Probable	62	6.5	405	0.23	0.51	0.907	1.007	na	na	na
LENOVOSKOYE												
DEVONIAN - D3F1A		Probable	988	7.4	7,296	0.16	0.77	0.849	1.305	na	na	na
LUGOVOYE												
PERMIAN - P2KZ		Probable	185	16.4	3,040	0.24	0.56	0.912	1.003	na	na	na
VOKTOCHNO LEMUSKOYE												
PERMIAN - P2KZ26		Probable	247	6.6	1,621	0.21	0.57	0.852	1.010	na	na	na
PERMIAN - P2KZ 25		Probable	62	5.6	345	0.23	0.59	0.852	1.010	na	na	na
GEORGIEVSKOYE												
PERMIAN - P2U 19		Proven	62	16.3	1,013	0.21	0.52	0.888	1.014	na	na	na
PERMIAN - P2U 19		Probable	309	9.8	3,040	0.21	0.52	0.888	1.014	na	na	na
PERMIAN - 2PU 19		Probable	124	6.2	770	0.21	0.51	0.890	1.014	na	na	na
PERMIAN - P2U 17		Proven	62	9.8	608	0.20	0.51	0.882	1.022	na	na	na
PERMIAN - P2U 17		Probable	432	9.9	4,256	0.20	0.51	0.882	1.022	na	na	na
BITECH SILUR												
VOSTOCHNO PYZHELSKOYE												
DEVONIAN D3FM		Proven	556.00	13.1	7,296	0.08	0.90	0.817	1.319	na	na	na
		Probable	998.00	13.0	12,971	0.08	0.90	0.817	1.319	na	na	na
LEKKERSKOYE												
DEVONIAN - D3FM		Proven	988	42.7	42,157	0.10	0.89	0.850	1.259	na	na	na
DEVONIAN - D3FM		Probable	927	26.2	24,321	0.10	0.89	0.850	1.259	na	na	na
SILURIAN - S2		Proven	309	16.4	5,067	0.13	0.80	0.832	1.259	na	na	na
SILURIAN - S2		Probable	927	0.0	24	0.13	0.80	0.832	1.259	na	na	na

KOMITEK SUBSIDIARY
RESERVOIR PARAMETERS

Field Reservoir	Field Area	Category	Area (Acres)	Avg Net Thickness (Feet)	Net Volume (Acre-Feet)	Porosity (fraction)	Oil Saturation (fraction)	Oil Specific Gravity	Oil FVF (RBbl/STB)	Solution Gas Ratio (SCF/STB)	Estimated Original Pressure (psi)	Oil Viscosity (cp)
PYZHELSKOYE												
PERMIAN P1k		Proven	309	6.6	2,027	0.21	0.47	0.832	1.259	na	na	na
PERMIAN P1ar		Proven	803	15.4	12,357	0.19	0.74	0.832	1.259	na	na	na
PERMIAN P1ar		Probable	680	15.2	10,345	0.19	0.74	0.832	1.259	na	na	na
SUBORSKOYE												
PERMIAN P-1		Proven	2,224	0.0	102	0.14	0.74	0.946	1.052	na	na	na
PERMIAN P-1		Probable	1,421	26.2	37,293	0.14	0.74	0.946	1.052	na	na	na
DEVONIAN - D2FM		Proven	124	6.5	811	0.10	0.85	0.820	1.133	na	na	na
DEVONIAN - D2FM		Probable	62	6.5	405	0.10	0.85	0.820	1.133	na	na	na
DEVONIAN - D3FM		Proven	494	8.2	4,054	0.80	0.86	0.863	1.318	na	na	na
DEVONIAN - D3FM		Probable	247	8.2	2,027	0.80	0.86	0.863	1.318	na	na	na
YUZHNO KIRTAELSKOYE												
DEVONIAN - D3		Proven	124	34.0	4,216	0.13	0.85	0.837	1.333	na	na	na
INVESTNAFTA												
USINSKOYE												
D3fm		Proven	1,427	16.7	23,804	0.11	0.84	0.840	1.157	na	na	na
AMKOMI												
LEMEWSKOYE												
P2-XIII		Proven	587	17.5	10,275	0.26	0.63	0.888	1.010	na	na	na
P2-XIII		Probable	772	8.0	6,180	0.26	0.63	0.888	1.010	na	na	na
P2-XI		Proven	230	18.6	4,275	0.26	0.63	0.888	1.010	na	na	na
ISAKOVSKOYE												
P2-28		Proven	108	7.4	801	0.23	0.58	0.857	1.012	na	na	na
P2-28		Probable	63	3.3	205	0.23	0.58	0.857	1.012	na	na	na
PW-25		Proven	278	20.7	5,765	0.22	0.59	0.853	1.012	na	na	na
PW-25		Probable	167	8.8	1,475	0.22	0.59	0.853	1.012	na	na	na
PS-23		Proven	108	11.9	1,288	0.20	0.64	0.845	1.012	na	na	na
PS-23		Probable	93	6.5	608	0.20	0.64	0.845	1.012	na	na	na
P2-10a+b		Proven	124	14.3	1,768	0.22	0.56	0.890	1.004	na	na	na
P2-10a+b		Probable	112	6.6	735	0.22	0.56	0.890	1.004	na	na	na
P2-8		Proven	16	4.5	72	0.22	0.59	0.896	1.004	na	na	na
P1 a+s		Proven	46	11.3	521	0.16	0.74	0.890	1.020	na	na	na
NORTH ARESSKOYEL												
F2D3fm1		Proven	1,080	17.4	18,773	0.09	0.74	0.840	1.078	na	na	na
F2D3fm1		Probable	1,373	8.2	11,220	0.09	0.74	0.840	1.078	na	na	na
TYRYSHEVSKOYE												
D3fm1F0		Proven	454	15.2	6,884	0.12	0.84	0.844	1.099	na	na	na
D3fm1F0		Probable	1,041	15.6	16,254	0.12	0.84	0.844	1.099	na	na	na
UPPER KOSEWSKOYE												
P2-XII		Proven	432	20.4	8,796	0.24	0.59	0.876	1.010	na	na	na
P2-XII		Probable	297	15.7	4,650	0.24	0.59	0.876	1.010	na	na	na
WEST ARESSKOYE												
F0D3fm1		Proven	91	9.9	897	0.10	0.85	0.864	1.096	na	na	na
F0D3fm1		Probable	432	5.8	2,497	0.10	0.85	0.864	1.096	na	na	na
D3f3		Proven	274	16.4	4,487	0.10	0.93	0.840	1.096	na	na	na
D3f3		Probable	491	10.9	5,348	0.10	0.93	0.840	1.096	na	na	na
KYRTAYESLKOYE												
D2st		Proven	2,093	131.0	274,266	0.10	0.81	0.837	1.582	na	na	na
D2st		Probable	1,919	114.8	220,302	0.10	0.81	0.837	1.582	na	na	na
NORTHEN ARESSKOYE												
D2fm1		Proven	546	23.3	12,740	0.08	0.80	0.861	1.057	na	na	na
D2fm1		Probable	3,902	17.6	68,746	0.08	0.80	0.861	1.057	na	na	na

ARKHANGELSKGEOLDOBYCHA SUBSIDIARY
RESERVOIR PARAMETERS

Field	Reservoir	Field Area	Category	Area (Acres)	Avg Net Thickness (Feet)	Net Volume (Acre-Feet)	Porosity (fraction)	Permeability (md)	Oil Saturation (fraction)	Oil Specific Gravity	Oil FVF (RBbl/STB)	Solution Gas Ratio (SCF/STB)	Estimated Original Pressure (psi)	Oil Viscosity (cp)
ARDALINSKOYE														
	D3fm		Proven	4,054	81.4	329,870	0.11	436	0.83	0.845	1.205	361	5,207	1.14
DYUSUSHEVSKOYE														
	D3fm		Proven	856	45.9	39,316	0.10	335	0.84	0.860	1.290	444	5,290	1.73
	D3fm		Probable	1,101	34.2	37,629	0.10	335	0.84	0.860	1.290	444	5,290	1.73
EAST-GORINSKOYE														
	Cm2		Proven	262	27.3	7,141	0.18	2,060	0.84	0.834	1.111	37	2,451	3.59
EAST-GORINSKOYE II														
	Cm2		Proven	168	19.0	3,200	0.17	2,100	0.88	0.836	1.031	37	2,455	3.59
EAST-KHARYAGINSKOYE														
	D3fm-Main		Proven	747	35.7	26,695	0.10	1,000	0.90	0.840	1.205	466	5,137	8.99
	D3fm-Main		Probable	1,232	29.3	36,086	0.10	1,000	0.90	0.840	1.205	466	5,137	8.99
	D3fm-W.#7		Proven	32	15.1	484	0.09	1,000	0.89	0.858	1.205	476	5,191	9.18
	D3fm-W.#7		Probable	165	11.9	1,971	0.09	1,000	0.89	0.858	1.205	476	5,191	9.18
EAST-KOLVINSKOYE														
	D3fm		Proven	428	47.2	20,220	0.11	280	0.71	0.869	1.198	353	5,318	1.17
	D3fm		Probable	381	49.9	19,012	0.11	280	0.71	0.869	1.198	353	5,318	1.17
	D3f2-1		Proven	105	47.8	5,005	0.11	280	0.71	0.819	1.198	353	5,318	1.11
	D3f2-2		Proven	105	4.4	457	0.11	280	0.71	0.819	1.198	353	5,318	1.11
	S1		Proven	105	66.3	6,944	0.11	280	0.71	0.831	1.198	353	5,318	1.12
INZYREISKOYE														
	D3src(reef)		Proven	534	148.7	79,396	0.10	630	0.71	0.857	1.220	356	5,123	1.06
	D3src(reef)		Probable	1,419	127.6	181,028	0.10	630	0.71	0.857	1.220	356	5,123	1.06
	D3f1		Proven	107	67.3	7,180	0.13	286	0.84	0.823	1.235	670	6,498	24.53
	D2		Proven	480	108.1	51,870	0.11	58	0.81	0.823	1.444	na	6,498	24.53
KHYLCHUYUSKOYE														
	T1-II		Probable	840	6.6	5,513	0.21	3	0.44	0.836	1.163	399	2,489	2.17
	T1-II		Proven	309	10.8	3,344	0.21	2	0.47	0.840	1.190	401	2,429	2.18
	T1-II		Probable	1,297	7.5	9,789	0.21	2	0.47	0.840	1.190	401	2,429	2.18
	T1-I		Proven	62	6.6	405	0.17	24	0.61	0.840	1.190	371	2,519	4.20
	T1-I		Probable	4,695	19.7	92,421	0.17	24	0.61	0.840	1.190	371	2,519	4.20
	P2-8		Proven	1,544	14.8	22,801	0.18	40	0.61	0.840	1.136	341	2,639	4.20
	P2-8		Probable	1,606	9.8	15,809	0.18	40	0.61	0.840	1.136	341	2,639	4.20
	P2-8		Proven	494	21.0	10,377	0.19	10	0.61	0.840	1.136	341	2,534	4.20
	P2-8		Probable	556	7.9	4,378	0.19	10	0.61	0.840	1.136	341	2,534	4.20
	P2-6		Proven	2,039	22.0	44,812	0.17	2	0.56	0.847	1.136	334	2,699	3.07
	P2-6		Probable	1,347	15.7	21,180	0.17	2	0.56	0.847	1.136	334	2,699	3.07
	P1-I		Proven	185	9.2	1,702	0.19	2	0.65	0.835	1.190	311	2,879	1.78
	P1-I		Probable	463	6.6	3,040	0.19	2	0.65	0.835	1.190	311	2,879	1.78
	P1ar		Proven	1,668	24.0	39,948	0.21	2	0.65	0.852	1.149	299	3,051	1.83
	P1ar		Probable	2,718	22.6	61,533	0.21	2	0.65	0.852	1.149	299	3,051	1.83
MEDYNSKOYE														
	D1p		Proven	214	12.5	2,668	0.14	12	0.91	0.841	1.320	649	5,061	0.87
	D1 I		Proven	107	26.2	2,808	0.09	12	0.79	0.828	1.149	129	6,122	1.49

ARKHANGELSKGEOLDOBYCHA SUBSIDIARY
RESERVOIR PARAMETERS

Field	Reservoir	Field Area	Category	Area (Acres)	Avg Net Thickness (Feet)	Net Volume (Acre-Feet)	Porosity (fraction)	Permeability (md)	Oil Saturation (fraction)	Oil Specific Gravity	Oil FVF (RBbl/STB)	Solution Gas Ratio (SCF/STB)	Estimated Original Pressure (psi)	Oil Viscosity (cp)
MEZHDURECHENSKOYE														
	P1a+s		Proven	53	39.4	2,101	0.09	50	0.73	0.903	1.010	36	2,192	2.17
MYADSEYSKOYE														
	D3f		Proven	53	83.3	4,448	0.11	286	0.79	0.884	1.075	149	3,763	3.80
	D1 - A		Probable	62	28.9	1,784	0.07	10	0.70	0.847	1.316	654	5,801	0.88
	D1 - B		Proven	62	25.9	1,601	0.05	10	0.70	0.847	1.316	654	5,838	0.88
	D1 - V		Proven	62	48.9	3,020	0.06	10	0.70	0.847	1.316	654	5,924	0.88
	D1 - G		Proven	62	34.4	2,128	0.06	10	0.70	0.847	1.316	654	5,966	0.88
NORTH-SAREMBOYSKOYE														
	D1-L		Proven	5,004	98.2	491,410	0.06	10	0.77	0.882	1.119	238	4,460	5.73
	D1-L		Probable	4,571	82.0	374,953	0.06	10	0.77	0.882	1.119	238	4,460	5.73
	D1L-I		Proven	1,017	16.1	16,343	0.08	10	0.86	0.861	1.100	172	4,723	5.25
	D1L-I		Probable	6,035	15.6	94,042	0.08	10	0.86	0.861	1.100	172	4,723	5.25
	S2		Proven	53	28.2	1,506	0.09	10	0.82	0.846	1.149	273	6,039	2.17
NOVO-ISKRINSKOYE														
	Cm2		Proven	74	9.2	681	0.16	270	0.82	0.836	1.111	89	2,647	2.21
OSHKOTYNSKOYE														
	DF-4		Proven	428	78.4	33,559	0.08	495	0.72	0.787	1.275	488	4,952	0.94
	DF-4		Probable	1,319	10.6	14,016	0.08	495	0.72	0.787	1.275	488	4,952	0.94
	DF-6		Proven	803	20.3	16,326	0.07	475	0.82	0.787	1.275	431	4,893	0.98
PEREVOZNAYA														
	D1-G		Proven	320	18.4	5,884	0.05	10	0.70	0.847	1.319		2,331	0.85
	D1-D		Proved	320	9.2	2,942	0.05	10	0.70	0.847	1.319		2,331	0.85
PESCHANOOZERSKOYE														
	T1cb-G2		Proven	161	31.2	5,006	0.20	27	0.44	0.787	1.408	928	2,223	0.44
	T1cb-G2		Probable	371	21.7	8,038	0.20	27	0.44	0.787	1.408	928	2,223	0.44
	T1cb-V6+7		Proven	694	12.5	8,650	0.27	27	0.64	0.781	1.515	1,022	2,475	0.43
	T1cb-V6+7		Probable	560	10.6	5,926	0.27	27	0.64	0.781	1.515	1,022	2,475	0.43
	T1cb-V4		Proven	1,250	25.5	31,820	0.23	27	0.59	0.783	1.389	1,011	2,487	0.41
	T1cb-V4		Probable	2,772	13.5	37,333	0.23	27	0.59	0.783	1.389	1,011	2,487	0.41
	T1cb-V1		Proven	5,764	30.3	174,895	0.23	27	0.54	0.785	1.333	669	2,277	0.39
	T1cb-V1		Probable	476	17.4	8,280	0.23	27	0.54	0.785	1.333	669	2,277	0.39
	T1cb-V		Proven	1,014	30.2	30,610	0.22	27	0.58	0.783	1.282	1,011	2,263	0.39
	T1cb-V		Probable	4,108	25.0	102,605	0.22	27	0.58	0.783	1.282	1,011	2,263	0.39
SEDYAGINSKOYE														
	P1ar		Proven	161	15.1	2,424	0.20	73	0.75	0.893	1.099	111	1,350	22.76
	P1ar		Probable	1,029	11.6	11,898	0.20	73	0.75	0.893	1.099	111	1,350	22.76
	P1ar		Proven	1,017	49.2	50,053	0.13	50	0.78	0.893	1.099	111	1,442	22.76
	C1sr		Proven	53	23.0	1,226	0.16	35	0.82	0.854	1.136	212	2,294	8.54
	D1kn+sr		Proven	1,070	43.6	46,688	0.15	12	0.92	0.866	1.070	107	4,363	5.71
	D1kn+sr		Probable	1,467	35.9	52,709	0.15	12	0.92	0.866	1.070	107	4,363	5.71

ARKHANGELSKGEOLDOBYCHA SUBSIDIARY
RESERVOIR PARAMETERS

Field	Reservoir	Field Area	Category	Area (Acres)	Avg Net Thickness (Feet)	Net Volume (Acre-Feet)	Porosity (fraction)	Permeability (md)	Oil Saturation (fraction)	Oil Specific Gravity	Oil FVF (RBbl/STB)	Solution Gas Ratio (SCF/STB)	Estimated Original Pressure (psi)	Oil Viscosity (cp)
SOUTH-KHYLCHUYUSKOYE														
	P1k -2+3		Proven	556	12.1	6,749	0.20	73	0.58	0.851	1.176	433	2,864	2.05
	P1k -2+3		Probable	494	9.8	4,864	0.20	73	0.58	0.851	1.176	433	2,864	2.05
	P1a-s(reef)		Proven	7,333	162.0	1,187,954	0.18	73	0.87	0.850	1.220	508	3,388	2.04
	P1a-s(reef)		Probable	3,330	65.6	218,486	0.18	73	0.87	0.850	1.220	508	3,388	2.04
TABROVOYAKHINSKOYE														
	D3f		Proven	107	16.4	1,751	0.07	990	0.94	0.837	1.099	248	5,996	8.74
	D3f		Probable	3,128	8.6	26,912	0.07	990	0.94	0.837	1.099	248	5,996	8.74
TEDINSKOYE														
	D3fm		Proven	160	4.6	735	0.16	40	0.94	0.923	1.136	na	4,711	6.27
	D3fm-III (w)		Proven	107	147.6	15,797	0.12	50	0.86	0.871	1.136	402	4,850	1.74
	D3fm-III (w)		Probable	122	58.0	7,073	0.12	50	0.86	0.871	1.136	402	4,850	1.74
	D3fm-III(c)		Proven	107	127.9	13,690	0.16	880	0.92	0.904	1.124	254	4,744	8.68
	D3fm-III(c)		Probable	526	64.6	33,996	0.16	880	0.92	0.904	1.124	254	4,744	8.68
	D3fm-III (n+s)		Proven	1,174	99.7	117,063	0.16	510	0.91	0.924	1.111	219	4,628	9.97
	D3fm-III (n+s)		Probable	965	48.6	46,912	0.16	510	0.91	0.924	1.111	219	4,628	9.97
	D3fm-II		Proven	374	60.7	22,712	0.10	110	0.81	0.859	1.205	395	4,859	1.79
	D3fm-II		Probable	102	2.5	255	0.10	110	0.81	0.859	1.205	395	4,859	1.79
	D3fm-I		Proven	160	19.0	3,036	0.13	790	0.85	0.853	1.266	427	4,939	1.36
TOBOYSKOYE														
	D3f		Proven	2,140	77.8	166,392	0.10	780	0.90	0.920	1.075	151	4,194	15.73
	D3f		Probable	2,988	81.4	243,037	0.10	780	0.90	0.920	1.075	151	4,194	15.73
	D1p		Proven	856	12.8	10,953	0.12	10	0.64	0.840	1.316	648	5,113	0.87
	D1p		Probable	909	11.8	10,740	0.12	10	0.64	0.840	1.316	648	5,113	0.87
	D1-A		Proven	62	26.9	1,662	0.07	10	0.70	0.847	1.316	654	6,081	0.88
	D1-B		Proven	62	23.6	1,459	0.06	10	0.70	0.847	1.316	654	6,127	0.88
	D1-B		Probable	62	23.6	1,459	0.06	10	0.70	0.847	1.316	654	6,127	0.88
	D1-V		Proven	62	48.9	3,020	0.06	10	0.70	0.847	1.316	654	6,150	0.88
	D1-G		Proven	124	26.9	3,324	0.06	10	0.70	0.847	1.316	654	6,210	0.88
	D1-D		Proven	53	19.7	1,051	0.07	50	0.70	0.847	1.316	654	6,256	0.88
TORAVEYSKOYE														
	T1+2		Proven	3,024	14.5	43,850	0.25	27	0.75	0.961	1.111	176	1,646	16.01
	T1+2		Probable	1,202	11.9	14,272	0.25	27	0.75	0.961	1.111	176	1,646	16.01
	T1 - 1+2		Proven	1,418	32.0	45,315	0.27	150	0.56	0.919	1.064	114	1,730	15.30
	T1 - 1+2		Probable	1,010	27.1	27,361	0.27	150	0.56	0.919	1.064	114	1,730	15.30
	T2-II		Proven	2,707	46.9	127,030	0.28	27	0.65	0.948	1.111	na	1,514	32.29
	T2-II		Probable	1,852	43.1	79,744	0.28	27	0.65	0.948	1.111	na	1,514	32.29
	T2-I		Proven	2,710	40.1	108,577	0.28	27	0.65	0.948	1.111	na	1,514	32.29
	T2-I		Probable	1,112	39.3	43,701	0.28	27	0.65	0.948	1.111	na	1,514	32.29
	T1-IV		Proven	1,418	32.0	45,315	0.27	150	0.56	0.919	1.064	na	1,730	15.30
	T1-IV		Probable	1,010	27.1	27,361	0.27	150	0.56	0.919	1.064	na	1,730	15.30
	T1-III		Proven	2,474	30.4	75,188	0.26	140	0.56	0.915	1.064	na	1,799	15.78
	T1-III		Probable	980	27.3	26,745	0.26	140	0.56	0.915	1.064	na	1,799	15.78
	T1-II		Proven	349	8.7	3,050	0.25	90	0.55	0.892	1.136	na	1,949	6.13
	T1-I		Proven	1,652	14.1	23,277	0.25	90	0.55	0.892	1.136	na	1,949	6.13
	T1-I		Probable	883	9.2	8,082	0.25	90	0.55	0.892	1.136	na	1,949	6.13
	P1		Proven	3,042	111.3	338,582	0.16	73	0.80	0.902	1.099	210	2,358	6.86
	P1		Probable	2,833	77.6	219,977	0.16	73	0.80	0.902	1.099	210	2,358	6.86

ARKHANGELSKGEOLDOBYCHA SUBSIDIARY
RESERVOIR PARAMETERS

Field	Reservoir	Field Area	Category	Area (Acres)	Avg Net Thickness (Feet)	Net Volume (Acre-Feet)	Porosity (fraction)	Permeability (md)	Oil Saturation (fraction)	Oil Specific Gravity	Oil FVF (RBbl/STB)	Solution Gas Ratio (SCF/STB)	Estimated Original Pressure (psi)	Oil Viscosity (cp)
UST-TALOTINSKOYE														
	D1p		Proven	53	41.1	2,194	0.11	20	0.75	0.868	1.157	670	5,158	0.90
VARANDEYSKOYE														
	T2+1		Proven	8,504	17.2	146,537	0.25	27	0.66	0.947	1.075	173	1,979	8.99
	T2+1		Probable	587	8.7	5,083	0.25	27	0.66	0.947	1.075	173	1,979	8.99
	T1-IV		Proven	1,410	14.8	20,821	0.23	46	0.52	0.945	1.075	na	2,204	8.97
	T1-IV		Probable	1,382	13.0	18,006	0.23	46	0.52	0.945	1.075	na	2,204	8.97
	T1-III		Proven	4,673	42.5	198,411	0.23	46	0.52	0.945	1.075	na	2,204	8.97
	T1-III		Probable	1,418	21.2	30,015	0.23	46	0.52	0.945	1.075	na	2,204	8.97
	T1-1		Proven	2,781	9.6	26,780	0.18	27	0.63	0.906	1.124	251	2,331	4.87
	T1-1		Probable	1,395	10.6	14,812	0.18	27	0.63	0.906	1.124	251	2,331	4.87
	P1		Proven	3,249	55.7	180,985	0.15	120	0.80	0.902	1.099	212	2,474	6.51
	P1		Probable	1,001	24.6	24,625	0.15	120	0.80	0.902	1.099	212	2,474	6.51
WEST-LEKKEYAGINSKOYE														
	D1kn+sr		Proven	53	21.7	1,156	0.13	12	0.81	0.872	1.050	97	3,835	14.91
	D2		Proven	53	12.5	666	0.11	12	0.69	0.874	1.050	101	3,950	15.99
	D1 l		Proven	2,515	59.1	148,496	0.09	12	0.70	0.881	1.200	311	4,721	5.90
	D1 l		Probable	13,367	71.2	952,322	0.09	12	0.70	0.881	1.200	311	4,721	5.90
WEST-RAKITZNSKOYE														
	Cm2		Proven	5	9.6	48	0.16	270	0.83	0.832	1.111	89	2,699	2.20
YAREYUSKOYE														
	P1 ar-II		Proven	2,224	22.0	48,886	0.12	3,200	0.70	0.842	1.149	296	3,005	1.79
	P1 ar-II		Probable	7,104	21.3	151,501	0.12	3,200	0.70	0.842	1.149	296	3,005	1.79
	P1 ar-I		Proven	1,236	18.7	23,105	0.11	73	0.68	0.847	1.149	3	3,025	1.80
	P1 ar-I		Probable	3,027	19.4	58,594	0.11	73	0.68	0.847	1.149	3	3,025	1.80
	P1 a-s		Proven	4,077	40.4	164,534	0.12	73	0.81	0.847	1.149	310	3,107	2.03
	P1 a-s		Probable	7,413	26.2	194,570	0.12	73	0.81	0.847	1.149	310	3,107	2.03
YURIY ROSSIKHIN														
	D3f1		Proven	53	91.9	4,903	0.10	286	0.80	0.817	1.493	1,024	6,585	0.65
	D2		Proven	53	63.3	3,380	0.10	810	0.81	0.805	1.515	958	6,822	0.66

Exhibit 60

NORTH CASPIAN SEA - OFFSHORE - RUSSIAN FEDERATION
RESERVOIR PARAMETERS

Field	Reservoir	Field Area	Category	Area (Acres)	Avg Net Thickness (Feet)	Net Volume (Acre-Feet)	Porosity (fraction)	Permeability (md)	Oil Saturation (fraction)	Oil Specific Gravity	Oil FVF (RBbl/STB)	Solution Gas Ratio (SCF/STB)	Estimated Original Pressure (psi)	Oil Viscosity (cp)
KORCHAGINA														
OIL														
	Necomian SS	Main	Proven	3,657	52.2	190,960	0.244	na	0.732	0.807	1.266	na	na	na
	Necomian SS		Probable	10,082	43.2	435,549	0.244	na	0.732	0.807	1.266	na	na	na
	Volzhsky	West	Proven	964	38.3	36,887	0.197	na	0.795	0.819	1.333	na	na	na
	Volzhsky		Probable	1,310	33.3	43,575	0.197	na	0.795	0.819	1.333	na	na	na

Field	Reservoir	Field Area	Category	Area (Acres)	Avg Net Thickness (Feet)	Net Volume (Acre-Feet)	Porosity (fraction)	Permeability (md)	Gas Saturation (fraction)	Z Factor Inverse	Reservoir Pressure PSI	Liquird Content g perm m3
KORCHAGINA												
GAS												
	Necomian SS	Main	Proven	9,341	104.0	971,441	0.235	na	0.754	1.130	2400	76
	Necomian SS		Probable	4,423	58.7	259,760	0.235	na	0.754	1.130	2400	76
	Volzhsky	West	Proven	815	26.6	21,670	0.190	na	0.870	1.140	2448	77

Part 11 – ADDITIONAL INFORMATION

CREATION OF THE COMPANY AND DESCRIPTION OF ITS CHARTER

This section provides a summary of our initial privatisation, the material provisions of our charter and certain provisions of Russian law relating to our organisation and operation.

INITIAL PRIVATISATION

Our state-owned predecessor, International Oil Concern LangepasUraiKogalymneft, was established on November 25, 1991. We were established as an open joint stock company in connection with our privatisation by the Russian Government pursuant to Presidential Decree 1403, dated November 17, 1992 under which the Government adopted Resolution 299, dated April 5, 1993, approving our charter. As an open joint stock company we operate under the provisions of our charter and the Federal Law on Joint Stock Companies of the Russian Federation. Our initial charter was registered with the Moscow Registration Chamber on April 22, 1993 with a registration number of 24020. As set forth in Resolution 299 the Russian government contributed to us 51% of the voting shares (representing 38% of the economic interest) of 15 enterprises.

In 1994 the Russian Government disposed of 51% of our share capital through (i) an exchange of shares for vouchers tendered by private investors in Russia, (ii) sales to private investors in Russia for cash and (iii) the distribution of shares to employees. Following this initial phase of privatisation we owned approximately 51% of the voting shares (representing approximately 38% of the economic interests) in each of our major oil production, oil refining and regional distribution subsidiaries. In 1995 pursuant to Presidential Decree 327, dated April 1, 1995, subsequent decisions of the Russian Government, and a resolution passed by our shareholders at the 1995 annual shareholders' meeting, we commenced the acquisition through the issuance and exchange of our shares of all the shares in each of our 15 subsidiaries. In addition, pursuant to Governmental Resolution No. 861 dated September 1, 1995, the Russian Government authorised the exchange of our newly issued shares for shares of nine additional enterprises.

OBJECTIVES OF THE COMPANY

Our principal activities are set out in full in Article 3 of our charter. In summary they include the following:

- the exploration of oil and gas fields and other deposits, the drilling of wells, the extraction, transportation and refining of oil and gas, the production of petroleum products, petrochemical and other products (including consumer goods and services) and the sale of oil, petroleum products and other refined products;
- the construction, upgrade and operation of oil and gas extraction, transportation and refining facilities;
- research and development activities;
- investment and financial activities; and
- any other types of activities that do not contravene the objectives set forth in our charter and that are not prohibited by the laws of the Russian Federation.

MANAGEMENT OF THE COMPANY

The charter provides for our management, governance and control by the following:

- General Shareholders' Meetings;
- the Board of Directors;
- the President;
- Management Committee; and
- Audit Commission.

GENERAL SHAREHOLDERS' MEETING

The powers of a shareholders' meeting are set forth in the Federal Law on Joint Stock Companies and in our charter. Among the issues that our shareholders have the power to decide are:

- charter amendments; provided, however, that our Board of Directors may amend the charter following an increase in our share capital or in connection with the creation or liquidation of branches or representative offices;
- the initiation of a reorganisation or liquidation;
- the election and removal of the members of our Board of Directors;
- the appointment and removal of our President;
- the election and removal of members of our Audit Commission;
- the determination of the number, nominal value and type of authorised shares and rights granted by such shares;
- an increase in our share capital by increasing the nominal value of our shares or through a private placement of additional shares;
- an increase in our share capital through a public offering of additional ordinary shares if the amount of ordinary shares to be issued exceeds 25% of our previously issued ordinary shares;
- a decrease of our share capital;
- the private placement of securities convertible into our shares;
- the public offering of securities convertible into our ordinary shares if the amount of shares to be issued upon conversion of such convertible securities exceeds 25% of our previously issued ordinary shares;
- the approval of transactions with interested parties, as defined under "– Interested Party Transactions";
- the approval of major transactions, as defined under "– Major Transactions";
- the approval of our annual report and accounts and a distribution of profits and losses;
- the approval of our independent auditors;
- the approval of our participation in holding companies, financial and industrial groups and associations of commercial enterprises; and
- the approval of internal regulations governing the activities of our management and control bodies.

Voting at a shareholders' meeting is generally on the principle of one vote per ordinary share, with the exception of the election of the Board of Directors, which is done through cumulative voting. Cumulative voting is a type of voting in which a shareholder may cast a number of votes for one or more nominees for the Board of Directors of an amount equal to the number of shares held by such shareholder multiplied by the number of directors to be elected. This method of voting enhances the ability of minority shareholders to obtain representation on our Board of Directors. The Russian Federation appoints and authorises a representative to vote its ordinary shares at shareholders' meetings. Currently, the Russian Federation has authorised Vladimir Vladimirovich Malin, who is the Chairman of the Russian Federal Property Fund and a member of our Board of Directors, to vote its shares at our shareholders' meetings.

Decisions are generally passed by an affirmative vote of a majority of the voting shares present at a shareholders' meeting.

The Federal Law on Joint Stock Companies and our charter require a 75% affirmative vote of the voting shares present at a shareholders' meeting to approve the following:

- charter amendments;
- a reorganisation or liquidation;
- a determination of the number, nominal value and type of authorised shares and the rights granted by such shares;
- the approval of major transactions involving assets with a value exceeding 50% of the value of OAO LUKOIL's assets;

- an increase in our share capital through (i) a public offering of additional ordinary shares if the amount of such newly issued ordinary shares exceeds 25% of our previously issued ordinary shares or (ii) a private placement of additional shares;
- the public offering of securities convertible into our ordinary shares if the amount of shares to be issued upon conversion of such convertible securities exceeds 25% of our previously issued ordinary shares or the private placement of securities convertible into our shares; and
- the acquisition of shares from our shareholders.

The quorum requirement for our shareholders' meetings is met if shareholders owning more than 50% of our issued voting shares are present. If this quorum requirement is not met, another shareholders' meeting must be scheduled, in which case the quorum requirement is met if shareholders owning at least 30% of the issued voting shares are present at that meeting.

The annual shareholders' meeting must be convened by our Board of Directors between March 1 and June 30 of each year and the agenda must include the following items:

- election of members of the Board of Directors;
- election of members of the Audit Commission;
- approval of the annual report, balance sheet and profit and loss statement;
- approval of any distribution of profits or losses; and
- approval of an independent auditor.

Extraordinary shareholders' meetings may be called by the Board of Directors on its own initiative or at the request of the Audit Commission, the independent auditor or a shareholder or group of shareholders owning in the aggregate at least 10% of the issued voting shares as of the date of the request.

A shareholder or a group of shareholders owning in the aggregate at least 2% of our issued voting shares may add their proposals to the agenda of the annual shareholders' meeting and may nominate candidates to serve as our President or as members of our Board of Directors or Audit Commission. Any such shareholders must provide us with agenda proposals or nominations within thirty calendar days of the end of the fiscal year preceding such annual shareholders' meeting.

The rights of holders of our DRs to vote in respect of resolutions at a shareholders' meeting are described in paragraph 12 of the Terms and Conditions of the ADRs, Condition 12 of the Terms and Conditions of the Series A GDRs and Condition 12 of the Terms and Conditions of the Series B GDRs (see "Part 9 – The Depositary Receipts").

NOTICE AND PARTICIPATION

All shareholders entitled to participate in a shareholders' meeting must be notified of a meeting no less than 20 days prior to the date of the meeting. However, if our reorganisation is an agenda item, shareholders must be notified at least 30 days prior to the date of the meeting, and if it is an extraordinary shareholders' meeting to elect our Board of Directors by cumulative vote, shareholders must be notified at least 50 days prior to the date of the meeting. The list of shareholders entitled to participate in a shareholders' meeting will be compiled based on data contained in our shareholder register on a date to be established by the Board of Directors. The date that our Board of Directors establishes for the compilation of the list of shareholders entitled to participate in a shareholders' meeting must not be (i) earlier than the date of adoption of the resolution to hold a shareholders' meeting and (ii) more than 50 days before the date of the meeting. In the case of an extraordinary shareholders' meeting to elect our Board of Directors, such list must be compiled within the 65-day period prior to the meeting.

BOARD OF DIRECTORS

Members of our Board of Directors are elected by a majority vote of shareholders at our annual shareholders' meeting by cumulative voting. Directors are elected for one-year terms and may be re-elected an unlimited number of times. Our Board of Directors has the authority to make overall management decisions for us, except those matters reserved to our shareholders.

The Federal Law on Joint Stock Companies requires at least a seven-member Board of Directors for an open joint stock company with more than 1,000 holders of ordinary shares, and at least a nine-member Board of Directors for an open joint stock company with more than 10,000 holders of ordinary shares. Our charter provides that our Board of Directors consists of eleven members.

The Federal Law on Joint Stock Companies prohibits a Board of Directors from acting upon issues that fall within the exclusive competence of the general shareholders' meeting. Our Board of Directors has the exclusive power to decide the following issues:

- establishing strategic priorities;
- organising shareholders' meetings, including approving an agenda and determining the date of record for shareholders entitled to participate;
- increasing our share capital through the issuance of additional shares in a public offering; provided, however, that (i) the number of shares to be issued in such a public offering is less than or equal to 25% of our previously issued ordinary shares and (ii) the shares to be issued in such a public offering are within the total number and categories of authorised shares set forth in our charter;
- approving the placement of bonds and other securities other than the placement of (i) securities convertible into our shares in a closed subscription and (ii) securities convertible into our ordinary shares in a public offering in which the number of ordinary shares to be issued upon conversion of such convertible securities exceeds 25% of our previously issued ordinary shares, both of which require shareholder approval;
- determining the market value of our property and our securities for the purposes of their issuance and repurchase;
- acquisition of our shares, bonds and other securities;
- electing members of our Management Committee, determining the terms and conditions, including remuneration, of our service agreements with members of our Management Committee and our President, and recommending to our shareholders the remuneration of members of our Audit Commission and the fees of our external auditors;
- recommending the amount of the dividend on shares and the procedure for payment thereof;
- using our reserve and other funds;
- approving major and interested-party transactions where required by the Federal Law on Joint Stock Companies;
- approving our internal regulations other than the internal regulations, which are within the exclusive competence of our shareholders' meetings or the management bodies;
- creating branches and representative offices;
- reviewing and preliminarily approving the annual report and accounts and interim reports prepared by the Management Committee and submitting them to our shareholders for their approval;
- forming committees of the Board of Directors; and
- approving our registrar, determining the terms and conditions of our agreement with the registrar and its termination.

The Federal Law on Joint Stock Companies and our charter generally require the affirmative vote of a majority of our directors present at a meeting for an action to pass. A quorum exists if at least 50% of our directors are present. Russian law requires a qualified vote or unanimous vote of all of our directors for certain decisions, such as the approval of major transactions, interested-party transactions and the issuance of additional shares.

THE PRESIDENT

Our shareholders appoint our President, who is also the Chairman of our Management Committee, for a term of five years. Our Board of Directors determines the remuneration payable to the President and the terms and conditions of his employment. The President is responsible for the day-to-day management of our activities.

MANAGEMENT COMMITTEE

The size of our Management Committee is determined by our Board of Directors and currently consists of 22 members. Members of the Management Committee are nominated by the Chairman of the Management Committee and confirmed by our Board of Directors for a term of one year. The Management Committee is our collective executive body and, under the direction of its Chairman, is responsible for our day-to-day management.

AUDIT COMMISSION

The Audit Commission verifies the accuracy of our financial reporting under Russian law and generally supervises our financial activity. The members of our Audit Commission are elected at each annual shareholders' meeting for a term of one year. Members of our Audit Commission may be shareholders, but may not be members of our Board of Directors or Management Committee. Remuneration payable to the members of our Audit Commission is recommended by the Board of Directors and approved by our shareholders.

The Audit Commission has the right to call an extraordinary shareholders' meeting and may conduct an audit of our financial and business records at any time. In addition it must conduct an audit if requested by a majority of the shareholders at a shareholders' meeting or at the request of the Board of Directors, the President or any shareholder or group of shareholders owning at least 10% of our voting shares. Our Audit Commission currently has three members. Currently, the members of our Audit Commission are Svetlana Alekseyevna Gulyukina, Vladimir Nikolayevich Nikitenko and Tatiana Sergeevna Sklyarova.

RIGHTS OF THE HOLDERS OF ORDINARY SHARES

Each fully paid ordinary share, except for treasury shares, gives its holder the right to:

- transfer shares without the consent of us or other shareholders;
- receive dividends;
- participate in shareholders' meetings and vote on matters to be decided thereby;
- transfer voting rights to its representative on the basis of a power of attorney;
- if holding, alone or with other holders, not less than 2% of our issued voting shares, make proposals to the Board of Directors for the inclusion of matters on the agenda for shareholders' meetings and nominate candidates to serve as our President or as members of our Board of Directors, Management Committee, Audit Commission and Counting Commission;
- if holding, alone or with other holders, not less than 10% of the issued voting shares, demand the calling of an extraordinary shareholders' meeting or an unscheduled audit by the Audit Commission;
- acquire shares by exercising preemptive rights that arise upon the issuance of new shares;
- upon our liquidation, receive a proportionate amount of our property after the fulfillment of our obligations;
- have access to our documents as provided by the Federal Law on Joint Stock Companies and receive copies of such documents for a reasonable fee; and
- exercise any other rights granted to a holder of our ordinary shares in our charter or under Russian law.

Dividends and Dividend Rights

Our Board of Directors recommends the payment of annual dividends to our shareholders, who approve such annual dividends by a majority vote at the annual shareholders' meeting. The annual dividend approved at the shareholders' meeting may not be more than the amount recommended by the Board of Directors. Annual dividends are distributed to shareholders entitled to participate in the annual shareholders' meeting. Dividends are not paid on treasury shares.

The Federal Law on Joint Stock Companies allows us to pay dividends to our shareholders only out of net profits calculated under Russian accounting principles and as long as the following conditions are met:

- the share capital has been paid in full;
- the value of our net assets, minus the proposed dividend payment, is not less than, and would remain following the payment of dividends, not less than the sum of our share capital and reserve fund;

- we have repurchased all shares from shareholders who have exercised their right to demand repurchase; and
- we are not, and would not become as a result of the payment of dividends, insolvent.

At a meeting on April 11, 2002, our Board of Directors recommended to our shareholders the payment of dividends of 15 rubles per ordinary share. At our annual shareholders' meeting on June 27, 2002, our shareholders approved the payment of dividends of 15.00 rubles ($0.50) per ordinary share.

SHARE CAPITAL INCREASE

We may increase our share capital by issuing new shares or increasing, by using net income, the nominal value of shares that we have already issued. Any decision to increase our share capital through the issuance of shares in a public offering where the number of shares to be issued is greater than 25% of the number of our previously issued ordinary shares or through the issuance of shares in a private placement requires a 75% vote of our shareholders present at a shareholders' meeting. A decision to increase our share capital in a public offering where the number of shares to be issued is less than or equal to 25% of the number of our previously issued ordinary shares requires the unanimous vote of all of our directors. A decision to increase our share capital by increasing the nominal value of our shares requires a simple-majority vote of our shareholders at a shareholders' meeting.

The Federal Law on Joint Stock Companies requires newly issued shares to be sold at market value, except in the following limited circumstances:

- where existing shareholders exercise a preemptive right to purchase shares at not less than 90% of their market value or the price paid by third parties, or
- fees up to 10% are paid to intermediaries, in which case the fees paid may be deducted from their price.

The market value may not be less than the nominal value of the shares. An independent appraiser determines the value of any in-kind payments for new shares.

The Federal Commission on the Securities Market, under the power given to it by the Federal Law on the Securities Market, has issued detailed procedures for the registration and issue of shares of a joint stock company. These procedures require:

- prior registration of a share issuance with the Federal Commission on the Securities Market;
- public disclosure of information relating to the share issuance; and
- following the placement of shares, registration and public disclosure of the results of the placement of shares.

CAPITAL DECREASE; SHARE BUY-BACKS

The Federal Law on Joint Stock Companies does not allow a company to reduce its share capital below the minimum share capital required by law. As of March 15, 2002 the minimum share capital for an open joint stock company was the ruble equivalent of approximately $3,200. Any reduction in our share capital, whether through the repurchase and cancellation of shares or a reduction in the nominal value of the shares, requires a majority vote at a shareholders' meeting. Additionally, within 30 days of a decision to reduce our share capital, we must issue a written notice to our creditors and publish this decision. Our creditors would then have the right to demand, within 30 days of publication or receipt of our notice, the repayment of all amounts due to them and compensation for any damages incurred.

The Federal Law on Joint Stock Companies allows our Board of Directors to authorise our repurchase of up to 10% of our shares in exchange for cash. Either we must resell the repurchased shares at their market price within one year of their repurchase or our shareholders must decide to cancel them, which would decrease our share capital. A decrease in our share capital would trigger the creditor rights discussed above.

The Federal Law on Joint Stock Companies allows us to repurchase our shares only if, at the time of repurchase:

- our share capital is paid in full;
- we are not, and would not become as a result of the repurchase, insolvent;
- the value of our net assets is not less than and, following the repurchase of the shares, would not be less than the sum of our share capital and reserve fund; and

- we have repurchased all shares from shareholders who have exercised their right to demand the repurchase of their shares as provided by Russian law and described below.

Russian legislation and our charter provide that our shareholders may demand that we repurchase their shares if they voted against or did not vote on any of the following events:

- a reorganisation;
- an amendment to the charter that negatively affects a shareholder; or
- the approval by shareholders of a major transaction as defined under Russian law.

We may spend only up to 10% of our net assets for share repurchases demanded by shareholders. If the value of shares in respect of which shareholders have exercised their right to demand repurchase exceeds 10% of our net assets, we will repurchase from each shareholder exercising its right to demand repurchase a number of shares proportionate to the number of shares specified in the demand of such shareholder.

APPROVAL OF THE MINISTRY OF ANTIMONOPOLY POLICY OF THE RUSSIAN FEDERATION

Pursuant to Russian antimonopoly legislation, any transaction that would result in a shareholder (including affiliates) holding 20% or more of our issued voting shares must be approved in advance by the Ministry of Antimonopoly Policy of the Russian Federation.

NOTIFICATION OF FOREIGN OWNERSHIP

Pursuant to Russian securities legislation, any foreign person or company acquiring shares in a Russian joint stock company must notify the Russian Federal Commission on the Securities Markets of such acquisition on the date of the acquisition in the form and substance required by Russian securities legislation. Other than this notification requirement, there are no requirements or restrictions with respect to foreign ownership of our shares.

PREEMPTIVE RIGHTS

The Federal Law on Joint Stock Companies grants existing shareholders a preemptive right to purchase shares or securities convertible into our shares that we propose to sell in a public offering. Shareholders who voted against or did not participate in voting on the placement of shares or securities convertible into our shares in a private placement are entitled to acquire an amount of such shares or convertible securities proportionate to their existing holdings of the shares. This rule does not apply when the shares are placed solely among existing shareholders if all such existing shareholders are entitled to acquire new shares of an amount that is proportionate to their existing holdings. We must provide shareholders with written notice of the proposed sale of shares at least 45 days prior to the offering, during which time shareholders may exercise their preemptive rights. If a shareholder elects to exercise its preemptive right to purchase shares, and the amount of shares that is proportionate to their existing shareholdings is not a whole number, then such shareholder is entitled to receive a fractional amount of shares.

ANTI-TAKEOVER PROTECTIONS

Russian legislation requires that any person intending, either alone or with affiliates, to acquire more than 30% of the ordinary shares, including shares already held by such a shareholder, of a company having more than 1,000 shareholders must give written notice to the target company of its intention to acquire the shares at least thirty days, but in any event not more than 90 days, before such acquisition.

Additionally, within thirty days of any such acquisition, the acquiring shareholder must offer to buy all of the issued ordinary shares and securities convertible into ordinary shares at their market price, which should not be less than the weighted-average acquisition price of the ordinary shares over the six months before the date of the acquisition. The same requirement applies at each 5% increment over 30%. Shareholders holding a majority of the issued voting shares present at a shareholders' meeting, excluding the vote of the person acquiring shares and that person's affiliates, may elect to waive this requirement. Alternatively our charter may contain a provision waiving this requirement. Currently our charter does not contain a waiver of and our shareholders have not waived this requirement. If the acquiring shareholder fails to make the required offer, it may vote only those shares of the company that have been acquired in accordance with the above procedures.

LIABILITY OF SHAREHOLDERS

The Civil Code, the Federal Law on Joint Stock Companies and the Federal Law on Limited Liability Companies generally provide that shareholders in a Russian joint stock company and members in a Russian limited liability company are not liable for the obligations of the company and bear only the risk of loss of their investment. This may not be the case, however, when one company is capable of determining the decisions made by another company. The company capable of determining such decisions is called an effective parent. The company whose decisions are capable of being so determined is called an effective subsidiary.

If the effective subsidiary is a joint stock company, the effective parent bears joint and several responsibility for a transaction concluded by an effective subsidiary if (i) the effective parent caused the effective subsidiary to conclude the transaction and (ii) the ability of the effective parent to determine decisions made by the effective subsidiary is provided for in the charter of the effective subsidiary or in a contract between the companies. If the effective subsidiary is a limited liability company, the effective parent bears joint and several responsibility if the effective parent caused the effective subsidiary to conclude the transaction (and without regard to how the effective parent's ability to determine decisions of the effective subsidiary arises).

In addition, an effective parent, a shareholder, member, or other person that is capable of determining decisions made by an effective subsidiary may be secondarily liable for such company's debts in the case of its insolvency or bankruptcy. If the effective subsidiary is a joint stock company, then the effective parent, shareholder, or other person capable of making decisions will be secondarily liable if (i) the effective subsidiary becomes insolvent or bankrupt as a result of the actions of the effective parent, shareholder or other person; and (ii) the effective parent, shareholder, or other person knew or should have known that such actions would result in the insolvency or bankruptcy of the effective subsidiary. If the effective subsidiary is a limited liability company, then the effective parent, member, or other person capable of determining decisions will be secondarily liable if the effective subsidiary insolvency or bankruptcy is caused by the intentional wrongful conduct or negligence of such effective parent, member, or other person, as the case may be.

Shareholders (other than the effective parent) of an effective subsidiary that is a joint stock company may claim compensation for the effective subsidiary's losses from the effective parent if (i) the effective parent caused the effective subsidiary to take any action or fail to take any action that resulted in a loss and (ii) the effective parent knew or should have known that such action or failure to take such action would result in a loss. Members (other than the effective parent) of an effective subsidiary that is a limited liability company may claim compensation for the effective subsidiary's losses from the effective parent if the effective parent through its intentional wrongful conduct or negligence caused the effective subsidiary to take any action that resulted in a loss. In both cases, it does not matter how the effective parent's ability to make decisions for the effective subsidiary arises.

DISTRIBUTIONS ON LIQUIDATION TO SHAREHOLDERS

Under Russian legislation the liquidation of a company results in its termination without the transfer of rights and obligations to other persons as legal successors. Our charter allows us to be liquidated:

- by a 75% vote of our shareholders at a shareholders' meeting; or
- by court order.

Following a decision to liquidate us, the right to manage our affairs would pass to a liquidation commission. In the case of a voluntary liquidation, shareholders appoint the members of the liquidation commission at a shareholders' meeting. The court appoints members of the liquidation commission in the case of an involuntary liquidation. Creditors may file claims within a period to be determined by the liquidation commission, but which must be at least two months from the date of publication of the notice of liquidation by the liquidation commission.

The Civil Code gives creditors the following order of priority during liquidation:

- individuals owed compensation for injuries or deaths caused by a company;
- employees;
- secured creditors;
- federal, regional and local authorities and state non-budget funds; and
- other creditors in accordance with Russian law.

The remaining assets of a company are distributed among shareholders in the following order of priority:

- payments to repurchase shares from shareholders having the right to demand repurchase;
- payments of declared but unpaid dividends on preferred stock and the liquidation value of the preferred stock, if any; and
- payments to holders of ordinary and preferred shares on a *pro rata* basis.

SHARE REGISTRATION, TRANSFERS AND SETTLEMENT

Our shares are registered shares entered in our share register. Any of our shareholders may obtain an extract from the share register certifying the number of shares that the shareholder holds. Russian law requires that the register of shareholders of a joint stock company with more than 50 shareholders be maintained by an independent registrar. OJSC Registrar Nikoil maintains our register of shareholders.

The purchase, sale or other transfer of shares is accomplished through registration of the transfer in the share register maintained by the independent registrar. When making entries in the register, the independent registrar may not require any documents in addition to those required by Russian law. Any refusal to register the shares in the name of the transferee or, upon request of the shareholder, in the name of a nominee holder, is unlawful.

Alternatively Russian law contemplates that the transfer of title to shares may be evidenced by entries on the depositary accounts of shareholders with a licenced depositary that is registered in the share register of the company as a nominee holder.

Although there are no restrictions on the sale of our shares by a non-resident of Russia to another non-resident or to a Russian resident, Russian currency control legislation provides that a sale of our shares to a Russian resident must be made for rubles unless the Russian resident obtains a Central Bank licence authorising payment in U.S. dollars or another convertible currency. While Russian commercial banks generally have the requisite licence, it is very difficult as a practical matter for other Russian residents to obtain one. Accordingly shareholders wishing to sell their ordinary shares to a Russian resident other than a licenced commercial bank will need to establish a special ruble account into which the ruble proceeds of the sale will be deposited and converted into U.S. dollars or another convertible currency and repatriated. See “Regulation – Currency Exchange Controls and Export Proceeds Repatriation”.

The ability to arrange for the conversion of rubles into U.S. dollars or another convertible currency is subject to the availability of U.S. dollars or such other convertible currency in Russia’s currency markets. Although there is an existing market within Russia for the conversion of rubles into U.S. dollars and other convertible currencies, including the interbank currency exchange and over-the-counter and currency futures markets, the liquidity of such markets is limited. At present there is no market for the conversion of rubles into convertible currencies outside Russia. Moreover, there is currently no viable market in which to hedge ruble deposits or ruble-denominated investments.

APPROVAL OF MAJOR TRANSACTIONS

The Federal Law on Joint Stock Companies defines a “major transaction” as a transaction (including a loan, pledge or suretyship), or series of transactions, not in the ordinary course of business and not in connection with the placement of shares or securities convertible into ordinary shares, involving the acquisition or disposal of assets, the value of which constitutes 25% or more of the balance sheet value of the assets of a company. Major transactions involving assets ranging from 25 to 50% of the balance sheet value of the assets of a company require the unanimous approval of all members of the Board of Directors or, in the absence of such approval, the affirmative vote of shareholders holding a majority of the voting shares present at a shareholders’ meeting. Major transactions involving assets in excess of 50% of the balance sheet value of the company’s assets require a 75% affirmative vote of shareholders present at a shareholders’ meeting.

APPROVAL OF INTERESTED PARTY TRANSACTIONS

The Federal Law on Joint Stock Companies contains requirements for transactions with interested parties. The definition of “interested parties” includes any person that (i) is a member of the Board of Directors or any management body (including the chief executive officer) of a company or the managing company of such company or (ii) owns, together with any affiliates, at least 20% of such company's voting shares or that may give instructions to such company with which such company must comply if that person, or that person's close relatives or affiliates:

- is a party to, or beneficiary of, a transaction with the company, whether directly or as a representative or intermediary;
- own, together with any close relatives or affiliates, at least 20% of the issued shares of a legal entity that is a party to, or beneficiary of, a transaction with the company, whether directly or as a representative or intermediary; or
- is a member of the Board of Directors or any management body of the company (or the managing company of such company) that is a party to, or beneficiary of, a transaction with the company, whether directly or as a representative or intermediary.

A managing company is a company that has entered into a contract with a second company pursuant to which the managing company manages the second company. The managing company takes the place of a chief executive officer.

A company with more than 1,000 shareholders must obtain the approval of one of the following prior to entering into an interested party transaction:

- a majority of independent members of the Board of Directors of the company who (1) are not "interested parties" in the transaction, and (2) who are not, and were not during the year preceding the date of approval, affiliates of the company (except for being its director) or who and whose close relatives are not, and were not during the year preceding the date of approval, members of any management body of the company (except for the Board of Directors) or the managing company of such company; or
- a majority of shareholders at a shareholders' meeting that are not "interested parties" in the transaction if (1) the value of such a transaction is at least 2% of the value of the company's assets, (2) the transaction involves the issuance of shares or securities convertible into shares in an amount that equals at least 2% of the company's issued ordinary shares and ordinary shares in which the issued securities convertible into ordinary shares may be converted or (3) all members of the Board of Directors of the company are interested parties or are not independent directors.

SHARE CAPITAL

Our original charter provided for an initial share capital of 8,184,213,000 rubles, consisting of 8,184,213 ordinary shares having a nominal value per share of 1,000 rubles. Our Board of Directors approved further amendments to our charter providing for an increase in share capital to 11,884,203,000 rubles, consisting of 379,527 preferred shares and 11,504,676 ordinary shares, each having a nominal value per share of 1,000 rubles. We registered these share issues with the Securities and Stock Market Department of the Ministry of Finance of the Russian Federation, or the Securities and Stock Market Department, on July 2, 1993 and on February 14, 1994, respectively.

Pursuant to Decree of the President of the Russian Federation No. 1705, dated December 31, 1992, and the Notification by the Federal Property Fund of the Russian Federation No. FI-14-1/659, dated March 2, 1995, our shares were split eight-for-one. Following this share split, our total share capital remained at 11,884,203,000 rubles, but the number of issued shares increased to 95,073,624, consisting of 3,036,216 preferred shares and 92,037,408 ordinary shares, each class having a nominal value per share of 125 rubles.

At the annual shareholders' meeting on April 21, 1995, the shareholders authorised a five-for-one share split of the issued ordinary and preferred shares resulting in a total number of 460,187,040 issued ordinary shares and 15,181,080 issued preferred shares, each class having a nominal value of 25 rubles per share. To acquire additional interests in the share capital of our subsidiaries and certain other enterprises through an exchange of shares, our shareholders also authorised at the 1995 annual meeting an additional issuance of 189,364,351 ordinary shares and 49,830,784 preferred shares, each class having a nominal value per share of 25 rubles. This increased our share capital by 5,979,878,375 rubles. The Securities and Stock Market Department registered the new shares on May 29, 1995. Following registration our total share capital was 17,864,081,375 rubles, consisting of 65,011,864 preferred shares and 649,551,391 ordinary shares, each class having a nominal value per share of 25 rubles.

On June 5, 1996, at our annual shareholders' meeting, our shareholders approved a further amendment to the charter authorising the Board of Directors to issue an additional 19,800,000 ordinary shares and 12,200,000 preferred shares. The Board of Directors approved the issuance of these additional shares in January 1997 and registered the issuance with the Securities and Stock Market Department. As a result, our share capital increased by 800 million rubles. On January 1, 1998, the Government redenominated the ruble by removing three zeros from its face value. As a result of the redenomination our share capital decreased to 18,664,081.375 rubles.

In 1999 we issued 11,500,000 preferred shares, having a nominal value per share of 0.15 rubles, convertible into ordinary shares at a rate of six-for-one, in exchange for 98.25% of the voting shares of OJSC KomiTEK and shares in the KomiTEK group of companies. We also authorised the creation of 69,000,000 new ordinary shares, with a nominal value per share of 0.025 rubles, to be issued to back the conversion of these preferred shares. Holders of the newly issued preferred shares exercised their conversion rights on November 30, 1999. The conversion resulted in a total amount of 738,351,391 issued ordinary shares and 77,211,864 issued preferred shares, each class having a nominal value per share of 0.025 rubles.

At our annual shareholders' meeting on June 8, 2000, our shareholders approved the issuance of up to 18,600,000 ordinary shares, and we ultimately issued 18,431,061 ordinary shares, in connection with the acquisition of shares in OJSC Arkhangelskgeoldobycha, OJSC LUKOIL-Ukhtaneftepererabotka and OJSC LUKOIL-Kominefteproduct. Specifically we issued 17,710,697 ordinary shares and paid $130 million to the shareholders of OJSC Arkhangelskgeoldobycha in exchange for 74% of the shares in that company. In addition we issued 670,816 ordinary shares in exchange for a 13% minority interest in OJSC LUKOIL-Ukhtaneftepererabotka and 49,548 ordinary shares in exchange for a 22% minority interest in OJSC LUKOIL-Kominefteproduct.

At our annual shareholders' meeting on June 28, 2001, our shareholders authorised 93,780,803 additional ordinary shares, of which 77,211,864 were to be issued to back the conversion of new preferred convertible shares at the rate of one ordinary share to one preferred share. In August 2001 we issued the convertible preferred shares in exchange for all our previously issued and outstanding preferred shares. Following the exchange we issued 77,211,864 ordinary shares upon the conversion of the newly issued convertible preferred shares. We issued the remaining 16,568,939 ordinary shares to LukInter Finance B.V. through an open subscription. Holders of these newly issued ordinary shares, as with all holders of our ordinary shares, have preemptive rights to acquire newly issued shares as described above in "– Preemptive Rights."

As of June 27, 2002 our share capital equals 21,264,081.375 rubles, consisting of a total amount of 850,563,255 issued ordinary shares, all of which are fully paid and have a nominal value per share of 0.025 rubles.

SHARE OPTION SCHEMES

We have not established any share option schemes for our employees or granted options to the holders of our shares or debt securities.

PRINCIPAL INTERESTS IN THE COMPANY

The following table sets out details, in so far as is known to us, as of July 12, 2002 (being the latest practicable date prior to the date of this document), unless otherwise indicated, of all shareholders (other than Directors and members of our Management Committee but including nominee shareholders) that hold 3% or more of our share capital.

Name of Shareholder	Percent of issued ordinary share capital
ZAO ING Bank Eurasia/ING Depositary (nominee)	49.30%
OOO Special Depositary Company "Garant" (nominee)	11.86%
Capital Group	10.84%
Russian Federal Property Fund	7.69%(1)
ZAO Depositary Company "NIKOIL" (nominee)	6.68%(2)
NIKoil Group	6.68%(2)
Russian Federation Ministry of Property Relations	5.79%
National Depositary Center (nominee)	5.42%
ZAO Depositary Clearing Company (nominee)	3.56%
LukInter Finance B.V.	3.18%

Notes:

(1) Includes 50 million shares held indirectly through Komprivatizatsia, a special purpose vehicle established for purposes of a proposed offering.

(2) Includes shares held as nominee for NIKoil's own account.

CERTAIN TRANSACTIONS AND RELATIONSHIPS

LUKOIL Garant

LUKOIL Garant is a private pension fund that operates a benefit plan covering the majority of our employees. It also provides pension benefits and services to employees of other companies that are not related to us. LUKOIL Garant's principal asset is approximately 11.9% of our outstanding share capital. Two members of our Management Committee sit on the nine-member Council of the Fund, which is the governing board of LUKOIL Garant. The Council delegates day-to-day management of the Fund to the Executive Directorate, which is currently comprised of eight management positions. Mr. Berezhnoy, a member of our Board of Directors, is the General Director and a member of the Executive Directorate of LUKOIL Garant. Due to these interlocking relationships, we may be considered to have influence over LUKOIL Garant even though we do not have direct legal control. In 2001 we entered into a share swap transaction in which we transferred to LUKOIL Garant 14.8 million of our ordinary shares in exchange for LUKOIL Garant's 57.8% interest in AGD.

OAO LUKOIL-Moscow

Mr. Alekperov, our President and Director, formerly owned 20% of OAO LUKOIL-Moscow, a holding company that engages in construction and retail services. OOO LUKOIL-Holding Service, one of our subsidiaries, currently owns 20%. Mr. Chumack, a former Vice President of OAO LUKOIL, owns 47%. The remainder is owned by a number of LUKOIL-Moscow employees. In 2001 we purchased $21 million of services, primarily construction services, from LUKOIL-Moscow and sold $28 million of refined products to LUKOIL-Moscow. In 2000 we purchased $79 million of promissory notes issued by LUKOIL-Moscow from Morgan Grenfell, which notes we sold in 2001.

It has been reported that Mr. Chumack formerly owned an interest in the Moscow refinery. Through intermediaries associated with the Moscow refinery, we have sold crude oil to, and purchased refined products from, the Moscow refinery.

OAO RITEK

We have a 50.5% interest in OAO RITEK, one of our key western Siberia subsidiaries. See "Part 5 – Business – Exploration and Production." Mr. Graifer, the Chairman of our Board of Directors, is the General Director of RITEK. In addition, Mr. Graifer, Mr. Alekperov and other members of our Board of Directors and Management Committee own shares in RITEK.

NIKOIL Investment Banking Group

The NIKoil group is comprised of a number of Russian financial services companies, including an investment bank, management company, brokerage, insurance company and registrar. Mr. Tsvetkov, a member of our Board of Directors, is a member of the Board of Directors and Management Board of NIKoil. OAO Registrar NIKoil is our registrar. As of December 31, 2001 NIKoil held 6.68% of our outstanding share capital. See " – Principal Interests in the Company."

Government of the Russian Federation

As of June 30, 2002 the Government of the Russian Federation held 13.5% of our outstanding share capital and currently has two representatives on our Board of Directors. We make crude oil and refined product sales to the government or entities controlled by or operating on behalf of the government. See "Part 5 – Business – Refining, Marketing and Distribution."

DETAILS OF CONVERTIBLE U.S. DOLLAR BONDS

On November 3, 1997, LukInter Finance B.V., one of our subsidiaries, issued high-yield premium exchangeable redeemable bonds in aggregate principal amount of $350,000,000, maturing on November 3, 2003, or the November 1997 bonds. At the initial conversion price each November 1997 bond is exchangeable for 5.625 of our Series B Global Depositary Shares (subject to adjustment). Our Series B Global Depositary Shares were issued pursuant to a deposit agreement dated November 3, 1997 made between the Company, The Bank of New York as depositary and LukInter Finance B.V. and admitted to the Official List of the U.K. Listing Authority as specialist securities. Each Series B Global Depositary Receipt represents four of our ordinary shares. Each November 1997 bond may be exchanged into Series B Global Depositary Shares at any time up to 15 days prior to redemption or October 17, 2003, whichever is earlier. We must redeem for cash all November 1997 bonds not converted by the maturity date at a redemption price of 153.314% of their face value. We may redeem the November 1997 bonds for cash prior to maturity, subject to early redemption charges. As of the date of this document, none of the November 1997 bonds had been converted or exchanged.

In connection with the issuance of the bonds, LukInter Finance entered into a Sale and Repurchase Agreement, dated as of November 3, 1997, among itself, LLC LR Invest, Acquagate Investments Co. Limited and Rienco Investments Limited. Pursuant to this agreement, LukInter Finance obtained the common shares necessary to satisfy the conversion rights under the bonds. To ensure that LukInter Finance has the necessary funds to pay the bondholders on redemption of the bonds, the agreement also provides LukInter Finance with a put option that can be exercised at any time after closing. Upon exercise of the put option, a subsidiary of LUKOIL Garant will be required to repurchase the shares that have not been previously used to satisfy conversion rights under the bonds, up to a maximum of 7,876,000 shares, at a price that is substantially higher than the current market price, which will enable LukInter Finance to pay the principal, premium and interest due to maturity on the outstanding bonds. We intend to cause LukInter Finance to exercise this put option prior to November 2003. See "Part 3 – Risk Factors – Risks Relating to Our Shares."

EMPLOYEES

We had 120,022, 136,429 and 178,345 employees, as of December 31, 1999, 2000 and 2001, respectively. We believe that our relations with our employees are satisfactory.

The following table shows our approximate number of employees at our oil production, refining and distribution subsidiaries and corporate personnel as of the dates indicated.

	Year ended December 31,		
	1999	**2000**	**2001**
Oil production	82,163	86,611	104,228
Refining	11,280	12,132	14,919
Sales service and engineering	9,638	18,898	28,951
Distribution	8,561	9,270	13,699
Petrochemicals	6,750	7,537	14,427
Head office	1,630	1,981	2,121
Total	**120,022**	**136,429**	**178,345**

SUBSIDIARY COMPANIES

Our principal subsidiaries, being those that we consider to be likely to have a significant effect on the assessment of the assets and liabilities, financial position, profits and losses and prospects of our consolidated group, are listed below.

Name of Company	Registered Office	Proportion Owned	Primary Field of Activity
OOO LUKOIL– Nizhnevolzhskneft	16 Komsomolskaya Street Volgograd 400066 Russia	100%	Exploration and oil production
LUKOIL Overseas Holding Ltd.	P.O. Box 3443, Road Town, Tortola British Virgin Islands	100%	Exploration and oil production
LUKOIL INTERNATIONAL GmbH	Schwarzenbergplatz 6 A-1030 Vienna Austria	100%	Oil refining, marketing and distribution
OOO LUKOIL– Permneft	62 Lenina Street Perm 614600 Russia	100%	Exploration and oil production
OOO LUKOIL– Permnefteorgsyntez	84 Promyshlennaya Street Perm 614055 Russia	100%	Oil refining
OOO LUKOIL– Volgogradneftepererabotka	55 40th Ann. Komsomol Volgograd 400029 Russia	100%	Oil refining
OOO LUKOIL– Western Siberia	20 Pribaltiyskaya Street Kogalym, Tyumen Region 626481 Russia	100%	Exploration and oil production
OAO KomiTEK	100 Internatsionalnaya Street Syktyvkar, Republic of Komi 167000 Russia	99.86%	Exploration and oil production and refining
ZAO LUKOIL Perm	9 Popova Street Perm 614600 Russia	73%	Exploration and oil and mineral production, refining, and distribution

PRINCIPAL ESTABLISHMENTS

The table below sets out the location, approximate size, tenure, and term of our principal establishments:

Address	Size m^2	Annual Rent $	Tenure	Term
11 Sretensky Boulevard Moscow 101000 Russia	38,462	N/A	Freehold	N/A
14 Rue du Rhone 5th Floor 1204 Geneva Switzerland	691	289,631	Lease	August 31, 2003
20 Pribaltiyskaya Street Kogalym, Tyumen Region 628481 Russia	28,000	N/A	Freehold	N/A
62 Lenina Street Perm 614990 Russia	13,567	N/A	Freehold	N/A
9 Popova Street Perm 614600 Russia	9,575	N/A	Freehold	N/A
100 Internatsionalnaya Street Syktyvkar, Republic of Komi 167000 Russia	2,000	N/A	Freehold	N/A
84 Promyshlennaya Street Perm 614055 Russia	10,000,000	N/A	Freehold	N/A
55 40th Ann. Komsomol Volgograd 40029 Russia	7,573,464	N/A	Freehold	N/A

MATERIAL CONTRACTS

The following contracts are those contracts (not being contracts entered into in the ordinary course of business) that (i) are material to us and into which we entered within the two years immediately preceding the date of this document or (ii) that contain provisions under which we have material obligations or entitlements:

- an agreement, dated October 12, 1999, between LUKOIL Petrol AD and the Bulgarian Privatisation Agency, pursuant to which we acquired approximately 7.8 million shares of Neftochim AD, which owns the Burgas Refinery, for a purchase price of $101 million. Pursuant to the acquisition agreement, we must invest an aggregate amount of $286.3 million to upgrade the refinery and complete certain environmental measures;
- a joint development and production sharing agreement, dated September 20, 1994 between SOCAR and an international consortium in which we hold a 10% interest through our subsidiary LUKOIL Overseas Chirag Finance Limited. The agreement provides for the exploration and development of the Azeri-Chirag-Gunashli oil fields, which will require an initial capital expenditure of approximately $3.5 billion, of which our share is approximately $407 million in 2002–2004;
- a production sharing agreement, dated November 18, 1997, among the Government of Kazakstan, OAO LUKOIL, British Gas, ENI, and Texaco, which provides for the exploration and development of the Karachaganak field;

- a loan agreement between OAO LUKOIL and CSFB International, dated as of June 7, 2002, pursuant to which OAO LUKOIL has received a loan in the amount of $200 million for a term of 48 months from July 10, 2002. The loan bears interest at a rate of LIBOR plus 3.70%. Repayment of this loan is secured with certain export proceeds;
- a contract for the transportation of oil, dated February 1, 2002, between OAO LUKOIL and AK Transneft providing for the transportation of oil via Transneft's pipeline system through December 31, 2002. Payment for Transneft's services is based on tariffs approved by the Russian Federal Energy Commission;
- a loan agreement between OAO LUKOIL and Raiffeisen Zentralbank Osterreich AG, dated December 24, 2001 and amended on January 30, 2002, pursuant to which OAO LUKOIL has received a loan in the amount of $300 million. The principal amount of the loan is to be repaid by forty-two equal installments starting from January 28, 2003. The interest rate on the loan is the sum of one-year LIBOR plus 3.5% per annum. OAO LUKOIL's performance of payment obligations under the loan agreement is secured with crude oil export proceeds;
- a sponsor's agreement dated on or about July 31, 2002 between OAO LUKOIL and Morgan Stanley & Co. International Limited pursuant to which we agreed to appoint Morgan Stanley & Co. International Limited as our sponsor in connection with the introduction of our ordinary shares and ADRs to the Official List of the U.K. Listing Authority and to trading on the London Stock Exchange. The agreement includes certain warranties and indemnities given by us to Morgan Stanley & Co. International Limited; and
- a financing agreement, dated February 7, 1997, among OAO LUKOIL, Atlantic Richfield Company, LUKARCO Finance B.V., and LUKARCO B.V. providing for Atlantic Richfield Company to provide up to $4.5 billion of loans either directly to LUKARCO B.V. or to LUKARCO Finance B.V. for onlending to LUKARCO B.V. and a related guarantee agreement, also dated February 7, 1997, between OAO LUKOIL and Atlantic Richfield Company pursuant to which OAO LUKOIL guarantees up to 54% of the sum of (i) amount advanced under such financing agreement, (ii) interest thereon, (iii) amounts attributable to credit support provided by Atlantic Richfield Company under such financing agreement, and (iv) fees due to Atlantic Richfield Company in connection with such credit support.

TAXATION

The following discussion is a summary of certain tax consequences under the laws of the Russian Federation and the United Kingdom and under U.S. federal income tax law for holders of our ordinary shares, including those ordinary shares that trade in the form of depositary shares, or DSs, whether in the form of American DSs or global DSs. The summary is general in nature and is based on the laws of the Russian Federation, the United Kingdom and the United States in effect as of the date of these Listing Particulars. You should consult with your tax advisors with respect to the precise Russian, U.K. and U.S. tax consequences of acquiring, owning and disposing of our ordinary shares or DSs. This summary does not seek to address the applicability of any double tax treaty relief. In this regard, however, it is noted that there may be practical difficulties involved in claiming double tax treaty relief. Under no circumstances should you view this summary as tax advice. In addition, see "Part 3 – Risk Factors – The Russian Tax System imposes substantial burdens on us and is subject to frequent change and significant uncertainty."

Russian Tax Considerations

For the purposes of this summary, a "non-resident holder" means (i) a physical person, physically present in the Russian Federation for less than 183 days in a given calendar year or (ii) a legal person or organisation, in each case not organised under Russian law, that holds and disposes of DSs or ordinary shares otherwise than through a permanent establishment in Russia.

A "Russian resident" as used herein means (i) a Russian legal person or organisation organised under Russian law or (ii) a Russian permanent establishment of a foreign legal entity.

The Russian tax rules applicable to securities, and in particular to those held by non-resident holders, are characterised by significant uncertainties and by an absence of interpretative guidance. Russian tax law and procedures are not well developed and rules are sometimes interpreted differently by different tax inspectorates and inspectors. In addition both the substantive provisions of Russian tax law and the interpretation and application of those provisions by the Russian tax authorities may be subject to more rapid and unpredictable change than in a jurisdiction with more developed capital markets. The relevant chapters of Part Two of the Tax Code that set out the regulatory framework for the taxation of the income of individuals and the profits of Russian and foreign legal entities do not regulate all the issues arising in connection with the purchase, ownership and disposition of shares and DSs by non-resident holders. In particular, the Russian tax authorities have not provided any guidance regarding the treatment of the share deposit arrangements of the type relating to DSs.

Taxation of Dividends

Dividends paid to a non-resident holder generally are subject to Russian withholding tax, which will be withheld by us acting as a tax agent. The applicable tax rate on dividends will depend on whether the dividend recipient is a legal entity or an individual. Dividends paid to a non-resident holder that is a legal entity generally will be subject to Russian withholding tax at a rate of 15%. Dividends paid to non-resident individuals are subject to Russian withholding tax at a rate of 30%.

Russian tax reporting obligations of a non-resident individual

If income received by a non-resident-holder (who is an individual) is treated as taxable in Russia but has not been withheld for any reason (e.g. paid by foreign company) such an individual is technically liable to declare his or her income to the Russian tax authorities and pay the tax.

Withholding tax may be reduced under the terms of a double tax treaty between the Russian Federation and the country of residence of the non-resident holder. For example, the Convention Between the United States of America and the Russian Federation for the Avoidance of Double Taxation and the Prevention of Fiscal Evasion with Respect to Taxes on Income and Capital, or the U.S.-Russia Tax Treaty, provides for reduced withholding rates on dividends paid to U.S. holders who are beneficial owners of the dividends. For example a 10% rate applies to dividends paid to U.S. holders owning less than 10% of the entity's outstanding shares and a 5% rate applies to dividends paid to U.S. holders that are legal entities owning 10% or more of the entity's outstanding shares. Similarly, the Convention Between the Government of the Russian Federation and the Government of the United Kingdom and Northern Ireland on the Avoidance of Double Taxation and the Prevention of Fiscal Evasion with Respect to Taxes on Income and Capital Gains, or the U.K.-Russia Tax Treaty, also provides for a 10% withholding rate on dividends paid to U.K. holders who are beneficial owners of the dividends.

However, treaty relief may not be available to non-resident holders of DSs because of the absence of any interpretative guidance on the beneficial ownership concept in Russia and the fact that the depositary (and not the holders of the DSs) is the legal holder of the shares under Russian law. In the absence of any clarification from the Russian tax authorities on the application of relevant double tax treaties, we likely will not be able to apply the reduced rates and will have to withhold tax at applicable domestic rates on dividends payable to a non-resident holder. See "– U.S./U.K. Tax Treaty Relief Procedures.".

Taxation of Capital Gains

A non-resident holder generally should not be subject to any Russian income or withholding taxes in connection with the sale, exchange or other disposition of DSs outside of Russia. The Tax Code provides that capital gains realised by non-resident legal entities from the sale of shares or derivative instruments (where the underlying assets are in the form of shares of Russian companies) that are listed and sold on foreign exchanges legally, will not be recognised as income from Russian sources and, therefore, shall be not subject to Russian withholding taxes.

A non-resident legal entity will be subject to taxes on capital gains only in connection with the sale to a Russian resident of shares of a Russian company that has more than 50% of its assets in the form of immovable property in Russia. The non-resident holder may deduct the original purchase price from the proceeds of the sale if he provides documentary support of the original purchase price to the Russian purchaser, acting as tax agent. In such event the net proceeds of the sale are subject to a withholding tax at the rate of 24%. Without documentary support, the non-resident entity is not entitled to deduct the original purchase price and the gross proceeds of the sale are subject to a 20% rate. Please note that since capital gains may be calculated in rubles the taxable base could be affected by changes in the ruble exchange rates.

A non-resident individual will generally be subject to withholding tax at the rate of 30% on the gross proceeds from a disposal of the shares or DSs, less any available cost deduction, where the proceeds of such disposal are received from a source within Russia, subject to any available double tax treaty relief. For such purposes income is received from "a source within Russia" if the shares or DSs are sold in the territory of the Russian Federation. However, there is no definition of "sale in the territory of the Russian Federation" in relation to transactions involving securities. There is a risk that any sale of shares (as opposed to depositary shares) in a Russian company may be considered a sale in the territory of the Russian Federation. A sale of DSs may also be considered a sale in the territory of the Russian Federation if the purchaser is a Russian resident. Please note that capital gains are calculated in rubles using the respective exchange rates on the date of sale and the date of purchase and, thus, the proceeds of the sale subject to taxation would be affected by changes in ruble exchange rates.

A non-resident holder may be able to avoid Russian withholding tax on the disposition of shares under the terms of a double tax treaty between the Russian Federation and the country of residence of the non-resident holder. For example, under the U.S.-Russia Tax Treaty, U.S. holders are exempt from the withholding tax on capital gains unless 50% or more of the assets of the issuer are represented by immovable property. The non-resident holder may deduct the original purchase price from the proceeds of the sale if he provides documentary support to the Russian purchaser, acting as tax agent. In such event, the net proceeds of the sale are subject to a withholding rate of 24%. Without documentary support, the non-resident entity is not entitled to deduct the original purchase price and the gross proceeds of the sale are subject to a 20% withholding rate. The U.K.-Russia Tax Treaty provides for an exemption from withholding tax on capital gains received by U.K. holders unless the shares which: (a) derive all or substantially all of their value directly or indirectly from immovable property in Russia; and (b) are not quoted on an approved stock exchange.

Before payment of the proceeds from a disposal of shares (when a Russian issuer has more than 50% of its assets in the form of immovable property in Russia), the U.S. corporate holders entitled to treaty relief should provide the Russian resident purchasing the shares with a confirmation of residency certified by U.S. tax authorities that complies with the U.S.-Russia double tax treaty. See "U.S./U.K. Advance Tax Treaty Clearance Procedures."

U.S./U.K. Tax Treaty Relief Procedures

The Profits Tax Chapter of the Russian Tax Code, which became effective on January 1, 2002, eliminates the requirement that a non-resident corporate holder should obtain tax treaty clearance from Russian tax authorities prior to receiving any income derived from the shares (i.e., from the payment of dividends or the sale of such shares). However, Russian tax authorities, in connection with a tax audit, may still dispute the fact that the non-resident is eligible to benefit from the double tax treaty and require the tax agent (i.e., the company paying dividends or the Russian purchaser of the shares) to pay any tax, penalties and interest.

Otherwise a non-resident corporate holder seeking to obtain relief from Russian withholding tax under a tax treaty must provide a confirmation of its tax residence that complies with the applicable double tax treaty in advance of receiving income. U.S. holders may obtain such confirmation by writing to the Internal Revenue Service, Philadelphia Service Center, Foreign Certification Request, P.O. Box 16347, Philadelphia, PA, 19114–0447. U.K. holders may obtain such confirmation by writing to their local U.K. tax inspector.

In accordance with the Tax Code a non-resident holder who is an individual must present to the tax authorities a document on his or her tax residency and a document justifying the income received and the tax paid off-shore, confirmed by the foreign tax authorities. Formally such requirement means that an individual cannot rely on the tax treaty until he or she pays the tax in the residence jurisdiction.

If a non-resident does not obtain advance tax-treaty clearance and tax is withheld by a Russian resident on capital gains or other amounts, the non-resident holder may apply for a refund within three years from the end of the tax period in which the tax was withheld when the recipient is a company or within the one-year period from the end of the tax period in which the tax was withheld when the recipient is an individual. To process a claim for a refund, the Russian tax authorities require (i) a confirmation of the residence of a non-resident at the time the income was paid, (ii) an application for refund of the tax withheld in a format provided by the Russian tax authorities and (iii) copies of the relevant contracts and payment documents confirming the payment of the tax withheld to the appropriate Russian authorities (Form 1012DT (2002) is designed to combine (i) and (ii) for foreign corporates). The Russian tax authorities may require a Russian translation of some documents. The refund of the tax withheld should be granted within one month of the filing of the application for the refund and the relevant documents have been filed with the Russian tax authorities. However, procedures for processing such claims have not been clearly established and there is significant uncertainty regarding the availability and timing of such refunds.

United Kingdom Tax Considerations

The comments below are of a general nature based on current U.K. law and practice. They do not necessarily apply where the income is deemed for tax purposes to be the income of persons other than persons who are the absolute beneficial owners of DSs or ordinary shares. In particular these comments do not apply to the following:

- investors who do not hold their DSs or ordinary shares as capital assets;
- investors that own (or are deemed to own) 10% or more of our voting rights; or
- special classes of investors such as dealers.

Withholding tax on dividends

Dividend payments in respect of DSs or ordinary shares issued by a company organised under the laws of the Russian Federation should not be subject to U.K. withholding tax. As discussed in "– Russian tax considerations – Taxation of Dividends," such dividends will be subject to Russian withholding taxes.

Taxation of Dividends

A U.K. holder of interests in DSs or ordinary shares that receives a dividend on the DSs or ordinary shares may be subject to U.K. income tax or corporation tax, as the case may be, on the gross amount of any dividend paid before the deduction of any Russian withholding taxes, subject to the availability of any credit for Russian tax withheld. An individual holder of interests in DSs or ordinary shares who is resident and domiciled in the United Kingdom will generally be subject to U.K. income tax on the dividend paid on the DSs or ordinary shares. An individual holder of interests in DSs or ordinary shares who is resident but not domiciled in the United Kingdom (or is resident, but not ordinarily resident, and domiciled in the United Kingdom, and either a Commonwealth citizen (this includes a British citizen) or a citizen of the Republic of Ireland) will generally be subject to U.K. income tax on the dividend paid on the DSs or ordinary shares to the extent that the dividend is remitted to the United Kingdom. A dividend is remitted to the United Kingdom if it is paid to the United Kingdom or transmitted or brought to the United Kingdom in any way.

A corporate holder of interests in DSs or ordinary shares that is resident in the United Kingdom will generally be subject to U.K. corporation tax on the dividend paid on the DSs or ordinary shares. A corporate holder of interests in DSs or ordinary shares that is not resident in the United Kingdom will generally not be subject to U.K. corporation tax on any dividend paid on the DSs or ordinary shares unless the DSs or ordinary shares are attributable to a trade carried on by the holder in the United Kingdom through a branch of agency.

Taxation of Disposals

The disposal by a U.K. holder of interests in DSs or ordinary shares may give rise to a chargeable gain or allowable loss for the purposes of U.K. taxation of chargeable gains.

An individual holder of interests in DSs or ordinary shares who is resident or ordinarily resident and domiciled in the United Kingdom will generally be liable for U.K. capital gains tax on chargeable gains made on the disposal of an interest in DSs or ordinary shares. An individual holder of interests in DSs or ordinary shares who is resident or ordinarily resident, but not domiciled, in the United Kingdom will be liable for U.K. capital gains tax to the extent that the chargeable gains made on the disposal of an interest in DSs or ordinary shares are remitted or deemed to be remitted to the United Kingdom. Dealings in the DSs or ordinary shares on the London Stock Exchange may give rise to remitted profits that would, therefore, give rise to a U.K. capital gains tax liability.

A corporate holder of interests in DSs or ordinary shares that is resident in the United Kingdom will generally be subject to U.K. corporation tax on any chargeable gain arising from a disposal of DSs or ordinary shares. A corporate holder of interests in DSs or ordinary shares that is not resident in the United Kingdom will be subject to U.K. corporation tax on any chargeable gain arising from their disposal where the DSs or ordinary shares in question are attributable to a trade carried on by the holder in the United Kingdom through a branch or agency.

Effect of withholding taxes

As discussed in "Taxation-Russian tax considerations–Taxation of Dividends" and "–Taxation of Capital Gains" above, dividend payments in respect of ordinary shares will be, and certain capital gains may be, subject to Russian withholding taxes. A U.K. resident investor should generally be entitled to a credit for Russian tax (if any) properly withheld from such payments against such investor's liability to income tax or corporation tax on such amounts, subject to U.K. tax rules for calculation of such a credit.

Stamp duty

Payment of U.K. stamp duty will not normally be required in connection with a transfer of interests in DSs or ordinary shares, provided that the instrument of transfer is executed and retained outside the United Kingdom and the shareholder register is not held in the United Kingdom.

No U.K. stamp duty reserve tax will be payable in respect of an agreement to transfer interests in DSs or ordinary shares.

United States Federal Income Tax Considerations

The following is a summary of the principal U.S. federal income tax consequences to a U.S. holder, as defined below, of owning our DSs or ordinary shares. The summary below is based on the Internal Revenue Code of 1986, as amended, or the U.S. Tax Code, regulations promulgated thereunder by the U.S. Department of the Treasury, and judicial and administrative interpretations thereof, all as in effect on the date hereof and all of which are subject to change, possibly retroactively. The tax treatment of a holder of DSs or ordinary shares may vary depending upon the holder's particular situation. Certain holders (including but not limited to, insurance companies, tax-exempt organisations, financial institutions, persons subject to the alternative minimum tax, broker-dealers, persons that have a "functional currency" other than the U.S. dollar, persons that received ordinary shares as compensation for services and persons owning, directly, indirectly or constructively, 10% or more of our voting shares) may be subject to special rules not discussed below. The following summary is limited to investors who hold the DSs or ordinary shares as "capital assets" within the meaning of Section 1221 of the U.S. Tax Code and not as part of a "hedge," "straddle," or "conversion transaction" within the meaning of Sections 1221, 1092, and 1258 of the U.S. Tax Code and the regulations thereunder. The summary below does not address the effect of any U.S. state or local tax on a holder of ordinary shares.

As used herein, the term "U.S. holder" means a beneficial owner of DSs or ordinary shares that is a U.S. person. As used herein, the term "U.S. person" means:

- a citizen or resident of the United States for U.S. federal income tax purposes;
- a corporation created or organised in or under the laws of the United States or a political subdivision thereof;
- an estate the income of which is subject to U.S. federal income taxation regardless of its source; or
- a trust if a U.S. court is able to exercise primary supervision over the administration of the trust and one or more U.S. persons, within the meaning of Section 7701(a)(30) of the U.S. Tax Code, have authority to control all substantial decisions of the trust, or a trust in existence on August 20, 1996, which was treated as a U.S. person under the law in effect immediately before that date and made a valid election to continue to be treated as a U.S. person under the U.S. Tax Code.

For purposes of the U.S. Tax Code, U.S. holders of our DSs will be treated as the owners of the ordinary shares represented by such depositary shares. Accordingly, except to the extent that the context requires otherwise, references to ordinary shares in the discussion that follows are deemed to include depositary shares. Exchanges, deposits and withdrawals of ordinary shares for DSs or DSs for ordinary shares by a U.S. holder will not result in the recognition of gain or loss for U.S. federal income tax purposes.

Distributions

The gross amount of a distribution (including any Russian tax withheld on the distribution) with respect to our ordinary shares will be treated as a dividend taxable as ordinary income on the date of receipt, to the extent of our current and accumulated earnings and profits as determined for U.S. federal income tax purposes. U.S. holders will not be eligible for the dividends-received deduction otherwise allowed under the U.S. Tax Code for distributions to domestic corporations in respect of distributions on the ordinary shares.

The amount of any distribution paid in a currency other than the U.S. dollar (e.g., rubles) will be the U.S.-dollar value of such currency on the date the U.S. holder (or the depositary, in the case of depositary shares) receives the distribution, regardless of whether the payment is in fact converted into U.S. dollars. Generally any gain or loss resulting from currency exchange rate fluctuations during the period from the date the U.S. holder included the dividend payment in income to the date the U.S. holder converts the payment into U.S. dollars would be treated as ordinary income or loss. The currency gain or loss generally would be income or loss from sources within the United States for foreign tax credit limitation purposes. If the foreign currency received in a distribution is converted into U.S. dollars on the date received by U.S. holders or the depositary on behalf of such U.S. holders, as the case may be, U.S. holders generally should not be required to recognise any gain or loss on such conversion. Any distribution in excess of our current and accumulated earnings and profits will first be treated as a non-taxable return of capital to the extent of the U.S. holder's tax basis in the ordinary shares, and thereafter as capital gain. The portion of any distribution treated as a non-taxable return of capital will reduce such U.S. holder's tax basis in such ordinary shares.

Subject to certain limitations, the Russian tax withheld on dividends paid to a U.S. holder will be creditable against the U.S. holder's U.S. federal income tax liability. In the event that a reduction in or rebate of Russian withholding tax is allowed by Russian law but is not obtained by a U.S. holder, a U.S. foreign tax credit will not be allowed in excess of the amount of tax imposed by Russian law and the U.S.-Russia Tax Treaty. Dividends will be income from sources outside the United States, but generally will be "passive income" or, for certain U.S. holders, "financial services income," which will be treated separately from other types of income for purposes of computing the foreign tax credit available to a U.S. holder.

Sale or exchange

A U.S. holder generally will recognise gain or loss for U.S. federal income tax purposes upon the sale or exchange of ordinary shares in an amount equal to the difference between the U.S. dollar value of the amount realised from such sale or exchange and the U.S. holder's adjusted tax basis, determined in U.S. dollars, for such ordinary shares. The amount realised with respect to the disposition of the ordinary shares for foreign currency generally will be (1) in the case of a cash basis taxpayer, the U.S. dollar value of the payment received determined on the settlement date of the sale of such ordinary shares (using the spot rate on such date) or (2) in the case of an accrual basis taxpayer, the U.S. dollar value of the payment received determined on the date of disposition of such ordinary shares (or, if such taxpayer so elects, the settlement date of the sale of such ordinary shares) (using the spot rate on such date). Such gain or loss will be a capital gain or loss, and will be long-term capital gain, taxable to individuals at a maximum rate of 20%, if the ordinary shares were held for more than one year. The deductibility of capital losses is subject to limitations. Any such gain or loss generally will be income or loss from sources within the United States for foreign tax credit limitation purposes.

If a U.S. holder receives a currency other than the U.S. dollar (e.g., rubles) upon a sale or exchange of ordinary shares, gain or loss, if any, recognised on the subsequent sale, conversion, or disposition of such currency will be U.S.-source ordinary income or loss. However, if such currency is converted into U.S. dollars on the date received by the U.S. holder, the U.S. holder generally will not be required to recognise any additional gain or loss on such conversion.

Passive Foreign Investment Company Considerations

The foregoing discussion assumes that we are not currently, and will not in the future be, classified as a passive foreign investment company, or PFIC, within the meaning of the U.S. Tax Code. Generally, if during any taxable year of a non-U.S. corporation, 75% or more of such non-U.S. corporation's gross income consists of certain kinds of "passive" income, or if the average value (or if the non-U.S. corporation so elects, the average adjusted basis) during a taxable year of such non-U.S. corporation's "passive assets" (generally assets that generate passive income) is 50% or more of the average value (or average basis) of all its assets, such non-U.S. corporation will be classified as a PFIC for such year. In making the foregoing determinations, we will be treated as having received directly our *pro rata* share of the income earned by any of our affiliates in which we own a 25% or greater interest and owning directly our *pro rata* share of the assets of any such affiliates.

Based on our current and projected income, assets and activities, we do not believe we will be classified as a PFIC for our current or any succeeding taxable year. However, because PFIC status is a factual matter that must be determined annually, and because there exist legal uncertainties with respect to the determination of PFIC status for companies engaged in commodities businesses, we can provide no assurances in this regard. If we were treated as a PFIC for any taxable year, the tax treatment of a U.S. holder on the receipt of dividends or the sale or exchange of common shares would be significantly different from that described above.

Consequences of PFIC classification. If we were classified as a PFIC for any taxable year in which a U.S. holder is a holder of our ordinary shares, such U.S. holder will be subject to special rules, generally resulting in increased tax liability in respect of gain realised on the sale or other disposition of the ordinary shares or upon the receipt of certain distributions on the ordinary shares. For example, gain recognised on disposition of PFIC stock or the receipt of an "excess distribution" from a PFIC is (1) treated as if it were ordinary income earned ratably on each day in the taxpayer's holding period for the stock at the highest marginal rate in effect during the period in which it was deemed earned and (2) subject to an interest charge as if the resulting tax had actually been due in such earlier year or years. (An excess distribution is the amount of any distribution received by a U. S. holder during the taxable year that exceeds 125% of the immediately preceding three-year average of distributions received from the corporation, subject to certain adjustments.) The foregoing rules will continue to apply with respect to a U.S. holder who held our ordinary shares while we met the definition of a PFIC even if we ceased to meet the definition of a PFIC.

United States backup withholding and information reporting

Dividend payments made within the United States in respect of the ordinary shares may be subject to information reporting to the IRS and to a current 30% backup withholding tax. Backup withholding will not apply, however, to a holder who furnishes a correct taxpayer identification number or certificate of foreign status and makes any other required certification, or is otherwise exempt.

If a U.S. holder sells ordinary shares to or through a U.S. office of a broker, the payment of the proceeds is subject to both U.S. backup withholding and information reporting unless the holder certifies that it is eligible for an exemption. If a U.S. holder sells ordinary shares outside the United States through a non-U.S. office of a non-U.S. broker, and the sales proceeds are paid to the U.S. holder outside the United States, then backup withholding and information reporting requirements generally will not apply to that payment. However, information reporting, but not backup withholding, will apply to a payment of sales proceeds, even if that payment is made outside the United States, if the ordinary shares are sold through a non-U.S. office of a broker that (1) is a U.S. person, (2) derives 50% or more of its gross income for a specified three-year period from the conduct of a trade or business in the United States, (3) is a "controlled foreign corporation" with respect to the United States, or (4) is a non-U.S. partnership, if at any time during its tax year either (a) one or more of its partners are U.S. persons, as defined in U.S. Treasury regulations, who in the aggregate hold more than 50% of the income or capital interest in the partnership or (b) the partnership is engaged in a U.S. trade or business, unless the U.S. holder establishes an exemption.

Any amounts withheld under the backup withholding rules from a payment to a holder will be allowed as a refund or a credit against such holder's U.S. federal income tax, provided that the holder has complied with applicable reporting obligations.

WORKING CAPITAL

We believe that our consolidated group has sufficient working capital for its present requirements, that is, for at least the twelve months following the date of publication of this document.

LITIGATION

During the twelve months preceding the date of publication of these Listing Particulars, neither we nor any member of our consolidated group has been engaged in any legal or arbitration proceedings, nor are any legal or arbitration proceedings pending or threatened, as far as we are aware, that may have or have had in the recent past a significant effect on our financial position except for the pending actions described below. In addition, we are not subject to any legal claims in relation to exploration or extraction rights that are potentially of material significance to us, except for the pending litigation described below.

On November 27, 2001, Archangel Diamond Corporation, or ADC, filed a claim in Colorado state court against us and OJSC Arkhangelskgeoldobycha, or AGD, one of our consolidated subsidiaries, alleging among other things breach of contract and breach of certain common law duties. ADC claims that AGD failed to honor a series of agreements providing for the transfer of a Russian diamond field development licence to ADC. ADC is seeking to recover approximately $4.8 billion comprised of $1.2 billion of actual and $3.6 billion of punitive damages. In addition ADC is seeking an injunction prohibiting us or AGD from transferring the licence to a third party. While the claim is in its early stages and no assurance can be given about the ultimate outcome, we do not believe that the ultimate resolution of this matter will have a material adverse effect on our financial condition.

GENERAL

Significant Changes

There has been no significant change in our financial or trading position or that of any member of our consolidated group since December 31, 2001, the end of the period to which our latest audited accounts relate.

Auditors

KPMG Limited, located at 11 Gogolevsky Boulevard, 119019 Moscow, Russia, is our independent auditor. KPMG audited the financial statements of our consolidated group in accordance with Russian law and U.S. GAAP for the years ended December 31, 1999, 2000 and 2001. No other information in this document has been audited.

Consents

KPMG Limited and KPMG Audit Plc have given, and have not withdrawn, their written consent to the inclusion in this document of the Accountants Report set out in "Part 7 – Financial Information" and the references thereto, in the form and context in which they are included, and have authorised the contents of the Accountants Report for the purposes of Regulation 6(1)(e) of the Financial Services and Markets Act 2000 (Official Listing of Securities) Regulations 2001.

Miller and Lents, Ltd. has given, and has not withdrawn, its written consent to the inclusion in this document of its Competent Person's Report set out in "Part 10 – Competent Person's Reserves Report," and the references thereto, in the form and context in which they are included, and has authorised the contents of the Reserves Report for the purposes of Regulation 6(1)(e) of the Financial Services and Markets Act 2000 (Official Listing of Securities) Regulations 2001.

Interests of Directors and the Competent Person

Neither any of our directors nor Miller and Lents has an interest, direct or indirect, in any assets that have been, within the two years preceding the date of publication of this document, acquired or disposed of by or leased to us, or are proposed to be acquired or disposed of by or leased to us, nor have any of our directors or Miller and Lents had any interest in any consideration passing to or from us. In addition, except as disclosed in "Part 6 – Management – Additional Information about our Directors", neither our directors nor Miller and Lents has an interest in our share capital.

Listings on other Stock Exchanges

Currently our ordinary shares are traded on the Moscow Interbank Currency Exchange, the Russian Trading System and the Saint Petersburg Currency Exchange.

In addition, the ADSs (as defined in "Part 9 – The Depositary Receipts – Terms and Conditions of the ADRs") are traded on the following stock exchanges and trading systems:

- the Bavarian Stock Exchange;
- the Berlin Stock Exchange;
- the Düsseldorf Stock Exchange;
- the Frankfurt Stock Exchange;
- the Hamburg Stock Exchange;
- the London Stock Exchange;
- the NEWEX Vienna Stock Exchange;
- the Stuttgart Stock Exchange; and
- the XETRA electronic trading system.

No Offer to the Public

The ordinary shares and depositary receipts that are the subject of these listing particulars have not been marketed and are not available to the public in connection with our application to admit them to the Official List of the U.K. Listing Authority.

Public Takeover Offers

During the period covered by the last financial year and the current financial year, there has not occurred any public takeover offer by a third party in respect of our shares.

During the period covered by the last financial year and the current financial year, there has not occurred any public takeover by us in respect of another company's shares, except as set out below.

Bitech Petroleum Corporation
We entered into an agreement with Bitech Petroleum Corporation, a Canadian company listed on the Toronto Stock Exchange, pursuant to which we made a cash offer of C$1.55 per share for all of Bitech's issued and outstanding common shares. Shareholders holding 92.7% of Bitech's common shares accepted our offer. We acquired the remaining 7.3% of Bitech's common shares in accordance with the compulsory acquisition provisions of the Canada Business Corporations Act.

DOCUMENTS AVAILABLE FOR INSPECTION

Copies of the following documents in the English language will be available for inspection during normal business hours on any weekday (Saturdays and public holidays excepted) for a period of fourteen days from the date of this document at the offices of Akin, Gump, Strauss, Hauer & Feld, our legal adviser, located at One Angel Court, London, EC2R 7HJ, United Kingdom:

- our charter;
- the material contracts referred to above;
- the service agreements of our directors discussed in "Part 6 – Management";
- the Accountants' Report included in "Part 7 – Financial Information";
- the competent person's Reserves Report prepared by Miller and Lents, Ltd. included in "Part 10 – Competent Person's Reserves Report";
- the letters of consent of KPMG Limited, KPMG Audit Plc, and Miller and Lents, Ltd. referred to above;
- a deposit agreement amended and restated as of March 11, 1998 between OAO LUKOIL, The Bank of New York as Depositary and all Owners and Beneficial Owners (as defined herein) from time to time of Level 1 ADRs;
- a deposit agreement expected to be entered into on or about August 5, 2002 between OAO LUKOIL, The Bank of New York as Depositary and all Owners and Beneficial Owners (as defined therein) from time to time of the Reg S ADRs;
- a deposit agreement amended and restated as of March 11, 1998 between OAO LUKOIL, The Bank of New York as Depositary and all Owners and Beneficial Owners (as defined therein) from time to time of the Existing 144A ADRs;
- a deposit agreement expected to be entered into on or about August 5, 2002 between OAO LUKOIL, The Bank of New York as Depositary and all Owners and Beneficial Owners (as defined therein) from time to time of the New 144A ADRs;
- a written statement made by KPMG Limited and KPMG Audit Plc setting out the adjustments made by them in arriving at the figures shown in the Accountants' Report; and
- our published audited consolidated accounts for each of the years that ended on December 31, 1999, 2000, and 2001 and the unaudited interim financial results for the three-month period ended March 31, 2002.

Part 12 – DEFINITIONS AND GLOSSARY

The expressions below shall have the following meanings throughout this document and the Competent Person's Reserves Report unless the context requires otherwise:

References to:

- bbl means barrel
- mbls or mbbls means thousand barrels
- mmbls or mmbbls (MMBbls) means million barrels
- boe means barrels of oil equivalent
- mboe means thousand barrels of oil equivalent
- mmboe means million barrels of oil equivalent
- mcf means thousand cubic feet
- mmcf means million cubic feet
- bcf means billion cubic feet
- tcf means trillion cubic feet
- mcm means thousand cubic meters
- mmcm means million cubic meters
- bcm means billion cubic meters
- km means kilometer
- tonne means metric tonne, or 1000 kilograms
- b/mm means barrels per million cubic feet
- CI means contour interval
- md means milliDarcy, a unit of permeability
- RBbl/STB means reservoir barrels per stock tank barrel of oil
- SCF/STB means standard cubic feet per stock tank barrel of oil
- CP means centipoise, a unit of viscosity

Equivalent measurements are based upon (some of which are for convenience purposes only):

- 1 barrel equals 0.137 tonnes of oil (subject to variation)
- 1 barrel equals 42 U.S. gallons
- 1 barrel of oil equivalents equals 1 barrel of crude oil
- 1 barrel of oil equivalent equals 170 standard cubic meters of natural gas
- 1 barrel of oil equivalent equals 6 mcf of natural gas
- 1 barrel of oil equivalent equals 0.122 tonnes of NGLs
- 1 billion standard cubic meters of natural gas equals 1 million standard cubic meters of oil equivalents
- 1 cubic meter equals 35.3 cubic feet
- 1 km equals 0.62 miles
- 1 square kilometer equals 0.39 square miles
- 1,000 standard cubic meters of natural gas equals 5.88 boe
- 1 standard cubic foot equals 0.0283 standard cubic meter
- 1 tonne of NGLs equals 1.3 standard cubic meters of oil equivalents
- 1 tonne equals 7.3 barrels (subject to variation)

"API gravity" means the industry standard method of expressing specific gravity of crude oils. Higher API gravities mean lower specific gravity and lighter oils.

"catalytic cracking" means a refinery process whereby crude oil is broken down into simpler hydrocarbon compounds at the molecular level by means of extreme heat and exposure to a chemical catalyst.

"coke" means a solid material similar to coal produced from processing crude oil.

"completion" means the installation of permanent equipment for the production of oil or gas.

"condensate" is a term used to describe light liquid hydrocarbons separated from crude oil after production and sold separately.

"development well" means a well drilled within the known area of an oil or gas reservoir to the depth of a stratigraphic horizon known to be productive.

"distillation" means the first stage in the refining process in which crude oil is heated and unfinished petroleum products are initially separated at their various boiling points.

"downstream" is a term used to refer to all petroleum activities from the refining of crude oil into petroleum products to the distribution, marketing and shipping of the products. The opposite of downstream is upstream.

"exploratory well" means a well drilled to find and produce oil or gas in an unproven area, to find a new reservoir in a field previously found to be productive of oil or gas in another reservoir, or to extend a known reservoir.

"field" means an area consisting of a single or multiple reservoirs all grouped in or related to the same individual geological structure or stratigraphic condition.

"hydrocarbons" means compounds formed from the elements hydrogen (H) and carbon (C) and may be in solid, liquid or gaseous forms.

"natural gas" means petroleum that consists principally of light hydrocarbons. It can be divided into lean gas, primarily methane but often containing some ethane and smaller quantities of heavier hydrocarbons (also called sales gas) and wet gas, primarily ethane, propane and butane as well as smaller amounts of heavier hydrocarbons; partially liquid under atmospheric pressure.

"operator" means a company appointed by venture stake holders to take primary responsibility for day-to-day operations of exploration and production activities.

"petrochemicals" means chemicals such as ethylene, propylene and benzene that are derived from petroleum.

"petroleum" is a collective term for hydrocarbons, whether solid, liquid or gaseous. The proportion of different compounds in a petroleum find varies from discovery to discovery. If a reservoir primarily contains light hydrocarbons, it is described as a gas field. If heavier hydrocarbons predominate, it is called an oil field. An oil field may feature free gas above the oil and contain a quantity of light hydrocarbons, also called associated gas.

"petroleum gas" means gas occurring in combination with crude oil, as distinct from gas occurring separately or manufactured from crude oil.

"probable reserves" are those reserves that, on the available evidence and taking into account technical and economic factors, have a better than 50% chance of being produced.

"proven reserves" are those reserves that, on the available evidence and taking into account technical and economic factors, have a better than 90% chance of being produced.

"royalty" as employed in the Reserves Report is a tax on production that is equal to the royalty percentage multiplied by the gross revenue to the interest of the Company.

"seismic" is the use of shock waves generated by controlled explosions to ascertain the nature and contour of geological structures.

"3-D seismic" means seismic data that is acquired and processed to yield a three-dimensional picture of the subsurface.

"upstream" is a term that includes exploring for oil, developing oil fields and producing oil from the oil fields. The opposite of upstream is downstream.

"workover" means operations on a producing well to restore or increase production.

sterling financial print 42114