PetroNeft Resources plc
Annual Report 2011
Годовой Отчет 2011

PetroNeft Resources plc is an international oil and gas exploration and production company, focused on Russia. The Company's shares are listed on the London AIM and Dublin ESM Markets.

Forward Looking Statements

This report contains forward-looking statements. These statements relate to the Group's future prospects, developments and business strategies. Forward-looking statements are identified by their use of terms and phrases such as 'believe', 'could', 'envisage', 'potential', 'estimate', 'expect', 'may', 'will' or the negative of those, variations or comparable expressions, including references to assumptions.

The forward-looking statements in this report are based on current expectations and are subject to risks and uncertainties that could cause actual results to differ materially from those expressed or implied by those statements. These forward-looking statements speak only as at the date of these financial statements.

Highlights

Operational Highlights

- Average production of 2,049 bopd.
- Group 2P reserves increase 36% to 131.7 mmbbls.
- Group Proved reserves increase 50% to 20.0 mmbbls.
- Largest single discovery made by PetroNeft to date at Sibkrayevskoye in August 2011. It contains 49.8 mmbbls of 2P reserves.
- Expanding the central processing facility capacity to 14,800 bfpd.

+50%

Increase in Proved (P1) reserves

Financial Highlights

- First full year of production.
- Capital expenditure of US$52 million.
- Improved Macquarie Debt facility – April 2011.
- New US$15 million loan facility with Arawak Energy – May 2012.

+36%

Increase in Proved and Probable (2P) reserves

Overview

Review of the Year

Governance

Financial Statements

Producing oil from an expanding asset base

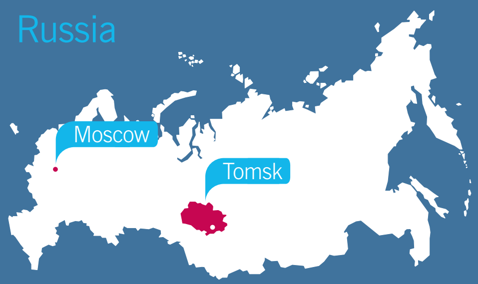
History

The Group has its origins in PetroNeft LLC, a Texas-based company, which was established in 2003 as an oil and gas investment and consultancy company focused principally on the Russian market. In May 2005, PetroNeft LLC acquired a Russian company, Stimul-T, which had acquired a 100% interest in Licence 61 following a competitive auction process in the November 2004 Tomsk Licence Auction. PetroNeft Resources plc was incorporated on 15 September 2005 and was admitted to the London AIM and Dublin ESM Markets in September 2006.

Our Assets

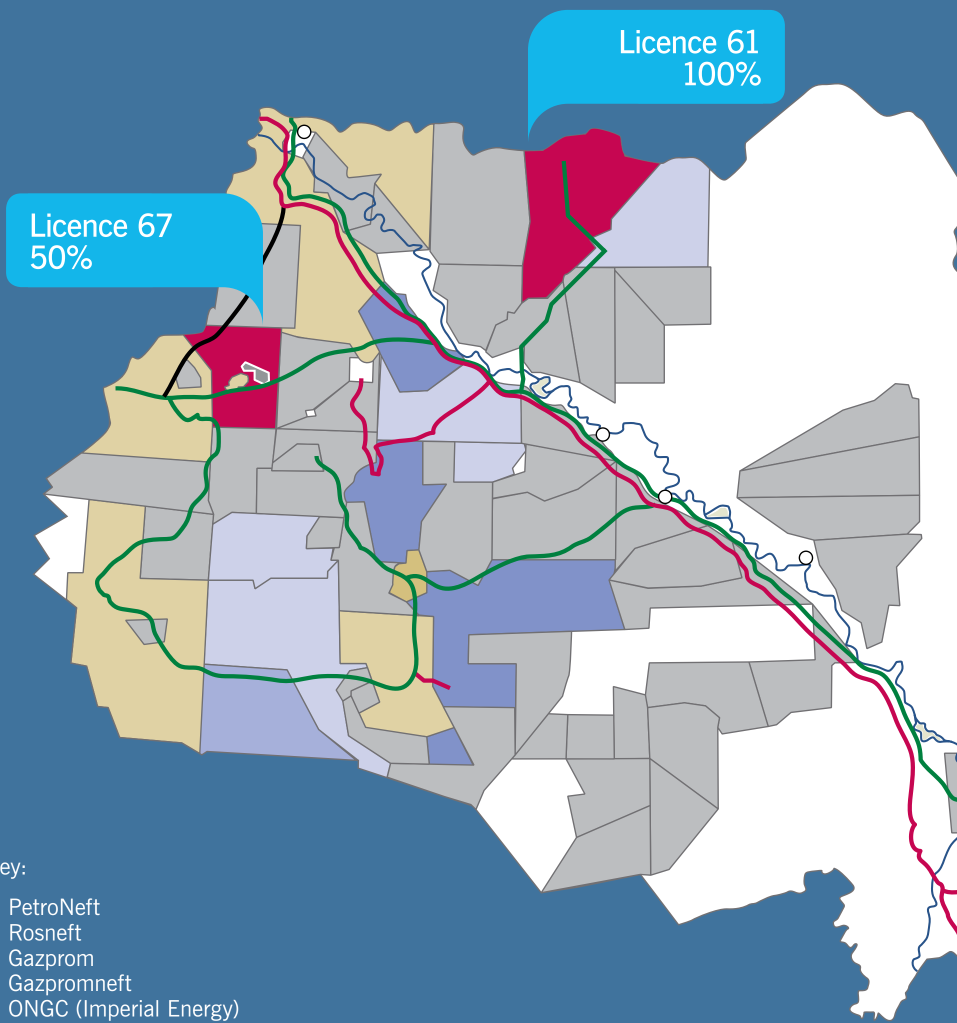
The main assets of the Company are a 100% interest in a 4,991 km^2 oil and gas licence (Licence 61) in the Tomsk Oblast in Russia and a 50% operating interest in a 2,447 km^2 oil and gas licence (Licence 67) also located in the Tomsk Oblast. Both licences are located in the prolific Western Siberian Oil and Gas Basin.

Russia



Scale
0 1,000 km

Tomsk Oblast



Key:

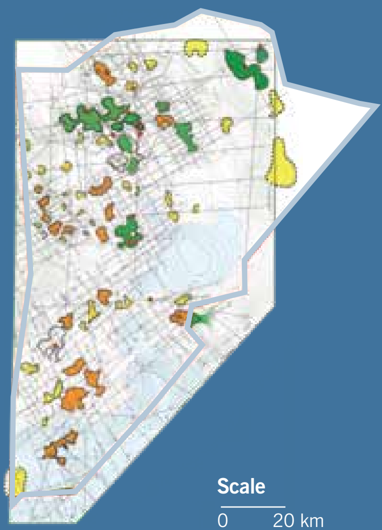
- PetroNeft
- Rosneft
- Gazprom
- Gazpromneft
- ONGC (Imperial Energy)
- Other
- Oil Pipeline
- Gas Pipeline
- All-weather Road

“The objective is to acquire new Core Exploration and Production Areas that satisfy the Group’s strict technical and legal evaluation criteria.”

Strategy

The Group’s strategy is to develop an oil exploration, development and production business in Russia, using the combined skills, experience and resources of the Group’s Directors and employees. In the short-term this is to be achieved through a focus on growth of production and cash flows at Licence 61 and a rigorous appraisal and exploration programme on Licences 61 and 67, by seeking to bring the existing discoveries into production as rapidly as possible and by exploiting the additional opportunities already identified and summarised in the Ryder Scott Report.

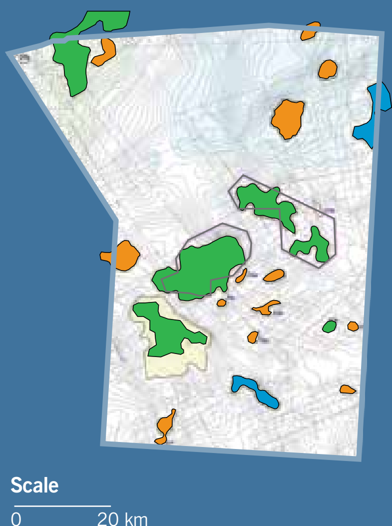
In addition to operations on Licences 61 and 67, the Company continues to evaluate new projects for acquisition. The objective is to acquire new Core Exploration and Production Areas that satisfy the Group’s strict technical and legal evaluation criteria. While the main focus for new acquisitions will be the West Siberian Basin, the Company will also consider projects in other areas within the Russian Federation.



Licence 61

Licence 61 contains seven known oil fields: Lineynoye, Tungolskoye, West Lineynoye, Kondrashevskoye, Arbuzovskoye, Sibkrayevskoye and North Varyakhskaya and over 25 Prospects and Leads that are currently being explored.

Page More information see page 04



Licence 67

Licence 67 contains the Cheremshanskoye and Ledovoye oil fields and numerous prospects and leads.

Page More information see page 06

Licence 61

As well as seven discovered oil fields in Licence 61 there are over 25 additional prospects to be explored.

2011 Work Programme

Production Wells and Facilities
In 2011 the capacity of the oil processing facilities at Lineynoye were expanded to 14,800 bfpd and 14 development/delineation wells were drilled from Pads 2 and 3 at the Lineynoye oil field. The Pad 1 wells which were drilled in 2010 responded to the pressure maintenance programme that was initiated in June 2011 and the natural production decline has now halted in many wells and in some cases started to reverse.

A fracture stimulation programme for the Pad 2 wells was carried out in November 2011. The initial response was positive and the field peaked at 3,000 bopd in December; however, production from Pad 2 wells decreased rapidly due to higher than expected well decline rates and water cuts. In some of the Pad 2 wells the reservoir pressure has declined and is a factor in the production decline. We have now converted one of the Pad 2 wells to a water injection well with the aim of restoring some of the reservoir pressure and will convert further wells as necessary.

Exploration, Delineation and Reserve Expansion
In 2011 three further exploration/delineation wells were drilled in Licence 61. The wells were a delineation well at Kondrashevskoye, followed by exploration wells at Sibkrayevskaya and North Varyakhskaya. All three wells were successful with a major discovery being made at Sibkrayevskoye which alone contains 2P reserves of 49.8 mmbbls.

2012 Programme

The focus for 2012 is to bring the Arbuzovskoye oil field into production with a secondary focus on delineation of the Sibkrayevskoye oil field.

7 Oil Fields

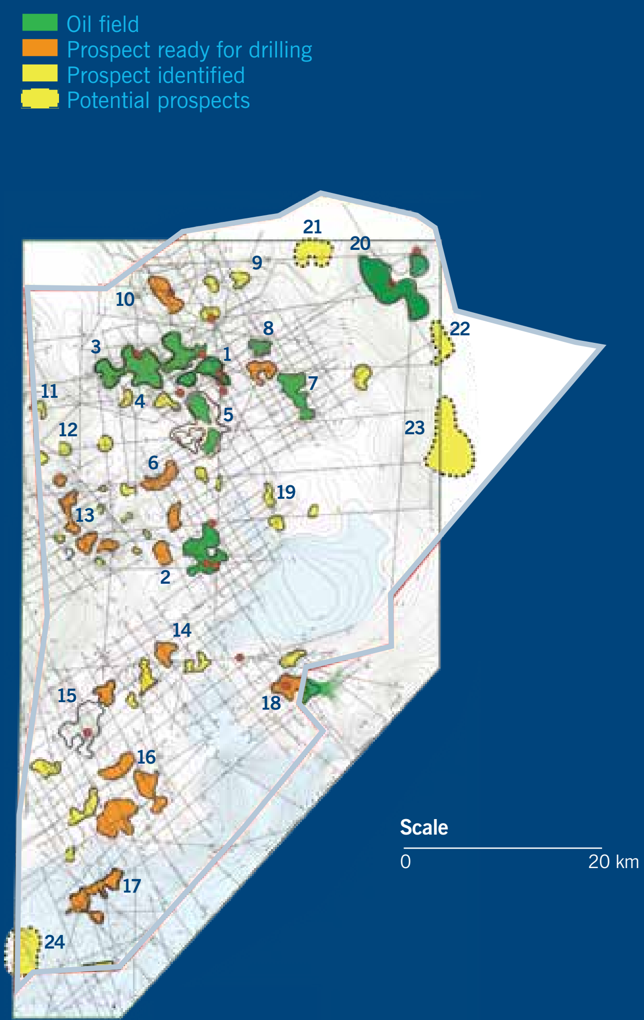
01 Lineynoye oil field
02 Tungolskoye oil field
03 West Lineynoye oil field
05 Kondrashevskoye oil field
07 Arbuzovskoye oil field
08 North Varyakhskoye
20 Sibkrayevskoye

23 Prospects

02 Tungolskoye West Lobe and North (2)
04 Lineynoye Lower
06 West Korchegskaya (Lower Jurassic)
08 Upper Varyakhskaya
09 Emtorskaya East
10 Emtorskaya Crown
11 Sigayevskaya
12 Sigayevskaya East
13 Kulikovskaya Group (2)
14 Kusinskiy Group (2)
15 Tuganskaya Group (3)
16 Kirillovskaya (4)
17 North Balkinskaya
18 Traverskaya
19 Tungolskoye East

4 Potential Prospects

21 Emtorskaya North
22 Sibkrayevskaya East
23 Sobachya
24 West Balkinskaya



New Oil Field Discovery at Sibkrayevskoye

Largest ever discovery by PetroNeft.

Sibkrayevskaya No. 372 Exploration Well Objectives

- Parallel well No. 370 which had been drilled in 1972.
- To target 8.4 m of 'missed pay' oil pay in Upper Jurassic interval identified by re-interpretation of vintage well logs from 1972 well.

Results

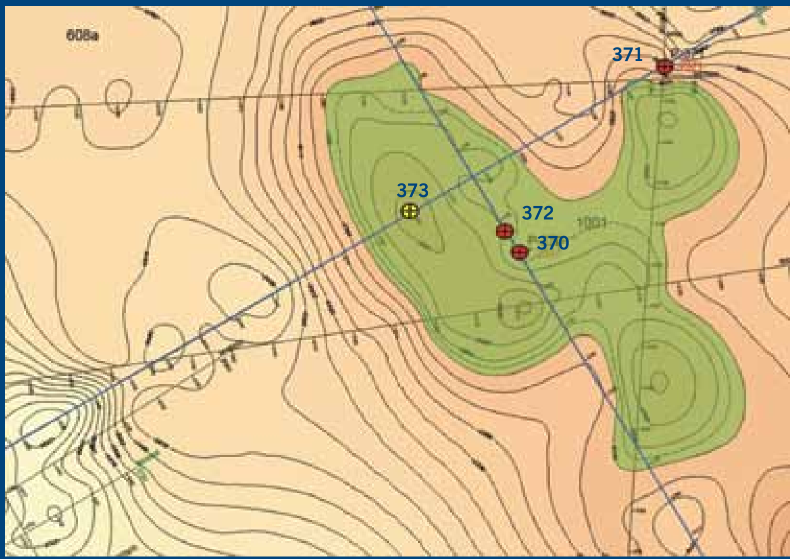
- Well No. 372 confirms 12.3 m of 'missed pay'.
- Open hole inflow test 170 bopd, 37 degree API.
- Over 50 km^2 of closure above oil-down-to level in well 372.
- Additional seismic and well data will be required to fully assess the discovery.

Proposed Delineation Objectives

Sibkrayevskaya No. 373 Delineation
- Crestal well located on modern 2D seismic line.
- 25 m higher structurally to well No. 372.
- Determine lateral distribution of J1-2 primary interval.
- Determine if secondary J1-3 interval is oil saturated on crest of structure.

Additional Seismic Acquisition
- Large 2D survey to cover Sibkrayevskoye, surrounding area and Emtorskaya high.
- Focused 3D survey within Sibkrayevskoye oil field also possible.

Timing: 2012/13 Dependent on Funding
- Sibkrayevskaya No. 373 location is fully stocked with drilling rig in place and ready to go.
- 2D grid pattern for seismic acquisition is mapped out.



Scale
0 2 km

Structure Map on Base Bazhenov Horizon

Arbuzovskoye Field Development

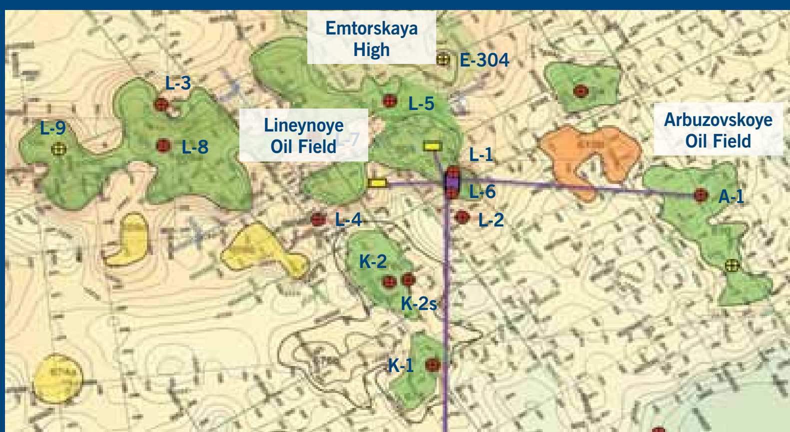
Increasing production in 2012.

Arbuzovskoye Oil Field

- Discovered in November 2010.
- 2P reserves of 13.3 mmbbls.
- The Arbuzovskoye No. 1 discovery well achieved an inflow of 289 bopd from an open hole test from the Upper Jurassic J1 sandstones.
- A step rate DST was performed and stabilised flow on an 8 mm choke was 176 bopd without a pump.
- The oil is high quality with a 47 degree API gravity.

Arbuzovskoye Field Development

- Drill up to ten wells in 2012.
- Construct 10 km pipeline and utilities connection from Central Processing Facility to Arbuzovskoye.
  - Completed in April 2012.
- Pump added to Arbuzovskoye No. 1 well in early 2012.
  - The well has produced at about 350 bopd in June 2012.



Scale
0 2 km

Structure Map on Base Bazhenov Horizon

Licence 67

Successful two well programme completed in 2011/12.

2011 Work Programme

In 2011/2012 two wells were drilled, one at the Cheremshanskaya prospect and a second at the Ledovoye oil field. These wells resulted in the discovery of a new oil field at Cheremshanskoye (December 2011) and the confirmation of the Upper Jurassic J1-3 oil pool at Ledovoye field with a potential new oil pool discovery in the lower Cretaceous (February 2012). It is important to note that both wells were drilled parallel to existing wells in order to optimise the coring and testing of potential by-passed pay zones identified in the vintage wells drilled in 1962 and 1973 respectively.

The Cheremshanskaya No. 3 well discovered three separate oil pools and established the Cheremshanskoye oil field. These intervals were the J14, the J1-3 and the J1-1 + Bazhenov and there were successful flow tests from each interval. The area of the field is very large encompassing almost 40 km^2 and further delineation and pilot testing will be required to assess the true size of the field and ultimate development plan. There are large producing fields nearby with similar characteristics and the strong indications are that Cheremshanskoye will prove to be a substantial discovery upon further delineation. The likely next step here is to acquire 3D seismic data over the field.

The Ledovaya No. 2a well was spudded on 5 December 2011 in order to target oil in both the Lower Cretaceous and Upper Jurassic intervals with oil discovered in both zones. The well achieved stabilised natural oil flow of 52 bopd from the Upper Jurassic interval whereas the core and log data also indicate that the well has discovered a new oil pool in the secondary objective Lower Cretaceous interval containing 4.5 m of potential oil pay. The Lower Cretaceous zone will eventually need to be flow tested behind casing for confirmation. We are pleased with the result given that the same interval is productive at the neighbouring Stolbovoye field which is located 24 km to the south.

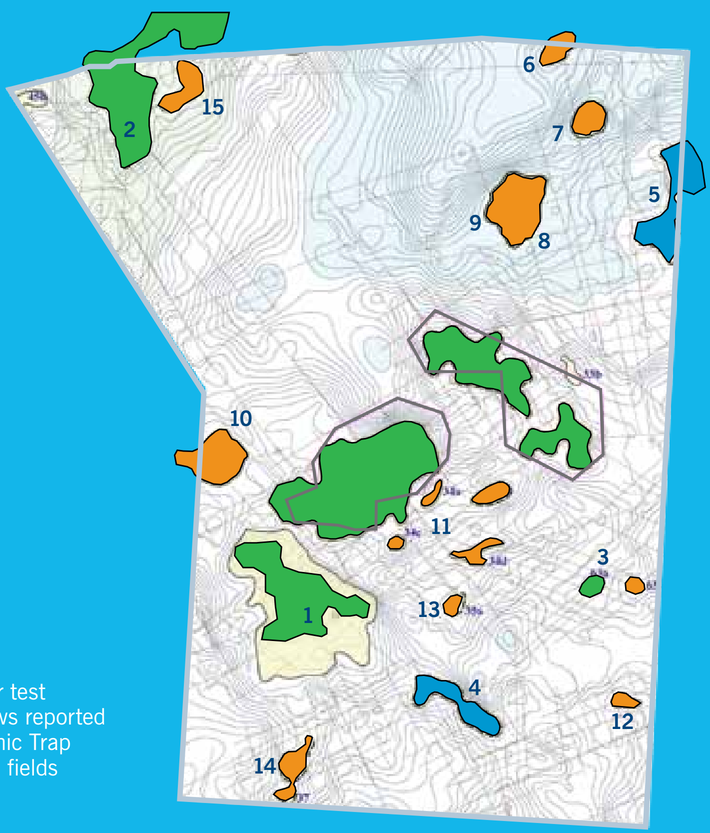
More details of the testing programme on both wells are provided in the Chief Executive Officer's Report.

Drilled Structures

01 Cheremshanskoye
02 Ledovoye oil field
03 Sklonovaya
04 North Pionerskaya
05 Bolotninskaya

Identified Prospects and Leads

06 Levo-Ilyakskaya
07 Syglynigaiskaya
08 Grushevaya
09 Grushevaya Stratigraphic trap
10 Malostolbovaya
11 Nizhenolomovaya Terrasa Gp.
12 Baikalskaya
13 Malocheremshanskaya
14 East Chermshanskaya
15 East Ledovoye



Drilled Structure with oil show or test
Drilled Structure with no oil shows reported
Undrilled Structure or Stratigraphic Trap
Excluded area with producing oil fields

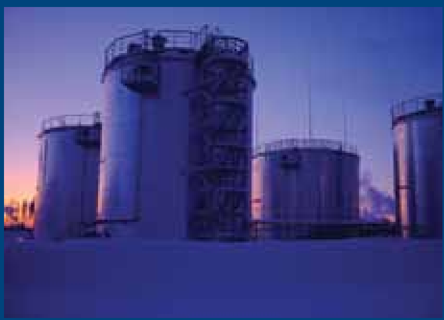
Scale
0 25 km

Our Reserves

Year-round production commenced in 2010. Since acquiring Licence 61 in 2005, Group proved and probable reserves have grown by 372% to 132 mmbbls.

2P Reserve Growth

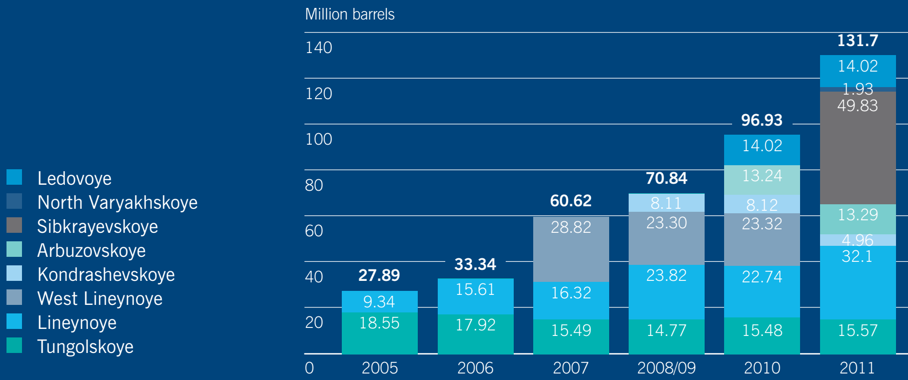
Licences 61 & 67



- 2P reserves are as estimated by Ryder Scott, Petroleum Consultants, each year and conform to the definitions approved by the Society of Petroleum Engineers ('SPE') Petroleum Resources Management System ('PRMS') rules.
- Lineynoye and West Lineynoye confirmed as one field in 2011.

36%

Increase in 2P reserves in 2011



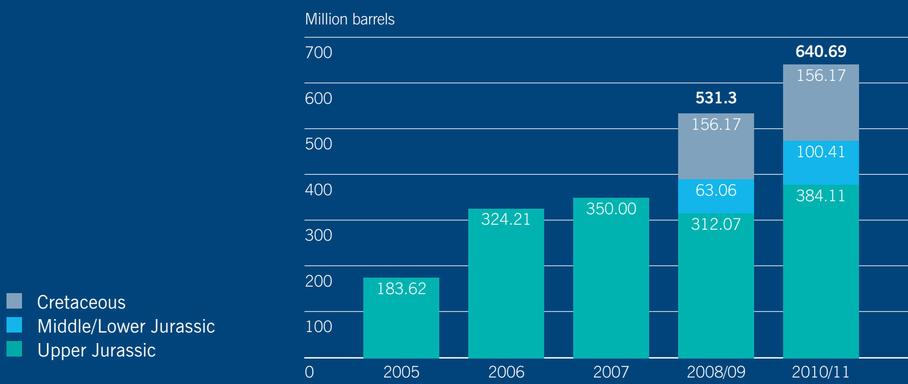
3P Reserves and Exploration Resources (P4) Growth

Licences 61 & 67

- 3P reserves are as estimated by Ryder Scott, Petroleum Consultants, each year and conform to the definitions approved by the Society of Petroleum Engineers ('SPE') Petroleum Resources Management System ('PRMS') rules.
- All Exploration Resources (P4) are based on structures with unequivocal four-way dip closure at the reservoir horizon as identified by 2D seismic data.

50%

Increase in Proved (P1) reserves in 2011



Chairman's Statement

With the Arbuzovskoye and Sibkrayevskoye oil fields the Group can generate significant cash in the coming years that should enable it to expand its oil reserve base both through exploration and delineation in current licence areas and through business development opportunities in Tomsk and further afield in Russia.

A Busy but Mixed Year

2011 was a busy year. It was PetroNeft's first full year of production and saw its largest ever work programme with 14 production wells and five exploration and delineation wells. Whilst we had great success with our exploration wells the production wells were disappointing despite having shown initial promise.

Production

14 new production wells were drilled at the Lineynoye oil field, 12 at Pad 2 and two at Pad 3. A programme of hydraulic fracturing was carried out on ten of these wells in November 2011. The initial response was positive and the field peaked at 3,000 bopd in December; however, production from the Pad 2 wells decreased rapidly and has now stabilised at around 2,200 bopd.

The Pad 1 wells which were drilled in 2010 responded very quickly to the pressure maintenance programme that we initiated in June 2011. There are currently three injection wells on Pad 1 and the production decline has now halted in many wells and in some cases started to reverse. We will convert additional Pad 2 wells to water injection wells in the coming months with the aim of restoring some of the reservoir pressure and increasing production.

The next field in our development programme is Arbuzovskoye where we plan to drill up to ten production wells in 2012. The Arbuzovskoye No. 1 exploration well is now producing about 350 bopd which is an excellent rate prior to fracture stimulation. This also confirms that we should not see similar issues to Lineynoye Pad 2 at Arbuzovskoye.

Reserves Growth

The Company drilled five exploration and delineation wells in 2011, all of which were successful. We are especially delighted with the new discoveries at Sibkrayevskoye and Cheremshanskoye which we feel will prove to be major oil fields with further seismic and well delineation. These are both especially important discoveries as they prove our strategy of following up on previously drilled structures by re-interpreting old well data using modern software and techniques to identify by-passed pay.

Independent reserve auditor Ryder Scott has completed an assessment of PetroNeft's petroleum reserves and resources on Licence 61 as at 1 January 2012. As a result, total proved and probable ('2P') reserves net to PetroNeft, including our share of Licence 67, have risen by 36% from 96.9 million bbls to 131.7 million bbls. Total proved reserves ('P1') have increased by 50% from 13.3 million bbls to 20.0 million bbls in spite of the results with the Lineynoye Pad 2 wells.

Ryder Scott did not update the reserves in Licence 67 at the end of 2011 as all of the well testing was not completed. Studies are now underway to better define the three new oil pools discovered at Cheremshanskoye and two oil pools at Ledovoye.

Successful Debt Financing

On 30 May 2012, PetroNeft signed a three-year loan agreement with Arawak Energy Russia B.V. ('Arawak') for US$15 million. The loan is secured on PetroNeft's 50% interest in Licence 67 and will be repayable in one lump sum at the end of the three-year loan period in May 2015. The interest payable under the loan will be LIBOR plus 6%, a competitive rate given present market conditions. Under the terms of the loan PetroNeft also granted Arawak 4,000,000 warrants over shares at a strike price of US$0.1345 per share.

The existing US$30 million facility with Macquarie Bank Limited remains in place and Macquarie has granted permission under the terms of their facility for this additional debt facility with Arawak.

It remains the Board's intention to fund the Company with a mixture of debt and equity for business development purposes and to accelerate the appraisal and development programme on Licences 61 and 67. We will also consider active portfolio management including the farm out or sale of assets as well as acquiring new assets as opportunities arise. The financial review and Note 2 to the Consolidated Financial Statements discuss the funding situation of the Group in more detail.

Business Development

The principal near-term objective of the Group remains the development of the northern oil fields on Licence 61. However, we have not lost sight of our longer term objective of securing assets outside of Licence 61 to provide growth for the future.

The acquisition of Licence 67 (Ledovy) in January 2010 was a first step in this growth. Licence 67 was acquired under the August 2008 Area of Mutual Interest ('AMI') with Arawak where they have exercised their right to acquire 50% of the Licence. Licence 67 has now provided collateral in a new US$15 debt financing with Arawak and on 30 May 2012, PetroNeft entered into a new three-year AMI with Arawak. Under the agreement the two companies will continue to jointly pursue new opportunities in Western Siberia, building on the success of the previous AMI agreement that ran for three years to August 2011.

We have a good working relationship with Arawak and look forward to working with them to develop Licence 67 and acquire new assets under the AMI. We continue to actively examine a number of acquisition opportunities in the Tomsk region and elsewhere in Russia and will update shareholders in more detail at the appropriate time.

Corporate Development

We have now transitioned from an exploration company to an exploration and production company. The management structure in Tomsk has been revised over the past couple of years with as a result most new positions being filled by excellent candidates from within our own organisation. We intend to operate the new Arbuzovskoye field with our existing workforce. The Group headcount now stands at 174 employees.

I would like to thank all of our employees for their dedication to the Company and their hard work in 2011.

Summary

Overall, 2011 was a busy year with mixed results. PetroNeft's first full year of production and its largest ever work programme resulted in great exploration success but disappointing productivity in the Pad 2 production wells.

PetroNeft has moved quickly to understand the production issues at Pad 2 and I am confident we can avoid similar problems at Arbuzovskoye and Sibkrayevskoye which are the next two major developments.

With the Arbuzovskoye and Sibkrayevskoye oil fields the Group can generate significant cash in the coming years that should enable it to expand its oil reserve base both through exploration and delineation in current licence areas and through business development opportunities in Tomsk and further afield in Russia.

PetroNeft is fortunate to have a highly experienced and dedicated team whose knowledge and experience have enabled us to meet the array of challenges facing the Group in recent years. I am confident that this team will enable PetroNeft to continue to add shareholder value.

Finally, I know that I speak for all the Directors, management and staff of the Group in giving sincere thanks to our shareholders, both old and new, for your continued support through the past year.

T. David Golder

David Golder
Non-Executive Chairman

Chief Executive Officer's Report

The largest single discovery made by PetroNeft to date was discovered at Sibkrayevskoye in August 2011. It contains 49.8 mmbbls of 2P reserves and was the sixth oil field discovered by PetroNeft.

General

2011 was the first full year of production for PetroNeft and was accompanied with the largest ever work programme. The major disappointment for the year was the production performance of the Pad 2 wells at Lineynoye oil field. While the log evaluation and initial performance of these wells after fracture stimulation showed great promise the final result was very disappointing. Aside from this, there were a number of significant successes as highlighted below:

Licence 61 Highlights

- The largest single discovery made by PetroNeft to date was discovered at Sibkrayevskoye in August 2011. It contains 49.8 mmbbls of 2P reserves and was the sixth oil field discovered by PetroNeft.
- In September 2011 a seventh oil field was discovered at North Varyakhskoye. It contains 1.9 mmbbls of 2P reserves.
- 2011 work programme consisted of expanding the central processing facility capacity to 14,800 bpd, construction of two new pads, drilling of 14 development wells and three exploration/delineation wells. All projects were completed to schedule and within budget.
- PetroNeft's proved reserves (P1) increase 50% to 20.0 mmbbls.
- The Q1 2012 work programme consisted of the construction of a 10 km pipeline and utilities line from Lineynoye to Arbuzovskoye.

Licence 67 Highlights

- In October 2011 a new oil field with three separate oil pools was discovered at Cheremshanskoye.
- In February 2012 oil was confirmed in the primary Upper Jurassic objective at Ledovoye oil field along with a potential new oil pool in the secondary Lower Cretaceous interval.

Licence 61 (Tungolsky)

Licence 61 – Lineynoye Development

In 2011 the processing facilities at Lineynoye were expanded to 14,800 bfpd and 14 development wells were drilled from Pads 2 and 3.

The Pad 1 wells which were drilled in 2010 responded to the pressure maintenance programme that we initiated in June 2011. There are currently three injection wells on Pad 1 and the natural production decline has now halted in many wells and in some cases started to reverse. We are encouraged with the water flood response on the Pad 1 wells.

A fracture stimulation programme for the Pad 2 wells was carried out in November 2011. The initial response was positive and the field peaked at 3,000 bopd in December; however, production from Pad 2 wells decreased rapidly due to higher than expected well decline rates and water cuts. Production has now stabilised at around 2,200 bopd. In some of the Pad 2 wells the reservoir pressure has declined and is a factor in the production decline. We have now converted one of the Pad 2 wells to a water injection well with the aim of restoring some of the reservoir pressure. Additional wells will be converted as part of a normal water injection and pressure maintenance programme.

As the Pad 2 wells did not perform nearly as well as those on Pad 1, we commenced a number of studies on the Pad 2 wells, including a field wide pressure transient test of individual wells in order to understand the difference in results. These studies will be completed later in 2012.

The drilling results indicate that the field extends further north than previously estimated and that the Lineynoye and West Lineynoye fields are one connected structure. In fact, the Pad 2 drilling results indicate that field wide oil water contact lies below the structural spill point between Lineynoye and the Emtorskaya high to the north providing further evidence that the field is much larger and potentially includes the Emtorskaya high structures to the north.

At this stage we know that all of the Pad 2 wells were lower on the structure than the Pad 1 wells, the reservoir section was closer to the oil-water-contact and the oil saturation in the wells was lower. This resulted in higher initial water cuts in the wells than expected. It also appears that the reservoirs at Pad 2 are tighter than at Pad 1, in part due to the higher water saturations, and the combination of relative permeability and fractional flow effects in the reservoir. However, this is not always obvious from the log analysis. Some of these problems can be avoided in the future by drilling higher on the structures and avoiding potential oil and water zones. More extensive testing and coring of the production wells will also be carried out in the future.

Licence 61 – Arbuzovskoye Development

The Pilot Production Design for the Arbuzovskoye oil field was approved by the Russian State Central Development Committee in November 2011. Construction of a 10 km pipeline and utilities line from the Lineynoye Central Processing Facilities to Arbuzovskoye and mobilisation of the drilling rig and supplies to drill up to ten new production wells was carried out in Q1 2012 while winter roads were in place to handle the heavy loads. Production from the new wells is now expected to commence in Q3 2012.

Arbuzovskoye contains 2P reserves of 13.2 million barrels of oil according to independent reserve consultants Ryder Scott. The Arbuzovskoye No. 1 discovery well demonstrated good reservoir properties and produced a stabilised natural flow of 176 bopd on an 8 mm choke. Based on this result we expect good initial production rates from the Arbuzovskoye development wells that can be augmented later with fracture stimulation. The Arbuzovskoye No. 1 discovery well has been completed with an electrical submersible pump and is now producing through the pipeline at a steady rate of about 350 bopd. This is an excellent pre-frac rate and confirms that we do not foresee similar issues to the Lineynoye Pad 2 wells arising at Arbuzovskoye.

Licence 61 – Exploration, Delineation and Reserve Expansion

In 2011 three further exploration/delineation wells were drilled in Licence 61. The wells were a delineation well at Kondrashevskoye, followed by exploration wells at Sibkrayevskaya and North Varyakhskaya. All three wells were successful with a major discovery being made at Sibkrayevskoye.

The Sibkrayevskaya No. 372 well at the Sibkrayevskaya prospect located in the north east corner of Licence 61 was spudded on 9 July 2011. It was a follow up to well No. 370 which was drilled in 1972. A comprehensive re-interpretation of the vintage well logs and drilling data from the 370 well using digitalised logs and modern interpretation tools had identified potential 'missed pay' in the Upper Jurassic J1 interval. In the new well, No. 372, the Upper Jurassic J1 oil reservoir horizon was intersected as expected at -2,350.5 metres true vertical depth. The log evaluation indicates that the J1 interval consists of 12.6 metres of net pay with good reservoir properties and oil saturation throughout, exceeding pre-drill estimates. An open hole test was conducted over this interval and tested at a pro-rated inflow of 170 bopd unstimulated. Based on preliminary analysis, the oil is of good quality with an API gravity of 37 degrees, which is consistent with other fields in Licence 61.

Sibkrayevskoye is a very large structure which will require additional seismic and well delineation. The 372 well was drilled in a flank position on the structure and current mapping shows an area of over 50 km^2 up dip from the oil-down-to level defined in the well. Sibkrayevskoye is currently estimated to contain about 50 million barrels of 2P reserves. While additional seismic and drilling will be required to fully define the size of the field, it is currently the largest field discovered by the Company and will be an important element of our future development and production growth plans. We have selected a delineation well location, prepared a drilling pad and moved the drilling rig and supplies to location in Q1 2012 so we have the option of advancing the Sibkrayevskoye development later in 2012. The discovery also extends the area of known oil to the northeast corner of the licence area and improves the prospectivity of other structures in this area.

Reserves Upgrade

Independent reserve consultants Ryder Scott completed an assessment of PetroNeft's petroleum reserves and resources on Licence 61 as at 1 January 2012. The principal changes from the previous year's report were the addition of proved and probable reserves at the Sibkrayevskoye and North Varyakhskoye oil fields which were discovered in August and September 2011 respectively. The development drilling results at Lineynoye have confirmed that Lineynoye and West Lineynoye are one continuous oil field. The Pad 2 and 3 wells and fracture stimulation results led to a reserve write down in this area of the field; however, this reduction was more than compensated for by the successful exploration programme.

As a result of the new report on Licence 61, total proved and probable (2P) reserves net to PetroNeft have risen by 36% from 96.9 mmbbls to 131.7 mmbbls. Total proved reserves (P1) have increased by 50% from 13.3 mmbbls to 20.0 mmbbls.

While the current focus is the quick development and tie-in of new fields in the vicinity of the Lineynoye Central Processing Facilities, we have a significant portfolio of prospects in the southern portion of the Licence, of which many have potential in multiple horizons including the Cretaceous. An all weather road is available through a significant portion of this part of the Licence and crosses over some prospects giving us some flexibility when these prospects are drilled in the future.

Licence 67 (Ledovy)

Licence 67 was registered in January 2010. The 2010 work programme focused on the overall re-evaluation of all the previous data on the Licence area with modern technology. Well and seismic data was reprocessed and the results of this evaluation were used to select the location of two exploration wells and will be used to assess where to acquire the 750 km of new seismic data required to be completed under the licence terms.

In 2011/2012 two wells were drilled, one at the Cheremshanskaya prospect and a second at the Ledovoye oil field. These wells resulted in the discovery of a new oil field at Cheremshanskoye (December 2011) with three separate oil pools and the confirmation of the Upper Jurassic J1-3 oil pool at Ledovoye field with a potential new oil pool discovery in the lower Cretaceous (February 2012).

It is important to note that both wells were drilled parallel to existing wells in order to optimise the coring and testing of potential by-passed pay zones identified in the vintage wells drilled in 1962 and 1973 respectively.

Chief Executive Officer's Report (continued)

Licence 67 – Cheremshanskaya No. 3 Well

In summary, the Cheremshanskaya No. 3 well discovered three separate oil pools and established the Cheremshanskoye oil field. These intervals were the J14, the J1-3 and the J1-1 + Bazhenov. The area of the field is very large encompassing almost 40 km^2 and further delineation and pilot testing will be required to assess the true size of the field and ultimate development plan. There are large producing fields nearby with similar characteristics and the strong indications are that Cheremshanskoye will prove to be a substantial discovery upon further delineation. The likely next step here is to acquire 3D seismic data over the field.

Testing of the Lower Jurassic J14 interval which contains 8.6 m of net pay was completed in December 2011. The well flowed naturally to the surface at a rate of 6 m3/d (38 bfpd), consisting of a light, high quality, low viscosity oil with an API gravity of 50 degrees, gas and water. This is understood to be the first natural flow ever achieved from this Lower Jurassic interval in the Tomsk Oblast. Sustained commercial production has been achieved from this interval in other fields in the region following fracture stimulation.

The next phase of testing focused on the primary Upper Jurassic J1-3 interval. The initial log interpretation indicated this interval to be water bearing, however, additional log and core interpretation indicated that it may contain up to 7.0 m of net oil pay. The testing plan was to isolate the interval from the rest of the Upper Jurassic interval (J1-1 and J1-2) which were also interpreted to be oil bearing, and to get an independent test of the true saturation of this J1-3 interval.

Testing of the primary Upper Jurassic J1-3 interval was successfully completed in February 2012. The J1-3 interval which was initially interpreted to be water bearing, proved to be oil bearing. Based on the cased hole testing the interval is interpreted to contain 6.5 m of net pay (4.7 m of oil saturation and 1.8 m of oil and water saturation). Average inflow was about 44 bfpd consisting of 20.3% oil and 79.7 % formation water. The oil is good quality with a 34 degree API.

The J1-3 interval was then isolated with a cement packer and the J1-1 + Bazhenov interval was tested. This interval consisted of 1.2 m of net pay in the J1-1 plus 3 m of fractured shale at the base of the Bazhenov Formation. Average oil inflow from the J1-1 + Bazhenov was about 12.6 bopd of high quality oil with a 40 degree API gravity.

Licence 67 – Ledovaya No. 2a Well

The Ledovaya No. 2a well was spudded on 5 December 2011. The well was targeting oil in both the Lower Cretaceous and Upper Jurassic intervals. Based on the initial evaluation of log and core data the primary Upper Jurassic J1/1-2 reservoir interval contains about 10 m of high quality sandstone. The top five metres are interpreted as oil bearing whereas the lower five metre zone are interpreted to be an oil plus water transitional zone.

Testing of the combined J1-1 and J1-2 interval consisting of 5 m of net oil pay was completed in April 2012. The well achieved stabilised natural oil flow of 8.3 m3/day (52 bopd) on a 3 mm choke. The oil is good quality with a 34 degree API gravity. The well has been temporarily suspended and we are reviewing our options for further delineation/development of the field.

The core and log data also indicate that the well has discovered a new oil pool in the secondary objective Lower Cretaceous interval. Data indicates that a sandstone interval from 2,515 to 2,523 m contains 4.5 m of potential oil pay. The zone will eventually need to be flow tested behind casing for confirmation; however, we do not have a good cement bond over the interval behind casing to currently test the interval. At this stage we are pleased with the result given that the same interval is productive at the neighbouring Stolbovoye field which is located 24 km to the south.

Ryder Scott did not update the reserves in Licence 67 at the end of 2011 as all of the well testing was not completed. Studies are now underway to better define the three new oil pools discovered at Cheremshanskoye and two oil pools at Ledovoye.

Business Development

The Group actively pursues opportunities in the Tomsk Region and Russia in general. These include potential corporate acquisitions and participating in State Auctions. The Group has developed a high technical and economic standard with regard to acquisitions and many opportunities do not meet this test. However, our experience shows that there are quality opportunities available and we just need to be patient and deliberate in our search.

This work came to fruition in January 2010 with the acquisition of Licence 67 at a State Auction in the Tomsk region. Since then we have evaluated a number of new opportunities and are pursuing a select number of these.

Arawak Area of Mutual Interest

On 30 May 2012, PetroNeft entered into a new three-year AMI with Arawak. Under the agreement the two companies will continue to jointly pursue new opportunities in Western Siberia, building on the success of the previous AMI agreement that ran for three years to August 2011. Under the previous AMI, Arawak opted to take a 50% interest in Licence 67 which was acquired by PetroNeft in January 2010.

Health, Safety and Environmental

The Group is fully committed to high standards of Health, Safety and Environmental ('HSE') management. More details of our HSE activities are included in the HSE report on page 14.

Personnel

The Group made one important senior management appointment in early 2012. In March, Dmitry Shelkovnikov, who has worked with us since 2006, was appointed to the Group as Chief Engineer having previously been Chief Drilling engineer and Chief of Production for LLC Stimul-T. Dmitry has over ten years experience in the development of oil and gas fields in the Tomsk region. He has advanced degrees from Tomsk Polytechnic University in the drilling of oil and gas wells and the design, construction and operation of oil and gas infrastructure.

Conclusion

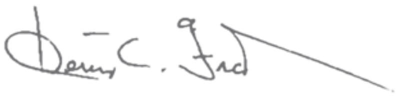
Despite the significant exploration successes of the Group at Sibkrayevskoye and Cheremshanskoye this past year, we are disappointed because of the results of the Pad 2 wells. This is especially painful because the initial log interpretation and fracture stimulation results were encouraging. We are now studying the results to see what can be done to manage the wells and to insure that we can avoid a similar situation in the future.

While these studies will take some time to complete, we now have a good initial understanding of the differences between the Lineynoye Pad 1 and the Pad 2 wells. We do not foresee similar issues arising at either the Arbuzovskoye or Sibkrayevskoye fields which will be the next major developments in Licence 61.

We will now focus on developing Arbuzovskoye and seek to build on our existing production profile and positive cash flows throughout the remainder of 2012. The Arbuzovskoye No. 1 well has been completed with an electrical submersible pump and is now producing through the pipeline to Lineynoye at a steady rate of about 350 bopd. This is an excellent pre-frac rate and confirms that we do not foresee similar issues to the Lineynoye Pad 2 wells arising at Arbuzovskoye. We plan to drill up to ten production wells at Arbuzovskoye in 2012.

We are delighted with the new discoveries at Sibkrayevskoye (Licence 61) and Cheremshanskoye (Licence 67) which we feel will prove to be major oil fields with further seismic and well delineation. These are both especially important discoveries, because they prove our strategy of following up on previously drilled structures by re-interpreting old well data using modern software and techniques to identify by-passed pay.

We have learned valuable lessons this past year and going forward we will take a more deliberate approach with additional coring, testing and high grading of the production wells prior to fracture stimulation. We have an excellent and determined workforce and a good asset base. We are confident that we can address the production issues and can grow our production and oil reserve base in 2012.



Dennis Francis
Chief Executive Officer

VP of Business Development and Operations, Karl Johnson with Dmitry Shelkovnikov, Chief Engineer.

Ryder Scott Estimated Reserves in Oil Fields (net to PetroNeft)

Oil Field Name	Proved	Proved & Probable	Proved, Probable & Possible
Licence 61	**1P mmbo**	**2P mmbo**	**3P mmbo**
Lineynoye	8.9	32.1	40.7
Tungolskoye	1.3	15.6	19.7
Kondrashevskoye	1.8	5.0	6.3
Arbuzovskoye	2.0	13.3	16.6
Sibkrayevskoye	3.7	49.8	67.8
North Varyakhskoye	0.8	1.9	2.4
	18.5	**117.7**	**153.5**
Licence 67			
Ledovoye	1.5	14.0	17.4
	20.0	**131.7**	**170.9**

- All oil in discovered fields is in the Upper Jurassic section.
- Reserves were determined in accordance with the Society of Petroleum Engineers ('SPE') Petroleum Resources Management System ('PRMS') rules.
- Licence 67 will be co-developed with Arawak Energy and the reserves above reflect PetroNeft's 50% share.

Health, Safety and Environmental Report

The Group is fully committed to high standards of Health, Safety and Environmental ('HSE') management and being socially responsible within the communities where we work. There are inherent risks in the oil and gas industry and these are managed through policies and practices, which stress the need for individual and collective responsibility within our staff structure and with contractors that operate for the Group.

Alexey Balyasnikov, the General Director of Stimul-T, has primary responsibility for all aspects of HSE management. As well as reporting directly to Group CEO, Dennis Francis, he attends all Board meetings to report to the full Board on HSE issues.

There were no lost time incidents in the year relating to employees of PetroNeft and two lost time incidents relating to the employee of a contractor both of which resulted in only minor injuries and no events which breached the stringent environmental regulations in Russia.

Health and Safety Management

The Group has a Labour Safety and Industrial Security Department headed up by Elena Morgunova. The role of the Department is to minimise the risks to employees and contractors from the day-to-day operation of our business, to train all staff in safety awareness and to prepare contingency plans to minimise the potential impact of any unplanned incidents or events. For that purpose we:

- Control compliance of all employee operations with labour safety requirements and ensure that employees of the Group and employees of contractors are adequately trained in the use of relevant equipment.
- Monitor all contracts the Group enters into in order to ensure that contractors are informed of the labour safety policies of the Group.
- Carry out regular site inspections to ensure full compliance.
- Develop and deliver labour safety and industrial security training to Group employees.
- Maintain an Emergency Response Plan for explosion and fire hazard facilities of the Group.
- Develop and get approved by state authorities:
  - Regulation for control of industrial safety compliance at hazardous facilities.
  - Regulation for order of accident investigation at hazardous industrial facilities of the Group.
- Maintain a vaccination and insurance programme for tick-borne encephalitis, a disease common in the West Siberian environment.

Environmental Impact Management

The Board recognises that the Group's activities can have a significant impact on the environment. As part of its responsibilities under Russian law, an environmental assessment of Licence 61 was carried out before any drilling work commenced in 2007. This was to establish the state of the environment within Licence 61 in advance of any major works. A similar assessment at Licence 67 was completed in the first half of 2011.

Since early 2007 there has been a dedicated full-time Environmental Engineer, Elena Nepriyateleva, on staff in our Tomsk office. Her responsibilities include:

- Monitoring of exploration and production activities.
- Monitoring activities of sub-contractors.
- Maintaining compliance with various environmental laws and regulations.

In 2011 the main activities from an environmental perspective were:

- Environmental monitoring system has been introduced at Lineynoye field.
- Planning and approvals for 2011 production drilling and field development and exploration/delineation programmes.
- Completion of Environmental Baseline Study for Licence 67.
- Preparation of programme for environmental and subsoil monitoring in Licence 67.

This included the use of an independent company to supervise the work of both our own staff and the staff of contractors working at our sites.

Gas Utilisation

The initial facilities design at Lineynoye emphasised the installation of gas piston power generators to utilise associated gas from the oil production to generate electricity for the camp, facilities and field needs and thereby minimise the flaring of associated gas. This has been very successful and has led to our operations being amongst the top three in the region in terms of percentage of gas utilisation. We continue to work towards a goal of 100% gas utilisation and are currently studying an option to mix associated gas with water for use in our water flood operations thereby re-injecting the gas back to the formation it came from.

Compliance and Inspections

The Group reports on its HSE activities to various statutory authorities in Russia on a quarterly and annual basis and is also subject to regular inspections by various bodies. Inspections relating to compliance with Natural Resource Management Law (Rosprirodnadzor) in relation to the newly constructed facilities at Lineynoye took place in 2010 and 2011 and no significant issues arose from these inspections.

Community

One of PetroNeft's key philosophies is to operate as a compliant, well-intentioned Group within the communities where we work. This entails ensuring compliance with laws and regulations and returning and paying our taxes on time.

During 2011 we also made contributions to orphanages in the Tomsk Oblast and contributed to social programs run in the Alexandrovskoye region of Tomsk where Licence 61 is located.

Principal Risks and Uncertainties

The principal risks and uncertainties affecting the Group and the actions taken by the Group to mitigate these risks and uncertainties are:

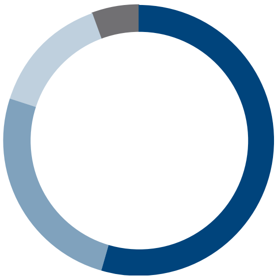
Risk Category	Risk Issue	Mitigation
Country Risks	Political – federal risks	Fields/acquisitions below 500 million boe are not considered strategic to the Russian state.
		State is encouraging small operators.
	Political – local risks	Tomsk Oblast administration is very supportive of development.
		Local management are well respected in region.
	Ownership of assets	Licences were acquired at government auctions. Work programme for Licence 61 is complete. Work programme for Licence 67 is not onerous.
		25 year licence term can be extended based on approved production plan.
	Changes in tax structure	Fiscal system is stable – recent and proposed changes largely benefit upstream oil and gas companies.
		Proactive lobbying effort made in area of tax legislation.
Technical Risks	Exploration risk	Proven oil and gas basin with multiple plays.
		Good quality 2D seismic.
		Knowledgeable exploration team with proven track record in region.
	Drilling risk	Relatively shallow wells with proven technology.
		Good rig availability.
		Experienced operations team.
	Production/ Completion risk	Routine completion practices including fracture stimulation.
		Reserves high-graded; extensive reservoir simulation and reservoir management will be undertaken.
		Performance of similar fields in region.
	Reserve risk	SPE and Russian reserves updated and in substantive alignment.
Financial Risks	Availability of finance	Good relations with funding providers and partners as demonstrated by new debt facilities in 2011 and 2012.
	Oil price	Robust project sanction economics – conservative base case assumptions. Russian tax system means economics are not too sensitive to changes in oil price. Board will consider use of appropriate hedging instruments.
	Industry cost inflation	Rigorous contracting procedures with competitive tendering. Also the relationship of the dollar/rouble exchange rate to the oil price provides a natural balance between costs and income.
	Uninsured events	Comprehensive insurance programme in place.
Other Risks	HSE incidents	HSE standards set and monitored regularly across the Group.
	Export quota	Equal access to export quotas available for all oil producers using Transneft.
		Conservative assumption in economics – domestic net back price now largely in alignment with export net back.
	Third party pipeline access	25 year transportation agreement in place for Licence 61, several options available for ultimate development of Licence 67.
	Transneft pipeline access	Available capacity and access confirmed.
		East Siberia-Pacific Ocean ('ESPO') pipeline allows export of oil to Pacific market.

Financial Review

We had a record work programme in 2011 with over US$55 million of capital investment in production and exploration wells as well as an expansion of the capacity of our oil processing facilities at the Lineynoye oil field.

2011 Capital expenditure of US$55 million (including 50% in Licence 67).

Production Wells	US$30m
Equipment and facilities	US$14m
Exploration – L61	US$8m
Exploration – L67	US$3m



2011 was the first full year of production in the Group's history. The issues at Pad 2 led to production being lower than expected which clearly has a knock on effect to the near term cash generation capability of the group.

During the year we renegotiated the debt facility with Macquarie Bank Limited moving from an amortising facility to a reserve based facility which is less expensive than the amortising facility. We had a record work programme in 2011 with over US$55 million of capital investment in production and exploration wells as well as an expansion of the capacity of our oil processing facilities at the Lineynoye oil field.

In 2012 we hope to grow our production through the drilling of up to ten additional production wells at the Arbuzovskoye oil field.

Net Loss

The net loss for the year increased to US$17,913,356 from US$7,125,394 in 2010. The main reason for the increase in the net loss is the impairment of oil and gas properties of US$5,000,000 and an increase of US$4,977,291 in foreign exchange loss on US Dollar denominated loans from PetroNeft to its wholly owned subsidiary, Stimul-T whose functional currency is the Russian Rouble. This loss arises due to the weakening of the Russian Rouble against the US Dollar in the last year. Administrative expenses were consistent with 2010 while the share-based payment expense increased from US$460,500 to US$1,108,446 primarily because of a full year's charge relating to share options which were issued in December 2010.

Revenue, Cost of Sales and Gross Margin

Revenue from oil sales was US$29,031,693 for the year (2010: US$5,155,646). Cost of sales includes depreciation of US$3,968,704 (2010: US$530,235). We would expect the gross margin to improve in future periods as our facilities and field operations are fully staffed and can handle additional production from the Arbuzovskoye oil field under the current cost structure. We produced 748,079 barrels of oil (2010: 189,508 barrels) in the year and sold 719,422 barrels of oil (2010: 158,295 barrels) of oil achieving an average oil price of US$40.35 per barrel (2010: US$32.57 per barrel). The increase in production and barrels sold is a result of 2011 being the first year of all round production for the Group. All of our oil was sold on the domestic market in Russia.

Finance Costs

Finance costs of US$2,501,070 (2010: US$1,356,918) relate to interest on loans, arrangement fees in relation to the loan facilities and the unwinding of discount on the decommissioning provision. The reason for the increase is the increased drawdown on debt facilities during the year.

Finance Revenue

Finance revenue of US$59,854 (2010: US$126,595) primarily arises from interest earned on bank deposits.

Taxation

The current tax charge arises on interest earned from bank deposits. The deferred tax charge arises on interest earned by PetroNeft on loans to its wholly owned subsidiary Stimul-T.

Capital Investment

Several major capital projects were completed in 2011 and further significant investment is planned in 2012. 2011 projects included:

- Drilling and completion of 14 development wells and one water source well at the Lineynoye oil field.
- Expansion of oil processing and oil storage facilities at the Lineynoye oil field.
- Drilling and completion of five exploration and delineation wells.

In 2012, funding permitting, the Group intends to invest up to US$20 million principally to develop the Arbuzovskoye oil field which was sanctioned by the Board in November 2011.

Current and Future Funding of PetroNeft

In April 2011 a revised borrowing base loan facility was agreed with Macquarie Bank Limited for up to US$75 million with availability of US$30 million subject to six monthly reviews. To date the availability under the loan facility has remained at US$30 million with the next review due to take place on 30 June 2012.

In May 2012 PetroNeft entered into a new loan facility for US$15 million with our partner Arawak Energy. This loan carries an interest rate of LIBOR plus 6% and 4,000,000 warrants were granted to Arawak. It is a three year loan repayable in one lump sum in May 2015.

The Lineynoye Pad 2 results meant that certain production and cash flow covenants that were part of the Macquarie facility were not met during the year, at and post the year-end. While Macquarie waived these targets at year-end, it meant that it was not possible to increase the amount available under the facility. Also, Macquarie have indicated that they would prefer to reduce the available amount by approximately US$7.5 million, however they are giving the Group time to work this out while continuing to support the ongoing development at Arbuzovskoye. Macquarie supported and agreed to the Arawak additional debt facility and did not seek repayment of their own debt facility as they want to see Arbuzovskoye coming into production as it offers the best option for increasing Group production and cash flows.

These circumstances represent a material uncertainty that may cast significant doubt upon the Group's ability to continue as a going concern which is described in more detail in Note 2 to the Consolidated Financial Statements.

Macquarie remain a committed lender and are also the largest shareholder of the Company and are prepared to give us time to allow the Arbuzovskoye field come into production thereby allowing either an increase in the available amount under the loan agreement as more reserves move to the proved reserves category, or some repayment of the loan facility out of the resulting cash flows.

The Group is also in discussions with a range of strategic investors about possible farm-outs, long term off-take agreements and potential equity or asset investments which would strengthen the Group's financial position.

Financial Risk Management

The Board sets the treasury policies and objectives of the Group, which include controls over the procedures used to manage financial risk. The Group's activities expose the Group to a variety of financial risks including foreign currency, commodity price, credit, liquidity and interest rate risks. These financial risks are managed by the Group under policies approved by the Board. Details of the Group's financial risk management policies are set out in detail in Note 25 to the Consolidated Financial Statements.

Investor Relations

During 2011, the CEO and CFO held regular meetings with analysts and institutional investors. The Group's website, www.petroneft.com, was also upgraded during the year bringing easier navigation and additional tools and information for users.

The target for 2012 is to continue our programme of meetings and specifically to try to rebuild the Group's credibility with investors.

Significant Shareholders

So far as the Directors are aware, the names of the persons other than the Directors who, directly or indirectly, are interested in 3% or more of the Issued Share Capital at 20 June 2012 are as follows:

Name of Shareholder	Ordinary Shares	Percentage
Macquarie Bank Limited	30,388,047	7.30%
Ali Sobraliev	23,014,273	5.53%
Arawak Energy Russia B.V.	14,114,344	3.39%

Paul Dowling
Chief Financial Officer

Key Financial Metrics

	2011 US$	2010 US$
Revenue	**29,031,693**	5,155,646
Cost of sales	**(25,598,616)**	(4,284,181)
Gross profit	**3,433,077**	871,465
Gross margin	**12%**	17%
Administrative expenses		
Overheads	**(5,848,021)**	(5,601,591)
Share-based payment expense	**(1,108,446)**	(460,500)
Other foreign exchange gain	**159,244**	285,038
	(6,797,223)	(5,777,053)
Foreign exchange loss on intra-group loans	**(5,114,345)**	(137,054)
Impairment of oil and gas properties	**(5,000,000)**	–
Finance revenue	**59,854**	126,595
Finance costs	**(2,501,070)**	(1,356,918)
Income tax expense	**(1,491,320)**	(852,429)
Loss for the year attributable to equity holders of the Parent	**(17,913,356)**	(7,125,394)
Capital expenditure in the year	**52,136,170**	41,646,953
Net proceeds of equity share issues	**–**	40,793,563
Bank and cash balance at year end (including restricted cash)	**6,030,005**	25,281,881

Board of Directors

1

2

3

4

5

6

7

1. David Golder

Non-Executive Chairman (Age 64)

Mr. Golder has been Non-Executive Chairman of the Company since 2005. He is also Chairman of the Remuneration Committee and a member of the Audit Committee. He has over 40 years experience in the petroleum industry and was formerly Senior Vice President of Marathon Oil Company ('Marathon'), retiring in 2003. From June 1996 to 1999, Mr. Golder was seconded from Marathon to Sakhalin Energy Investment Company where he was Executive Vice President – Upstream. Located in Moscow, he managed all upstream activities which focused on the oil development and company infrastructure aspects of the Sakhalin II Project onshore and offshore Sakhalin Island. Mr. Golder is a member of the Society of Petroleum Engineers. He has a BSc degree in Petroleum & Natural Gas Engineering from Pennsylvania State University and has completed the Program for Management Development at Harvard University.

2. Dennis Francis

Chief Executive Officer and Executive Director (Age 63)

Mr. Francis has been Chief Executive Officer and an Executive Director of the Company since its formation in 2005. He has over 40 years experience in the petroleum industry and was with Marathon for 30 years. From 1990, Mr. Francis was the USSR/FSU task force manager, responsible for developing new opportunities for Marathon in Russia. Marathon and its partners ultimately won the first Russian competitive tender, which was to develop the Sakhalin II Project offshore Sakhalin Island. Mr. Francis was instrumental in the formation of Sakhalin Energy Investment Company and was a director in that company. He is a member of the American Association of Petroleum Geologists and Society of Exploration Geophysicists. He has a BSc degree in geophysical engineering and an MSc degree in geology, both from the Colorado School of Mines. He has also completed the Program for Management Development at Harvard University.

3. Paul Dowling

Chief Financial Officer and Executive Director (Age 40)

Mr. Dowling joined the Company in October 2007 and was appointed to the Board of Directors in April 2008. He has 20 years experience in the areas of accounting, auditing, taxation, financial reporting, AIM/IPO reporting, corporate restructuring, corporate finance and acquisitions/disposals. Most recently he was a Partner in the accounting firm, LHM Casey McGrath, located in Dublin. Mr. Dowling is a fellow of the Association of Chartered Certified Accountants (ACCA) and a member of the Irish Taxation Institute. He currently represents the ACCA with the Consultative Committee of Accountancy Bodies – Ireland ('CCAB-I'). He is also a non-executive Director of Moesia Oil & Gas plc, an unlisted company, focused on oil and gas exploration and development in Central and Eastern Europe.

4. Dr. David Sanders

General Legal Counsel, Executive Director and Company Secretary (Age 63)

Dr. Sanders has been General Legal Counsel, Executive Director and Company Secretary of the Company since its formation in 2005. He is an attorney at law and has over 35 years experience in the petroleum industry, including 20 years of doing business in Russia and three years in the oil and gas litigation division of the law firm of Fulbright & Jaworski LLP. In 1988, Dr. Sanders joined Marathon where he analysed and reviewed joint venture agreements for worldwide production until his assignment in 1991 to the negotiating team for the Sakhalin II Project in Russia. Dr. Sanders has a degree in electronics from Pennsylvania Institute of Technology, a liberal arts degree from the University of Houston and a doctorate of jurisprudence from South Texas College of Law. He is a member of the State Bar of Texas and of the American Bar Association.

5. Gerard Fagan

Non-Executive Director (age 63)

Mr. Fagan was appointed as a Non-Executive Director in 2010. He is a member of the Audit Committee and a member of the Remuneration Committee. Mr. Fagan previously worked with Smurfit Kappa Group plc ('Smurfit Kappa') for 23 years before his retirement as Group Financial Controller in September 2009. During this time he had global responsibility for controlling financial operations of Smurfit Kappa, a company with turnover of €7 billion and operations in over 30 countries worldwide. Mr. Fagan has vast experience in mergers and acquisitions, corporate finance, accounting, taxation, insurance and corporate governance. He is both a Chartered and Chartered Certified Accountant and has previously served on the audit committee of the Institute of Chartered Accountants in Ireland. Mr. Fagan is also a Non-Executive Director of Smurfit Kappa Group Foundation, Liffey Reinsurance Company Limited, The Baxendale Insurance Company Limited, Bramshott Management Limited and Bramshott Europe Fund plc.

6. Thomas Hickey

Independent Non-Executive Director (Age 43)

Mr. Hickey has been a Non-Executive Director of the Company since 2005. He is Chairman of the Audit Committee and a member of the Remuneration Committee. He is Corporate Development Director of Petroceltic International plc, an AIM listed oil and gas company focussed on the Middle East-North Africa and the Mediterranean basin. He was Chief Financial Officer and a Director of Tullow Oil plc from 2000 to 2008. During this time Tullow grew via a number of significant acquisitions and exploration success. Prior to joining Tullow Oil plc, he was an Associate Director of ABN AMRO Corporate Finance (Ireland) Limited. In this role, he advised public and private companies in a wide range of industry sectors in the areas of fund raising, stock exchange requirements, mergers and acquisitions, flotation and related transactions. Mr. Hickey is a Commerce graduate of University College Dublin and a Fellow of the Irish Institute of Chartered Accountants. He is also a non-executive director of Ikon Science Limited, a UK geological software company.

7. Vakha Sobraliev

Non-Executive Director (Age 57)

Mr. Sobraliev has been a Non-Executive Director of the Company since 2005. He is a member of both the Audit and Remuneration Committees. He has over 35 years experience operating and managing energy service companies and state operating units exploring for and exploiting oil resources in the Western Siberian oil basin. Mr. Sobraliev is currently a shareholder and General Director of Tomskburneftegaz LLC, an oil and gas well drilling and services company operating in Western Siberia. From 1975 to 2000, Mr. Sobraliev worked for Tomskneft and Strezhevoy drilling boards in various drilling and economic capacities including chief engineer and chief accountant. He has degrees in mining engineering and economics from Tomsk Polytechnic Institute and the Tomsk State University respectively. Mr. Sobraliev is a resident of Tomsk, Russia.

Directors' Report
For the Year Ended 31 December 2011

The Directors present herewith their Annual Report and the audited financial statements of PetroNeft Resources plc (the 'Company') and its subsidiaries (collectively, the 'Group') for the year ended 31 December 2011.

Principal Activity

The principal activities of the Group are that of oil and gas exploration, development and production. The Group was established to acquire and develop oil and gas exploration, development and production interests in Russia and other countries of the former Soviet Union. A detailed business review is included in the Chairman's Statement, Chief Executive Officer's Report and in the Financial Review.

Results and Dividends

The loss for the year before tax amounted to US$16,422,036 (2010: US$6,272,965). After a tax charge of US$1,491,320 (2010: US$852,429) the loss for the year amounted to US$17,913,356 (2010: US$7,125,394). The Directors do not recommend payment of a dividend. Accordingly, an amount of US$17,913,356 has been debited to reserves.

Review of the Development and Performance of the Business

In compliance with the requirements of the Companies Acts, 1963 to 2009, a fair review of the performance and development of the Group's business during the year, its position at the year-end and its future prospects is contained in the Chief Executive Officer's Report on pages 10 to 13 and the Financial Review on pages 16 and 17. The key financial metrics used by management are set out in the Financial Review on page 17.

Corporate Governance

The Company is not subject to the UK Combined Code on Corporate Governance applicable to companies with full listings on the Dublin and London Stock Exchange. The Company does, however, intend, in so far as is practicable and desirable, given the size and nature of the business and the constitution of the Board, to comply with the Corporate Governance Guidelines for AIM Companies (the 'QCA Guidelines') as published by the Quoted Companies Alliance (the 'QCA').

The QCA Guidelines were devised, in consultation with a number of significant institutional small company investors, as an alternative corporate governance code applicable to AIM companies. An alternative code was proposed because the QCA considered the Combined Code on Corporate Governance to be inappropriate to many AIM companies.

The QCA Guidelines state that "the purpose of good corporate governance is to ensure that the Company is managed in an efficient, effective and entrepreneurial manner for the benefit of all shareholders over the longer term." The guidelines set out a code of best practice for AIM companies. Those guidelines require, among other things, that:

a) certain matters be specifically reserved for the Board's decision;
b) the Board should be supplied in a timely manner with information (including regular management financial information) in a form and of a quality appropriate to enable it to discharge its duties;
c) the Board should, at least annually, conduct a review of the effectiveness of the Company's system of internal controls and should report to shareholders that they have done so;
d) the roles of Chairman and Chief Executive should not be exercised by the same individual or there should be a clear explanation of how other Board procedures provide protection against the risks of concentration of power within the Company;
e) the Company should have at least two independent Non-Executive Directors on the Board and the Board should not be dominated by one person or group of people;
f) all Directors should be submitted for re-election at regular intervals subject to continued satisfactory performance;
g) the Board should establish audit, remuneration and nomination committees; and
h) there should be a dialogue with shareholders based on a mutual understanding of objectives.

PetroNeft satisfies all of these requirements with the exception of having a permanent nomination committee in place. Major corporate decisions of the Group are subject to Board approval. The Board is supplied in a timely manner with information in a form and of a quality appropriate to enable it to discharge its duties. These matters include approval of the Group's general commercial strategy, financial statements, Board membership, significant acquisitions and disposals, major capital expenditures, overall corporate governance and risk management and treasury policies. The Company holds regular Board meetings throughout the year.

In accordance with the QCA Guidelines, the Board has established Audit and Remuneration Committees, as described below, and utilises other committees as necessary in order to ensure effective governance.

Audit Committee

The members of the Audit Committee are Thomas Hickey, David Golder, Gerard Fagan and Vakha Sobraliev. It is chaired by Thomas Hickey. The Audit Committee's responsibilities include, among other things, reviewing interim and year-end financial statements and preliminary announcement, accounting principles, policies and practices, internal controls and overseeing the relationship with the external auditor including reviewing the results of their audit.

Remuneration Committee

The members of the Remuneration Committee are David Golder, Gerard Fagan, Thomas Hickey and Vakha Sobraliev. It is chaired by David Golder. The Remuneration Committee's responsibilities include, among other things, determining the policy and elements of remuneration for Executive Directors, provided however, that no Director shall be directly involved in any decisions as to their own remuneration.

Nomination Committee

Given the current size of the Group, a permanent Nominations Committee is not considered necessary. The Board reserves to itself the process by which a new Director is appointed.

The percentage of Non-Executive Directors on the Board is above the recommended 50%. The Group has adopted a model code for Directors' dealings that is appropriate for an AIM company. The Group complies with Rule 21 of the AIM Rules relating to Directors' dealings and will take all reasonable steps to ensure compliance by the Directors and the Group's applicable employees and their relative associates.

Shareholder Communication

Shareholder communication is given high priority by the Group and there are regular meetings between senior executives, institutional shareholders, analysts and brokers. These meetings, which are governed by procedures designed to ensure that price sensitive information is not divulged, are designed to facilitate a two-way dialogue based upon the mutual understanding of objectives. The Annual General Meeting ('AGM') affords individual shareholders the opportunity to question the Chairman and the Board and their participation is welcomed. Shareholders are also welcome to telephone or email the Company at any time.

The Chairmen of the Audit Committee and Remuneration Committee are available at the AGM to answer questions. In addition, major shareholders can meet with the Chairman of the Board or any Executive and Non-Executive Directors on request.

The Board is kept appraised of the views of shareholders, and the market in general, through feedback from the meetings programme. Analysts' reports on the Company are also circulated to the Board on a regular basis. The Group's website, www.petroneft.com, is also a key communication tool with all shareholders. News releases are made available on the website immediately after release to the Stock Exchange, where presentations, reserve reports and other materials are also available.

Internal Control

The Directors have overall responsibility for the Group's system of internal control and have delegated responsibility for the implementation of this system to executive management. This system is reviewed annually and includes financial controls that enable the Board to meet its responsibilities for the integrity and accuracy of the Group's accounting records.

The Group's system of internal financial control provides reasonable, though not absolute, assurance that assets are safeguarded, transactions authorised and recorded properly and that material errors or irregularities are either prevented or detected within a timely period.

Directors

The present Directors are listed on page 19.

In accordance with Article 83 of the Articles of Association, Thomas Hickey and Vakha Sobraliev retire by rotation and, being eligible, offer themselves for re-election.

Directors, Company Secretary and Their Interests

The Directors and Company Secretary who held office at 31 December 2011 had no interest, other than those shown below, in the Ordinary Shares of the Company. All interests shown below are beneficial interests.

	Ordinary Shares as at 20 June 2012	Ordinary Shares as at 31 December 2011	Ordinary Shares as at 1 January 2011
David Golder	3,165,458	3,165,458	3,165,458
Dennis Francis	22,760,416	22,760,416	22,570,416
Paul Dowling	331,583	331,583	206,583
David Sanders	2,238,235	2,238,235	2,213,235
Vakha Sobraliev	–	–	–
Gerard Fagan	200,000	200,000	200,000
Thomas Hickey	1,826,283	1,826,283	1,726,283

In addition to the above, the Directors hold the following share options:

Director	Options held as at 1 January 2011	Granted in Year	Exercised in Year	Options held as at 31 December 2011	Exercise price
David Golder	735,000	–	–	735,000	£0.19–£0.66
Dennis Francis	1,870,000	–	–	1,870,000	£0.19–£0.66
Paul Dowling	1,135,000	–	–	1,135,000	£0.19–£0.66
David Sanders	840,000	–	–	840,000	£0.19–£0.66
Vakha Sobraliev	655,000	–	–	655,000	£0.19–£0.36
Gerard Fagan	150,000	–	–	150,000	£0.66
Thomas Hickey	443,000	–	–	443,000	£0.19–£0.66

Details of the terms and conditions of the option scheme are included in Note 29 of the financial statements.

Directors' Report (continued)
For the Year Ended 31 December 2011

Principal Risks and Uncertainties

The Group has a risk management structure in place which is designed to identify, manage and mitigate business risks. Risk assessment and evaluation is an essential part of the Group's internal control system.

Details of the principal risks and uncertainties affecting the Group, as required to be disclosed in accordance with the Companies Acts, 1963 to 2009, are listed on page 15.

Remuneration Committee Report

The Group's policy on senior executive remuneration is designed to attract and retain people of the highest calibre who can bring their experience and independent views to the policy, strategic decisions and governance of the Group.

In setting remuneration levels, the Remuneration Committee takes into consideration the remuneration practices of other companies of similar size and scope. A key philosophy is that staff must be properly rewarded and motivated to perform in the best interests of the shareholders. Bonuses for Executive Directors are based on performance targets which include elements relating to shareholder return and individual performance.

The share option scheme is designed to incentivise performance and loyalty of Directors and key employees. Options vest when certain operational and total shareholder return targets are met. Share option holdings of the Directors are disclosed on page 21.

The Board has also agreed to allow Directors elect to have their Directors' fees paid in shares. Under this scheme, the number of shares issued will be based on the closing price at each quarter end. Elections under this scheme must be for a minimum of one year. Certain Directors elected to receive a portion of their remuneration for 2008 to 2011 in shares instead of cash.

	2011					2010				
Director	Basic remuneration* US$	Bonuses US$	Pension US$	Share-based payment US$	Total remuneration US$	Basic remuneration* US$	Bonuses US$	Pension US$	Share-based payment US$	Total remuneration US$
Executive Directors										
Dennis Francis	**330,306**	**–**	**16,007**	**79,876**	**426,189**	246,712	127,805	–	48,198	422,715
Paul Dowling	**269,613**	**–**	**11,685**	**67,233**	**348,531**	216,838	103,277	10,615	34,283	365,013
David Sanders	**269,867**	**–**	**12,985**	**67,773**	**350,625**	219,787	71,639	–	41,829	333,255
	869,786	**–**	**40,677**	**214,882**	**1,125,345**	683,337	302,721	10,615	124,310	1,120,983
Non-Executive Directors										
David Golder	**62,608**	**–**	**–**	**28,711**	**91,319**	33,474	–	–	14,222	47,696
Gerard Fagan	**41,739**	**–**	**–**	**27,245**	**68,984**	8,316	–	–	1,252	9,568
Thomas Hickey	**41,739**	**–**	**–**	**23,922**	**65,661**	26,494	–	–	11,388	37,882
Vakha Sobraliev	**27,826**	**–**	**–**	**22,765**	**50,591**	13,247	–	–	10,570	23,817
	173,912	**–**	**–**	**102,643**	**276,555**	81,531	–	–	37,432	118,963
Total Directors remuneration	**1,043,698**	**–**	**40,677**	**317,525**	**1,401,900**	764,868	302,721	10,615	161,742	1,239,946

* Certain amounts were paid in shares instead of cash.

Statement of Directors' Responsibilities in Respect of the Financial Statements

Company law in the Republic of Ireland requires the Directors to prepare financial statements for each financial year which give a true and fair view of the state of affairs of the Company and of the Group and of the profit or loss of the Group for that period.

In preparing these financial statements, the Directors are required to:

- select suitable accounting policies and then apply them consistently;
- make judgments and estimates that are reasonable;
- comply with applicable International Financial Reporting Standards as adopted by the European Union; and
- prepare the financial statements on the going concern basis unless it is inappropriate to presume that the Group and Company will continue in business.

The Directors are responsible for keeping proper books of account that disclose with reasonable accuracy at any time the financial position of the Company and enable them to ensure that the financial statements comply with the Companies Acts, 1963 to 2009. They are also responsible for safeguarding the assets of the Group and hence for taking reasonable steps for the prevention and detection of fraud and other irregularities.

Political Donations
The Company did not make any political donations during the year.

Going Concern
The Directors are required to make an assessment of the Group's ability to continue in operational existence as a going concern. After making appropriate enquiries including the considerations referred to in this Annual Report, the Directors are confident that the Group and Company will have adequate resources to continue in operational existence for the foreseeable future. However, the Directors have concluded that there are material uncertainties facing the business. Further details are set out in the Financial Review and in Note 2 to the Consolidated Financial Statements.

Books of Account
The measures taken by the Directors to ensure compliance with the requirements of Section 202, Companies Act 1990, regarding proper books of account are the implementation of necessary policies and procedures for recording transactions, the employment of competent accounting personnel with appropriate expertise and the provision of adequate resources to the financial function. The books of account of the Company are maintained at 20 Holles Street, Dublin 2, Ireland.

Important Events After the Balance Sheet Date
In May 2012 PetroNeft signed a new three year loan facility agreement with Arawak Energy ('Arawak') for US$15 million. This loan carries an interest rate of LIBOR plus 6%. 4,000,000 warrants were granted to Arawak as part of this loan facility. Also in May 2012 PetroNeft entered into a new three year Area of Mutual Interest ('AMI') agreement with Arawak on similar terms to the previous AMI which expired in August 2011.

Auditors
Ernst & Young, Chartered Accountants, have indicated their willingness to continue in office in accordance with the provisions of Section 160(2) of the Companies Act, 1963.

Annual General Meeting
Your attention is drawn to the Notice of the Annual General Meeting ('AGM') set out on page 59. The AGM will be on 19 September 2012 in the Herbert Park Hotel, Ballsbridge, Dublin 4, Ireland.

Your Directors believe that the Resolutions to be proposed at the AGM are in the best interests of the Company and its shareholders as a whole and, therefore, recommend you to vote in favour of the Resolutions. Your Directors intend to vote in favour of the Resolutions in respect of their own beneficial holdings of 30,521,975 Ordinary Shares.

Approved by the Board on 25 June 2012.

Dennis Francis
Director

Paul Dowling
Director

Independent Auditor's Report to the Members of PetroNeft Resources plc

We have audited the Group and Parent Company financial statements (the 'financial statements') of PetroNeft Resources plc for the year ended 31 December 2011, which comprise the Consolidated Income Statement, the Consolidated Statement of Comprehensive Income, the Consolidated and Parent Company Balance Sheets, the Consolidated and Parent Company Cash Flow Statements, the Consolidated and Parent Company Statement of Changes in Equity, and the related Notes 1 to 31. These financial statements have been prepared under the accounting policies set out therein.

This report is made solely to the Company's members, as a body, in accordance with section 193 of the Companies Act, 1990. Our audit work has been undertaken so that we might state to the Company's members those matters we are required to state to them in an auditors' report and for no other purpose. To the fullest extent permitted by law, we do not accept or assume responsibility to anyone other than the Company and the Company's members as a body, for our audit work, for this report, or for the opinions we have formed.

Respective Responsibilities of Directors and Auditors

The Directors are responsible for the preparation of the financial statements in accordance with applicable Irish law and International Financial Reporting Standards ('IFRSs') as adopted by the European Union, as set out in the Statement of Directors' Responsibilities.

Our responsibility is to audit the financial statements in accordance with relevant legal and regulatory requirements and International Standards on Auditing (UK and Ireland).

We report to you our opinion as to whether the financial statements give a true and fair view and have been properly prepared in accordance with the Companies Acts, 1963 to 2009. We also report to you our opinion as to: whether proper books of account have been kept by the Company; whether, at the balance sheet date, there exists a financial situation which may require the convening of an extraordinary general meeting of the Company; and whether the information given in the Directors' Report is consistent with the financial statements. In addition, we state whether we have obtained all the information and explanations necessary for the purposes of our audit and whether the Company Balance Sheet is in agreement with the books of account.

We also report to you if, in our opinion, any information specified by law regarding Directors' remuneration and other transactions is not disclosed and, where practicable, include such information in our report.

We read the other information contained in the Annual Report and consider whether it is consistent with the audited financial statements. The other information comprises only the Chairman's Statement, the Chief Executive Officer's Report, Health, Safety and Environmental Report, the Financial Review and the Directors' Report. We consider the implications for our report if we become aware of any apparent misstatements or material inconsistencies with the financial statements. Our responsibilities do not extend to any other information.

Basis of Audit Opinion

We conducted our audit in accordance with International Standards on Auditing (UK and Ireland) issued by the Auditing Practices Board. An audit includes examination, on a test basis, of evidence relevant to the amounts and disclosures in the financial statements. It also includes an assessment of the significant estimates and judgements made by the Directors in the preparation of the financial statements, and of whether the accounting policies are appropriate to the Group's and Company's circumstances, consistently applied and adequately disclosed.

We planned and performed our audit 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 statements are free from material misstatement, whether caused by fraud or other irregularity or error. In forming our opinion, we also evaluated the overall adequacy of the presentation of information in the financial statements.

Opinion

In our opinion the financial statements give a true and fair view, in accordance with IFRSs as adopted by the European Union, of the state of affairs of the Group and of the Company as at 31 December 2011, and of the loss of the Group for the year then ended and have been properly prepared in accordance with the Companies Acts, 1963 to 2009.

We have obtained all the information and explanations we consider necessary for the purposes of our audit. In our opinion proper books of account have been kept by the Company. The Company Balance Sheet is in agreement with the books of account.

In our opinion the information given in the Directors' Report is consistent with the financial statements.

In our opinion, the Company Balance Sheet does not disclose a financial situation which under section 40(1) of the Companies (Amendment) Act, 1983 would require the convening of an extraordinary general meeting of the Company.

Emphasis of matter – going concern

In forming our opinion, which is not qualified, we have considered the adequacy of the disclosures made in Note 2 to the financial statements concerning the Group and the Company's ability to continue as a going concern. These conditions indicate the existence of a material uncertainty which may cast significant doubt about the Group and the Company's ability to continue as a going concern.

The financial statements do not include any adjustments to the carrying amount or classification of assets and liabilities that would result if the Group or the Company was unable to continue as a going concern.

George Deegan
For and on behalf of Ernst & Young
Dublin
25 June 2012

Consolidated Income Statement
For the Year Ended 31 December 2011

	Note	2011 US$	2010 US$
Continuing operations			
Revenue	5	**29,031,693**	5,155,646
Cost of sales		**(25,598,616)**	(4,284,181)
Gross profit		**3,433,077**	871,465
Administrative expenses		**(6,797,223)**	(5,777,053)
Impairment of oil and gas properties	13	**(5,000,000)**	–
Exchange loss on intra-Group loans		**(5,114,345)**	(137,054)
Operating loss	6	**(13,478,491)**	(5,042,642)
Profit on disposal of subsidiary undertaking	12	**223,222**	–
Loss on disposal of oil and gas properties	13	**(391,188)**	–
Share of joint venture's net loss	16	**(334,363)**	–
Finance revenue	7	**59,854**	126,595
Finance costs	8	**(2,501,070)**	(1,356,918)
Loss for the year for continuing operations before taxation		**(16,422,036)**	(6,272,965)
Income tax expense	10	**(1,491,320)**	(852,429)
Loss for the year attributable to equity holders of the Parent		**(17,913,356)**	(7,125,394)
Loss per share attributable to ordinary equity holders of the Parent			
Basic and diluted – *US dollar cent*	11	**(4.30)**	(1.97)

Consolidated Statement of Comprehensive Income
For the Year Ended 31 December 2011

	2011 US$	2010 US$
Loss for the year attributable to equity holders of the Parent	**(17,913,356)**	(7,125,394)
Currency translation adjustments	**(1,802,179)**	(33,696)
Total comprehensive loss for the year attributable to equity holders of the Parent	**(19,715,535)**	(7,159,090)

Approved by the Board on 25 June 2012.

Dennis Francis
Director

Paul Dowling
Director

Consolidated Balance Sheet
As at 31 December 2011

	Note	2011 US$	2010 US$
Assets			
Non-current Assets			
Oil and gas properties	13	**92,697,976**	62,143,801
Property, plant and equipment	14	**1,925,938**	1,674,216
Exploration and evaluation assets	15	**24,552,717**	21,391,491
Equity-accounted investment in joint venture	16	**3,851,880**	–
		123,028,511	85,209,508
Current Assets			
Inventories	18	**1,856,813**	907,947
Trade and other receivables	19	**2,810,459**	8,064,978
Cash and cash equivalents	20	**1,030,005**	22,781,881
Restricted cash	20	**5,000,000**	2,500,000
		10,697,277	34,254,806
Assets held for sale	12	**–**	2,020,678
		10,697,277	36,275,484
Total Assets		**133,725,788**	121,484,992
Equity and Liabilities			
Capital and Reserves			
Called up share capital	24	**5,636,142**	5,624,840
Share premium account		**122,431,629**	122,082,388
Share-based payment reserve		**4,894,985**	3,641,064
Retained loss		**(43,791,153)**	(25,877,797)
Currency translation reserve		**(7,630,511)**	(5,828,332)
Other reserves		**336,000**	336,000
Equity attributable to equity holders of the Parent		**81,877,092**	99,978,163
Non-current Liabilities			
Provisions	23	**1,147,988**	743,670
Deferred tax liability	10	**3,157,557**	1,636,475
		4,305,545	2,380,145
Current Liabilities			
Trade and other payables	21	**12,938,593**	5,401,479
Interest-bearing loans and borrowings	22	**34,604,558**	13,725,205
		47,543,151	19,126,684
Total Liabilities		**51,848,696**	21,506,829
Total Equity and Liabilities		**133,725,788**	121,484,992

Approved by the Board on 25 June 2012.

Dennis Francis
Director

Paul Dowling
Director

Consolidated Statement of Changes in Equity
For the Year Ended 31 December 2011

	Share capital US$	Share premium US$	Share-based payment and other reserves US$	Currency translation reserve US$	Retained loss US$	Total US$
At 1 January 2010	4,724,013	81,328,170	2,704,929	(5,794,636)	(18,752,403)	64,210,073
Loss for the year	–	–	–	–	(7,125,394)	(7,125,394)
Currency translation adjustments	–	–	–	(33,696)	–	(33,696)
Total comprehensive loss for the year	–	–	–	(33,696)	(7,125,394)	(7,159,090)
New share capital subscribed	872,841	42,307,945	–	–	–	43,180,786
Transaction costs on issue of share capital	–	(2,387,223)	–	–	–	(2,387,223)
Share options exercised	27,406	813,714	–	–	–	841,120
Remuneration and other emoluments paid in shares	580	19,782	–	–	–	20,362
Share-based payment expense	–	–	460,500	–	–	460,500
Share-based payment expense – Macquarie warrants (Note 29)	–	–	811,635	–	–	811,635
At 31 December 2010	5,624,840	122,082,388	3,977,064	(5,828,332)	(25,877,797)	99,978,163
At 1 January 2011	**5,624,840**	**122,082,388**	**3,977,064**	**(5,828,332)**	**(25,877,797)**	**99,978,163**
Loss for the year	**–**	**–**	**–**	**–**	**(17,913,356)**	**(17,913,356)**
Currency translation adjustments	**–**	**–**	**–**	**(1,802,179)**	**–**	**(1,802,179)**
Total comprehensive loss for the year	**–**	**–**	**–**	**(1,802,179)**	**(17,913,356)**	**(19,715,535)**
Share options exercised	**11,302**	**349,241**	**–**	**–**	**–**	**360,543**
Share-based payment expense	**–**	**–**	**1,108,446**	**–**	**–**	**1,108,446**
Share-based payment expense – Macquarie warrants (Note 29)	**–**	**–**	**145,475**	**–**	**–**	**145,475**
At 31 December 2011	**5,636,142**	**122,431,629**	**5,230,985**	**(7,630,511)**	**(43,791,153)**	**81,877,092**

Consolidated Cash Flow Statement
For the Year Ended 31 December 2011

	Note	2011 US$	2010 US$
Operating activities			
Loss before taxation		**(16,422,036)**	(6,272,965)
Adjustment to reconcile loss before tax to net cash flows			
Non-cash			
Depreciation		**4,293,949**	811,949
Impairment of oil and gas properties		**5,000,000**	–
Loss on disposal of oil and gas properties		**391,188**	–
Profit on disposal of subsidiary undertaking		**(223,222)**	–
Share of loss in joint venture		**334,363**	–
Share-based payment expense		**1,108,446**	460,500
Write off of leasehold land payments		**–**	176,825
Remuneration and other emoluments paid in shares		**–**	20,362
Finance revenue	7	**(59,854)**	(126,595)
Finance costs	8	**2,501,070**	1,356,918
Working capital adjustments			
Decrease/(increase)in trade and other receivables		**3,372,948**	(3,444,866)
Increase in inventories		**(646,118)**	(808,561)
Increase in trade and other payables		**6,285,719**	2,944,919
Income tax paid		**(68,029)**	–
Net cash flows received from/(used in) operating activities		**5,868,424**	(4,881,514)
Investing activities			
Purchase of oil and gas properties		**(32,967,288)**	(32,006,996)
Advance payments to contractors		**(199,568)**	(3,883,284)
Purchase of property, plant and equipment		**(570,396)**	(217,524)
Disposal of property, plant and equipment		**–**	1,154
Exploration and evaluation payments		**(6,629,469)**	(3,736,142)
Investment in joint venture undertaking		**(3,850,000)**	–
Increase in restricted cash		**(2,500,000)**	(2,500,000)
Interest received		**55,861**	161,961
Net cash used in investing activities		**(46,660,860)**	(42,180,831)
Financing activities			
Proceeds from issue of share capital		**–**	43,180,786
Transaction costs of issue of shares		**–**	(2,387,223)
Proceeds from exercise of options		**360,543**	841,120
Proceeds from loan facilities		**37,000,000**	16,000,000
Transaction costs on loans and borrowings		**(472,696)**	(584,467)
Repayment of loan facilities		**(16,212,000)**	(1,788,000)
Interest paid		**(1,729,447)**	(835,467)
Net cash received from financing activities		**18,946,400**	54,426,749
Net (decrease)/increase in cash and cash equivalents		**(21,846,036)**	7,364,404
Translation adjustment		**94,160**	(309,002)
Cash and cash equivalents at the beginning of the year		**22,781,881**	15,726,479
Cash and cash equivalents at the end of the year	20	**1,030,005**	22,781,881

Company Balance Sheet
As at 31 December 2011

	Note	2011 US$	2010 US$
Non-current Assets			
Property, plant and equipment	14	**9,444**	9,136
Financial assets	17	**45,038,371**	40,368,922
		45,047,815	40,378,058
Current Assets			
Trade and other receivables	19	**110,522,328**	75,051,933
Cash and cash equivalents	20	**950,825**	21,001,248
Restricted cash	20	**5,000,000**	2,500,000
		116,473,153	98,553,181
Total Assets		**161,520,968**	138,931,239
Equity and Liabilities			
Capital and Reserves			
Called up share capital	24	**5,636,142**	5,624,840
Share premium account		**122,431,629**	122,082,388
Share-based payment reserve		**4,894,985**	3,641,064
Retained loss		**(10,238,869)**	(8,854,833)
Other reserves		**336,000**	336,000
Equity attributable to equity holders of the Parent		**123,059,887**	122,829,459
Non-current Liabilities			
Deferred tax liability	10	**3,157,557**	1,636,475
		3,157,557	1,636,475
Current Liabilities			
Trade and other payables	21	**698,966**	740,100
Interest bearing loans and borrowings	22	**34,604,558**	13,725,205
		35,303,524	14,465,305
Total Liabilities		**38,461,081**	16,101,780
Total Equity and Liabilities		**161,520,968**	138,931,239

Approved by the Board on 25 June 2012.

Dennis Francis
Director

Paul Dowling
Director

Company Statement of Changes in Equity
For the Year Ended 31 December 2011

	Share capital US$	Share premium US$	Share-based payment and other reserves US$	Retained loss US$	Total US$
At 1 January 2010	4,724,013	81,328,170	2,704,929	(6,569,543)	82,187,569
Loss for the year	–	–	–	(2,285,290)	(2,285,290)
Total comprehensive loss for the year	–	–	–	(2,285,290)	(2,285,290)
New share capital subscribed	872,841	42,307,945	–	–	43,180,786
Transaction costs on issue of share capital	–	(2,387,223)	–	–	(2,387,223)
Share options exercised	27,406	813,714	–	–	841,120
Remuneration and other emoluments paid in shares	580	19,782	–	–	20,362
Share-based payment expense	–	–	460,500	–	460,500
Share-based payment expense – Macquarie warrants (Note 29)	–	–	811,635	–	811,635
At 31 December 2010	5,624,840	122,082,388	3,977,064	(8,854,833)	122,829,459
At 1 January 2011	**5,624,840**	**122,082,388**	**3,977,064**	**(8,854,833)**	**122,829,459**
Loss for the year	**–**	**–**	**–**	**(1,384,036)**	**(1,384,036)**
Total comprehensive loss for the year	**–**	**–**	**–**	**(1,384,036)**	**(1,384,036)**
Share options exercised	**11,302**	**349,241**	**–**	**–**	**360,543**
Share-based payment expense	**–**	**–**	**1,108,446**	**–**	**1,108,446**
Share-based payment expense – Macquarie warrants (Note 29)	**–**	**–**	**145,475**	**–**	**145,475**
At 31 December 2011	**5,636,142**	**122,431,629**	**5,230,985**	**(10,238,869)**	**123,059,887**

Company Cash Flow Statement
For the Year Ended 31 December 2011

	Note	2011 US$	2010 US$
Operating activities			
Profit/(loss) before taxation		**107,284**	(1,432,861)
Adjustment to reconcile profit/(loss) before tax to net cash flows			
Non-cash			
Depreciation of property, plant and equipment		**3,654**	3,517
Share-based payment expense		**418,997**	225,975
Write off of financial assets		**–**	224,546
Remuneration and other emoluments paid in shares		**–**	20,362
Finance revenue		**(6,271,781)**	(3,405,833)
Finance costs		**2,438,971**	1,739,347
Working capital adjustments			
Increase in trade and other receivables		**(29,267,707)**	(42,094,642)
(Decrease)/increase in trade and other payables		**56,657**	25,985
Income tax paid		**(68,029)**	–
Net cash flows used in operating activities		**(32,581,954)**	(44,693,604)
Investing activities			
Purchase of property, plant and equipment		**(3,962)**	(4,809)
Investment in financial assets	17	**(3,980,000)**	(78,285)
Increase in restricted cash		**(2,500,000)**	(2,500,000)
Interest received		**48,553**	199,821
Net cash used in investing activities		**(6,435,409)**	(2,383,273)
Financing activities			
Proceeds from issue of share capital		**–**	43,180,786
Transaction costs of issue of shares		**–**	(2,387,223)
Proceeds from exercise of share options		**360,543**	841,120
Proceeds from loan facilities		**37,000,000**	16,000,000
Transaction costs on loans and borrowings		**(472,696)**	(584,467)
Repayment of loan facilities		**(16,212,000)**	(1,788,000)
Interest paid		**(1,729,447)**	(835,467)
Net cash received from financing activities		**18,946,400**	54,426,749
Net (decrease)/increase in cash and cash equivalents		**(20,070,963)**	7,349,872
Translation adjustment		**20,540**	(293,485)
Cash and cash equivalents at the beginning of the year		**21,001,248**	13,944,861
Cash and cash equivalents at the end of the year	20	**950,825**	21,001,248

Notes to the Financial Statements
For the Year Ended 31 December 2011

1. General Information on the Company and the Group

PetroNeft Resources plc ('the Company', or together with its subsidiaries, 'the Group') is a company incorporated in Ireland. The Company is listed on the Alternative Investments Market ('AIM') of the London Stock Exchange and the Enterprise Securities Market ('ESM') of the Irish Stock Exchange. The address of the registered office and the business address in Ireland is 20 Holles Street, Dublin 2. The Company is domiciled in the Republic of Ireland.

The principal activities of the Group are oil and gas exploration, development and production.

2. Going Concern

In April 2011 a revised borrowing base loan facility was agreed with Macquarie Bank Limited ('Macquarie') for up to US$75 million, with US$30 million immediately available subject to six monthly reviews. Refer to Note 22 for further detail. To date the availability under the borrowing base loan facility has remained at US$30 million with the next review due to take place on 30 June 2012.

In May 2012 PetroNeft entered into a new loan facility for US$15 million with our partner Arawak Energy Russia B.V. ('Arawak'). Refer to Note 22 for further details. This loan carries an interest rate of LIBOR plus 6%. 4,000,000 warrants were granted to Arawak as part of this loan facility. The Arawak loan facility is a three year loan repayable in one lump sum in May 2015.

The Lineynoye Pad 2 results meant that certain production and cash flow covenants that were part of the Macquarie facility were not met during, at and post the year-end. While Macquarie waived these covenants at the year-end, it meant that it was not possible to increase the amount available under the borrowing base loan facility. Macquarie supported and agreed to the Arawak additional loan facility and did not seek repayment of their base loan facility as Macquarie prefer to see Arbuzovskoye coming into production as it offers the best option for increasing Group production and cash flows.

Although Macquarie remains a supportive lender and key shareholder, they have indicated, absent any alternative funding option, their preference that the debt be reduced by about US$7.5 million over the next 12 months. However they did not seek a repayment out of the proceeds of the Arawak loan facility and remain supportive of the Group's plans to bring the Arbuzovskoye oil field into production this year particularly in light of the recent rates achieved from the Arbuzovskoye No. 1 well. The Board has a plan to bring the Arbuzovskoye oil field into production in the coming months thereby increasing the Group's long-term cash flows.

The Board remain positive about the resilience of the Group despite the pressures outlined above. The Group has analysed its cash flow requirements through to 31 December 2013 in detail. The cash flow includes estimates for a number of key variables including timing of cash flows of development expenditure, oil price, production rates, and with the ongoing support of its lenders and management of working capital the Directors believe that the Group's cash flow forecasts represent the Group's best estimate of the actual results over the forecast period at the date of approval of the financial statements. The cash flow is stress tested to assess the adverse effect arising from reasonable changes in circumstance. It is recognised that the cash flow impact of these changes could result in additional funding being required. The Group is also in discussions with a range of strategic investors about possible farm-outs, long term off-take agreements and potential equity or asset investments which would strengthen the Group's financial position.

These circumstances represent a material uncertainty that may cast significant doubt upon the Group and the Company's ability to continue as a going concern. Nevertheless, after making enquiries, and considering the uncertainties described above, the Directors are confident that the Group and the Company will have adequate resources to continue in operational existence for the foreseeable future. For these reasons, the Directors continue to adopt the going concern basis in preparing the annual report and accounts.

Accordingly, these financial statements do not include any adjustments to the carrying amount or classification of assets and liabilities that would result if the Group or Company was unable to continue as a going concern.

3. Accounting Policies

3.1 Basis of Preparation

The financial statements have been prepared on a historical cost basis as modified by the measurement at fair value of share-based payment and certain financial assets and liabilities including derivative financial instruments. The financial statements are presented in US Dollars ('US$').

The accounting policies set out below have been applied consistently by all the Group's subsidiaries and joint venture to all periods presented in these Consolidated Financial Statements.

Statement of Compliance

The Consolidated Financial Statements of PetroNeft Resources plc and its subsidiaries have been prepared in accordance with International Financial Reporting Standards ('IFRS') as adopted by the European Union ('EU').

3.2 Basis of Consolidation

The Consolidated Financial Statements comprise the financial statements of PetroNeft Resources plc and its subsidiaries as at 31 December each year.

Subsidiaries are fully consolidated from the date of acquisition, being the date on which the Group obtains control, and continue to be consolidated until the date that such control ceases. The financial statements of the subsidiaries are prepared for the same reporting period as the Parent Company. All intra-Group balances, income and expenses and unrealised gains and losses resulting from intra-Group transactions are eliminated in full.

A change in the ownership interest of a subsidiary, without a loss of control, is accounted for as an equity transaction. If the Group loses control over a subsidiary, it:

- Derecognises the assets (including goodwill) and liabilities of the subsidiary
- Derecognises the carrying amount of any non-controlling interest
- Derecognises the cumulative translation differences recognised in equity
- Recognises the fair value of the consideration received
- Recognises the fair value of any investment retained
- Recognises any surplus or deficit in profit or loss
- Reclassifies the parent's share of components previously recognised in other comprehensive income to profit or loss or retained earnings, as appropriate

3.3 Significant Accounting Judgements, Estimates and Assumptions

The preparation of the Group's Consolidated Financial Statements in compliance with IFRS as adopted by the European Union ('EU') requires management to make judgements, estimates and assumptions that affect the reported amounts of assets, liabilities and disclosed contingent liabilities at the end of the reporting year and the amounts of revenues and expenses recognised during the reporting period. Estimates and judgements are continuously evaluated and are based on management's experience and other factors, including expectations of the future events that are believed to be reasonable under the circumstances. However, uncertainty about these assumptions and estimates could result in outcomes that require an adjustment to the carrying amount of the asset or liability affected in future periods.

(a) Judgements

In the process of applying the Group's accounting policies, management has made the following judgements, apart from those involving estimations, which have a significant effect on amounts recognised in the Consolidated Financial Statements.

Going Concern

In preparing the Consolidated Financial Statements, the Directors are required to make an assessment of the Group's ability to continue in operational existence as a going concern. After making appropriate enquiries, the Directors are confident that the Group and Company will have adequate resources to continue in operational existence for the foreseeable future. However, the Directors have concluded that there are material uncertainties facing the business. Further details are set out in the Finance Review and in Note 2 to the Consolidated Financial Statements.

Exploration and Evaluation Expenditure

Exploration and evaluation expenditure represents active exploration projects. These amounts will be written off to the Consolidated Income Statement as exploration costs unless commercial reserves are established, or the determination process is not completed. The outcome of ongoing exploration, and therefore whether the carrying value of these assets will ultimately be recovered, is inherently uncertain.

The Group has capitalised intangible exploration and evaluation assets in accordance with IFRS 6 *Exploration for and Evaluation of Mineral Resources*, which are evaluated for indicators of impairment. Any impairment review, where required, involves significant judgement related to matters such as recoverable reserves, production profiles, oil and gas prices, discount rate, development, operating and offtake costs and other matters. The carrying amount of intangible exploration and evaluation assets at 31 December 2011 is US$24.6 million (2010: US$21.4 million).

Carrying Value of Oil and Gas Properties

Certain oil and gas properties are depreciated using the unit-of-production ('UOP') basis at a rate calculated by reference to proved and probable reserves. This results in a depreciation charge proportional to the depletion of the anticipated remaining production from the field.

Each item's life, which is assessed annually, has regard to both its physical life limitations and to present assessments of economically recoverable reserves of the field at which the asset is located. These calculations require the use of estimates and assumptions, including the amount of recoverable reserves and estimates of future capital expenditure. The calculation of the UOP rate of depreciation could be impacted to the extent that actual production in the future is different from current forecast production based on proved and probable reserves. This would generally result from significant changes in any of the factors or assumptions used in estimating reserves.

These factors could include:

- Changes in proved and probable reserves;
- The effect on proved and probable reserves of differences between actual commodity prices and commodity price assumptions; and
- Unforeseen operational issues.

(b) Estimates and Assumptions

The key assumptions concerning the future and other key sources of estimation uncertainty at the balance sheet date, that have a significant risk of causing a material adjustment to the carrying amount of assets and liabilities within the next financial year, are discussed below:

Reserves Base

Certain oil and gas properties are depreciated on a unit-of-production basis at a rate calculated by reference to proved and probable reserves, determined in accordance with the Society of Petroleum Engineers Petroleum Resources Management System rules and incorporating the estimated future cost of developing and extracting those reserves. Commercial reserves are determined using estimates of oil in place, recovery factors and future oil prices. Future development costs are estimated using assumptions as to the number of wells required to produce the commercial reserves, the cost of such wells and associated production facilities, and other capital costs. The current long-term Urals blend oil price assumption used in the estimation of commercial reserves is an export price of US$90 and a Russian domestic price of US$40.

Notes to the Financial Statements (continued)
For the Year Ended 31 December 2011

3. Accounting Policies (continued)

3.3 Significant Accounting Judgements, Estimates and Assumptions (continued)

Recoverability of Oil and Gas Properties

The Group assesses each asset or cash generating unit ('CGU') every reporting period to determine whether any indication of impairment exists. Where an indicator of impairment exists, a formal estimate of the recoverable amount is made, which is considered to be the higher of the fair value less costs to sell and value in use. These assessments require the use of estimates and assumptions such as long-term oil prices (considering current and historical prices, price trends and related factors), discount rates, operating costs, future capital requirements, decommissioning costs, exploration potential, reserves (see 3.3(b) reserves base above) and operating performance (which includes production and sales volumes). These estimates and assumptions are subject to risk and uncertainty. Therefore, there is a possibility that changes in circumstances will impact these projections, which may impact the recoverable amount of assets and/or CGUs.

Fair value is determined as the amount that would be obtained from the sale of the asset in an arm's length transaction between knowledgeable and willing parties. Fair value for oil and gas properties is generally determined as the present value of estimated future cash flows arising from the continued use of the assets, which includes estimates such as the cost of future expansion plans and eventual disposal, using assumptions that an independent market participant may take into account. Cash flows are discounted to their present value using a discount rate that reflects current market assessments of the time value of money and the risks specific to the asset. Management has assessed its CGUs as being an individual field, which is the lowest level for which cash inflows are largely independent of those of other assets.

Impairment of Non-financial Assets

The Group assesses whether there are any indicators of impairment for all non-financial assets at each reporting date. When value-in-use or fair-value-less-costs-to-sell calculations are undertaken, management must estimate the future expected cash flows from the asset or cash-generating unit and determine a suitable discount rate in order to calculate the present value of those cash flows.

It is reasonably possible that the oil price assumption may change, which may then impact the estimated life of a field and may then require a material adjustment to the carrying value of the assets. The Group continuously monitors internal and external indicators of possible/potential impairment relating to its tangible and intangible assets.

Impairment of Financial Assets

Investments in subsidiaries are stated at cost and are reviewed for impairment if there are indications that the carrying value may not be recoverable in the Parent balance sheet.

Share-based Payment Transactions

The Group measures the cost of equity-settled transactions by reference to the fair value of the equity instruments at the date on which they are granted. Estimating fair value requires determining the most appropriate valuation model for a grant of equity instruments, which is dependent on the terms and conditions of the grant. This also requires determining the most appropriate inputs to the valuation model; including the expected life of the option, volatility and dividend yield, and making assumptions about them. The model and assumptions used are discussed in Note 29.

Decommissioning Costs

Decommissioning costs will be incurred by the Group at the end of the operating life of certain of the Group's facilities and properties. The ultimate decommissioning costs are uncertain and cost estimates can vary in response to many factors including changes to relevant legal requirements, the emergence of new restoration techniques or experience at other sites. The expected timing and amount of expenditure can also change, for example, in response to changes in reserves or changes in laws and regulations or their interpretation. As a result, there could be significant adjustments to the provisions established which would affect future financial results. Refer to Note 23 for details of this provision and related assumptions.

3.4 Summary of Significant Accounting Policies

(a) Foreign Currencies

The Consolidated Financial Statements are presented in US dollars, which is the Group's presentational currency. The US dollar is also the Company's functional currency. Each entity in the Group determines its own functional currency and items included in the financial statements of each entity are measured using that functional currency. The Company's Russian subsidiaries' functional currency is the Russian Rouble. Transactions in foreign currencies are initially recorded at the rate ruling at the date of the transaction. Monetary assets and liabilities denominated in foreign currencies are retranslated at the rate of exchange ruling at the balance sheet date, including foreign exchange differences arising on intercompany loans from the Company to the Russian subsidiaries. All differences are taken to profit or loss. Non-monetary items are translated using the exchange rates ruling as at the date of the initial transaction.

The assets and liabilities of foreign operations are translated into US dollars at the rate of exchange ruling at the balance sheet date and their Income Statements are translated at the average exchange rates for the year. The exchange differences arising on the translation are taken directly to a separate component of equity.

The relevant average and closing exchange rates for 2011 and 2010 were:

	2011		2010	
US$1 =	Closing	Average	Closing	Average
Russian Rouble	**32.077**	**29.330**	30.538	30.434
Euro	**0.7722**	**0.7188**	0.7546	0.7549
British Pound	**0.6470**	**0.6235**	0.6465	0.6803

(b) Business Combinations and Goodwill

Business combinations are accounted for using the acquisition method. The cost of an acquisition is measured as the aggregate of the consideration transferred, measured at acquisition date fair value and the amount of any non-controlling interest in the acquiree. For each business combination, the acquirer measures the non-controlling interest in the acquiree either at fair value or at the proportionate share of the acquiree's identifiable net assets. Acquisition costs incurred are expensed and included in administrative expenses.

When the Group acquires a business, it assesses the financial assets and liabilities assumed for appropriate classification and designation in accordance with the contractual terms, economic circumstances and pertinent conditions as at the acquisition date. This includes the separation of embedded derivatives in host contracts by the acquiree.

If the business combination is achieved in stages, the acquisition date fair value of the acquirer's previously held equity interest in the acquiree is remeasured to fair value at the acquisition date through profit or loss.

Any contingent consideration to be transferred by the acquirer will be recognised at fair value at the acquisition date. Subsequent changes to the fair value of the contingent consideration which is deemed to be an asset or liability, will be recognised in accordance with IAS 39 either in profit or loss or as a change to other comprehensive income. If the contingent consideration is classified as equity, it should not be remeasured until it is finally settled within equity.

Goodwill is initially measured at cost being the excess of the aggregate of the consideration transferred and the amount recognised for non-controlling interest over the net identifiable assets acquired and liabilities assumed. If this consideration is lower than the fair value of the net assets of the subsidiary acquired, the difference is recognised in profit or loss.

After initial recognition, goodwill is measured at cost less any accumulated impairment losses. For the purpose of impairment testing, goodwill acquired in a business combination is, from the acquisition date, allocated to each of the Group's cash-generating units that are expected to benefit from the combination, irrespective of whether other assets or liabilities of the acquiree are assigned to those units.

Where goodwill forms part of a cash-generating unit and part of the operation within that unit is disposed of, the goodwill associated with the operation disposed of is included in the carrying amount of the operation when determining the gain or loss on disposal of the operation. Goodwill disposed of in this circumstance is measured based on the relative values of the operation disposed of and the portion of the cash-generating unit retained.

(c) Interest in Joint Venture

The Group has an interest in a joint venture, which is a jointly controlled entity ('JCE'), whereby the venturers have a contractual arrangement that establishes joint control over the economic activities of the entity. The agreement requires unanimous agreement for financial and operating decisions among the venturers. The JCE controls the assets of the joint venture, earns its own income and incurs its own liabilities and expenses. Interests in the JCE are accounted for using the equity method. Under the equity method, the investment in the joint venture is carried in the statement of financial position at cost plus post acquisition changes in the Group's share of net assets of the joint venture. Goodwill relating to the joint venture is included in the carrying amount of the investment and is neither amortised nor individually tested for impairment. The profit or loss reflects the Group's share of the results of operations of the joint venture. Where there has been a change recognised directly in other comprehensive income or equity of the joint venture, the Group recognises its share of any changes and discloses this, when applicable, in the consolidated income statement or the statement of changes in equity, as appropriate. Unrealised gains and losses resulting from transactions between the Group and the joint venture are eliminated to the extent of the interest in the joint venture. The share of the joint venture's net profit/(loss) is shown on the face of the consolidated income statement. This is the profit/(loss) attributable to Group's interest in the joint venture. The financial statements of the JCE are prepared for the same reporting period as the venturer. Where necessary, adjustments are made to bring the accounting policies in line with those of the Group.

The Group, acting as the operator of the JCE, receives reimbursement of direct costs recharged to the joint venture, such recharges represent reimbursements of costs that the operator incurred as an agent for the joint venture and therefore have no effect on profit or loss. When the Group charges a management fee to cover other general costs incurred in carrying out the activities on behalf of the joint venture, it is not acting as an agent. Therefore, the general overhead expenses and the management fee are netted against each other.

Notes to the Financial Statements (continued)
For the Year Ended 31 December 2011

3. Accounting Policies (continued)

3.4 Summary of Significant Accounting Policies (continued)

(d) Oil and Gas Exploration, Evaluation and Development Expenditure

Oil and gas exploration, evaluation and development expenditure is accounted for using the successful efforts method of accounting.

Pre-licence Costs

Pre-licence costs are expensed in the period in which they are incurred.

Exploration and Evaluation Costs

Payments to acquire the legal right to explore are capitalised at cost as intangible assets. If no future activity is planned, the carrying value of these costs is written off. Costs directly associated with an exploration well are capitalised until the drilling of the well is complete and the results have been evaluated. These costs include employee remuneration, materials and fuel used, rig costs and payments made to contractors. If hydrocarbons are not found, the exploration expenditure is written off as a dry hole. If extractable oil is found and, subject to further appraisal activity, which may include the drilling of further wells, is likely to be developed commercially, the costs continue to be carried as an intangible asset. All such carried costs are subject to technical, commercial and management review as well as review for impairment at least once a year to confirm the continued intent to develop or otherwise extract value from the discovery. If this is no longer the case, the costs are written off. When proved reserves are determined and development is sanctioned, the relevant expenditure is transferred to oil and gas properties after impairment is assessed and any resulting impairment loss is recognised. The net proceeds or costs of pilot production are allocated to exploration and evaluation costs.

Development Costs

Expenditure on the construction, installation or completion of infrastructure facilities such as platforms, pipelines and the drilling of development wells, including unsuccessful development or delineation wells, is capitalised within oil and gas properties and depreciated from the commencement of production on a unit-of-production basis other than certain non-production related equipment and facilities which are expected to have a shorter useful economic life and are depreciated on a straight-line basis.

(e) Oil and Gas Properties and Other Property, Plant and Equipment

Oil and gas properties and other property, plant and equipment are stated at cost, less accumulated depreciation.

The initial cost of an asset comprises its purchase price or construction cost, any costs directly attributable to bringing the asset into operation, the initial estimate of the decommissioning obligation, and for qualifying assets, relevant borrowing costs. The purchase price or construction cost is the aggregate amount paid and the fair value of any other consideration given to acquire the asset.

Depreciation

Oil and gas properties are depreciated on the following basis:

- Production related items including the wells, production facility and pipeline are depreciated on a unit-of-production basis over the proved and probable reserves of the field concerned. The unit-of-production rate for the amortisation of field development costs takes into account expenditures incurred to date, together with sanctioned future development expenditure to extract these reserves. The related depreciation is included within cost of sales.
- Certain non-production related equipment and facilities which are expected to have a shorter useful economic life are depreciated on a straight-line basis over their estimated useful lives at annual rates ranging from 10% to 50%. The related depreciation is included within administrative expenses.

Property, plant and equipment are generally depreciated on a straight-line basis over their estimated useful lives at the following annual rates:

- Land and buildings – 3% to 7% or remaining term of the lease, whichever is shorter.
- Plant and machinery – 10% to 35%.
- Motor vehicles – 14% to 35%.

(f) Impairment of Property, Plant and Equipment and Intangible Assets

At each balance sheet date, the Group reviews the carrying amounts of its property, plant and equipment and intangible assets to determine whether there is any indication that those assets may be impaired. If such indication exists, the recoverable amount of the asset is estimated in order to determine the extent of any impairment loss.

The recoverable amount is determined as the higher of the fair value less costs to sell for the asset and the asset's value-in-use. If the carrying amount of the asset exceeds its recoverable amount, the asset is impaired and an impairment loss is charged to the Consolidated Income Statement so as to reduce the carrying amount in the Consolidated Balance Sheet to its recoverable amount.

Fair value is determined as the amount that would be obtained from the sale of the asset in an arm's length transaction between knowledgeable and willing parties. Direct costs of selling the asset are deducted. Fair value for oil and gas assets is generally determined as the present value of the estimated future cash flows expected to arise from the continued use of the asset, including any expansion prospects, and its eventual disposal, using assumptions that a market participant could take into account. These cash flows are discounted by an appropriate discount rate to arrive at a net present value ('NPV') of the asset.

Value-in-use is determined as the present value of the estimated future cash flows expected to arise from the continued use of the asset in its present form and its eventual disposal. Value-in-use is determined by applying assumptions specific to the Group's continued use and cannot take into account future development. These assumptions are different to those used in calculating fair value and consequently the value-in-use calculation is likely to give a different result to a fair value calculation.

Where it is not possible to estimate the recoverable amount of an individual asset, the Group estimates the recoverable amount of the cash-generating unit to which the asset belongs.

(g) Financial Assets – Investment in Subsidiaries

Investments in subsidiaries are stated at cost and are reviewed for impairment if there are indications that the carrying value may not be recoverable.

(h) Cash and Cash Equivalents

Cash and cash equivalents on the balance sheet comprise cash at bank and on hand and short-term deposits with an original maturity of three months or less.

(i) Financial Assets

Financial assets within the scope of IAS 39 Financial Instruments: Recognition and Measurement ('IAS 39') are classified as financial assets at fair value through profit or loss or loans and receivables, as appropriate. When financial assets are recognised initially, they are measured at fair value plus, in the case of investments not at fair value through profit or loss, directly attributable transaction costs. The Group determines the classification of its financial assets on initial recognition and, where allowed and appropriate, re-evaluates this designation at each financial year-end.

The Group does not have held-to-maturity investments or available-for-sale financial assets or financial assets at fair value through the Consolidated Income Statement.

Loans and receivables are non-derivative financial assets with fixed or determinable payments that are not quoted in an active market. After initial measurements, loans and receivables are carried at amortised cost using the effective interest rate method ('EIR') less any allowance for impairment. Amortised cost is calculated by taking into account any discount or premium on acquisition and fees or costs that are an integral part of the EIR. The EIR amortisation is included in finance revenue in the Consolidated Income Statement. The losses arising from impairment are recognised in the Consolidated Income Statement in finance costs.

The Group assesses at each year-end whether a financial asset or group of financial assets is impaired. If there is objective evidence that an impairment loss on assets carried at amortised cost has been incurred, the amount of the loss is measured as the difference between the asset's carrying amount and the present value of estimated future cash flows (excluding future expected credit losses that have not been incurred) discounted at the financial asset's original effective interest rate (i.e. the effective interest rate computed at initial recognition). The amount of the loss is recognised in the Consolidated Income Statement.

If, in a subsequent period, the amount of the impairment loss decreases and the decrease can be related objectively to an event occurring after the impairment was recognised, the previously recognised impairment loss is reversed, to the extent that the carrying value of the asset does not exceed its amortised cost at the reversal date. Any subsequent reversal of an impairment loss is recognised in the Consolidated Income Statement.

In relation to trade receivables, a provision for impairment is made when there is objective evidence (such as the probability of insolvency or significant financial difficulties of the debtor) that the Group will not be able to collect all of the amounts due under the original terms of the invoice. The carrying amount of the receivable is reduced through use of an allowance account. Impaired debts are written-off when they are assessed as uncollectible.

(j) Financial Liabilities

Financial liabilities within the scope of IAS 39 are classified as financial liabilities at fair value through profit or loss, loans and borrowings, or as derivatives, as appropriate. The Group determines the classification of its financial liabilities at initial recognition.

All financial liabilities are recognised initially at fair value and in the case of loans and borrowings, plus directly attributable transaction costs.

The Group's financial liabilities include trade and other payables and loans and borrowings.

Financial Liabilities at Fair Value Through Profit or Loss

Financial liabilities at fair value through profit or loss include financial liabilities held for trading and financial liabilities designated upon initial recognition at fair value through the Consolidated Income Statement.

Financial liabilities are classified as held for trading if they are acquired for the purpose of selling in the near term. Derivatives, including separated embedded derivatives, are also classified as held for trading unless they are designated as effective hedging instruments. Gains or losses on liabilities held for trading are recognised in the Consolidated Income Statement.

Notes to the Financial Statements (continued)
For the Year Ended 31 December 2011

3. Accounting Policies (continued)

3.4 Summary of Significant Accounting Policies (continued)

Interest Bearing Loans and Borrowings

After initial recognition, interest bearing loans and borrowings are subsequently measured at amortised cost using the effective interest rate method. Gains and losses are recognised in the Consolidated Income Statement when the liabilities are derecognised as well as through the effective interest rate method ('EIR') amortisation process.

Amortised cost is calculated by taking into account any discount or premium on acquisition and fee or costs that are an integral part of the EIR. The EIR amortisation is included in finance cost in the Consolidated Income Statement.

Derecognition

A financial liability is derecognised when the obligation under the liability is discharged or cancelled or expires.

When an existing financial liability is replaced by another from the same lender on substantially different terms, or the terms of an existing liability are substantially modified, such an exchange or modification is treated as a derecognition of the original liability and the recognition of a new liability, and the difference in the respective carrying amounts is recognised in the Consolidated Income Statement.

(k) Inventories

Inventories are stated at the lower of cost and net realisable value. Cost of producing and processing crude oil is accounted on weighted average basis. This cost includes all costs incurred in the normal course of business in bringing each product to its present location and condition. The cost of crude oil includes appropriate proportion of depreciation and overheads based on normal capacity. Net realisable value of crude oil is based on estimated selling price in the ordinary course of business less any costs expected to be incurred to completion and disposal.

(l) Provisions

General

Provisions are recognised when the Group has a present obligation (legal or constructive) as a result of a past event and it is probable that an outflow of resources embodying economic benefits will be required to settle the obligation and a reliable estimate can be made of the amount of the obligation. Where the Group expects some or all of a provision to be reimbursed, for example, under an insurance contract, the reimbursement is recognised as a separate asset but only when the reimbursement is virtually certain. The expense relating to any provision is presented in the Consolidated Income Statement net of any reimbursement. If the effect of the time value of money is material, provisions are discounted using a current pre-tax rate that reflects, where appropriate, the risks specific to the liability. Where discounting is used, the increase in the provision due to the passage of time is recognised as a finance cost.

A contingent liability is disclosed where the existence of an obligation will only be confirmed by future events or where the amount of the obligation cannot be measured with reasonable reliability. Contingent assets are not recognised, but are disclosed where an inflow of economic benefits is probable.

Decommissioning Liability

A decommissioning liability is recognised when the Group has a present legal or constructive obligation as a result of past events, and it is probable that an outflow of resources will be required to settle the obligation, and a reliable estimate of the amount of obligation can be made. The amount recognised is the estimated cost of decommissioning, discounted to its present value. A corresponding amount equivalent to the provision at the time of recognition is recognised as part of the cost of the related oil and gas properties or in exploration and evaluation expenditure. Changes in the estimated timing of decommissioning or decommissioning cost estimates are dealt with prospectively by recording an adjustment to the provision and a corresponding adjustment to oil and gas properties or exploration and evaluation expenditure. The unwinding of the discount on the decommissioning provision is included as a finance cost.

(m) Taxes

Current Income Tax

Current income tax assets and liabilities for the current and prior periods are measured at the amount expected to be recovered from or paid to the taxation authorities. The tax rates and tax laws used to compute the amount are those that are enacted or substantively enacted, by the reporting date, in the countries where the Group operates and generates taxable income.

Deferred Income Tax

Deferred income tax is provided using the liability method on temporary differences at the balance sheet date between the tax bases of assets and liabilities and their carrying amounts for financial reporting purposes. Deferred income tax liabilities are recognised for all taxable temporary differences, except:

- in respect of taxable temporary differences associated with investments in subsidiaries, associates and interests in joint ventures, where the timing of the reversal of the temporary differences can be controlled and it is probable that the temporary differences will not reverse in the foreseeable future.

Deferred income tax assets are recognised for all deductible temporary differences, carry forward of unused tax credits and unused tax losses, to the extent that it is probable that taxable profit will be available against which the deductible temporary differences and the carry forward of unused tax credits and unused tax losses can be utilised except:

- in respect of deductible temporary differences associated with investments in subsidiaries, associates and interests in joint ventures, deferred income tax assets are recognised only to the extent that it is probable that the temporary differences will reverse in the foreseeable future and taxable profit will be available against which the temporary differences can be utilised.

The carrying amount of deferred income tax assets is reviewed at each balance sheet date and reduced to the extent that it is no longer probable that sufficient taxable profit will be available to allow all or part of the deferred income tax asset to be utilised. Unrecognised deferred income tax assets are reassessed at each balance sheet date and are recognised to the extent that it has become probable that future taxable profit will allow the deferred tax asset to be recovered.

Deferred income tax assets and liabilities are measured at the tax rates that are expected to apply to the year when the asset is realised or the liability is settled, based on tax rates (and tax laws) that have been enacted or substantively enacted at the balance sheet date.

Deferred income tax relating to items recognised outside of profit and loss is recognised outside profit and loss. Deferred tax items are recognised in correlation to the underlying transaction either in other comprehensive income or directly in equity.

Deferred income tax assets and deferred income tax liabilities are offset if a legally enforceable right exists to set off current tax assets against current income tax liabilities and the deferred income taxes relate to the same taxable entity and the same taxation authority.

(n) Revenue Recognition

Revenue from the sale of crude oil is recognised when the significant risks and rewards of ownership have been transferred, which is when title passes to the customer. This generally occurs when product is physically transferred into a pipe or other delivery mechanism.

Revenue is stated after deducting sales taxes, excise duties and similar levies.

(o) Borrowing Costs

Borrowing costs directly attributable to the acquisition, construction or production of an asset that necessarily takes a substantial period of time to get ready for its intended use or sale are capitalised as part of the cost of the respective assets. All other borrowing costs are expensed in the period they occur. Borrowing costs consist of interest and other costs that an entity incurs in connection with the borrowing of funds.

(p) Share-based Payment

Employees (including senior executives) and Directors of the Group may receive fees and remuneration in the form of share-based payment transactions, whereby employees render services as consideration for equity instruments (‘equity-settled transactions’).

In situations where equity instruments are issued and some or all of the goods or services received by the entity as consideration cannot be specifically identified, the unidentified goods or services received (or to be received) are measured as the difference between the fair value of the share-based payment transaction and the fair value of any identifiable goods or services received at the grant date. This is then capitalised or expensed as appropriate.

Equity-settled Transactions

The cost of equity-settled transactions is measured by reference to the fair value at the date on which they are granted. The fair value is determined by an external valuer using an appropriate pricing model, further details of which are given in Note 29.

The cost of equity-settled transactions is recognised, together with a corresponding increase in equity, over the period in which the performance and/or service conditions are fulfilled. The cumulative expense recognised for equity-settled transactions at each reporting date until the vesting date reflects the extent to which the vesting period has expired and the Group’s best estimate of the number of equity instruments that will ultimately vest. The income statement charge or credit for a period represents the movement in cumulative expense recognised as at the beginning and end of that period and is recognised in employee benefits expense.

No expense is recognised for awards that do not ultimately vest, except for equity-settled transactions where vesting is conditional upon a market or non-vesting condition, which are treated as vesting irrespective of whether or not the market or non-vesting condition is satisfied, provided that all other performance and/or service conditions are satisfied.

Where the terms of an equity-settled transaction are modified, the minimum expense recognised is the expense as if the terms had not been modified, if the original terms of the awards are met. An additional expense is recognised for any modification that increases the total fair value of the share-based payment transaction, or is otherwise beneficial to the employee as measured at the date of modification.

Where an equity-settled award is cancelled, it is treated as if it had vested on the date of cancellation, and any expense not yet recognised for the award is recognised immediately. This includes any award where non-vesting conditions within the control of either the entity or the employee are not met. However, if a new award is substituted for the cancelled award, and designated as a replacement award on the date that it is granted, the cancelled and new awards are treated as if they were a modification of the original award, as described in the previous paragraph.

Where appropriate, the dilutive effect of outstanding options is reflected as additional share dilution in the computation of diluted earnings per share.

Notes to the Financial Statements (continued)
For the Year Ended 31 December 2011

3. Accounting Policies (continued)

3.4 Summary of Significant Accounting Policies (continued)

(q) Share Issue Expenses

Costs of share issues are written off against the premium arising on the issue of share capital.

(r) Operating Leases

The determination of whether an arrangement is, or contains, a lease is based on the substance of the arrangement at inception date, or whether the fulfilment of the arrangement is dependent on the use of a specific asset or assets or the arrangement conveys a right to use the asset.

Operating lease payments are recognised as an expense in the Consolidated Income Statement on a straight line basis over the lease term.

(s) Finance Revenue

For all financial instruments measured at amortised cost, interest income or expense is recorded using the effective interest rate, which is the rate that exactly discounts the estimated future cash payments or receipts through the expected life of the financial instrument or a shorter period, where appropriate, to the net carrying amount of the financial asset or liability. Interest income is included in finance revenue in the income statement.

(t) Defined Contribution Pension Costs

Pension benefits are funded over the employees' period of service by way of contributions to a defined contribution scheme. Contributions are charged to the Consolidated Income Statement in the year to which they relate.

3.5 Changes in Accounting Policy and Disclosures

The Group has adopted the following new and amended IFRS and IFRIC interpretations in respect of the 2011 financial year-end:

	Effective date
IAS 24 Related Party Disclosures (Amendment)	1 January 2011
IAS 32 Financial Instruments – Presentation (Amendment)	1 February 2010
IFRIC 14 Prepayments of a Minimum Funding Requirement (Amendment)	1 January 2011

There were no significant changes necessary arising from the above amendments to the Group during the year.

IFRS and IFRIC Interpretations Effective in Respect of the 2012 Financial Year-end

The Group has not applied the following standards and interpretations that have been issued but are not yet effective:

IAS 12 Income Taxes – Recovery of Underlying Assets effective 1 January 2012
IFRS 7 Financial Instruments: Disclosures – Enhanced Derecognition Disclosure Requirements effective 1 July 2011
Improvements to IFRSs (May 2010) – amendments applying in respect of the 2012 financial year-end

The standards and interpretations addressed above will be applied for the purposes of the Group Consolidated Financial Statements with effect from the dates listed. Their application is not currently envisaged to have a material impact on the Group's Consolidated Financial Statements.

IFRS and IFRIC Interpretations Effective Subsequent to the 2012 Financial Year-end

IAS 1 Financial Statement Presentation – Presentation of Items of Other Comprehensive Income effective 1 July 2012
IAS 19 Employee Benefits (Amendment) effective 1 January 2013
IAS 27 Separate Financial Statements (as revised in 2011) effective 1 January 2013
IAS 28 Investments in Associates and Joint Ventures (as revised in 2011) effective 1 January 2013
IFRS 9 Financial Instruments: Classification and Measurement effective 1 January 2013
IFRS 10 Consolidated Financial Statements effective 1 January 2013
IFRS 11 Joint Arrangements effective 1 January 2013
IFRS 12 Disclosure of Involvement with Other Entities effective 1 January 2013
IFRS 13 Fair Value Measurement effective 1 January 2013

The Group is in the process of assessing the impact of these standards but does not currently envisage their application to have a material impact on the Group's Consolidated Financial Statements.

4. Segment Information

At present the Group has one reportable operating segment, which is oil exploration and production. As a result, there are no further disclosures required in respect of the Group's reporting segment.

The risk and returns of the Group's operations are primarily determined by the nature of the activities that the Group engages in, rather than the geographical location of these operations. This is reflected by the Group's organisational structure and the Group's internal financial reporting systems.

Management monitors and evaluates the operating results for the purpose of making decisions consistently with operating profit or loss in the Consolidated Financial Statements.

Geographical Segments

All of the Group's sales are in Russia. Substantially all of the Group's capital expenditures are in Russia.

Non-current Assets

Assets are allocated based on where the assets are located:

	2011 US$	2010 US$
Russia	**123,019,068**	85,200,373
Ireland	**9,443**	9,135
	123,028,511	85,209,508

5. Revenue

	2011 US$	2010 US$
Revenue from crude oil sales	**29,031,693**	5,155,646
	29,031,693	5,155,646

All revenue arises from sales to third parties based in the Russian Federation.

More than 99% of revenue or US$28,891,704 (2010: US$5,139,106) arises from sales of crude oil to NTK Finko.

6. Operating Loss

	Note	2011 US$	2010 US$
Operating loss is stated after charging/(crediting):			
Included in cost of sales			
Cost of inventory recognised as an expense		**25,598,616**	4,284,181
Impairment of oil and gas properties	13	**5,000,000**	–
Foreign exchange loss on intra-Group loans		**5,114,345**	137,054
Included in administrative expenses			
Impairment of leasehold land payment		**–**	176,825
Other foreign exchange gains		**(159,244)**	(285,038)
Operating lease rentals – land and buildings		**318,739**	308,349
Depreciation of property, plant and equipment			
Included in administrative expenses		**145,328**	117,177
Included in cost of sales		**62,136**	9,595
Capitalised during year		**174,677**	129,134
	14	**382,141**	255,906
Depreciation of oil and gas properties			
Included in cost of sales		**3,906,568**	520,640
Included in administrative expenses		**179,917**	164,537
Included in closing inventories		**302,748**	99,386
	13	**4,389,233**	784,563
Auditors' remuneration			
– audit of group financial statements		**216,676**	244,564
– other assurance services		**8,043**	–
– tax advisory services		**8,403**	20,556
		233,122	265,120

7. Finance Revenue

	2011 US$	2010 US$
Bank interest receivable	**55,861**	126,595
Unwinding of discount on deposit paid for pipeline usage	**3,993**	–
	59,854	126,595

Notes to the Financial Statements (continued)
For the Year Ended 31 December 2011

8. Finance Costs

	2011 US$	2010 US$
Interest on loans	**2,438,971**	643,542
Unwinding of discount on decommissioning provision	**62,099**	20,787
Discount on deposit paid for pipeline usage (see below)	**–**	342,053
Share-based payment in relation to initial US$5 million loan facility	**–**	350,536
	2,501,070	1,356,918

During 2010 the Group paid a deposit of US$400,000 to Nord Imperial for the usage of their pipeline. This deposit will be returned at the end of the contract which is in 2033. In the Consolidated Financial Statements this deposit has been discounted and the unwinding of the discount of US$3,993 (2010: discount of US$342,053) has been taken to finance revenue in the current year (2010: finance costs).

9. Employees

	2011 Number	2010 Number
Number of employees		
The average numbers of employees (including Directors) during the year was:		
Directors	**7**	7
Senior management	**5**	5
Support staff	**162**	88
	174	100

	2011 US$	2010 US$
Employment costs (including Directors)		
Wages and salaries	**5,119,742**	3,969,500
Social insurance costs	**995,261**	520,945
Share-based payment expense	**1,108,446**	460,500
Pension contributions	**59,719**	14,602
	7,283,168	4,965,547

An amount of US$1,884,599 (2010: US$1,389,177) in employment costs was capitalised during the year.

	2011 US$	2010 US$
Directors' emoluments		
Remuneration and other emoluments – Executive Directors	**869,786**	986,058
Remuneration and other emoluments – Non-Executive Directors	**145,007**	61,169
Remuneration and other emoluments payable or paid in shares	**28,905**	20,362
Pension contributions	**40,677**	10,615
Share-based payment expense	**317,525**	161,742
	1,401,900	1,239,946

An amount of US$92,222 relating to Executive Directors salaries was re-charged to Russian BD Holdings B.V. in 2011.

10. Income Tax

	2011 US$	2010 US$
Current income tax		
Current income tax charge	**7,756**	42,083
Adjustment in respect of prior periods	**(37,518)**	–
Total current income tax	**(29,762)**	42,083
Deferred tax		
Relating to origination and reversal of temporary differences	**1,521,082**	810,346
Total deferred tax	**1,521,082**	810,346
Income tax expense reported in the Consolidated Income Statement	**1,491,320**	852,429

The Tax Expense Comprises:

All income tax charge relates to interest income received by the Company.

Reconciliation of the Total Tax Charge

The tax assessed for the year differs from that calculated by applying the standard rate corporation tax in the Republic of Ireland of 12.5%.

The differences are explained below:

	2011 US$	2010 US$
Loss before income tax	**(16,422,036)**	(6,272,965)
Accounting loss multiplied by Irish standard rate of tax of 12.5%	**(2,052,755)**	(784,121)
Share-based payment expense	**138,556**	57,563
Effect of higher tax rates on investment income	**781,785**	425,729
Non-deductible expenses	**720,592**	464,060
Tax deductible timing differences	**(81,116)**	(560,665)
Other	**(12,631)**	448,038
Losses available at higher rates	**(1,220,644)**	(481,094)
Taxable losses not utilised	**3,255,051**	1,282,919
Adjustment in respect of prior periods	**(37,518)**	–
Total tax expense reported in the Consolidated Income Statement	**1,491,320**	852,429

Deferred Tax

Deferred tax at 31 December relates to the following:

Group and Company	2011 US$	2010 US$
Deferred income tax liability		
Accrued interest income	**3,157,557**	1,636,475
	3,157,557	1,636,475

The Group has tax losses which arose in Russia that are available for offset against future taxable profits of the companies in which the losses arose. Deferred tax assets of US$7.2 million (2010: US$3.8 million), which expire in six to ten years, have not been recognised in respect of these losses as they may not be used to offset taxable profits elsewhere in the Group and they have arisen in subsidiaries that have been loss making over recent years.

Factors that May Affect Future Tax Charges

The Group had their first full year of year-round oil production in Russia during 2011. Such production is likely to result in taxable profits in Russia in future years, where the applicable tax rate is 20%.

11. Loss per Ordinary Share

Basic loss per Ordinary Share amounts are calculated by dividing net loss for the year attributable to ordinary equity holders of the parent by the weighted average number of Ordinary Shares outstanding during the year.

Basic and diluted earnings per Ordinary Share are the same as the potential Ordinary Shares are anti-dilutive.

	2011 US$	2010 US$
Numerator		
Loss attributable to equity shareholders of the Parent for basic and diluted loss	**(17,913,356)**	(7,125,394)
	(17,913,356)	(7,125,394)
Denominator		
Weighted average number of Ordinary Shares for basic and diluted earnings per Ordinary Share	**416,224,994**	361,023,606
Diluted weighted average number of shares	**416,224,994**	361,023,606
Loss per share:		
Basic and diluted – US dollar cent	**(4.30)**	(1.97)

Notes to the Financial Statements (continued)
For the Year Ended 31 December 2011

11. Loss per Ordinary Share (continued)
The Company has instruments in issue that could potentially dilute basic earnings per Ordinary Share in the future, but are not included in the calculation for the reasons outlined below:

- Employee Share Options – Refer to Note 29 for the total number of shares related to the outstanding options that could potentially dilute basic earnings per share in the future. These potential Ordinary Shares are anti-dilutive for the years ended 31 December 2011 and 2010.
- Warrants – At 31 December 2011, 6,700,000 (2010: 6,200,000) Ordinary Shares are subject to warrants being exercised (refer to Note 29). These potential Ordinary Shares are anti-dilutive for the years ended 31 December 2011 and 2010.

12. Assets Held for Sale
In January 2010, the Group acquired and registered Licence 67. Under the August 2008 Area of Mutual Interest agreement, Arawak Energy exercised their option to participate as a 50% partner in the development of Licence 67, which will be operated by PetroNeft. PetroNeft Resources Plc entered into an agreement with Arawak to jointly own and control a holding company (Russian BD Holdings B.V.) which holds all of the shares of LLC Lineynoye, an entity involved in oil and gas exploration and the registered holder of Licence 67. The legal agreements and documentation relating to the jointly controlled entity were completed in September 2011 when the assets were transferred to the jointly controlled entity. At 31 December 2010, assets in connection with Licence 67 were classified as held for sale.

On 9 September 2011, Russian BD Holdings B.V., which was previously a 100% subsidiary of PetroNeft, became a jointly controlled entity, resulting in a profit on disposal on consolidation of US$223,222 comprised as follows:

Profit on Disposal of Subsidiary Undertaking

	2011 US$
Fair value of net assets subsequent to disposal	**445,748**
Book value of net assets prior to disposal	**222,526**
	223,222

13 Oil and Gas Properties

Group	Wells US$	Equipment and facilities US$	Pipeline US$	Total US$
Cost				
At 1 January 2010	15,408,490	737,610	11,036,987	27,183,087
Additions	19,999,210	12,816,849	3,244,417	36,060,476
Transfer from property, plant and equipment	–	48,884	–	48,884
Translation adjustment	(194,658)	(49,843)	(107,368)	(351,869)
At 1 January 2011	**35,213,042**	**13,553,500**	**14,174,036**	**62,940,578**
Transfer from exploration and evaluation assets	**2,803,399**	**111,368**	**–**	**2,914,767**
Additions	**30,033,170**	**13,846,905**	**51,406**	**43,931,481**
Disposals	**(19,843)**	**(127,661)**	**(249,045)**	**(396,549)**
Translation adjustment	**(4,418,308)**	**(1,826,123)**	**(660,975)**	**(6,905,406)**
At 31 December 2011	**63,611,460**	**25,557,989**	**13,315,422**	**102,484,871**
Depreciation				
At 1 January 2010	16,316	1,510	–	17,826
Charge for the year	535,613	217,360	31,590	784,563
Translation adjustment	(1,862)	(2,820)	(930)	(5,612)
At 1 January 2011	**550,067**	**216,050**	**30,660**	**796,777**
Charge for the year	**3,476,558**	**816,099**	**96,576**	**4,389,233**
Impairment	**5,000,000**	**–**	**–**	**5,000,000**
Disposals	**(500)**	**(4,126)**	**(735)**	**(5,361)**
Translation adjustment	**(314,243)**	**(69,603)**	**(9,908)**	**(393,754)**
At 31 December 2011	**8,711,882**	**958,420**	**116,593**	**9,786,895**
Net book values				
At 31 December 2011	**54,899,578**	**24,599,569**	**13,198,829**	**92,697,976**
At 31 December 2010	34,662,975	13,337,450	14,143,376	62,143,801

The net book value at 31 December 2011 includes US$24,395,926 (2010: US$17,288,826) in respect of assets under construction, which are not yet being depreciated.

In November 2011 the Board sanctioned the development of the Arbuzovskoye oilfield. Exploration and evaluation costs of US$2,914,767 in relation to the Arbuzovskoye oilfield were transferred to oil and gas properties.

Expenditure of US$43,931,481 was incurred mainly in connection with the Lineynoye oil field, primarily relating to production wells, the Central Procession Facility (CPF) and oilfield infrastructure.

Loss on Disposal of Oil and Gas Properties

During the year, the Group disposed of pipeline and facilities relating to the decommissioning of the Lineynoye No. 1 well and the conversion of the Lineynoye No.6 well to a water injection well resulting in a loss on disposal of US$391,188.

Impairment Loss

An impairment of US$5 million (2010: US$Nil) was recognised in respect of the Lineynoye oil field. The trigger for the impairment test was primarily the effect of worse than expected production from Pads 2 and 3 at the Lineynoye oil field during the year. In addition, this triggered reduced estimates of the quantities of oil recoverable from this particular field.

In assessing whether impairment is required, the carrying value of an asset or cash-generating unit (CGU) is compared with its recoverable amount. The recoverable amount is the higher of the asset's/CGU's fair value less costs to sell and value in use. Given the nature of the Group's activities, information on the fair value of an asset is usually difficult to obtain unless negotiations with potential purchasers are taking place. Consequently, the recoverable amount used in assessing the impairment charges described below is value in use. The Group generally estimates value in use using a discounted cash flow model.

Key Assumptions Used in Value-in-use Calculations for the Lineynoye Oil Field

The calculation of value in use for the Lineynoye oil field ('CGU') is most sensitive to the following assumptions:

- Production volumes
- Discount rates
- Crude oil prices

Estimated production volumes are based on detailed data for the fields and take into account development plans for the fields agreed by management as part of the long-term planning process and estimated by Ryder Scott Petroleum Consultants in their report on the Group's reserves.

The Group generally estimates value in use for the oil exploration and production CGU using a discounted cash flow model. The future cash flows are discounted to their present value using a pre-tax discount rate of 16% that reflects current market assessments of the time value of money and the risks specific to the asset. This discount rate is derived from the Group's post-tax weighted average cost of capital ('WACC'), with appropriate adjustments made to reflect the risks specific to the asset/CGU and to determine the pre-tax rate. The WACC takes into account both debt and equity. The cost of equity is derived from the expected return on investment by the Group's investors. The cost of debt is based on its interest bearing borrowings the Group is obliged to service. Segment specific risk is incorporated by applying individual beta factors. The beta factors are evaluated annually based on publicly available market data.

The long-term forecast Urals blend oil price used of US$80 per barrel is based on management's estimates and available market data.

Notes to the Financial Statements (continued)
For the Year Ended 31 December 2011

14. Property, Plant and Equipment

Group	Land and buildings US$	Plant and machinery US$	Motor vehicles US$	Total US$
Cost				
At 1 January 2010	302,641	1,762,039	145,732	2,210,412
Reclassification	800,795	(800,795)	–	–
Additions	1,669	171,706	45,818	219,193
Transfer to oil and gas properties	–	–	(48,884)	(48,884)
Disposals	–	–	(17,869)	(17,869)
Translation adjustment	(5,390)	(13,086)	(1,200)	(19,676)
At 1 January 2011	**1,099,715**	**1,119,864**	**123,597**	**2,343,176**
Additions	**–**	**745,073**	**–**	**745,073**
Translation adjustment	**(52,992)**	**(116,255)**	**(5,927)**	**(175,174)**
At 31 December 2011	**1,046,723**	**1,748,682**	**117,670**	**2,913,075**
Depreciation				
At 1 January 2010	25,551	375,201	33,552	434,304
Charge for the year	64,365	176,496	15,045	255,906
Disposals	–	–	(16,715)	(16,715)
Translation adjustment	(444)	(3,804)	(287)	(4,535)
At 1 January 2011	**89,472**	**547,893**	**31,595**	**668,960**
Charge for the year	**66,787**	**288,205**	**27,149**	**382,141**
Translation adjustment	**(10,008)**	**(50,117)**	**(3,839)**	**(63,964)**
At 31 December 2011	**146,251**	**785,981**	**54,905**	**987,137**
Net book values				
At 31 December 2011	**900,472**	**962,701**	**62,765**	**1,925,938**
At 31 December 2010	1,010,243	571,971	92,002	1,674,216

Company	Plant and machinery US$
Cost	
At 1 January 2010	15,091
Additions	4,809
At 1 January 2011	**19,900**
Additions	**3,962**
At 31 December 2011	**23,862**
Depreciation	
At 1 January 2010	7,247
Charge for the year	3,517
At 1 January 2011	**10,764**
Charge for the year	**3,654**
At 31 December 2011	**14,418**
Net book values	
At 31 December 2011	**9,444**
At 31 December 2010	9,136

15. Exploration and Evaluation Assets

Group	Exploration and evaluation expenditure US$
Cost	
At 1 January 2010	18,217,242
Additions	5,367,284
Reclassified as assets held for sale	(2,020,678)
Translation adjustment	(172,357)
At 1 January 2011	**21,391,491**
Additions	**7,459,616**
Reclassification to oil and gas properties	**(2,914,767)**
Translation adjustment	**(1,383,623)**
At 31 December 2011	**24,552,717**

Net book values	
At 31 December 2011	**24,552,717**
At 31 December 2010	21,391,491

Exploration and evaluation expenditure represents active exploration projects. These amounts will be written off to the Consolidated Income Statement as exploration costs unless commercial reserves are established, or the determination process is not completed and there are no indications of impairment. The outcome of ongoing exploration, and therefore whether the carrying value of these assets will ultimately be recovered, is inherently uncertain.

In accordance with IFRS 6, once commercial viability is demonstrated the capitalised exploration and evaluation costs are transferred to oil and gas properties or intangibles, as appropriate after being assessed for impairment.

Additions in 2011 relate mainly to drilling of exploration wells in the Sibkrayevskaya and North Varyakhskaya prospects and the Kondrashevskoye oilfield.

16. Equity-accounted Investment in Joint Venture

PetroNeft Resources plc has a 50% interest in Russian BD Holdings B.V., a jointly controlled entity which holds 100% of LLC Lineynoye, an entity involved in oil and gas exploration and the registered holder of Licence 67. The interest in this joint venture is accounted for using the equity accounting method. Russian BD Holdings B.V. is incorporated in the Netherlands and carries out its activities in Russia.

	Share of net assets 2011 US$
At 1 January 2011	–
Subsidiary undertaking becoming joint venture (see Note 12)	**445,748**
Investment	**3,850,000**
Retained loss	**(334,363)**
Translation adjustment	**(109,505)**
At 31 December 2011	**3,851,880**

Summarised financial statement information prepared in accordance with IFRS of the equity-accounted joint venture entity is disclosed below:

Summarised Financial Statements of Equity-accounted Joint Venture (50% Share)

	2011 US$
Sales and other operating revenues	–
Operating expenses	**(176,278)**
Foreign exchange loss	**(149,640)**
Finance revenue	**1,408**
Finance costs	**(9,496)**
Loss before taxation	**(334,006)**
Taxation	**(357)**
Loss for the period	**(334,363)**

Notes to the Financial Statements (continued)
For the Year Ended 31 December 2011

16. Equity-accounted Investment in Joint Venture (continued)

	2011 US$
Current assets	3,906,526
Non-current assets	532,830
Total assets	**4,439,356**
Current liabilities	(581,340)
Non-current liabilities	(6,136)
Total liabilities	**(587,476)**

Capital Commitments – Joint Venture

	31 December 2011 US$
Details of capital commitments at the balance sheet date are as follows:	
Contracted for but not provided in the financial statements	1,146,596
Including contracted with related parties	1,078,820

Future minimum rentals payable under non-cancellable operating leases at the balance sheet date are as follows:

	31 December 2011 US$
Within one year	3,376
After one year but not more than five years	17,413
More than five years	59,793
	80,582

The above capital commitments in the joint venture are incurred jointly with Arawak Energy. The Group has a 50% share of these commitments.

17. Financial Assets

Company	Investment in joint venture US$	Investment in subsidiaries US$	Total US$
Cost			
At 1 January 2010	–	40,280,658	40,280,658
Capital contribution in respect of share-based payment expense	–	234,525	234,525
Additions	–	78,285	78,285
Impairment of investment in Pervomayka	–	(224,546)	(224,546)
At 1 January 2011	**–**	**40,368,922**	**40,368,922**
Capital contribution in respect of share-based payment expense	–	689,449	689,449
Subsidiary undertaking becoming a joint venture (Note 12)	1,008,816	(1,008,816)	–
Additions	3,850,000	130,000	3,980,000
At 31 December 2011	**4,858,816**	**40,179,555**	**45,038,371**
Net book value			
At 31 December 2011	**4,858,816**	**40,179,555**	**45,038,371**
At 31 December 2010	–	40,368,922	40,368,922

Details of the Company's holding in direct and indirect subsidiaries at 31 December 2011 are as follows:

Name of subsidiary	Registered office	Proportion of ownership interest	Proportion of voting power held	Principal activity
WorldAce Investments Limited	3 Themistocles Street, Nicosia, Cyprus	100%	100%	Holding company
LLC Stimul-T	147 Prospekt Lenina, Tomsk 634009, Russia	100%	100%	Oil and Gas exploration
LLC Pervomayka	Pobedy, Kolpashevo, Tomsk 634460, Russia	100%	100%	Property holding
Granite Construction	147 Prospekt Lenina, Tomsk 634009, Russia	100%	100%	Construction
Dolomite	147 Prospekt Lenina, Tomsk 634009, Russia	100%	100%	Oil and Gas exploration

As at 31 December 2010 PetroNeft Resources Plc had a 100% interest in Russian BD Holdings B.V. and a 100% interest in Lineynoye, both being subsidiaries of PetroNeft Resources Plc. During the year following the completion of the joint venture agreement with Arawak Energy the Group's interest in Russian BD Holdings B.V. reduced to 50% and this company became the 100% owner of Lineynoye. Arawak Energy now owns the other 50% of Russian BD Holdings B.V.

Name of entity	Registered office	Proportion of ownership interest	Proportion of voting power held	Principal activity
Russian BD Holdings B.V.	Prins Bernhardplein 200, 1097 JB Amsterdam, the Netherlands	50%	50%	Holding company
LLC Lineynoye	147 Prospekt Lenina, Tomsk 634009, Russia	50%	50%	Oil and Gas exploration

18. Inventories

	2011 US$	2010 US$
Oil stock	**1,619,333**	709,890
Materials	**237,480**	198,057
	1,856,813	907,947

19. Trade and Other Receivables

	2011 US$	2010 US$
Russian VAT	**1,802,450**	3,251,701
Other receivables	**77,860**	691,674
Receivables from jointly controlled entity (Note 28)	**520,921**	–
Advances to and receivables from related parties (Note 28)	**47,397**	1,957,647
Advances to contractors	**152,171**	1,925,637
Prepayments	**209,660**	238,319
	2,810,459	8,064,978

Company	2011 US$	2010 US$
Amounts owed by subsidiary undertakings	**110,023,692**	74,813,378
Amounts owed by other related companies	**288,976**	–
Prepayments	**209,660**	238,555
	110,522,328	75,051,933

The Directors consider that the carrying amount of trade and other receivables approximates their fair value.

Other receivables are non-interest bearing and are normally settled on 60-day terms.

Amounts owed by subsidiary undertakings are interest-bearing. Interest is charged at rates ranging from 0% to 10%.

Notes to the Financial Statements (continued)
For the Year Ended 31 December 2011

20. Cash and Cash Equivalents and Restricted Cash

Group	2011 US$	2010 US$
Cash at bank and in hand	**1,030,005**	22,781,881
Restricted cash	**5,000,000**	2,500,000
	6,030,005	25,281,881

Company	2011 US$	2010 US$
Cash at bank and in hand	**950,825**	21,001,248
Restricted cash	**5,000,000**	2,500,000
	5,950,825	23,501,248

At 31 December 2011 restricted cash amounting to US$5 million is being held in a Macquarie Debt Service Reserve Account ('DSRA'). This account is part of the security package held by Macquarie and may be offset against the loan in the event of a default on the loan or by agreement between the parties.

Bank deposits earn interest at floating rates based on daily deposit rates. Short-term deposits are made for varying periods of between one day and one month depending on the immediate cash requirements of the Group, and earn interest at the respective short-term deposit rates.

21. Trade and Other Payables

	2011 US$	2010 US$
Trade payables	**7,383,976**	3,858,187
Trade payables to related parties (Note 28)	**4,548,673**	614,078
Corporation tax	**7,827**	105,569
Other taxes and social welfare costs	**117,177**	176,804
Other payables	**160,237**	128,099
Accruals	**720,703**	518,742
	12,938,593	5,401,479

Company	2011 US$	2010 US$
Trade payables	**210,688**	224,218
Corporation tax	**7,827**	105,569
Other taxes and social welfare costs	**66,396**	112,398
Accruals	**414,055**	297,915
	698,966	740,100

The Directors consider that the carrying amount of trade and other payables approximates their fair value.

Trade and other payables are non-interest bearing and are normally settled on 60-day terms.

Trade payables and accruals principally comprise amounts outstanding for trade purchases and ongoing costs.

22. Loans and Borrowings

	Effective interest rate %	Maturity	2011 US$	2010 US$
Interest bearing				
Macquarie Bank – US$30,000,000 loan facility	17.21%	30 November 2011	**–**	13,725,205
Macquarie Bank – US$75,000,000 loan facility	9.51%	31 May 2014	**29,628,011**	–
Arawak – US$5,000,000 loan facility	9.11%	31 May 2012	**4,976,547**	–
			34,604,558	13,725,205
Contractual undiscounted liability			**35,000,000**	14,212,000

Macquarie Loan Facility

On 28 May 2010 the Group agreed a loan facility agreement for up to US$30 million with Macquarie to re-finance an existing facility of US$5 million. In April 2011, PetroNeft signed a revised borrowing base loan facility agreement with Macquarie for up to US$75 million. The initial borrowing base was set at US$30 million and remains at this level.

Under the various loan agreements Macquarie was granted 6.7 million warrants at various strike prices and with various expiry dates as detailed in Note 29. There was also a 1% cash arrangement fee associated with the new loan facility in 2011.

On the basis that Macquarie committed significant technical, engineering and legal resources to negotiating and agreeing the loan facility and subsequent draw downs, the warrants granted to Macquarie were in lieu of arrangement fees. The costs of the warrants fall within the scope of IFRS 2 Share-based Payment. This share-based payment expense constitutes a transaction cost under IAS 39 Financial Instruments: Recognition and Measurement and is included in the initial carrying amount of the loan facility and amortised over the duration of the loan. The total share-based payment expense in connection with warrants granted to Macquarie during the year amounted to US$0.1 million (2010: US$0.8 million) of which an amount of US$350,536 was expensed to the income statement in 2010 upon extinguishment of the existing loan facility.

Total transaction costs, including share-based payment expense connected with the warrants granted, incurred in 2011 amounted to US$0.6 million (2010: US$1.0 million) and are applied against the proceeds. The effective interest rate will be applied to the liability to accrete the transaction costs over the period of the loan.

Borrowing costs relating to drilling of development wells and construction of other oil and gas properties of US$745,000 were capitalised within oil and gas properties during 2010. Only borrowing costs incurred up to September 2010 (start of production) were capitalised.

Certain oil and gas properties (wells, central processing facility, pipeline) together with shares in WorldAce Investments Ltd, shares in Stimul-T, certain bank accounts and inventories are pledged as a security for the Macquarie loan facility agreement.

During the year the Group was in breach of certain financial and non-financial covenants and conditions subject to the loan agreement, relating primarily to receipt of certain amount of cash by sale of oil, certain financial ratios and registration of pledge over certain assets of the Group in favour of Macquarie and submitting the documents. These conditions were waived by Macquarie in a letter prior to the year-end, such that the Group was not in breach as at the year-end. However as the waiver did not extend to more than 12 months after the year-end, all of the Macquarie debt is classified as repayable within one year.

Arawak Energy Russia B.V. Loan Facility

The US$5 million loan from Arawak Energy Russia B.V. was a general purpose short-term bridge loan in advance of a larger three year-term loan completed in May 2012. It is repayable on 31 May 2012 out of the proceeds of the three-year loan. Total transaction costs, incurred in 2011 amounted to US$33,535 and are applied against the proceeds. The initial short term bridge loan was unsecured but the new three year term loan signed in May 2012 is secured on PetroNeft's 50% interest in Russian BD Holdings B.V.

23. Provisions

Decommissioning Costs – Non-current

	2011 US$	2010 US$
At 1 January	**743,670**	269,654
Arising during the year	**419,075**	457,219
Unwinding of discount	**62,099**	20,787
Translation adjustment	**(76,856)**	(3,990)
At 31 December	**1,147,988**	743,670

The decommissioning provision represents the present value of decommissioning costs relating to the Group's Russian oil interests, which are expected to be incurred near 2030. These provisions have been created based on the Group's internal estimates. Assumptions, based on the current economic environment, have been made which management believe are a reasonable basis upon which to estimate the future liability. A discount rate of 8.0% (2010: 8.2%) is used for the assessment of the provision. The charge relating to the unwinding of the discount on the provision is reflected in finance costs in the Consolidated Income Statement.

These estimates are reviewed regularly to take into account any material changes to the assumptions. However, actual decommissioning costs will ultimately depend upon future market prices for the necessary decommissioning works required, which will reflect market conditions at the relevant time. Furthermore, the timing of decommissioning is likely to depend on when the fields cease to produce at economically viable rates. This in turn will depend upon future oil prices, which are inherently uncertain.

Notes to the Financial Statements (continued)
For the Year Ended 31 December 2011

24. Share Capital – Group and Company

	2011 €	2010 €
Authorised		
800,000,000 (2010: 600,000,000) Ordinary Shares of €0.01 each	**8,000,000**	6,000,000
	8,000,000	6,000,000

An increase in the authorised share capital from 600,000,000 shares to 800,000,000 shares was approved by the shareholders at the Annual General Meeting held on 22 June 2011.

Allotted, called up and fully paid equity	Number of Ordinary Shares	Called up share capital US$
At 1 January 2010	350,367,711	4,724,013
Issued in the year	63,125,000	872,841
Remuneration and other emoluments paid in shares	42,721	580
Share options exercised in the year	1,997,000	27,406
At 1 January 2011	**415,532,432**	**5,624,840**
Share options exercised in the year	**824,000**	**11,302**
At 31 December 2011	**416,356,432**	**5,636,142**

25. Financial Risk Management Objectives and Policies

The Group and Company's principal financial instruments comprise cash and cash equivalents. The main purpose of these financial instruments is to provide finance for the Group and Company's operations. The Group has various other financial assets and liabilities such as receivables and trade payables, which arise directly from its operations.

The Group also enters into derivative transactions, primarily forward currency contracts. The purpose is to manage the currency risks arising from the Group and Company's operations and its sources of finance. The Group and Company entered into forward currency contracts during the year, however there are no contracts outstanding as at 31 December 2011 and 2010.

It is the Group and Company's policy that no trading in derivatives be undertaken.

The main risks arising from the Group and Company's financial instruments are commodity price risk, foreign currency risk, credit risk, liquidity risk, interest rate risk and capital risk. The Board reviews and agrees policies for managing each of these risks which are summarised below.

Commodity Price Risk

The Group is exposed to the risk of fluctuations in prevailing market commodity prices on the oil it produces. To date the Group has sold all of its oil on the domestic market in Russia. There are no banks providing hedging or derivative type contracts for oil sold on the domestic market so it is not possible to mitigate risks in this way. The high taxes on oil produced in Russia are based on prevailing international oil prices and therefore operate as a natural hedge to a fall in oil prices. A 10% reduction in the international oil price (assuming the original price was US$100 per barrel and it fell to US$90 per barrel) would result in approximately US$1.64 per barrel reduction in profits after tax.

Foreign Currency Risk

The Group and the Company undertake certain transactions denominated in foreign currencies. Hence, exposures to exchange rate fluctuations arise. Exchange rate exposures are managed within approved policy parameters utilising forward exchange contracts where appropriate.

At 31 December 2011 and 2010, the Group and the Company had no outstanding forward exchange contracts.

Foreign Currency Sensitivity Analysis

The Group's and the Company's principal currency exposures arise in the currencies of Russian Rouble, Euro, UK Sterling and US Dollar. The Group has an exposure to US Dollars because the functional currency of its Russian subsidiaries is Russian roubles. A change in the US Dollar: Russian Rouble exchange rate will therefore result in a foreign exchange gain or loss on the US Dollar denominated balances in these subsidiaries. The Company has an exposure to US Dollars because payments to some suppliers are effected in Euro and in UK Sterling, and the Company has bank accounts in Russian Rouble, Euro, UK Sterling and US Dollar.

In accordance with IFRS 7, the impact of foreign currencies is determined based on the balances of financial assets and liabilities at 31 December 2011. The sensitivity analysis includes only outstanding foreign currency denominated monetary items and largely results from payables and receivables, and adjusts their translation at the year-end for a 5% change in foreign currency rates. A positive number below indicates a reduction in loss and increase in other equity where the US dollar strengthens 5% against the relevant currency. For a 5% weakening of the US dollar against the relevant currency, there would be an equal and opposite impact on the loss and other equity, and the balances following would be negative.

If the US Dollar had gained/lost 5% against all currencies significant to the Group and Company at 31 December, the impact on loss and Equity for the Group and the Company is shown below.

Group	2011 US$	2010 US$
Impact on loss [lower/(higher)]	**1,003**	28,886
Impact on net equity [lower/(higher)]	**4,962**	116,724

Company	2011 US$	2010 US$
Impact on loss and net equity [lower/(higher)]	**1,003**	27,693

Credit Risk

Credit risk refers to the risk that a counterparty will default on its contractual obligations resulting in financial loss to the Group.

The Group and Company's financial assets comprise receivables and cash and cash equivalents. The credit risk on cash and cash equivalents is limited because the counterparties are banks with high credit ratings assigned by international credit-rating agencies. The Group and Company's exposure to credit risk arise from default of its counterparty, with a maximum exposure equal to the carrying amount of cash and cash equivalents in its consolidated balance sheet. As the Group or the Company does not have any significant receivables outstanding from third parties, this risk is limited.

The Group and the Company do not have any significant credit risk exposure to any single counterparty or any group of counterparties having similar characteristics. The Group and the Company define counterparties as having similar characteristics if they are connected entities.

Liquidity Risk Management

Liquidity risk is the risk that the Group and the Company will not have sufficient funds to meet liabilities. Ultimate responsibility for liquidity risk management rests with the Board of Directors, which has built an appropriate liquidity risk management framework for the management of the Group and Company's short, medium and long-term funding and liquidity management requirements. The Group and the Company manage liquidity risk by continuously monitoring forecast and actual cash flows and matching the maturity profiles of financial assets and liabilities. Cash forecasts are regularly produced to identify the liquidity requirements of the Group and the Company. To date, the Group and the Company have relied on shareholder funding, loan facilities and normal trade credit to finance its operations. As at 31 December 2011, the Group and the Company have an outstanding loan facility with Macquarie bank and with Arawak Energy Russia B.V. (see Note 22). See also Note 2 for additional details on going concern.

The Macquarie loan facility is repayable in May 2014. The Arawak Energy Russia B.V. loan facility was repayable on 31 May 2012 and has been re-financed through a new US$15 million three year term loan facility in May 2012. The rest of Group's and Company's financial liabilities as at 31 December 2011 and 2010 are all payable on demand. The Group and the Company expect to meet its other obligations from operating cash flows and debt financing. During the year the Group was in breach of certain financial and non-financial covenants and conditions subsequent to Macquarie loan agreement, relating primarily to receipt of certain amount of cash by sale of oil, certain financial ratios and registration of pledge over certain assets of the Group in favour of Macquarie and submitting the documents.

The expected maturity of the Group and Company's financial assets (excluding prepayments) as at 31 December 2011 and 2010 was less than one month.

The Group and the Company further mitigate liquidity risk by maintaining an insurance programme to minimise exposure to insurable losses.

The Group and the Company had no derivative financial instruments as at 31 December 2011 and 2010.

Interest Rate Risk

The Group and Company's exposure to the risk of changes in market interest rates relates primarily to the Group and Company's borrowings which are tied to the LIBOR interest rate and their holdings of cash and short-term deposits which are on variable rates ranging from 0.3% to 0.75%.

The Macquarie loan facility has a minimum LIBOR rate of 2%, the Arawak loan has no minimum rate attached. The effect of a rise of 1% in the LIBOR interest rate (e.g. from 0.3% to 1.3%) payable on borrowings would be to increase Group loss before tax by US$3,333 and Company loss before tax by US$3,333.

It is the Group and Company's policy, as part of its disciplined management of the budgetary process, to place surplus funds on short-term deposit in order to maximise interest earned.

The effect of a 10% reduction in deposit interest rates (e.g. from 10% to 9%) obtainable on cash and short-term deposits would be to increase Group loss before tax by US$5,586 (2010: US$12,660) and Company loss before tax by US$625,428 (2010: US$340,583).

Notes to the Financial Statements (continued)
For the Year Ended 31 December 2011

25. Financial Risk Management Objectives and Policies (continued)

Capital Risk Management

The Group and the Company manage capital to ensure that entities in the Group will be able to continue as a going concern while maximising the return to stakeholders through the optimisation of the debt and equity balance. The Group and the Company manage its capital structure and makes adjustments to it in light of changes in economic conditions. To maintain or adjust its capital structure, the Group and the Company may issue new shares or raise debt. No changes were made in the objectives, policies or processes during the years ended 31 December 2011 and 2010. The capital structure of the Group and the Company consists of equity attributable to equity holders of the Parent, comprising issued capital, reserves and retained losses as disclosed in the Consolidated Statement of Changes in Equity.

Group	2011 US$	2010 US$
External borrowings	**34,604,558**	13,725,205
Less cash and cash equivalents	**(1,030,005)**	(22,781,881)
Net debt	**33,574,553**	(9,056,676)
Equity	**81,877,092**	99,978,163
Net debt ratio	**41%**	-9%

Company	2011 US$	2010 US$
External borrowings	**34,604,558**	13,725,205
Less cash and cash equivalents	**(950,825)**	(21,001,248)
Net debt	**33,653,733**	(7,276,043)
Equity	**123,059,887**	122,829,459
Net debt ratio	**27%**	-6%

Fair Values

The carrying amount of the Group and Company's financial assets and financial liabilities is a reasonable approximation of the fair value.

Hedging

At the year ended 31 December 2011 and 2010, the Group had no outstanding contracts designated as hedges.

26. Loss of Parent Undertaking

The Company is availing of the exemption set out in section 148(8) of the Companies Act 1963 and section 7(1) (A) of the Companies (Amendment) Act 1986 from presenting its individual Income Statement to the annual general meeting and from filing it with the Registrar of Companies. The amount of the loss dealt with in the Parent undertaking for the year was US$1,384,036 (2010: US$2,285,290).

27. Capital Commitments

27.1 Details of Capital Commitments at the Balance Sheet Date are as Follows:

	2011 US$	2010 US$
Contracted for but not provided in the financial statements	**20,060,525**	26,320,142
Including contracted with related parties*	**17,026,563**	22,714,974

* The contracts with related parties relate to contracts for drilling wells at the Arbuzovskoye oilfield. This contract is to drill up to 15 oil wells and one water source well, however, the Group may reduce the number of wells to be drilled with minimal penalty which would result in the value of the contract reducing proportionately.

27.2 Future Minimum Rentals Payable Under Non-cancellable Operating Leases at the Balance Sheet Date are as Follows:

Land and buildings	2011 US$	2010 US$
Within one year	**226,608**	70,771
After one year but not more than five years	**279,869**	102,535
More than five years	**716,286**	433,630
	1,222,763	606,936

28. Related Party Disclosures

Transactions between PetroNeft Resources plc and its subsidiaries, Stimul-T, Granite, Pervomayka, Dolomite, World Ace Investments have been eliminated on consolidation. Details of transactions between the Group and other related parties are disclosed below.

In 2009 Stimul-T entered into a contract with LLC Tomskburneftegaz ('TBNG') for the drilling of nine wells in Pad 1 of the Lineynoye oilfield. Under this contract TBNG assumed substantially all liabilities in relation to the health and safety, environmental and other risks associated with drilling operation. The total value of the contract was up to US$9.5 million. Payments of US$253,377 (2010: US$8,243,900) were made during 2011 in relation to this contract. As at 31 December 2011 the outstanding amount payable to TBNG under this contract is US$Nil (2010: US$77,309). Vakha Sobraliev, a Director of PetroNeft, is the principal of TBNG. The contract was complete at 31 December 2011.

In 2010 Stimul-T entered into several contracts with TBNG for the drilling of wells at the Lineynoye oilfield, Arbuzovskaya prospect and Kondrashevskoye oilfield. Under these contracts TBNG assumes substantially all liabilities in relation to the health and safety, environmental and other risks associated with drilling operation. The total value of these contracts is US$31.2 million. Payments of US$17,691,713 were made during 2011 (2010: US$3,531,546) in relation to these contracts. As at 31 December 2011 the outstanding amount payable to TBNG is US$4,363,261 (2010: US$455,587). No advance payments are shown as at 31 December 2011 (2010: US$1,943,729).

In 2011 Stimul-T entered into a contract with TBNG for the drilling of well #1 at the North Varyakhskoye prospect. This is a 'turnkey' contract. Under this contract TBNG assumes substantially all liabilities in relation to the health and safety, environmental and other risks associated with drilling operation. The total value of the contract is US$2.5 million. Payments of US$2,038,585 were made during 2011 (2010: US$Nil) in relation to this contract. As at 31 December 2011 the outstanding amount payable to TBNG is US$Nil (2010: US$Nil).

An amount of US$172,577 (2010: US$Nil) was paid to TBNG during 2011 for dismantlement of equipment at various locations within Licence 61. US$Nil (2010: US$Nil) is outstanding to TBNG at 31 December 2011.

An amount of US$73,883 (2010: US$145,607) was received from TBNG during 2011 in relation to shared use of helicopter services, where the service provider billed the entire amount to Stimul-T, and for the sale of materials and other minor transactions with TBNG. A balance of US$44,805 (2010: US$13,918) is outstanding from TBNG at 31 December 2011.

A total of US$185,412 (2010: US$81,182) is outstanding to other parties, related to Vakha Sobraliev, a Director of PetroNeft for repair works on wells and transportation services. An amount of US$2,592 (2010: US$Nil) is shown as advance payments. Payments of US$1,292,074 (2010: US$444,644) were made to these entities during the year.

The Group provided various goods and services to the jointly controlled entity Russian BD Holdings B.V. and its wholly-owned subsidiary LLC Lineynoye during 2011 amounting to US$2,165,377, and an amount of US$520,921 is outstanding from these entities at 31 December 2011.

The Group has an indirect 50% interest in Lineynoye which in turn is 100% owned by the jointly controlled entity Russian BD Holdings B.V.

In 2011 Lineynoye entered into a contract with TBNG for the drilling of well No. 3 of the Cheremshanskaya prospect and well No. 2a of the Ledovoye oilfield. This is a 'turnkey' contract. Under this contract TBNG assumes substantially all liabilities in relation to the health and safety, environmental and other risks associated with drilling operation. The total value of the contract is US$4.6 million. Payments of US$3,461,009 were made during 2011 (2010: US$Nil) in relation to this contract. As at 31 December 2011 the outstanding amount payable to TBNG is US$549,178 (2010: US$Nil).

The following transactions occurred between Lineynoye, Russian BD Holdings B.V. and the Company:

	Lineynoye US$	Russian BD Holdings B.V. US$
At 1 January 2010	1,186,113	–
Advanced during year	843,006	–
Interest accrued in year	116,569	–
At 31 December 2010	2,145,688	–
Advanced during year	**3,350,000**	**–**
Transactions during year	**–**	**521,639**
Interest accrued in year	**112,035**	**–**
Repaid during year	**(5,288,118)**	**(463,313)**
Translation adjustment	**(88,955)**	**–**
Balance 31 December 2011	**230,650**	**58,326**

Up to 9 September 2011 both of the above companies were 100% subsidiaries of PetroNeft, however the above numbers reflect all transactions in 2010 and 2011.

Financial Statements

Notes to the Financial Statements (continued)
For the Year Ended 31 December 2011

28. Related Party Disclosures (continued)

Remuneration of Key Management

Key management comprise the Directors of the Company, the Vice President of Business Development and Operations, the General Director and the Executive Director of the Russian subsidiary Stimul-T, along with both the Chief Geologist and Chief Engineer of Stimul-T.
Their remuneration during the year was as follows:

	2011 US$	2010 US$
Compensation of key management	**1,730,623**	1,755,774
Contributions to defined contribution pension plan	**40,677**	10,615
Share-based payment expense	**512,727**	264,099
	2,284,027	2,030,488

Transactions with Subsidiaries

The Company had the following transactions with its subsidiaries during the years ended 31 December 2011 and 2010:

	Stimul-T US$	Granite Construction US$	Dolomite US$	Pervomayka US$	WorldAce Investments US$
Loans					
At 1 January 2010	28,026,868	–	–	–	105,157
Advanced during the year	31,866,972	810,000	10,050,000	–	8,501,342
Technical and management services provided	232,828	–	–	–	–
Interest accrued in year	3,115,747	8,776	67,000	–	–
Repaid during year	–	–	(10,117,000)	–	–
At 31 December 2010	63,242,415	818,776	–	–	8,606,499
Advanced during the year	**25,450,000**	**500,000**	**–**	**–**	**7,304,909**
Technical and management services provided	**206,242**	**–**	**–**	**–**	**–**
Interest accrued in year	**5,907,541**	**129,207**	**–**	**–**	**–**
Repaid during year	**(1,250,000)**	**–**	**–**	**–**	**–**
Translation adjustment	**(882,905)**	**–**	**–**	**–**	**(8,992)**
At 31 December 2011	**92,673,293**	**1,447,983**	**–**	**–**	**15,902,416**
Capital contributions					
Capital contributions 2010	–	40,432	314	13,739	–
Capital contributions 2011	**–**	**130,000**	**–**	**–**	**–**

29. Share-based Payment

Share Options

The expense recognised for employee services during the year is US$1,108,446 (2010: US$460,500). The Group share-based payment plan is described below. There was no cancellation or modification to the plan during 2011 and 2010.

Under the Group share option plan, employees of the Group can receive conditional awards of share options depending on their performance, seniority and length of service. The options typically vest in tranches and are subject to the achievement of vesting conditions related to drilling, production and shareholder return. The maximum term for options is seven years. There are no cash settlement alternatives.

Movement in the Year

The fair value of the options is estimated at the grant date using an option pricing model considering the terms and conditions upon which the instruments were granted. The following table illustrates the number and weighted average exercise prices ('WAEP') of, and movements in, share options during the year.

	2011 Number	2011 WAEP	2010 Number	2010 WAEP
Outstanding as at 1 January	**16,860,000**	**€0.295/£0.44**	13,537,000	€0.297/£0.272
Granted during the year	**–**	**–**	5,390,000	£0.66
Forfeited during the year	**(540,000)**	**£0.4671**	(70,000)	£0.3261
Exercised during the year	**(824,000)**	**€0.295/£0.3375**	(1,997,000)	€0.3029/£0.3467
Outstanding at 31 December	**15,496,000**	**€0.295/£0.44**	16,860,000	€0.295/£0.44
Exercisable at 31 December	**7,231,000**	**€0.295/£0.3476**	7,158,200	€0.295/£0.342

The range of exercise prices for options outstanding at the year-end is £0.19 to £0.66 (2010: £0.19 to £0.66).

The weighted average remaining contractual life for the share options outstanding as at 31 December 2011 was four years (2010: five years).

No options were granted in 2011. The weighted average fair value of options granted during 2010 was £0.282.

The weighted average share price of exercised options at the date of exercise in 2011 was £0.65 (2010: £0.575).

The weighted average share price of forfeited options in 2011 was £0.4671 (2010: £0.3261).

As no options were issued in 2011, no valuation was carried out in 2011. The following table lists the inputs to the model used for the year ended 31 December 2010:

Grant date	2010 December share price growth-based	2010 December TSR-based
Dividend yield	0%	0%
Expected volatility	70%	70%
Risk-free interest rate	1.6%	1.6%
Expected life of option	7	7
Expected early exercise %	100%	100%
Share price at date of grant and exercise price	£0.66	£0.66
Model used	Monte Carlo	Monte Carlo

The expected life of the options is based on the expectation of management and is not necessarily indicative of exercise patterns that may occur. The expected volatility was determined based on historical data of peer companies, taking into account the impact of financial crisis, which lead to extraordinary volatility, and also the fact that the Group has recently moved out of its early pure appraisal and development phase into a more stable production phase, which is likely to lead to reduction in volatility in the future. It reflects the assumption that historical volatility is indicative of future trends, which may also not necessarily be the actual outcome. The fair value is measured at the grant date.

Share-based Payment – Macquarie Loans

Movement in the Year

The fair value of the warrants is estimated at the grant date using an option pricing model considering the terms and conditions upon which the instruments were granted. The following table illustrates the number and weighted average exercise prices (‘WAEP’) of, and movements in, warrants during the year.

	2011 Number	2011 WAEP	2010 Number	2010 WAEP
Outstanding as at 1 January	**6,200,000**	**£0.33**	–	–
Granted during the year	**500,000**	**£0.42**	6,200,000	£0.33
Outstanding at 31 December	**6,700,000**	**£0.34**	6,200,000	£0.33
Exercisable at 31 December	**6,700,000**	**£0.34**	6,200,000	£0.33

The range of exercise prices for warrants outstanding at the year-end is £0.30 to £0.50 (2010: £0.30 to £0.50).

The weighted average remaining contractual life for the warrants outstanding as at 31 December 2011 was 0.91 years (2010: 1.71 years).

The weighted average fair value of warrants granted during the year was £0.18 (2010: £0.09).

The following table lists the inputs to the models used for valuing the warrants and the calculated value:

	July 2011	2010
Dividend yield	**0%**	0%
Expected volatility	**80%**	70%
Risk-free interest rate	**1.7%**	1.3%/2%
Expected life of warrant	**4**	1.9/4
Expected early exercise	**Financially optimal**	Financially optimal
Share price at date of grant	**£0.33**	£0.31/£0.47
Exercise price	**£0.418**	£0.3000/£0.5012
Model used	**Binomial**	Binomial
Total fair value of warrant	**US$145,475**	US$812,000

The expected life of the warrants is based on the expectation of management and is not necessarily indicative of exercise patterns that may occur. The expected volatility was determined based on historical data of peer companies, taking into account the impact of financial crisis, which lead to extraordinary volatility, and also the fact that the Group has recently moved out of its early pure appraisal and development phase into a more stable production phase, which is likely to lead to reduction in volatility in the future. It reflects the assumption that historical volatility is indicative of future trends, which may also not necessarily be the actual outcome. The fair value is measured at the grant date.

Notes to the Financial Statements (continued)
For the Year Ended 31 December 2011

30. Important Events after the Balance Sheet Date

In May 2012 PetroNeft signed a new three year loan facility agreement with Arawak for US$15 million. This loan carries an interest rate of LIBOR plus 6%. 4,000,000 warrants were granted to Arawak as part of this loan facility. Also in May 2012 PetroNeft entered into a new three year Area of Mutual Interest ('AMI') agreement with Arawak on similar terms to the previous AMI which expired in August 2011.

31. Approval of Financial Statements

The financial statements were approved, and authorised for issue, by the Board of Directors on 25 June 2012.

Notice of Annual General Meeting

Notice is hereby given that the Annual General Meeting of PetroNeft Resources plc will be held at the Herbert Park Hotel, Ballsbridge, Dublin 4 at 11.00 am on Wednesday 19 September 2012, for the purposes of considering and, if thought fit, passing, the following Resolutions, of which Resolutions numbered 1, 2, 3, 4 and 5 will be proposed as Ordinary Resolutions and Resolutions numbered 6 will be proposed as a Special Resolution.

Ordinary Business

1. To receive, consider and adopt the accounts for the year ended 31 December 2011 together with the Directors' and Auditors' Reports thereon.

2. To re-elect Mr. Hickey as a Director, who retires by rotation in accordance with Article 83 of the Articles of Association of the Company.

3. To re-elect Mr. Sobraliev as a Director, who retires by rotation in accordance with Article 83 of the Articles of Association of the Company.

4. To re-appoint Ernst & Young, Chartered Accountants, as Auditors and to authorise the Directors to fix the remuneration of the Auditors.

Special Business

5. That, in substitution for all existing authorities of the Directors pursuant to Section 20 of the Companies (Amendment) Act, 1983, the Directors be and are hereby generally and unconditionally authorised pursuant to Section 20 of the Companies (Amendment) Act, 1983 to exercise all the powers of the Company to allot relevant securities (within the meaning of the said Section 20) up to a maximum amount equal to the aggregate nominal value of the authorised but unissued share capital of the Company as at the date of passing of this Resolution. The authority hereby conferred shall expire (unless previously renewed, varied or revoked by the Company in general meeting) on the earlier of the date of the next annual general meeting of the Company held after the date of passing of this Resolution, and the close of business on 19 December 2013, save that the Company may before such expiry make an offer or agreement which would or might require relevant securities to be allotted after such expiry and the Directors may allot relevant securities in pursuance of such offer or agreement notwithstanding that the authority hereby conferred has expired.

6. That the Directors be and are hereby empowered pursuant to Sections 23 and 24 (1) of the Companies (Amendment) Act, 1983 to allot equity securities (within the meaning of the said Section 23) for cash pursuant to the authority conferred by Resolution numbered 7 above as if the said Section 23 does not apply to any such allotment provided that this power shall be limited to the allotment of equity securities;

   a) in connection with the exercise of any options or warrants to subscribe granted by the Company;

   b) (including, without limitation, any shares purchased by the Company pursuant to the provisions of the Companies Act 1990 and held as treasury shares) in connection with any offer of securities, open for a period fixed by the Directors, by way of rights, open offer or otherwise in favour of shareholders holding Ordinary Shares and/or any persons having a right to subscribe for, or convert securities into, ordinary shares in the capital of the Company (including, without limitation, any person entitled to options under any of the Company's share option schemes or any other person entitled to participate in any of the Company's profit sharing schemes for the time being) and subject to such exclusions or other arrangements as the Directors may deem necessary or expedient in relation to legal or practical problems under the laws or the requirements of any recognised body or stock exchange in any territory; and

   c) up to an aggregate nominal value equal to the nominal value of 10% of the issued share capital of the Company from time to time:

   each of (a), (b) and (c) above being separate powers, which powers shall expire on the earlier of the date of the next annual general meeting of the Company held after the date of passing of this Resolution and the close of business on 19 December 2013, save that the Company may before such expiry make an offer or agreement which would or might require equity securities to be allotted after such expiry and the Directors may allot equity securities in pursuance of such offer or agreement as if the power conferred hereby had not expired.

Dated this 25th day of June 2012

By order of the Board

David Sanders
Company Secretary

Registered Office:
20 Holles Street
Dublin 2

Glossary

1P	Proved reserves according to SPE standards.
2P	Proved and probable reserves according to SPE standards.
3P	Proved, probable and possible reserves according to SPE standards.
AGM	Annual General Meeting.
AIM	Alternative Investment Market of the London Stock Exchange.
AMI	Area of Mutual Interest.
API Gravity	A specific gravity scale developed by the American Petroleum Institute ('API') for measuring the relative density of various petroleum liquids, expressed in degrees.
Arawak	Arawak Energy Russia B.V.
bbl	Barrel.
bfpd	Barrels of fluid per day.
boe	Barrel of oil equivalent.
bopd	Barrels of oil per day.
C1	Proved resources according to Russian standards.
C2	Probable resources according to Russian standards.
C3	Possible resources according to Russian standards.
Company	PetroNeft Resources plc.
CSR	Corporate and Social Responsibility.
Custody Transfer Point	Facility/location at which custody of oil transfers to another operator.
DST	Drill stem test.
ESM	Enterprise Securities Market of the Irish Stock Exchange.
ESPO pipeline	East Siberia-Pacific Ocean pipeline which is expected to be completed in 2012.
Exploration resources	An undrilled prospect in an area of known hydrocarbons with unequivocal four-way dip closure at the reservoir horizon.
Hydraulic fracturing, fracture stimulation	The process of cracking open the rock formation around a well bore to increase productivity.
Group	Company and its subsidiary undertakings.
HSE	Health, Safety and Environment.
IAS	International Accounting Standard.
IFRIC	IFRS Interpretations Committee.
IFRS	International Financial Reporting Standard.
km	Kilometres.
km^2/sq km	Square kilometres.
KPI	Key Performance Indicator.
Licence 61	The Group's Exploration and Production Licence in the Tomsk Oblast, Russia. It contains seven known oil fields, Lineynoye, Tungolskoye, West Lineynoye, Arbuzovskoye, Kondrashevskoye, Sibkrayevskoye and North Varyakhskoye and 27 Prospects and Leads that are currently being explored.
Licence 67	The Group's Exploration and Production Licence in the Tomsk Oblast, Russia. It contains two existing drilled structures, Ledovoye and Sklonavaya, that have previously tested oil.
Lineynoye	Limited Liability Company Lineynoye, a wholly owned subsidiary of Russian BD Holdings B.V., registered in the Russian Federation.
Macquarie	Macquarie Bank Limited.
m	Metres.
mmbbls	Million barrels.
mmbo	Million barrels of oil.
Oil pay	A formation containing producible hydrocarbons.
P1	Proved reserves according to SPE standards.
P2	Probable reserves according to SPE standards.
P3	Possible reserves according to SPE standards.
Pervomayka	Limited Liability Company Pervomayka, a wholly owned subsidiary of PetroNeft, registered in the Russian Federation.
PetroNeft	PetroNeft Resources plc.
Russian BD Holdings B.V.	Russian BD Holdings B.V., a company owned 50% by PetroNeft and registered in the Netherlands.
SPE	Society of Petroleum Engineers.
Spud	To commence drilling a well.
Stimul-T	Limited Liability Company Stimul-T, a wholly owned subsidiary of PetroNeft, based in the Russian Federation.
TSR	Total Shareholder Return.
VAT	Value Added Tax.
WAEP	Weighted Average Exercise Price.

Group Information

Directors

David Golder (U.S. citizen)
(Non-Executive Chairman)

Dennis Francis (U.S. citizen)
(Chief Executive Officer)

Paul Dowling
(Chief Financial Officer)

David Sanders (U.S. citizen)
(General Legal Counsel)

Gerard Fagan
(Non-Executive Director)

Thomas Hickey
(Non-Executive Director)

Vakha Sobraliev (Russian citizen)
(Non-Executive Director)

Registered Office and Business Address

20 Holles Street
Dublin 2
Ireland

Secretary

David Sanders

Auditor

Ernst & Young
Chartered Accountants
Harcourt Centre
Harcourt Street
Dublin 2
Ireland

Nominated and ESM Adviser

Davy
49 Dawson Street
Dublin 2
Ireland

Joint Brokers

Davy
49 Dawson Street
Dublin 2
Ireland

Canaccord Genuity
88 Wood Street
London
EC2V 7QR
United Kingdom

Principal Bankers

Macquarie Bank Limited
Citypoint
1 Ropemaker Street
London
EC2Y 9HD
United Kingdom

AIB Bank
1 Lower Baggot Street
Dublin 2
Ireland

KBC Bank Ireland
Sandwith Street
Dublin 2
Ireland

Solicitors

Eversheds
One Earlsfort Centre
Earlsfort Terrace
Dublin 2
Ireland

White & Case
5 Old Broad Street
London
EC2N 1DW
United Kingdom

4 Romanov Pereulok
125009
Moscow
Russia

Registered Number

408101

Registrar

Computershare
Heron House
Corrig Road
Sandyford Industrial Estate
Dublin 18
Ireland

FSC www.fsc.org
MIX
Paper from responsible sources
FSC® C023105

Designed and produced by **Emperor Design Consultants Ltd**
Tel **+44 (0)131 220 7990 www.emperordesign.co.uk**

PetroNeft Resources plc

Dublin Office
20 Holles Street
Dublin 2
Ireland

Houston Office
Suite 518, 10333 Harwin Drive
Houston, TX 77036
USA